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Your reference
Project No. 159898

Our reference
1000385944

Sent By E-mail

British Columbia Utilities Commission
6th Floor - 900 Howe Street
Vancouver, BC V6Z 2V3

Attention: Patrick Wruck, Commission Secretary

Dear Mr. Wruck:

Kinder Morgan (Jet Fuel) Inc. ("PKMJF") 2019 Tariff Filing – Vancouver Airport Fuel Facilities Corporation ("VAFFC") – Public (Redacted) Responses to PKMJF IR No. 1

We are counsel for VAFFC in this matter and write to enclose a public (redacted) version of VAFFC's responses to PKMJF Information Request No. 1.

If you have any questions, please contact the writer.

Yours very truly,

for Matthew D. Keen
Partner

MDK/roe

CAN_DMS: \138276439\1

Vancouver Airport Fuel Facilities Corporation (VAFFC) Response to PKM Canada (Jet Fuel) Inc. (PKMJF) Information Request No. 1

1.0 VAFFC Forecasted Volumes and the VAFD Project

Reference (i): Exhibit C2-36-1 (Vancouver Airport Fuel Facilities Corporation ["VAFFC"] – Intervener Evidence and Confidentiality Request [“VAFFC Evidence”]), PDF p. 6

On PDF p. 6 of the VAFFC Evidence at paras 10-11 and 13, VAFFC states:

> VAFFC is a not-for-profit consortium of commercial airlines representing 34 of the domestic and international carriers serving YVR.
>
> VAFFC owns and operates the fuel facility system servicing YVR’s main domestic and international terminals and thereby provides fuel delivery service to all airlines using those terminals. Non-member airlines receive fuel delivery service from VAFFC on a fee-for-service basis. Each member airline purchases fuel for its own use and arranges delivery to the VAFFC fuel facilities at YVR, either through the Jet Fuel Line or via tanker trucks. VAFFC manages the storage and handling of each airline’s fuel and ensures its delivery to the airlines’ respective aircraft.
>
> …
>
> Prior to the onset of the COVID-19 pandemic, the Jet Fuel Line was able to supply up to about 80% of YVR’s fuel needs, with the remainder supplied by tanker trucks. This ratio fluctuates on a daily and seasonal basis depending on actual demand for fuel at YVR (i.e., the percentage of fuel delivered by tanker trucks increases during periods of peak demand). The existing fuel delivery system needed to be supplemented by approximately 70 fuel tanker truck deliveries per day (2,000 per month) before the COVID-19 pandemic, which were required to meet the airport’s peak fuel demand.

1.1 Does VAFFC[1] expect the Vancouver Airport Fuel Delivery (VAFD) Project to deliver 100% of jet fuel consumed at Vancouver International Airport (YVR) after the VAFD Project begins operations?

[1] Please note that for all of these information requests, references to VAFFC includes VAFFC and/or its members (*i.e.*, the commercial airlines representing 34 of the domestic and international carriers serving YVR).

Response:

No.

1.1.1 If yes, why?

Response:

Please see VAFFC's response to PKMJF IR 1.1.

1.1.2 If not, why not? Please fully explain your response.

Response:

VAFFC expects that, after the VAFD Project begins operations, some fuel will continue to be delivered to YVR by means other than the VAFD Project, including by truck and by the Jet Fuel Line. While VAFFC members will have a financial incentive to use VAFD infrastructure, other delivery methods may conceivably be more economic at times, depending on the member, fuel supplier, volume, mode of transportation, and market conditions.

1.2 Please describe all current sources of jet fuel supply for end users at YVR that VAFFC is aware of, including relative proportions that VAFFC is aware of, whether specifically or generally.

Response:

Current sources of jet fuel for end users at YVR include the Parkland refinery, marine imports from the Westridge marine terminal and truck deliveries from BP's Cherry Point refinery. In very general terms, the Parkland refinery supplies approximately 20% of the jet fuel used by end users at YVR, the Westridge marine terminal supplies approximately 40%, and the BP Cherry Point refinery supplies approximately 40%.

1.2.1 Please provide all information VAFFC has regarding past (since 2007), present and forecast jet fuel demand at YVR airport (*i.e.*, all jet fuel demand, not just from the PKMJF Jet Fuel Line (JFL)).

Response:

The following are the historical volumes of jet fuel demand at YVR, from 2007 to 2020, in litres:

2007: 1,337,996,561 L
2008: 1,358,799,613 L

2009: 1,224,268,768 L
2010: 1,264,696,094 L
2011: 1,299,846,462 L
2012: 1,315,843,214 L
2013: 1,330,677,019 L
2014: 1,421,066,397 L
2015: 1,486,798,339 L
2016: 1,646,409,307 L
2017: 1,816,776,879 L
2018: 1,896,125,400 L
2019: 1,871,868,022 L
2020: 760,122,443 L

The following are forecast volumes for jet fuel demand at YVR from 2021 to 2025, in litres. However, VAFFC notes that these forecasts are subject to a high degree of uncertainty due to the effects of the ongoing COVID-19 pandemic:

2021: 733,000,000 L
2022: 1,400,000,000 L
2023: 1,900,000,000 L
2024: 1,920,000,000 L
2025: 1,940,000,000 L

1.2.2 Please provide any data or information VAFFC has about the potential suppliers that will deliver jet fuel to the VAFD Project.

Response:

The member airlines of the VAFFC consortium procure jet fuel on an individual basis. The VAFD Project will permit the airlines to procure fuel from any global supplier and have it delivered to the new facility. At this time, VAFFC has not been made aware of any confirmed supplier arrangements.

1.2.3 Please describe and quantify how current and go-forward fuel demand estimates have been impacted by the COVID-19 pandemic, including the impact of travel restrictions. Please provide fuel demand estimates through to the anticipated date for commencement of service of the VAFD Project and for the following 5 years, as well as all information and assumptions this forecast is based on.

Response:

The COVID-19 pandemic has resulted in a significant reduction in jet fuel demand at YVR, due mainly to the overall reluctance by the public to travel during a pandemic, as well as the numerous travel restrictions imposed by the federal government. The reductions in volume since the start of the pandemic, as well as the 5-year forecast, are shown in VAFFC's response to PKMJF IR 1.2.1 above.

The 5-year forecast is highly variable and is subject to the evolution of the COVID-19 pandemic, including factors such as the rollout and efficacy of vaccines, the timing of travel restriction easements, and overall public confidence in air travel. In general, it is assumed for now that jet fuel demand will gradually attain pre-COVID 2019 levels by the end of 2023, after which a modest growth of 1% per annum has been forecasted.

1.2.4 Please describe all transportation options for transporting jet fuel to YVR, including those options currently available and any future anticipated options.

Response:

Current transportation options for transporting jet fuel to YVR include tanker trucks and the Jet Fuel Line. Once the VAFD Project is in service, pipeline deliveries to YVR through the VAFD Project, originating from marine-based shipments of jet fuel, will also be possible.

1.3 Please provide copies of any communications with suppliers of jet fuel to the JFL, including VAFFC and Parkland, regarding future supply of jet fuel for throughput on the JFL, VAFD Project, and other transportation alternatives.

Response:

VAFFC does not possess any such communications, other than high level inquiries from suppliers on the overall logistics of the new VAFD Project. These were general inquiries which resulted in site visits by suppliers in order for them to gain an overall understanding of site logistics ahead of the start of operations.

Member airlines of the VAFFC consortium have regular communications with suppliers in order to forecast demand. Typically, airlines provide suppliers with a 1-3 month forecast of jet fuel demand, such that suppliers can plan deliveries using the modes of transportation to YVR available to them.

1.4 Please describe the commercial arrangements in place or contemplated for the construction, operation, and provision of transportation service for the VAFD Project.

Response:

This request is general, extremely broad, and appears largely irrelevant to the present proceeding. A more focussed request, confined to issues raised in this proceeding by the evidence filed by VAFFC/InterGroup or PKMJF, may identify issues within VAFD "commercial arrangements" that are relevant to the tolls applicable to the Jet Fuel Line for the test period. However, the commercial arrangements regarding the construction and operation of the VAFD Project are not prima facie relevant to determining these tolls.

Notwithstanding the fact that relevance has not been shown, VAFFC is able to provide the following overview to assist the Commission. With respect to the provision of transportation service, VAFFC will not require commercial transportation agreements. Rather, VAFFC anticipates that its members will continue to enter into arrangements to purchase jet fuel from jet fuel suppliers. VAFFC expects that ownership of the jet fuel will transfer to members once these suppliers deliver jet fuel to the Fraser River marine terminal of the VAFD Project. The jet fuel will then be transported on the VAFD pipeline to YVR for use by the relevant members.

VAFFC does not intend to operate the VAFD Project for the purpose of generating a profit. VAFFC members will share the cost of operating the VAFD project according to a cost-sharing formula.

1.5 Is it anticipated that the VAFD Project will provide transportation service to parties other than VAFFC (*e.g.*, Parkland)?

Response:

No. The VAFD Project will provide services to members. Members may take title before the VAFD Project transports fuel.

1.5.1 If so, please provide the names of the potential shippers, as well as any analysis, reports or agreements that discuss under what terms and at what cost service would be provided.

Response:

Not applicable. Please see VAFFC's response to PKMJF IR 1.5.

VAFFC has not performed any analysis, reports etc. and has not initiated any agreements.

1.6 Please provide any minimum or other shipping quantity requirements agreed to with shippers or potential shippers in relation to the VAFD Project, as well as copies of any associated contracts or commercial arrangements including term and volume commitments, tolls, and surcharges (including with respect to abandonment obligations), as well as any provisions for owner or third-party shipper revenue or profit sharing.

Response:

Not applicable.

VAFFC has not entered into any agreements regarding minimum or other shipping quantity requirements with shippers or potential shippers in relation to the VAFD Project. Please also see VAFFC's response to PKMJF IR 1.4 concerning the relevance of this request.

1.7 Please provide monthly forecast volumes for transportation on the VAFD Project starting the first month the VAFD Project begins operations and for the following 5 years, as well as all information and assumptions this forecast is based on.

Response:

VAFFC included details regarding forecast fuel consumption at YVR as part of its application for an Environmental Assessment Certificate (the "**EAC Application**").[2] However, VAFFC has not developed any subsequent forecast volumes for the VAFD Project. Further, any such forecasts would be highly speculative at this point in time from the ongoing uncertainty with respect to fuel requirements given the effects of the COVID-19 pandemic.

Please also see VAFFC's response to PKMJF IF 1.2.1 and 1.2.3 above.

1.8 Please confirm VAFFC's intention to ship on the JFL after the VAFD Project begins operations.

Response:

Confirmed (with respect to VAFFC's members). As VAFFC notes at paragraph 39 of its evidence, once the VAFD Project becomes operational, VAFFC "expects members will ship on the Jet Fuel Line opportunistically, when it makes economic

[2] See, for example, Figure 2.3.2 from the EAC Application, available online here.

sense to do so, taking into account different jet fuel source prices and overall transportation cost options".[3]

1.8.1 What forecast VAFFC annual volume will remain for transportation on the JFL or alternative means of transportation following full utilization of the VAFD Project?

Response:

Please see VAFFC's response to PKMJF IR 1.7 and 1.8. VAFFC has not developed the forecasts requested by PKMJF and could not do so now.

1.8.2 Please provide VAFFC monthly forecast volumes to be shipped on the JFL starting the first month the VAFD Project begins operations and for the following 5 years.

Response:

Please see VAFFC's response to PKMJF IR 1.7 and 1.8. VAFFC has not developed the forecasts requested by PKMJF and could not do so now.

1.8.3 Please describe whether VAFFC would be willing to execute a take-or-pay contract with PKMJF to use the JFL for the period up to the VAFD Project commencing operations, the terms of which would allow PKMJF to have the opportunity to recover its costs, earn a reasonable profit, and collect a reasonable surcharge for future abandonment costs?

Response:

Yes, VAFFC's members may be willing to enter into a take-or-pay contract with PKMJF to use a significant proportion of the capacity of the Jet Fuel Line before the VAFD Project commences operation, depending on the terms to which PKMJF would be willing to agree, and particularly on whether PKMJF would be willing to agree to a toll that makes economic sense to VAFFC member shippers.

VAFFC agrees that a take or pay contract should allow PKMJF the opportunity to recover its real costs (including a portion of estimated future abandonment costs) and earn a reasonable profit. Consistent with the findings of the NEB, VAFFC considers abandonment costs the responsibility of the carrier.[4] The risk the carrier bears concerning timely collection of abandonment costs is one of the reasons it should earn a

[3] Exhibit C2-36-2, pdf p. 11.

[4] Exhibit C2-36-2, pdf p. 16, para. 60.

reasonable return. However, VAFFC does not consider PKMJF's current evidence to adequately or fairly describe its real costs. VAFFC is also not willing to enter into a take-or-pay contract that transfers significant new risks to shippers.

1.8.4 Please describe whether VAFFC would be willing to execute a take-or-pay contract with PKMJF to use the JFL for the period after the VAFD Project commences operations, the terms of which would allow PKMJF to have the opportunity to recover its costs, earn a reasonable profit, and collect a reasonable surcharge for future abandonment costs?

Response:

Yes, VAFFC's members may be willing to enter into a take-or pay contract for a smaller proportion of the JFL's capacity after the VAFD Project begins operations. VAFFC agrees that whatever toll structure PKMJF assembles should provide an opportunity to achieve cost recovery (including a portion of estimated future abandonment costs) and a reasonable profit. VAFFC resists any suggestion that the toll design should guarantee that PKMJF achieves those objectives. Please also see VAFFC's response to PKMJF IR 1.8.3.

1.9 A VAFFC spokesperson was quoted in a 2017 news article (referred to in PKMJF's amended application at para. 26 on p. 15) as stating: "[t]he airlines are the end customer…They're financing this project; naturally they're going to use it. And the capacity on that existing [Jet Fuel System] will decline to such a point where it's not really economical to maintain it." Please confirm that this continues to be VAFFC's position.

Response:

Not confirmed. The VAFFC spokesperson's opinion was based on mistaken personal assumptions captured in a news article that did not represent VAFFC's position. Evidence of VAFFC's position can be found on the project website (http://www.vancouverairportfuel.ca/projectOverview), as well as on public documents issued since 2017.

1.9.1 If not, why not?

Response:

This was never VAFFC's position.

Please see also VAFFC's response to PKMJF IR 1.8 and 1.9.

Reference (ii): Exhibit C2-36-1 (VAFFC Evidence), PDF p. 11

On PDF p. 11 of the VAFFC Evidence, at para 39, VAFFC states:

> Once the VAFD Project becomes operational, VAFFC does not expect its members to cease all shipments of jet fuel on the Jet Fuel Line. Rather, VAFFC expects members will ship on the Jet Fuel Line opportunistically, when it makes economic sense to do so, taking into account different jet fuel source prices and overall transportation cost options.

PKMJF seeks to understand the considerations that went into the development of the VAFD Project, and whether and how VAFFC has evaluated the economic impact that the VAFD Project will have on the transportation of jet fuel to YVR.

1.10 Please discuss the analysis that led to the decision to pursue the VAFD Project.

Response:

As with PKMJF IR 1.4, this request is broad and prima facie not relevant to the issues raised by the evidence filed to date by PKMJF and VAFFC / InterGroup. Nevertheless, the analysis and supporting reports that led to VAFFC's decision to pursue the VAFD Project have been publicly available on the BC Environmental Assessment Office's project page for the VAFD Project for the past decade.[5] VAFFC has reviewed the project page for the VAFD Project and confirms that it provides a comprehensive and accessible review of the available documentation.

Notably included on the project page is a report prepared by Golder Associates and Ausenco-Sandwell in 2011. This report evaluates four fuel delivery options that were available to VAFFC, including upgrading and/or replacing the existing Jet Fuel Line owned by PKMJF and development of a new pipeline connecting a jet fuel offloading terminal on the Fraser River to YVR (the VAFD Project).[6] A copy of this report is attached to these responses as Appendix PKMJF 1.10

VAFFC decided to pursue the VAFD project because it was the best option in light of the criteria assessed by VAFFC (including socio-economic and environmental impacts), and because the VAFD project would provide VAFFC and its members with greater security of jet fuel supply. Further, as noted in the consultation tracking table referenced in BCUC IR 2.8, although VAFFC consulted with PKMJF during the early planning for the VAFD Project about options for the expansion of the Jet

[5] Available here: EPIC (gov.bc.ca).

[6] Available here, under the heading "Evaluation of Third Party Options Review": https://www.vancouverairportfuel.ca/get_the_facts.

Fuel Line, PKMJF expressed no interest in such expansion. This contributed to VAFFC's decision to proceed with the VAFD Project.

1.10.1 Please provide copies of all economic analysis and studies conducted by VAFFC or its consultants assessing a bypass of the JFL.

Response:

Please see VAFFC's response to PKMJF IR 1.10.

1.10.2 Please provide copies of all analysis and studies conducted by VAFFC or its consultants that considered the environmental impacts of the VAFD Project, including negative impacts from the proliferation of pipelines serving YVR.

Response:

Please see VAFFC's response to PKMJF IR 1.10.

VAFFC also notes that there would be benefits resulting from the existence of multiple pipelines for transporting jet fuel to YVR, including, notably, an increased security of jet fuel supply for the airport.

1.10.2.1 Please provide copies of all analysis and studies conducted by VAFFC or its consultants that considers this issue in the context of the VAFD Project.

Response:

Please see VAFFC's response to PKMJF IR 1.10.

1.10.3 Please confirm that, during the development, permitting and construction phases of the VAFD Project, VAFFC was aware that PKMJF had previously sought approval from the BCUC to collect funding for abandonment of the JFL and that the BCUC ruled the request to be premature in BCUC Order P-3-08.

Response:

Confirmed. However, VAFFC notes that it was already considering the development of the VAFD Project prior to PKMJF's 2007 application to the BCUC for abandonment funding. Indeed, it was largely <u>because</u> of

VAFFC's contemplation of potentially proceeding with the VAFD Project that PKMJF filed its 2007 application.[7]

1.10.4 Please confirm that VAFFC was aware that the 2009-2018 Negotiated Settlement terms did not include collection of abandonment funding.

Response:

Not confirmed. PKMJF's December 2, 2008 Shipper Meeting presentation dated December 3, 2008 stated that "Collection [of abandonment funds] is prudent at this time",[8] but PKMJF's December 2008 application for 2009 tolls cautioned that: "No provision for Abandonment is included in the Revenue Requirements".[9] The revenue requirement sought for 2009 was $3.973 million.[10] In contrast, PKMJF's 2009-2018 Negotiated Settlement terms made no mention of abandonment cost responsibility one way or the other.[11] And, the revenue requirement sought was $4.8 million for 2009 and $5.694 million for 2010,[12] with a 2.5% escalation per year thereafter. In VAFFC's view risk of funding abandonment costs remained with PKMJF during the settlement period, and PKMJF was compensated for that risk.

Please see also the following excerpt from InterGroup's evidence, which VAFFC has adopted:

> *It is not credible that a regime was implemented which targeted known and fixed, stable revenues for 10 years out of the remaining 13 year life of the pipeline, but failed to consider establishment of any abandonment fund. To so conclude would be to find that PKMJF deliberately accepted an omission of the chance to fund the future costs of abandonment during the last 10 of 13 years of the pipeline. Either PKMJF would have to have been supremely confident that it could, to be colloquial, assuredly wallop shippers for abandonment costs in the final 3 years, or PKMJF would have had to be intensely oblivious to this pending risk. Neither of these is credible. It is even less credible that this approach was purportedly implemented concurrent with a massive [redacted] in the net income taken by the pipeline operator, as reviewed above (a [redacted] from the*

[7] See, for example paras. 22-24 of VAFFC's evidence: Exhibit C2-36-2, pdf pp. 8-9.

[8] See VAFFC's response to BCUC IR 16.12.

[9] Exhibit C-36-2, pdf p. 149.

[10] Exhibit C-36-2, pdf p. 149.

[11] Exhibit B-11, Appendix BCUC-KMJF 7.2: Jet Fuel Line 2009 Settlement Application, pdf pp. 99-113.

[12] Exhibit B-11, Appendix BCUC-KMJF 7.2: Jet Fuel Line 2009 Settlement Application, pdf pp. 100 and 103.

> *traditional level of return on rate base of around $0.720 million to [redacted] within 12 months). For more likely, the settlement was acceptable to all parties, including PKMJF, because it was understood to provide PKMJF with sufficient funds to address abandonment consistent with a 13-year life adopted for depreciation (whether recorded as abandonment accruals, or as extraordinary net income knowingly offsetting future as-yet recorded shareholder costs for abandonment). Whatever the intent at the time of the settlement, PKMJF's current Application effectively seeks to impose and crystallize now the identical outcomes that such improbable and commercially unreasonable approaches would have targeted, which is inherently double-counting abandonment recoveries from customers.*[13]

1.11 Please provide estimated tolls, including any tolls to be attributed to capital cost recovery, and associated financial and economic analysis, for providing transportation service on the VAFD Project.

Response:

Please see VAFFC's responses to PKMJF IR 1.4 and 1.10.

1.11.1 Please confirm that VAFFC members and/or shippers on the VAFD Project will share in the revenue or profits generated from the VAFD Project.

Response:

Please see VAFFC's response to PKMJF IR 1.4. VAFFC members will bear the costs of the VAFD.Project.

1.11.1.1 If so, please provide the "net toll" that VAFD Project shippers will pay in $/bbl (*i.e.*, applicable tolls minus applicable revenues).

Response:

Not applicable.

Please see VAFFC's response to PKMJF IR 1.11.1.

[13] Exhibit C2-36-1, p. A-24, pdf p. 51.

1.11.1.2 If not, please explain why not.

Response:

Please see VAFFC's response to PKMJF IR 1.11.1.

1.11.1.3 Please provides copies of any agreements or communications with VAFFC members considering how, or if, revenue from the VAFD Project will be distributed amongst VAFFC membership.

Response:

Please see VAFFC's response to PKMJF IR 1.11.1.

1.11.1.4 Please provide copies of any analysis, reports, studies, or communications with VAFFC members, board of directors, and shareholders, as well as potential VAFD Project shippers, considering the tolling methodology that will apply to service on the VAFD Project.

Response:

Please see VAFFC's response to PKMJF IR 1.4.

No such VAFD toll methodologies or analyses or presentations exist and if they did, VAFFC would decline to file them because this request is overly broad, of questionable relevance, and unduly onerous.

1.11.2 Please describe whether and, if so, how, VAFFC is taking on volume risk as part of its tolling structure for the VAFD Project.

Response:

Please see VAFFC's response to PKMJF IR 1.4.

1.12 Please provide any analysis, reports, or other communications regarding costs associated with transportation alternatives, existing or prospective, to the JFL, including trucking and barging.

Response:

Please see VAFFC's response to PKMJF IR 1.10. VAFFC does not possess any further analysis, reports or other communications.

1.13 Has VAFFC done any analysis regarding toll levels that would be required for the JFL to be an economic option for VAFFC shippers after the VAFD Project becomes operational?

Response:

No.

1.13.1 If yes, please provide the analysis and indicate the assumptions provided including the volumes, direct costs and allocated costs included in the analysis. Please specify the toll level in $/bbl that PKMJF would need to charge in order for VAFFC to continue shipping on the JFL after the VAFD Project is in service.

Response:

Not applicable.

Please see VAFFC's response to PKMJF IR 1.13.

1.13.2 If no analysis has been done, please explain why not.

Response:

Please see VAFFC's response to PKMJF IR 1.1.2 and 1.8 and to Parkland IR 1.1 and 1.2.

1.14 Please provide copies of any reports, studies or other material communications relating to the economic viability or economic life of the JFL that were conducted in relation to the development of the VAFD Project, along with any working papers that may have been prepared with respect to that issue.

Response:

Please see VAFFC's response to PKMJF IR 1.10. VAFFC does not possess any further analysis, reports or other communications.

1.15 Please confirm whether VAFCC will seek to have the VAFD Project regulated by the BCUC as a common carrier. If not confirmed, please explain fully.

Response:

Not confirmed.

VAFFC does not plan to seek to have the VAFD Project regulated by the BCUC as a common carrier. VAFFC intends to operate the VAFD Project on a not-for-

profit basis for the purpose of providing jet fuel transportation services to its members.

Please see also VAFFC's response to PKMJF IR 1.4.

2.0 Construction of the VAFD Project

Reference: Exhibit C2-36-1 (VAFFC Evidence), PDF p. 11

On PDF p. 11 of the VAFFC Evidence, at paras 37-38, VAFFC states:

> The VAFD Project received its conditional EAC on December 11, 2013, and the EAO determined that the VAFD Project had been substantially started on September 18, 2018. PKMJF sought accelerated depreciation and abandonment costs on June 7, 2019.
>
> **(c) Status of VAFD Project and VAFFC plans for after the VAFD Project enters operation**
>
> VAFFC is continuing construction on the VAFD Project. There have been some delays, due to the COVID-19 pandemic and work sequencing changes, with the result that the project is now not anticipated to be fully operational until approximately early 2023.

PKMJF is seeking additional information regarding the current and anticipated progression of the construction of the VAFD Project.

2.1 Please provide the actual and anticipated VAFD Project timeline from the time VAFFC purchased the waterfront property where the marine terminal for the VAFD Project will be located to the anticipated date it commences operations, including but not limited to:

Response:

As with PKMJF IR 1.4 and 1.10, this request is very broad and appears largely irrelevant to the issues raised by the evidence filed to date by PKMJF and VAFFC / InterGroup. However, VAFFC has responded to each specific request below and provided details where not unduly onerous, to assist the Commission.

2.1.1 Studies or reports which contributed to the development of the Project Description filed with the Environmental Assessment Office on January 16, 2009.

Response:

Please refer to VAFFC's response to PKMJF IR 1.10. Pre-2009 reports (i.e. reports which are not available on the BC Environmental Assessment

Office's project page for the VAFD Project) are unduly onerous to locate and are not relevant to this proceeding.

2.1.2 Studies or reports which contributed to and were prepared as part of the environmental assessment process which resulted in the 2013 issuance of the Environmental Assessment Certificate.

Response:

Please refer to VAFFC's response to PKMJF IR 1.10. Pre-2009 reports (i.e. reports which are not available on the BC Environmental Assessment Office's project page for the VAFD Project) are unduly onerous to locate and are not relevant to this proceeding.

2.1.3 Financial investment decision or equivalent.

Response:

From nearly the inception of the project, VAFFC planned to issue project-specific debt. It took steps to do so in 2017. Two tranches of debt have been issued, in 2018 and 2020.

2.1.4 Construction commencement.

Response:

Please see VAFFC's response to PKMJF IR 2.1.5.

2.1.5 Construction milestones (*e.g.*, commencement of excavation, commencement of pipe installation)

Response:

Please see Table 2.1.5 below for a list of major construction milestones for the VAFD Project.

Table 2.1.5

	Start	Finish
Construction		
Tankfarm Ground Improvement	June 2017	June 2019
HCBI Tanks & Foundations	Jun-10-2019	Nov 2020
TF0 Early Earthworks, Unsuitable Soils and Peat Disposal	Sep-03-2019	May 2020
Civil Works (+Underground Services & Concrete Works)	Jul-02-2020	Apr 2022
Electrical Primary Power Supply (FRF/FUF)	Feb-16-2021	Aug 2021
Mechanical/Piping Works	Dec-11-2020	Aug 2022
Fire Protection	Sep-28-2020	Jun 2022
Electrical & Control Works	Jun-25-2021	Jun 2022
PLC Installation	Jun-03-2022	Jul 2022
Site Completion Civil and Surfaces	Sep-08-2021	Oct 2022
Tank Farm 2, General Contract	Nov-04-2021	Apr 2022
CUC Pipeline Open Cut	Jul-03-2020	Jan-2020
RBS Pipeline HDD	Dec-02-2019	July 2021
Fuel Unloading Facilities Marine Works	Nov-10-2019	Nov 2021
Construction Works Completed	**Oct 2022**	
Commissioning and Start-up Completed	**Jan 2023**	
Project Fully Operational	**Feb 2023**	

2.1.6 Permitting milestones; and

Response:

Please see Table 2.1.6 below for a list of major permitting milestones for the VAFD Project.

Table 2.1.6

Permitting Agency	Permit Description	Scope Covered	Application Submitted	Permit Received
BC Environmental Assessment Office (EAO) (Cosigned by the Vancouver Fraser Port Authority (VFPA))	Environmental Assessment Certificate (EAC)	Entire Project	January 4, 2011	December 11, 2013 (BC EAO issued substantial start notice September 18, 2018)
Port of Vancouver (PoV)	Project Permit (PP)	Fuel Receiving Facility (TF-0)	May 13, 2015	February 24, 2016
BC Oil & Gas Commission (BC OGC)	Development Permit	Pipeline (P/L) & Marine Terminal (MT)	September 20, 2016	April 3, 2017
BC Ministry of Transportation and Infrastructure (MOTI)	Utility Permit (UP)	Pipeline within MOTI ROW	October 3, 2014	February 11, 2020
City of Richmond (CoR)	Development Permit (DP)	Marine Terminal (MT)	July 24, 2015	July 24, 2019
	Servicing Agreement (SA)	Marine Terminal (MT)	July 24, 2015	August 6, 2019
	Municipal Access Agreement (MAA)	Pipeline (P/L) & Marine Terminal (MT)	July 24, 2015	July 22, 2019
Vancouver Airport Authority (YVR)	Facilities Alterations Permit (FAP)	Pipeline within YVR jurisdiction.	April 18, 2017	October 16, 2017

2.1.7 All assessments, studies, reports, board of director materials, and member and shareholder materials to support the timeline.

Response:

The level of detail in these requests is overbroad and responding would be unduly onerous.

2.2 What is the current permitting and construction status of the VAFD Project?

Response:

The VAFD Project has all necessary permits for its construction and operation, other than day to day construction execution permits.

Regarding the construction status of the VAFD Project, please see VAFFC's response to PKMJF IR 2.1.5.

2.3 Please specify the month and year that the VAFD Project is anticipated to commence operations at any capacity.

Response:

VAFFC anticipates that the VAFD Project will commence operations in February 2023.

2.3.1 Please fully describe any reasons that VAFFC is aware of that may delay the commencement of operations and provide the anticipated impact that this may have on the commencement of operations.

Response:

VAFFC is not aware of any such reasons.

2.3.2 Please describe any impact of the COVID-19 pandemic on construction and permitting progress of the VAFD Project, as well as anticipated commencement of operations.

Response:

The COVID-19 pandemic delayed construction on the VAFD Project by approximately 6 months. VAFFC anticipates that the VAFD Project will commence operations in February 2023.

2.3.3 What is the full capacity of the VAFD Project?

Response:

The VAFD Project marine terminal has a storage tank capacity of 80 million litres.

2.3.4 What does "fully operational" mean in the above quote?

Response:

"Fully operational" means that the VAFD Project is able to receive fuel offloaded from vessels and barges, and transport this fuel by pipeline to YVR.

2.3.5 Please specify the month and year that the VAFD Project is anticipated to begin operating at full capacity.

Response:

VAFFC anticipates that the VAFD Project will begin operating at full capacity in February 2023 (at the time that the VAFD Project commences operations).

2.3.6 Please describe any reasons that VAFFC is aware of that may delay the commencement of full capacity operations and provide the anticipated impact that this may have on the commencement of full capacity operations.

Response:

VAFFC is not aware of any such reasons, beyond the delay that has been cause to date by the impacts of the COVID-19 pandemic.

Please also see VAFFC's response to PKMJF IR 2.3.2

2.4 Has the prospect of future expansion of the VAFD Project been considered by VAFFC? If yes, what is the cost and estimated length of construction?

Response:

No.

2.4.1 Please provide all studies, reports, board of director materials, shareholder and member materials, and shipper materials to support this response.

Response:

Not applicable. Please see VAFFC's response to PKMJF IR 2.4.

3.0 Historic Volumes

Reference: Exhibit C2-36-1 (VAFFC Evidence), PDF p. 3.

On PDF p. 3 of the VAFFC Evidence, at para 2, VAFFC states that:

> Over the past three decades VAFFC's member airlines have shipped most of the volumes on the Jet Fuel Line and are the end-users of all of the jet fuel shipped on the line. The costs of shipping on the Jet Fuel Line are ultimately borne by airline customers.

PKMJF seeks information regarding the historical volumes shipped by VAFFC on the JFL.

3.1 Please provide the annual volumes shipped by VAFFC on the JFL since 2007 to present.

Response:

VAFFC members (Air Canada) shipped the following actual volumes on the Jet Fuel Line in the years from 2013 to 2020, in litres:

2013: 804,093,208 L
2014: 906,194,728 L
2015: 891,418,632 L
2016: 1,044,421,860 L
2017: 1,218,901,558 L
2018: 1,181,429,701 L
2019: 1,113,218,924 L
2020: 391,348,055 L

VAFFC has been unable to obtain details regarding the actual volumes shipped by members on the Jet Fuel Line prior to 2013. This information should also be within the possession of PKMJF.

4.0 Tolling Matters

Reference (i): Exhibit C2-36-1(VAFFC Evidence, Appendix A: Regulatory Principles and Implications for 2019 – 2021 Test Year Revenue Requirements ["VAFFC Evidence, Appendix A"]), PDF p. 39

Table on PDF p. 39 of the VAFFC Evidence, Appendix A:

Topic	Public Utility	Common Carrier
Requirement to meet volume demanded	Utility must supply, and expand, to meet all reasonable demands as part of "obligation to serve"	Typically none, except offering surplus capacity on non-discriminatory basis. In the case of the JFL, intentional underservicing was not only possible, but pursued.
Entitlement to fair return	Within standard of the prudent investment principle, utility is legally entitled to a fair return on any investment (both annual revenue requirement and long-term recovery of rate base). In other words, a strong protection and expectation for both a return on, and a return of, capital.	When transporting common carriage volumes, prices to reflect fair annual costs for the service provided (shipping) without reference to unique circumstances of specific buyers or sellers (e.g., looming alleged obsolescence).

4.1 Is it Mr. Bowman's opinion that an oil pipeline that is considered a common carrier should not have an expectation for both a return on, and a return of, capital?

4.1.1 If yes, please fully explain your response.

4.1.2 If no, please fully explain your response.

Response to PKMJF IR 4.1, 4.1.1 and 4.1.2:

Please see the response to BCUC IR 18.6.

A common carrier should have all of the rights and expectations set out in the law, the regulations, and in the franchise documents provided them upon their establishment (if any). Mr. Bowman is not aware of any BC legislation or regulations that state that PKMJF is entitled to a return on, or a return of, capital, and there do not appear to be any franchise documents relevant to the Jet Fuel Line.

As a result, the ability to achieve a return on and return of capital appears to depend entirely on PKMJF acting as a reasonable business entity to make an investment of capital at its own risk, to preserve the ongoing value of their business investment, and to maximize the use of its service. Just like any entrepreneur, PKMJF may or may not be able to achieve this in practice, and as a result may or may not receive what the shareholder considers a fair return of and return on investment.

It is also relevant that the shareholder investment at any given time may not necessarily be tied to the original investment in the physical assets. One shareholder, for example, may find it opportune to decrease their risk of exposure to the entrepreneurial investment by selling their shares, while a different shareholder may choose to take on the risk (at a price they consider fair) by acquiring those shares. This acquiring shareholder would do their own assessment of risk as part of their acquisition, and receive in exchange the upside and downside consequences that come with investments laden with risk. Sophisticated parties who enter into such transactions would likely consider it appropriate to complete such a risk assessment at the time of acquisition.

4.2 With respect to Mr. Bowman's assertion that "[i]n the case of the JFL, intentional underservicing was not only possible, but pursued."

4.2.1 Please provide all evidence Mr. Bowman relied upon to support his assertion.

4.2.2 Is it Mr. Bowman's position that the JFL was under a requirement to provide more service that it has provided? If so, please fully explain and provide all evidence supporting this claim.

Response to PKMJF IR 4.2, 4.2.1 and 4.2.2:

Mr. Bowman understands that PKMJF was not under any obligation to provide more service with respect to the JFL than it has provided. Such an obligation would likely only exist to the extent it was codified, such as in a franchise agreement. It is Mr. Bowman's understanding that PKMJF does not have a franchise agreement with respect to the JFL. Such an agreement, if it existed, would codify aspects of PKMJF's rights and obligations, which could include an obligation to serve. For public utilities, the obligation to serve typically comes with a right to not face competition from a competing project – a right that JFL apparently does not possess either, as a common carrier.

Mr. Bowman's conclusion is not that JFL violated any legal obligation to expand and to serve, as there was no such obligation. Rather, PKMJF's own overriding interest to maximize the use and life of its asset should have driven action. The best way to maximize the life and use of the asset would have been to ensure the

JFL met the local demand at YVR. There are ample references in the materials from the 2007 JFL BCUC proceeding that PKMJF had knowledge that the JFL was inadequate to meet customers' needs, and was given opportunities to consider ways to preserve the value of the YVR market access (e.g., by twinning the JFL or via divestiture to a party that might pursue such a development). But the record shows that PKMJF pursued no such course. This is what is meant by "intentional underservicing".

4.3 With respect to Mr. Bowman's opinion that "[w]hen transporting common carriage volumes, prices to reflect fair annual costs for the service provided (shipping) without reference to unique circumstances of specific buyers or sellers (e.g., looming alleged obsolescence)."

4.3.1 Is it Mr. Bowman's opinion that the projected use (*i.e.*, volumes transported) of a common carrier oil pipeline should not be reflected in a revenue requirement study? If not, please fully explain and cite all authoritative sources supporting this claim.

Response:

No. Mr. Bowman has recommended that projected volumes transported under normal circumstances be part of the toll determination – see for example VAFFC's response to BCUC IR 6.12.

4.3.2 Is it Mr. Bowman's opinion that it is appropriate to analyze the economic life of an oil pipeline when developing depreciation rates? If not, please fully explain.

Response:

First, it is important to distinguish between the development of depreciation rates for accounting purposes and for toll-setting purposes.

For an accountant preparing depreciation rates to be used in a financial statement, information about economic life should be taken into account in order to portray to the reader (e.g., a potential investor) the financial position of the operation. Economic life is therefore essential for a proper calculation of net income. For this reason, any investor reviewing a financial statement would be fully apprised of the expected life of an asset, and could adjust their investment commitment (e.g., price) accordingly.

For toll-setting purposes, the development of depreciation rates may need to address other considerations.

For toll-setting for oil pipelines that are developed on the premise of a limited life due to extraneous factors, the life would be part of the assessment. For example, if a new field is developed on the premise of a given quantity of production over a given life (e.g., 20 years), then that life consideration would go into the initial decision by the pipeline owner to invest, and presumably would guide the negotiation over tolls with the shippers.

In the case of an oil pipeline that serves a permanent demand (such as YVR's ongoing demand for jet fuel), where there is an investment decision but later a risk arises that leads to premature abandonment of the facility (whether due to the fault of the investor or not), it is not apparent why this risk would ever fall to the shippers. The shippers moved their product and paid tolls for this service. The owner took on the development risk, with a secure permanent market that should be low risk. If a risk then arises and is either insufficiently addressed by the owner, or is unable to be addressed by the owner, and that leads to a reduced life, accelerated depreciation becomes merely a mathematical gimmick to inappropriately pass off this risk onto the shippers rather than having it remain appropriately with the owner.

4.3.3 Is it Mr. Bowman's opinion that when analyzing the economic life of an oil pipeline, the forecasted volumes transported by its existing and possible shippers should not be analyzed? If so, please fully explain.

Response:

No. See VAFFC's response to PKMJF IR 4.3.2. Economic life is highly relevant to pipeline owners, and should be carefully assessed in all investment decisions.

Reference (ii): Exhibit C2-36-1 (VAFFC Evidence, Appendix A), PDF p. 45

On PDF p. 45 of the VAFFC Evidence, Appendix A, Mr. Bowman states:

> Surprisingly, even though PKMJF had no entitlement to guarantees of capital cost recovery or accelerated depreciation, the 2009-2018 negotiated settlement largely secured this right for PKMJF (i.e., all asset costs to be recovered by 2023). But this was not the only surprising aspect – PKMJF also secured tolls with material unexplained increases from shippers. Costs to shippers therefore increased with little rationale and no apparent added value. As a Common Carrier and not a franchised Public Utility, customers are not captive to PKMJF, and it is clear PKMJF undermined their market position and the long-term potential value of their assets by making their own service less economic than necessary. Events since that time underline this perspective.

4.4 Is it Mr. Bowman's understanding that the shippers, including VAFFC, were forced into entering into the 2009-2018 negotiated settlement? If so, please provide all evidence supporting such an accusation.

4.4.1 If not, is it Mr. Bowman's understanding that the shippers, including VAFFC, voluntarily entered into the 2009-2018 negotiated settlement?

Response to PKMJF IR 4.4 and 4.4.1:

The nature of negotiations is that all parties must make concessions. Mr. Bowman understands that the 2009-2018 negotiation was a package deal, and that all parties received and accepted conditions that ultimately were determined to be favourable to a litigated outcome, with its attendant risks and costs.

Mr. Bowman only has access to the information on the record in this proceeding, and his understanding is entirely based on that evidence.

4.5 Is it Mr. Bowman's position that VAFFC and its members are not sophisticated commercial parties?

Response:

Mr. Bowman cannot comment on the interests of VAFFC, or the sophistication of VAFFC's members with respect to toll-setting principles.

Reference (iii): Exhibit C2-36-1 (VAFFC Evidence, Appendix A), PDF p. 51

On PDF p. 51 of the VAFFC Evidence, Appendix A, Mr. Bowman states:

> At the time of the 2009-2018 negotiated settlement, for whatever reasons were relevant at the time, shippers agreed to a tolling regime predicated on the PKMJF assets being fully depreciated and no longer in service as of the end of 2022 (13 years from the negotiated implementation of accelerated depreciation at January 1, 2010)[57]. This approach to asset depreciation could only reasonably be consistent with an assumed termination of pipeline service starting in the year 2023 (service after 2022 would otherwise be provided by a zero rate base asset, and there would be no basis to calculate a tariff that would provide any return to the owner who had taken on the risks of operation, etc.). Such termination of pipeline service would normally be understood to coincide with the final chance to collect from customers the costs needed for Removal or Abandonment of the pipeline and related assets. However, PKMJF's current filing portrays no abandonment reserves are in place (or credited as an offset to future customer funding obligations) as of January 1, 2019.

It is not credible that a regime was implemented which targeted known and fixed, stable revenues for 10 years out of the remaining 13 year life of the pipeline, but failed to consider establishment of any abandonment fund. To so conclude would be to find that PKMJF deliberately accepted an omission of the chance to fund the future costs of abandonment during the last 10 of 13 years of the pipeline. Either PKMJF would have to have been supremely confident that it could, to be colloquial, assuredly wallop shippers for abandonment costs in the final 3 years, or PKMJF would have had to be intensely oblivious to this pending risk. Neither of these is credible. It is even less credible that this approach was purportedly implemented concurrent with a massive [redacted] in the net income taken by the pipeline operator, as reviewed above (a [redacted] from the traditional level of return on rate base of around $0.720 million to [redacted] within 12 months). [Far] more likely, the settlement was acceptable to all parties, including PKMJF, because it understood to provide PKMJF with sufficient funds to address abandonment consistent with a 13-year life adopted for depreciation (whether recorded as abandonment accruals, or as extraordinary net income knowingly offsetting future as-yet recorded shareholder costs for abandonment). Whatever the intent at the time of the settlement, PKMJF's current Application effectively seeks to impose and crystallize now the identical outcomes that such improbable and commercially unreasonable approaches would have targeted, which is inherently double-counting abandonment recoveries from customers.

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[57] Exhibit A2-1, Appendix 1, 2009-2018 Negotiated Settlement.
[58] With respect to toll development, the proposed Abandonment trust proposes to collect the full costs estimated by the abandonment study, with no offset or credit for amounts provided or accrued prior to January 1, 2019.

4.6 Is it Mr. Bowman's opinion that a pipeline cannot earn a return if it has been fully depreciated?

Response:

No. A pipeline can earn any reasonable return that it negotiates with its customers (or, as demonstrated by the period 2009-2018, even an unreasonable return).

It is in the case of negotiations that break down, when recourse to a regulator is required, that the principles are less clear. It appears that PKMJF's practice was to largely adopt the public utility convention that the only return granted is on the undepreciated rate base, representing the unrecovered equity that the owner has invested. In the case of a zero rate base, this calculation would lead to zero return.

4.6.1 If yes, please provide all authoritative sources that support this opinion.

Response:

Not applicable. Please see the response to PKMJF IR 4.6.

4.7 Is it Mr. Bowman's opinion that if PKMJF's tolls are set on a cost of service basis, PKMJF should be provided the opportunity to recover its costs and earn a reasonable profit? If not, please explain why not.

Response:

PKMJF's tolls are set on a negotiated basis, unless recourse to the regulator is required. If set by the regulator, PKMJF should be provided the opportunity to recover costs and earn a fair return consistent with the principles discussed in InterGroup's evidence, Appendix A, section 2, and the discussion in VAFFC's response to BCUC IR 6 and the various subparts to that response.

4.8 Referring to footnote 57 on PDF p. 51, please provide all references in Exhibit A2-1, Appendix, 2009-2018 Negotiated Settlement, that the PKMJF assets would be fully depreciated as of the end of 2022?

Response:

Exhibit A2-1, page 2 states that notwithstanding any "forecast remaining life" the remaining life is overridden to no more than 13 years, which is consistent with a terminal life to 2022.

Such an approach is adopted when assets face an expected final date of use. This is the approach to depreciation because it makes no sense to, for example, replace a valve in year 6 and have that asset depreciated to year 19 (13 years later) when the pipeline that the valve is connected to will have been retired by that time.

4.9 Is it Mr. Bowman's understanding that when VAFFC membership[14] entered into the 2009-2018 negotiated settlement, it expected PKMJF to set aside a portion of revenues collected to fund an abandonment fund? If so, please provide all evidence supporting such a position.

Response:

Like any negotiation without prejudice, Mr. Bowman can only rely on the text of the settlement, and the relevant context. Mr. Bowman has no knowledge of the VAFFC membership's views.

[14] The 2009-2018 Negotiated Settlement was entered into by "KMJF and its shippers, including Air Canada". Accordingly, the reference to VAFFC in this request is intended to refer to the entity and/or its members who were parties to the 2009-2019 Negotiated Settlement.

Mr. Bowman's conclusions arise from the fact that PKMJF had a cost-of-service-based toll adjudication covering 2007 and 2008 and also 2009. Then, as part of the negotiation, the revenue requirements for PKMJF jumped massively compared to all previous forecasts. For 2009, the revenue requirements were revised upwards from the original 2009 proposed level of $3.973 million (which was a final revenue requirement), to $4.800 million, a jump of 21% in the same year. This then escalated to $5.694 million (a 19% increase) in 2010, a combined 66% increase ($2.271 million) in 2 years, over the initially approved 2008 level. Accelerated depreciation accounted for only $0.381 million of the increase.

No other cost category can explain such an increase, other than implementation of new accruals, and no other new accruals of this magnitude are conceivable for PKMJF except abandonment. Further, it is not conceivable that PKMJF would secure an overriding concept of a limited 13 year life, and then lock in tolls for 10 of these 13 years without addressing abandonment.

Regardless of whether the increase in revenues were or were not tied to abandonment, PKMJF had an expectation of a need for abandonment funds, had [redacted] profits from the high negotiated tolls, and was receiving ongoing information repeatedly confirming VAFFC was moving forward with the VAFD project. If PKMJF believed this meant abandonment was unavoidable, InterGroup's view is that accruing for abandonment out of the [redacted] returns being earned would be the only reasonable course of action in those circumstances.

4.10 Was Mr. Bowman consulted by VAFFC, or any of its membership, during the negotiations which led to the 2009-2018 negotiated settlement such that he was privy to the understandings and positions of VAFFC or its membership during those negotiations?

Response:

No.

4.10.1 If not, was Mr. Bowman otherwise made privy to the understandings and positions of VAFFC or its membership during the negotiations which led to the 2009-2018 negotiated settlement?

Response:

No.

Reference (vi): Exhibit C2-36-1 (VAFFC Evidence, Appendix A), PDF p. 52

On PDF p. 52 of the VAFFC Evidence, Appendix A, Mr. Bowman states:

> In short, the only reasonable way to set forward-looking tolls today in the wake of the negotiated settlement, would be to assume PKMJF acted or was expected to act consistent with a prudent pipeline operator during that period. This would yield an abandonment reserve as of December 31, 2018 of between $2.556 million[61] and $3.671 million[62] (likely the latter). Such a reserve should be directed by the BCUC to be established (for the purposes of setting 2019-2021 tolls), effective December 31, 2018, out of PKMJF's past tolls which were instead recorded as net income to the shareholder. To be clear - these amounts should not be collected from toll-payers a second time. Revenue Requirements for 2019 and going forward should be set to reflect abandonment funding for the remainder of reasonably estimated abandonment costs over and above this level (see the complementary evidence of Patricia Lee) over the appropriate depreciation period.

4.11 Is it Mr. Bowman's opinion that if it is shown that PKMJF's cost of service was higher than its revenues during a prior settlement period, its current rates should be adjusted to compensate for previous under-recovery in prior periods? If not, why not?

Response:

No. However, [redacted] profits in a past period arising solely because PKMJF misapplied reasonably expected depreciation, and prudent accrual practices, should be taken into account by the BCUC. These were not past profits (and do not represent retained earnings today) any more than if PKMJF failed to book income taxes, failed to depreciate the assets, or decided to defer recognition of O&M expenses to a future period when they could be rolled into tolls in a year to which they do not relate. The determination of an appropriate and accurate opening balance sheet is not about retroactive ratemaking, it is about appropriate Test Year ratemaking.

Reference (v): Exhibit C2-36-1 (VAFFC Evidence, Appendix A), PDF p. 53

On PDF p. 53 of the VAFFC Evidence, Appendix A, Mr. Bowman states:

> In respect of depreciation, the 2009-2018 negotiated settlement included an adjustment to the lives used to depreciate assets. The concept applied is what would be considered a "terminal life" or "life span" in depreciation practice – where an asset is determined to have an effective end date for retirement, and all components are targeted to be depreciated by no later than that date, regardless as to their physical characteristics or condition.

4.12 Mr. Bowman uses the term "terminal life" in his report:

4.12.1 What is Mr. Bowman's definition of "terminal life" in the context of developing an oil pipeline depreciation study?

Response:

The InterGroup evidence uses the term "Terminal Life" as the expected date of all assets having no residual value, and removal from service, sometimes also called a "life span date" or "truncation date".

4.12.2 Please provide all references in Exhibit A2-1, Appendix, 2009-2018 Negotiated Settlement, referred to in footnote 57 on PDF p. 51, to the term "terminal life."

4.12.3 Is it Mr. Bowman's understanding that a "terminal life" approach is used in oil pipeline depreciation studies? If so, please cite all instances.

Response to PKMJF IR 4.12.2 and 4.12.3:

The term "terminal life" is not used in the schedule in Exhibit A2-1, but the concepts of terminal life depreciation are pervasive in the mathematics applied in the schedule.

While Mr. Bowman is not aware of any application of the specific concept of terminal life or life span dates being applied to jet fuel pipelines specifically, the concept of a terminal life or life span date is pervasive throughout utility depreciation studies and the setting of revenue requirements. The concept is so ubiquitous that it is almost trite to provide "examples", but consider the following list, which is limited to a small sample of examples from Gannett Fleming (the firm previously retained by PKMJF for its 2007 depreciation studies):

- Alberta AUC Decision 20272-D01-2016, paragraph 655-662[15]
- Nova Gas Transmission before the NEB[16]
- Enbridge Gas Distribution[17]

[15] http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2016/20272-D01-2016.pdf

[16] http://www.tccustomerexpress.com/docs/ab_regulatory_filings/EX_002_12_2004_02_13_NGTL_04_Depreciation.pdf pdf page 89.

[17] https://www.enbridgegas.com/-/media/Extranet-Pages/Regulatory-Filings/RateCases/Rate-Cases-and-QRAMs/2013-Test-Year/EB-2011-0354/D---Operating-Cost/D2/D2-2-1.ashx pdf pages 36-37.

- OPG depreciation on nuclear generating assets[18]
- Manitoba Hydro generating stations[19] (note that Terminal Date is used interchangeably for the concept[20])
- Oklahoma Gas and Electric[21]
- Maritime Electric[22]
- Montana Dakota Utilities[23]

Also note that the above examples are typically of regulated utilities, which have a different expectation of assurance of recovery of invested capital than common carriers, and as such the accelerated depreciation associated with the life span is reviewed as part of rate setting.

5.0 Depreciation

Reference (i): Exhibit C2-36-1, (VAFFC Evidence, Appendix C: Review of Depreciation Methodology in PKMJF's Proposed Revenue Requirement of the 2019 Tariff Application ([“VAFFC Evidence, Appendix C”]), PDF p. 103

On PDF p. 103 of the VAFFC Evidence, Appendix C, Ms. Lee states:

> A review of PKMJF's 2019 Depreciation Study indicates that the proposed depreciation rates are excessive and not justified. First, the 2010 negotiated depreciation rates were designed to fully recover the JFL assets by a retirement date of December 31, 2022. By PKMJF's own submission, those rates should have been revised, but were not, each year of the contract period to reflect the impact of additions and retirements. It was PKMJF's responsibility to regularly review the depreciation rates and underlying life components

[18] https://archive.opg.com/pdf_archive/Regulatory%20Affairs/z5--EB-2013-0321/Exhibit%20F%20-%20Operating%20Costs/O267_F4-01-01_Attachment%25201.pdf pdf pages 19-22.

[19] http://www.pubmanitoba.ca/v1/exhibits/mh-gra-2012-13-14/appendix_5_7.pdf pdf pages 65-66

[20] http://www.pubmanitoba.ca/v1/exhibits/mh-gra-2012-14/Exhibit-53.pdf

[21] https://ogeenergy.gcs-web.com/static-files/59e7c091-1e75-4fbc-9506-358ffb034a88 pdf page 24.

[22] https://www.maritimeelectric.com/media/1091/final-rate-depreciation-application-and-appendices.pdf pdf page 28-29.

[23] https://www.montana-dakota.com/wp-content/uploads/PDFs/Rates-Services/MT/vol-i-direct-testimony.pdf?sfvrsn=2 pdf page 198

which, from all appearances, it did not. This would have reduced the reported undepreciated costs as of December 31, 2018.

5.1 In Ms. Lee's experience, how often do oil pipelines typically file new depreciation studies?

Response:

Ms. Lee does not have specific experience with jet fuel pipelines. That said, Ms. Lee's experience is that depreciation studies for utility-type assets are filed every three to five years and should be filed when the need to revise rates arises. Companies should review their depreciation rates and components every year and when circumstances dictate, such as in the case of a significant change in company planning, they should and have submitted revised depreciation studies.

5.2 Is Ms. Lee aware of any instances where an oil pipeline filed a new depreciation study annually? If so, please provide cites to all instances.

Response:

Ms. Lee does not have specific experience with jet fuel pipelines. It is not typical to have depreciation studies filed annually.

5.3 With respect to Ms. Lee's assertion that "the 2010 negotiated depreciation rates were designed to fully recover the JFL assets by a retirement date of December 31, 2022," please provide all cites to where PKMJF made this specific claim.

Response:

Please see the VAFFC response to PKMJF IR 4.8.

Reference (ii): Exhibit C2-36-1, (VAFFC Evidence, Appendix C), PDF p. 109

Schedule 5, on PDF p. 109 of the VAFFC Evidence, Appendix C:

Appendix C: Review of PKMJF's Depreciation Methodology **December 16, 2020**

Application for Tolls
Schedule 5
2019 Depreciation Study

Account	Number & Description	Original Cost 12/31/2018	Accumulatd Depreciation 12/31/2018	Net Service Value 12/31/2018	2018 Depreciation Expense	Existing Depreciation Rates	Forecast Remaining Life	Proposed Recovery 3 Years w Exception	
(a)		(b)	(c)	(d)	(e)	(f)	(g)=[d/e] [1/]	(h)	(i)=[h/b]
152	Land Rights	98,683.73	91,762.48	6,921.25	1,746.70	1.77%	4.0	2,307.08	2.34%
153	Line Pipe	6,107,724.24	3,558,941.50	2,548,782.74	282,472.58	4.86%	9.0	849,594.25	13.91%
156	Buildings	480,479.33	341,743.90	138,735.43	19,219.17	4.00%	7.2	46,245.14	9.62%
158	Pumping Equipment	1,138,930.25	900,553.22	238,377.03	52,390.80	4.60%	4.5	79,459.01	6.98%
159	Station Lines	1,931,570.82	1,572,956.16	358,614.66	81,898.61	4.24%	4.4	119,538.22	6.19%
160	Other Station Equipment	2,760,133.99	1,989,824.62	770,309.37	153,627.16	5.73%	5.0	256,769.79	9.30%
160C	Central Pipeline Control	329,325.99	329,325.99				na	na	na
161	Storage Tanks	1,878,251.02	1,228,896.83	649,354.19	91,993.66	4.90%	7.1	216,451.40	11.52%
163	Communications	239,200.52	223,358.50	15,842.02	5,513.46	10.00%	2.9	5,280.67	2.21%
185WE	Work Equipment	51,974.45	47,999.11	3,975.34	1,325.12	20.00%	3.0	1,325.11	2.55%
186HW	Computer Hardware	3,789.43	3,789.43			20.00%	na	na	na
186SW	Computer Software	8,625.11	8,625.11			20.00%	na	na	na
189D	AFUDC (Interest)	149,198.01	132,466.61	16,731.40	4,819.10	3.23%	3.5	5,577.13	3.74%
189E	AFUDC(Equity)	160,050.56	136,072.52	23,978.04	5,425.72	3.39%	4.4	7,992.68	4.99%
190	Construction Overhead	3,252,311.99	2,773,177.53	479,134.46	130,417.68	4.01%	3.7	159,711.49	4.91%
BS	Cost of Removal		(404,795.28)	404,795.28	49,516.56	7.69%	8.2	134,931.76	33.33%
	Total	18,590,249.44	12,934,698.23	5,655,551.21	880,366.33		6.4	1,885,183.74	10.14%

Summary of Depreciaiton Rates	2018	2019
Depreciation Expensse without Costs of Removal	830,849.77	1,750,251.98
Amortization of normal Costs of Removal	49,516.56	134,931.76
Total Provision for Pipeline	880,366.33	1,885,183.74

Notes:
[1/] Reflects depreciation and amortization effective as of January 1, 2010.

On PDF p. 109 of the VAFFC Evidence, Appendix C, Ms. Lee states:

> A review of the depreciation study indicates areas of concern where depreciation actions have not been in accord with generally accepted depreciation practices.

5.4 Please explain why Ms. Lee did not include all columns included in Schedule 5.

Response:

When the Schedule was copied into Ms. Lee's evidence, the last column was inadvertently omitted.

5.5 Ms. Lee asserts that a "review of the depreciation study indicates areas of concern where depreciation actions have not been in accord with generally accepted depreciation practices." What is the basis for Ms. Lee's understanding of generally accepted depreciation practices for oil pipelines? Please provide a list of authoritative sources.

Response:

Ms. Lee does not have specific experience with jet fuel pipelines.

For capital-intensive rate-regulated assets, including public utilities, "generally accepted depreciation practices" and the development of life characteristics are discussed in numerous books, some of which include Depreciation Systems by Frank K. Wolf and W. Chester Fitch; Engineering Valuation and Depreciation, by Marston, Winfrey, and Hempstead; National Association of Regulatory Utility Commissioners (NARUC), Public Utility Depreciation Practices, *Bulletin 155: Depreciation of Group Properties* by R. Winfrey; and *Bulletin 125: Statistical Analysis of Industrial Property Retirements* by R. Winfrey.

Reference (iii): Exhibit C2-36-1, (VAFFC Evidence, Appendix C), PDF p. 114

On PDF p. 114 of the VAFFC Evidence, Appendix C, Ms. Lee states:

> Using PKMJF's method of remaining life determination, the 13-year remaining life established in 2010 would have been adjusted each subsequent year to ensure recovery of any additions. In other words, the 2010 depreciation rates would apply to the January 1, 2010 embedded investments until fully recovered; additions in 2010 would be subject to a 12-year period or an 8.3% depreciation rate; 2011 additions would be subject to an 11-year period or a 9.1% depreciation rate; 2012 additions would be subject to a 10-year period or a 10% depreciation rate; and so on. In this manner, January 1, 2010 embedded net investments as well as all subsequent additions would be fully recovered by 2022, a reasonable interpretation of PKMJF's intent of the 2010 depreciation rate design.
>
> It is unclear if PKMJF's failure to book depreciation expense in this way reflects a lack of understanding or an attempt to increase earnings. As addressed in the complementary evidence (Appendix A, by P. Bowman), PKMJF has received more than sufficient toll revenue to recover the expenses it should have booked under the 2010 depreciation rate design.

5.6 With respect to Ms. Lee's assertion that "[i]t is unclear if PKMJF's failure to book depreciation expense in this way reflects a lack of understanding or an attempt to increase earnings":

5.6.1 By "book depreciation expense in this way," please confirm that Ms. Lee is referring to the approach she describes in the preceding paragraph.

Response:

Confirmed. However, based on the 13-year remaining life approved in 2009 for each account, the only reasonable conclusion was that a terminal date of year-end 2022 was to be implemented. In order to fully recover the JFL investment by the terminal date, consideration had to be given to any interim activity between 2009 and the 2022 retirement date. This required recalculating the depreciation rates each year so that the 1/1/2010 embedded investment and all net additions would be recovered by the terminal date. To the extent there were no subsequent additions, the depreciation rates would not need to be recalculated. This is the only way in which full recovery of all investment associated with the JFL would be achieved by the terminal date.

5.6.1.1 If so, please list all instances in which an oil pipeline was authorized to use this depreciation approach.

Response:

Please see the VAFFC response to PKMJF IR 4.12.3.

5.6.1.2 If not, please explain what approach she is referring to.

Response:

Not applicable.

Please see the VAFFC response to PKMJF IR 5.6.1.

5.6.2 Is Ms. Lee alleging that PKMJF inappropriately attempted to increase earnings? If so, please provide all evidence for making such an accusation.

Response:

Ms. Lee's comments focus on the mathematics, and the consequence of failing to apply the correct mathematics. Ms. Lee specifically indicates the reason for this error is unclear, and makes no such allegation.

5.7 With respect to Ms. Lee's statement regarding "PKMJF's method of remaining life determination," is it Ms. Lee's understanding this method is unique to PKMJF amongst oil pipelines?

Response:

Ms. Lee's understanding is that PKMJF's method of remaining life determination is and has been unique to PKMJF. Ms. Lee is not aware of any generally acceptable depreciation practice or procedure where the remaining life determined in the fashion that PKMJF has is considered appropriate. Remaining life of physical assets is developed, not backed-into as PKMJF has done.

Reference (iv): Exhibit C2-36-1, (VAFFC Evidence, Appendix C), PDF p. 115

On PDF p. 115 of the VAFFC Evidence, Appendix C, Ms. Lee states:

> In sum, there is no clear retirement date of the JFL other than PKMJF's estimate of the VAFD Project in-service date. **No prospect of continuing JFL operation has even been considered by PKMJF.** It is conceivable that Parkland and some other shippers (airline and non-airline) may use the JFL even if it had higher tolls. The JFL has a physical 25-year remaining life and PKMJF acknowledges that it connects to a myriad of supply sources: marine delivery options, the Parkland refinery, and the Trans Mountain pipeline. None of these factors have been fully considered to date. Regardless of which longer depreciation period might be best applied, the existing depreciation rates would provide full recovery of the remaining service value of the JFL assets by 2022, which is too short. Therefore, PKMJF's proposal for the depreciation rates in the current application is not supported and should be rejected.

5.8 With respect to Ms. Lee's claim that "[i]t is conceivable that Parkland and some other shippers (airline and non-airline) may use the JFL even if it had higher tolls":

5.8.1 Does Ms. Lee believe that it is likely that some other shippers (airline and non-airline) may use the JFL even if it had higher tolls?

Response:

Ms. Lee has not seen conclusive evidence that PKMJF would fail to have any shippers use the pipeline were it made available. [redacted]

PKMJF has chosen to omit such evidence from its application. In Ms. Lee's experience applicants bear the onus of establishing the context surrounding depreciation proposals. Ms. Lee's evidence comments on this absence.

5.8.2 Did Ms. Lee review any evidence that suggests that some other shippers (airline and non-airline) may use the JFL even if it had higher tolls? If so, please provide such evidence.

Response:

Yes, the evidence Ms. Lee reviewed included:

- Exhibit B-48, Appendix A, pdf. p. 32, Q. 145 [redacted]) and Q. 148 [redacted]
- Exhibit C1-4; Evidence of Robert Innis, Trans Mountain (Jet Fuel) Tolls and Accelerated Depreciation Hearing October 5, 2007; and
- BCUC Order P-3-08, Appendix A, page 10, where it was stated that "The Commission accepts that Chevron would continue to use the TMJ Pipeline even if it were the only shipper and tolls increased substantially."

Parkland's evidence in this proceeding also does not indicate inevitable cessation of service.

5.8.3 Does Ms. Lee believe that if some other shippers (airline and non-airline) may use the JFL even if it had higher tolls, there would be sufficient volumes to make it economic for both the shipper and PKMJF?

Response:

By definition, if some parties were to use the JFL, it must be economic under the circumstances.

6.0 Abandonment

Reference (i): Exhibit C2-36-1, (VAFFC Evidence, Appendix D: Review of PKMJF's proposed Abandonment Costs for the 2019 Tariff Application ([“VAFFC Evidence, Appendix D”]), PDF p. 122

On PDF p. 122 of the VAFFC Evidence, Appendix D, Ms. Lee states:

> In 2008, the NEB (now the CER) initiated a proceeding to address the financial issues of pipeline abandonment, identified as Stream 3 in its Land Management Consultation Initiative (LMCI). This proceeding introduced the trust fund concept in Canada. In May 2009, the NEB issued RH-2-2008 Reasons for Decision that set forth guiding principles and a Base Case for preparing preliminary abandonment cost estimates for pipeline abandonment costs. Also, the NEB recognized that preliminary abandonment cost estimates would require the use of assumptions rather than actual numbers. Even so, the use of assumptions was not a sufficient rationale to preclude making the cost estimates. On March 4, 2010, the NEB released a revised Base Case that included physical assumptions but no Unit Costs. Subsequently, in December 2010, the NEB issued a table containing revised Unit Costs.

PKMJF seeks clarification on Ms. Lee's opinion on the application of NEB guidelines, encapsulated in MH-001-2012, to the abandonment assumptions of the JFL.

6.1 With respect to Ms. Lee’s discussion regarding the NEB’s abandonment cost collection mechanism, is Ms. Lee aware of any instances where the NEB assumed that existing oil pipelines had already collected some or all of their abandonment costs in prior tolls? If so, please cite each and every instance.

Response:

To Ms. Lee’s knowledge, MH-001-2012 made no assumption whether abandonment costs had already been collected. Ms. Lee is not aware of any other instances.

Reference (ii): Exhibit C2-36-1, (VAFFC Evidence, Appendix D), PDF p. 123

On PDF p. 123 of the VAFFC Evidence, Appendix D, Ms. Lee states:

> VAFFC filed an application for an Environmental Assessment Certificate (EAC) with the BC Environmental Assessment Office (EAO) in February 2011 wherein it stated the need for the VAFD Project and expectations that PKMJF would abandon the JFL facilities soon after the Project became operational. The EAC was issued in 2013. Thus, it was clearly evident in 2009 and certainly by 2011 and 2013, at the latest, that VAFFC had made more than a tentative decision to proceed with the VAFD Project. Thus, PKMJF had ample

opportunity to file an application concerning the provision of abandonment costs as the BCUC encouraged it to do in Order P-7-2008. Regulators can provide the opportunity and mechanisms for recovery but it is the responsibility of the company, in this case PKMJF, to pursue the recovery when the need arises. With respect to the provision for abandonment costs, PKMJF failed its responsibility.

PKMJF seeks to better understand Ms. Lee's assertion that "[i]t was clearly evident in 2009 and certainly by 2011 and 2013, at the latest, that VAFFC had made more than a tentative decision to proceed with the VAFD Project".

6.2 With respect to Ms. Lee's opinion that "[i]t was clearly evident in 2009 and certainly by 2011 and 2013, at the latest, that VAFFC had made more than a tentative decision to proceed with the VAFD Project":

6.2.1 Please define what "more than a tentative decision to proceed" means.

Response:

The words "more than a tentative decision" are found at page 4 of Appendix A to Order No. P-7-08, where the BCUC held: "In the fullness of time, if TMJ is persuaded that the fuel supply options for the Vancouver Airport have sufficiently matured and that shippers on the pipeline have made even tentative decisions to abandon service on the pipeline, then a further application to the Commission would be justified."

6.2.2 Is Ms. Lee aware of any rulings in which a "more than tentative decision to proceed" has been applied to determine if abandonment costs should be allowed to be collected by an oil pipeline. If so, please provide all instances.

Response:

No. However, Ms. Lee was not suggesting that she viewed this as a trigger to collect abandonment costs. Ms. Lee was referencing the BCUC determination, as indicated in the response to PKMJF IR 6.2.1. above. In the context of that determination made by the BCUC (regardless as to whether it is unique or has precedential value), Ms. Lee simply suggests that PKMJF likely had more than crossed the trigger point.

6.2.3 Does Ms. Lee consider more than a tentative decision to proceed equivalent to a firm and final decision? If not, please explain the differences.

Response:

The word "tentative" means preliminary. "More than a tentative decision" would mean more than a preliminary decision. This does not necessarily mean firm and final. As with any company planning, plans change or firm up as time passes. In the case of an estimated final retirement date such as with the JFL, PKMJF estimated a date of year-end 2022 for all associated investment to be recovered. It is logical to conclude that abandonment recovery would be pursued concurrent with JFL setting a final retirement date in its depreciation parameters.

Additionally, VAFFC submitted its Project Description for the VAFD Project to the BC Environmental Assessment Office in 2009 as toll negotiations with PKMJF were continuing. In February 2011, VAFFC filed its application for an Environmental Assessment Certificate. Thus, VAFFC's steps to proceed with the VAFD Project, including the associated investment of time, money, and stakeholder capitol, would appear "more than tentative."

Please also see VAFFC's response to BCUC IR 2.6.1 and 2.8 for further details on information that would have been available to PKMJF regarding VAFFC's work on the VAFD Project (and VAFFC's attendant investment of time and resources).

7.0 Expert Qualifications

Reference: Exhibit C2-36-1, (VAFFC Evidence), PDF p. 5

On PDF p. 5 of the VAFFC Evidence, VAFFC states:

> To support its intervention, VAFFC has retained Patricia Lee, Patrick Bowman, and Melissa Davies, through InterGroup Consultants Ltd. ("InterGroup"), to provide their expert opinion. VAFFC adopts InterGroup's expert opinion (the "InterGroup Report"), which is being filed concurrently with VAFFC's evidence. This evidence also provides a synopsis of their conclusions.

PKMJF seeks additional information regarding the qualifications of Melissa Davies, Patrick Bowman, and Patricia Lee of InterGroup Consultants Ltd. that is directly related to the economics and management of oil pipelines, including tolls, tariffs, rates, and depreciation matters. PKMJF also seeks to better understand the direction regarding the evaluations conducted by Melissa Davies, Patrick Bowman, and Patricia Lee of InterGroup Consultants Ltd. in relation to the PKMJF 2019 Tariff Application.

7.1 Please provide additional details regarding the expertise and experience of Melissa Davies, Patrick Bowman, and Patricia Lee of InterGroup Consultants Ltd.

that is directly related to the economics and management of oil pipelines, including tolls, tariffs, rates, and depreciation matters.

7.1.1 Please list any oil pipeline depreciation studies authored by any of Ms. Davies, Mr. Bowman, and Ms. Lee.

Response to PKMJF IR 7.1 and 7.1.1:

None of Ms. Davies, Mr. Bowman, nor Ms. Lee have any experience with jet fuel pipelines. To the extent the principles are consistent between the JFL and other large capital-intensive utility-type infrastructure, the experience of Ms. Davies, Mr. Bowman, and Ms. Lee are set out in their respective CVs, filed as Appendix E of the InterGroup Report.

It is also worth noting that some aspects of the market characteristics of the JFL pipeline more closely align with permanent utility-type infrastructure (such as electrical or natural gas distribution utilities) than they do with many oil pipelines. The market characteristics of oil pipelines are often linked to the underlying field or basin, and the relative output and importance of these change over time leading to volume peaks and declines and to retirements. In contrast, the JFL is a market-service asset with a permanent and growing market – YVR. There is simply no rational reason the JFL would not be managed as a permanent and universal service to YVR, with enduring value to its investor-owners.

7.1.2 Please list any oil pipeline tolls, tariffs, and/or rates proceedings where any of Ms. Davies, Mr. Bowman, or Ms. Lee have provided expert testimony.

Response:

See the response to PKMJF IR 7.1.1.

7.2 Please provide full copies of the following documents:

7.2.1 Retainer letter or any other form of engagement agreement with InterGroup Consultants;

Response:

A copy of InterGroup's retainer letter is attached as Appendix PKMJF 7.2.1.

7.2.2 Any written instructions or direction given to InterGroup Consultants (to the extent such directions or instruction was given or supplemented by verbal communications, please describe those verbal communications);

Response:

Copies of two emails containing direction provided to Ms. Lee are attached as Appendix PKMJF 7.2.2.

Further verbal directions were provided during periodic phone calls between external counsel for VAFFC and Ms. Lee, Mr. Bowman and Ms. Davies. For example, during these calls, Ms. Lee, Mr. Bowman and Ms. Davies coordinated the overall structure of InterGroup's evidence with that of VAFFC, which topics the InterGroup Report would address (e.g. abandonment and depreciation), and scheduling for the provision of drafts for review.

7.2.3 Materials InterGroup Consultants was provided with to review;

Response:

Ms. Lee, Mr. Bowman and Ms. Davies were directed to the materials on the record of the present proceeding, and were provided copies of public materials that were filed with the BCUC in past proceedings relating to the Jet Fuel Line.

Copies of additional materials InterGroup was provided with to review are attached as Appendix PKMJF 7.2.3.

7.2.4 InterGroup Consultants working papers; and

Response:

InterGroup is still reviewing its records for working papers. VAFFC will provide any such working papers that InterGroup locates in due course.

7.2.5 Full report outputs.

Response:

InterGroup's full report outputs are provided in the InterGroup Report.[24]

[24] Exhibit C2-36-1, pdf pp. 18-190.

December 16, 2011

VANCOUVER AIRPORT FUEL DELIVERY PROJECT

Evaluation of Fuel Delivery Options

Submitted to:
Vancouver Airport Fuel Facilities Corporation (VAFFC)
c/o FSM Management Group Inc.
#103-12300 Horseshoe Way
Richmond, BC
V7A 4Z1

REPORT

Report Number: 1114470246-003-R-Rev0

Distribution:

3 Copies - VAFFC

2 Copies - Golder Associates Ltd.

2 Copies - Ausenco Sandwell

Ausenco Sandwell

Golder Associates

Acronyms

COSEWIC	Committee on the Status of Endangered Wildlife in Canada
DWT	Dead Weight Tonnage
EAC	Environmental Assessment Certificate
EAO	Environmental Assessment Office
FTE	full time equivalent (jobs)
GHG	greenhouse gas
km	kilometres
M l/d	million litres per day
M l/y	million litres per year
NO_x	Oxides of nitrogen
NWPA	Navigable Water Protection Application
OCIMF	Oil Companies International Marine Forum
PLEM	Pipeline end manifold
RFP	Request for Proposal
SARA	Species at Risk Act
SO_2	Sulphur dioxide
SPM	Single Point Mooring
TMJFI	Trans Mountain Jet Fuel Inc.
VAFFC	Vancouver Airport Fuel Facilities Corporation
YVR	Vancouver International Airport

Disclaimer

Reader's attention is specially drawn to the information contained in the Limitations and Use of Report page which is included in this report immediately subsequent to the Executive Summary. This report is written without prejudice to issues of aboriginal and/or treaty rights in all sections where the First Nations considerations are discussed.

Executive Summary

Vancouver Airport Fuel Facilities Corporation (VAFFC) retained Golder Associates Ltd. (Golder) and Ausenco Engineering Canada Inc. (Ausenco) to provide an independent and transparent high-level evaluation of four identified fuel delivery options. This report documents the results of the options evaluation.

VAFFC owns and operates fuel storage and distribution facilities at the Vancouver International Airport (YVR), which are shared among the airlines to provide the 1.4 billion litres per year (B l/y) of current JetA1 fuel demand. VAFFC seeks to increase the supply to meet anticipated future demands of 3 B l/y. The existing Trans Mountain Jet Fuel (TMJF) pipeline that runs from Westridge Terminal (Burrard Inlet, Canada) and Chevron's refinery does not have sufficient capacity to meet the current demands. Additional volumes are being supplied by tanker trucks directly to YVR from the Cherry Point refinery (Washington, USA).

Based on air passenger forecasts by YVR, VAFFC expects limitations of the current fuel delivery system to become critical by 2013. Thus, VAFFC is considering new fuel delivery options to address the issue of greater demand, while improving access to international jet fuel markets and enhancing cost efficiency. The four fuel delivery options that are the subject of the evaluation are as follows:

- **Option 1:** Modification of an existing deep-water terminal located on the north shore of South Arm Fraser River into a jet fuel offloading terminal, development of a new fuel storage facility (*i.e.*, a tank farm) and a pipeline connecting the facility to the existing YVR tank farm;
- **Option 2:** Development of a new offshore jet fuel offloading terminal off Sea Island and a pipeline to the existing YVR tank farm, and expansion of the existing tank farm to increase the storage capacity. Three potentially feasible alternatives are evaluated within this option: a single point mooring (SPM) system; a spread mooring (SM) system; and a fixed marine terminal.
- **Option 3:** Upgrade and/or replacement of the existing TMJF pipeline delivery system, and expansion of the jet fuel storage capacity at the existing Westridge Terminal; and
- **Option 4:** Modification of an existing marine terminal to serve as the transhipment terminal for large jet fuel tankers (including development of a new jet fuel tank farm and a new jet fuel barge loading facility on the north shore of Burrard Inlet), development of a jet fuel barge unloading terminal on the south bank of North Arm Fraser River near YVR, and development of a short pipeline to the existing YVR tank farm.

The analysis was carried out using an established multi-criteria analysis process, by examining project alternatives based on environmental, social, economic and technical criteria. The following approach was adopted to complete the options analysis:

- Dissect the complex issues to identify the various environmental, social, economic and technical priorities involved and develop a list of criteria or indicators for the priorities;
- Analyze the multiple indicators individually and jointly; and
- Evaluate the various indicators and present the process and the results of the evaluation in an open and transparent manner.

Environmental, social, economic, and technical criteria were developed to evaluate the fuel delivery options. The criteria are organized into a system with five "dimensions," namely Environmental, Socio-economic, First Nations, Operations, and Economic. A panel of senior environmental, social, economic, engineering, and maritime professionals from Golder and Ausenco was assembled for the analysis, with each panel member responsible for reviewing available information on the fuel delivery options and participating in an Options Analysis Workshop. The evaluation panel members identified broad-level considerations (priorities) or "themes" within each dimension, and then specific "indicators" were identified for each theme. The dimensions, themes, and indicators are depicted in Figure E-1.

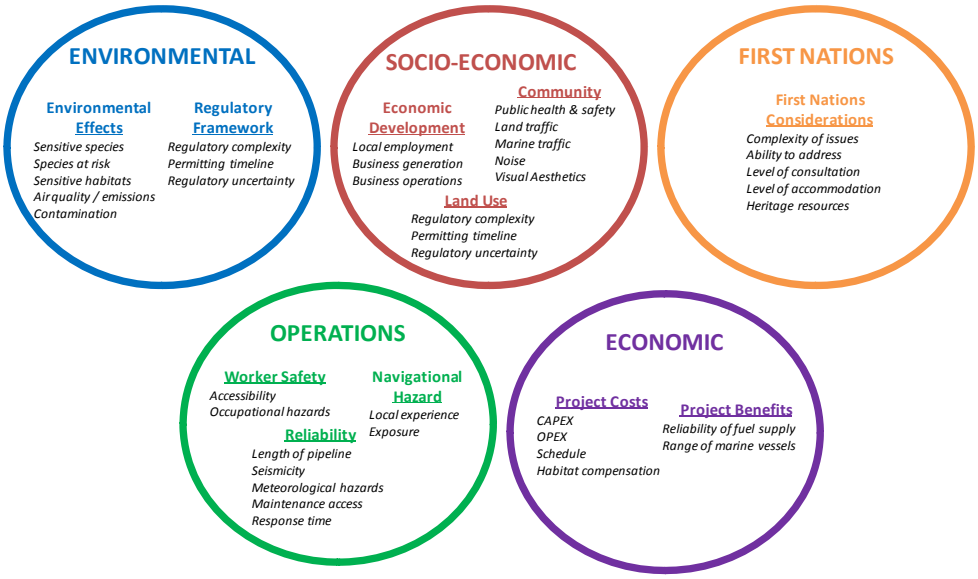

Figure E-1: Dimensions, Themes, and Indicators Considered in the Options Evaluation

The indicators were selected to represent the key project-specific criteria with a common understanding based on existing information and professional judgment. These indicators were intended to be sufficiently comprehensive and representative. They were selected based on professional judgment of relevance to the fuel delivery options and to reflect the potential subject of concerns to project interest groups including the various regulatory governing bodies, First Nations, and the proponent (VAFFC).

Option 1 has the highest merit compared to the others based on 80% of indicators being rated as negligible or minor concern as shown in Figure E-2. This is followed by Options 4 and 2C with corresponding percentages of about 70% and 65%, respectively.

The theme and overall dimension scores established for each option are illustrated in Figure E-3. All indicators are weighted equally within each theme, and all themes are weighted equally in each dimension. The comparisons are all relative, and the bar charts provide an overview where visual comparisons can be easily made. The graphs allow comparison of options against each other, within a given dimension. They also show the contribution of each theme within a dimension, as illustrated by the stacked bars that make up each column.

Consistent with the evaluations of indicator ratings and individual theme and dimension scores, the most favourable options appear to be Option 1 and Option 4. The main differences and disadvantages with Option 4 relative to Option 1 are the additional operational costs and schedule implications associated with the necessary transhipment facility. In addition, VAFFC would not retain full operational control of the system and would be subject to long-term agreements with the transhipment and storage facility and the transporting barge/tug operators. The advantages of Option 4 over Option 1 include a) utilization of an existing local marine terminal

which will result in a slightly more favourable socio-economic condition, primarily associated with less disruption to the community and current land use and b) somewhat lesser operational concerns (with the exception of frequent barge activities and weather hazards). A summary of the estimated costs for the options evaluated and the associated key contributing factors are presented in Appendix A

For a more detailed presentation of a summary of results, the reader is referred to Section 6.0 of the report.

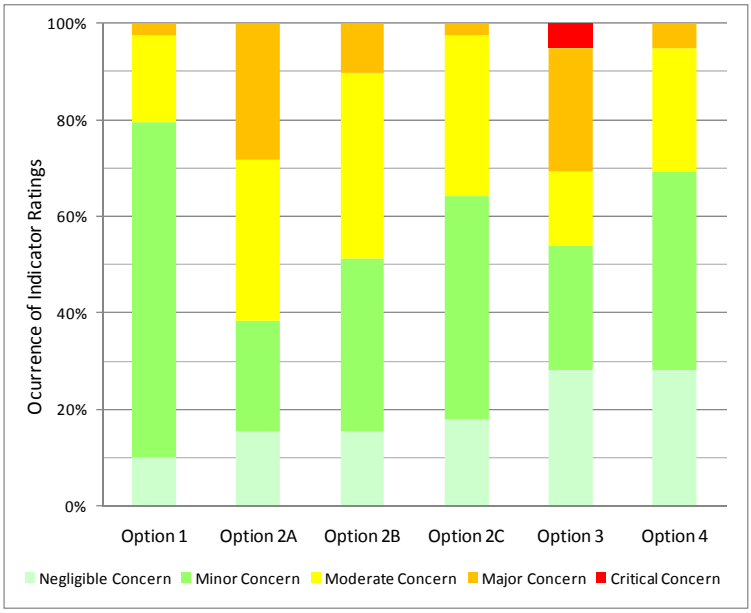

Figure E-2: Occurrence of Indicator Ratings by Option

VAFFC - EVALUATION OF FUEL DELIVERY OPTIONS

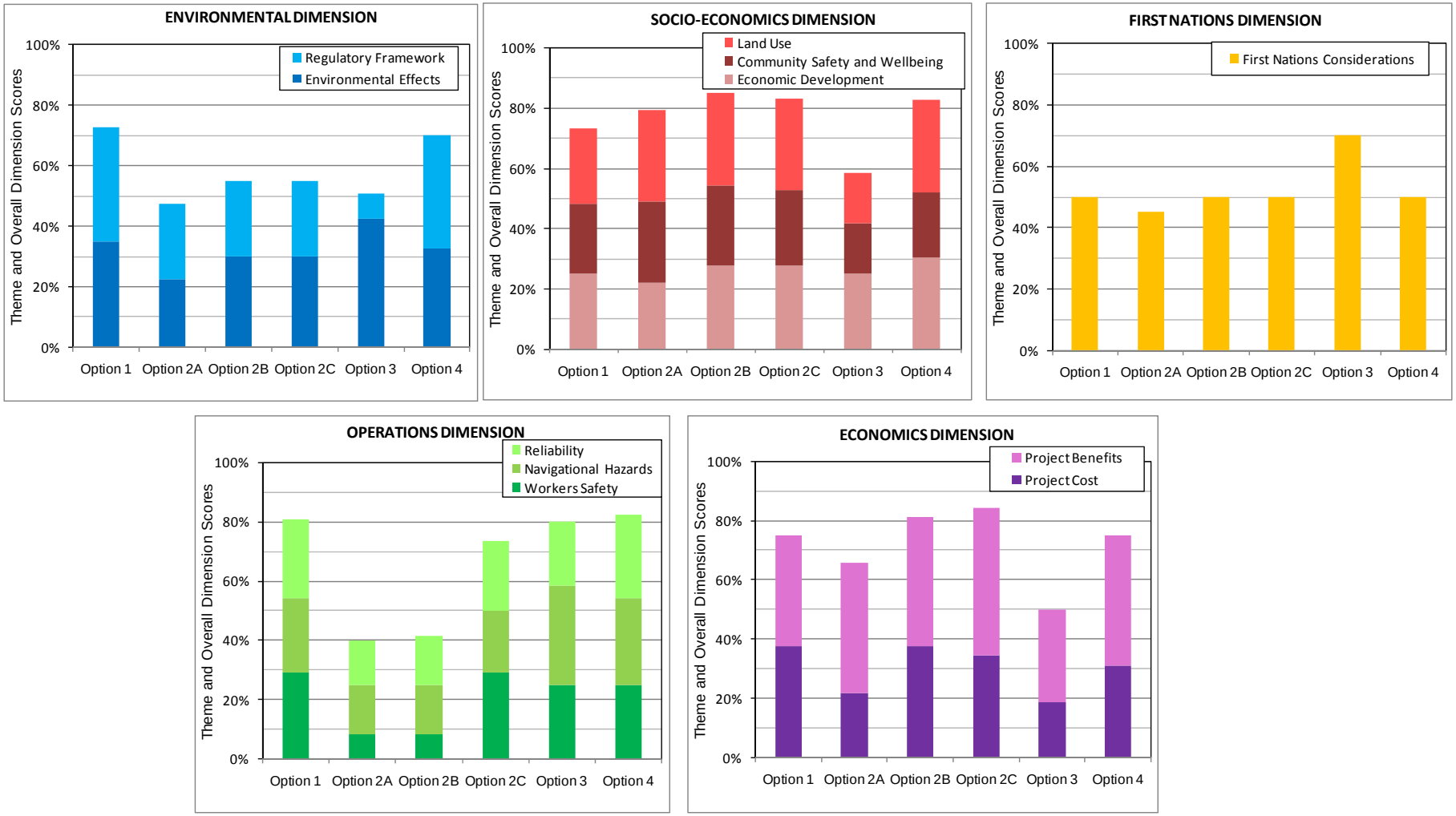

Figure E-3: Results by DIMENSION: Contribution of Theme Scores for Each Option

Limitations and Use of Report

This report was prepared for the exclusive use of VAFFC and it is intended to present the results of a multi-criteria evaluation for four fuel delivery options for YVR with respect to Environmental, Socio-community, First Nations, Operations and Economics. Any use that a third party makes of this report, or any reliance on or decisions to be made based on it, are the responsibility of the third parties. No assurance is made regarding the accuracy and completeness of the data reviewed. Golder disclaims responsibility of consequential financial effects on transactions or property values, or requirements for follow-up actions and costs.

The report is prepared based on the data and information available during the evaluation conducted by Golder and Ausenco, and must be considered in its entirety. It is based on the information associated with Option 1 provided by VAFFC at the time of the evaluation, including discussions with VAFFC personnel, and the available public domain information relevant to the evaluation of Options 2, 3 and 4, as presented in this report. No field sampling and analytical testing at or in proximity to any of four the potential project option sites was conducted as part of this evaluation.

In evaluating the options, Golder and Ausenco have relied in good faith on information provided as well as the public domain information and we have assumed that the information is factual and accurate. We accept no responsibility for any deficiency, misstatement or inaccuracy contained in this report as a result of omissions, misinterpretations or fraudulent acts of persons interviewed or contacted.

Further to the foregoing, but with specific regard to First Nations considerations, the evaluation presented in this report is without prejudice to aboriginal rights, including aboriginal title, and treaty rights, and is not intended for use as a replacement for consultation with First Nations whose interests may be adversely affected by any of the options reviewed for the purposes of this report.

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TABLES

FIGURES

APPENDICES

1.0 INTRODUCTION

Vancouver Airport Fuel Facilities Corporation (VAFFC) has retained Golder Associates Ltd. (Golder) and Ausenco Engineering Canada Inc. (Ausenco) to independently examine the technical and commercial viability of long-term alternative systems for aviation fuel delivery to Vancouver International Airport (YVR).

This report presents an evaluation of four potential fuel delivery options to YVR, as identified in the VAFFC Request for Proposals dated July 4, 2011. The objective is to provide an independent and transparent high-level evaluation of the VAFFC fuel delivery options according to environmental, social, economic, and technical criteria. A panel of senior environmental, social, economic, engineering, and maritime professionals from Golder and Ausenco was assembled for the analysis. Each panel member was responsible for reviewing available information on the fuel delivery options and participating in an Options Analysis Workshop. During the workshop, the options were collectively evaluated by the panel.

This report presents the background, approach, and results of the analysis. Following this Introduction section, the report is organized as follows:

- **Section 2** – Background information on the existing fuel delivery system, anticipated future requirements, and the proposed VAFFC fuel delivery project that is currently under review by the British Columbia Environmental Assessment Office (BC EAO);
- **Section 3** – Approach for the options analysis, including the evaluation criteria;
- **Section 4** – The fuel delivery options considered in the analysis;
- **Section 5** – Results of the analysis for each fuel delivery option; and
- **Section 6** – Summary of results.

2.0 BACKGROUND

VAFFC is a not-for-profit organization owned by a consortium of commercial airlines that represents a significant portion of international and domestic carriers that operate out of YVR. VAFFC owns and operates fuel storage and distribution facilities at the airport including fuel storage tanks, an underground pipeline hydrant system, and related equipment used to transfer fuel to the airplanes. These facilities are shared among the airlines to avoid duplication and enhance efficiency.

2.1 Existing Fuel Delivery System

The current consumption of JetA1 fuel is approximately 1.4 billion litres per year, with a peak demand of five million litres per day (M l/d). To meet future demands, the Fuel Delivery Project is designed to deliver three billion litres per year, with a peak demand of 10 M l/d.

Currently, JetA1 fuel for YVR is sourced primarily from two refineries: Chevron Canada Limited's refinery located on the south shore of Burrard Inlet in Burnaby (BC, Canada), and BP's Cherry Point refinery located south of Blaine in Washington, USA. In addition, a limited amount of product is also sourced from international suppliers and arrives via product tankers to the Westridge Terminal in Burnaby (BC, Canada).

Approximately 80% of YVR's current JetA1 fuel is transported to YVR via a pipeline owned and operated by Trans Mountain Jet Fuel Inc (TMJFI). The TMJFI pipeline was commissioned in 1969 and runs from Westridge Terminal and Chevron's refinery, both located on the south shore of Burrard Inlet, through Burnaby, Richmond, and Sea Island, to the existing YVR tank farm (52 million litres capacity). The pipeline has a maximum effective capacity in the order of 4 M l/d, and transports all of the Chevron jet fuel product and part of the Cherry Point jet fuel (shipped by barges to Westridge). The remaining 20% of the jet fuel is delivered directly to YVR from the Cherry Point refinery via tanker trucks.

The existing TMJFI pipeline is already at capacity and cannot meet the project throughput criteria of 10 M l/d.

2.2 Future Airport Requirements

Without a new fuel delivery system, any further growth in fuel demand at YVR will necessitate increased use of tanker trucks for delivery from the Cherry Point Refinery. This is not considered a viable option over the long-term due to the anticipated large quantity of fuel and large number of trucks that would be required. Based on air passenger forecasts by Vancouver Airport Authority, VAFFC expects limitations of the current fuel delivery system to become critical by 2013 (VAFFC, 2011). VAFFC is therefore considering new fuel delivery options to address the issue of greater demand, improve the access to international jet fuel markets, and enhance the cost efficiency as demanded by the various commercial airlines.

Assuming that the current fuel suppliers maintain the present delivery rates, an additional 1,600 M l/y from international suppliers will be required to meet the anticipated long-term demand for fuel. Table 1 provides a summary of the anticipated future demand for fuel from YVR and the expected sources.

Table 1: Anticipated Future Demand for JetA1 Fuel at YVR

Fuel Supplier	Annual Demand (M l/y)	Peak Daily Demand (M l/d)	%
Chevron Burnaby	500	1.6	16
Cherry Point	700	2.4	24
International Offshore Source	1,800	6	60
Total Anticipated Demand	3,000	10	100

2.3 Proposed and Alternative Fuel Delivery Systems

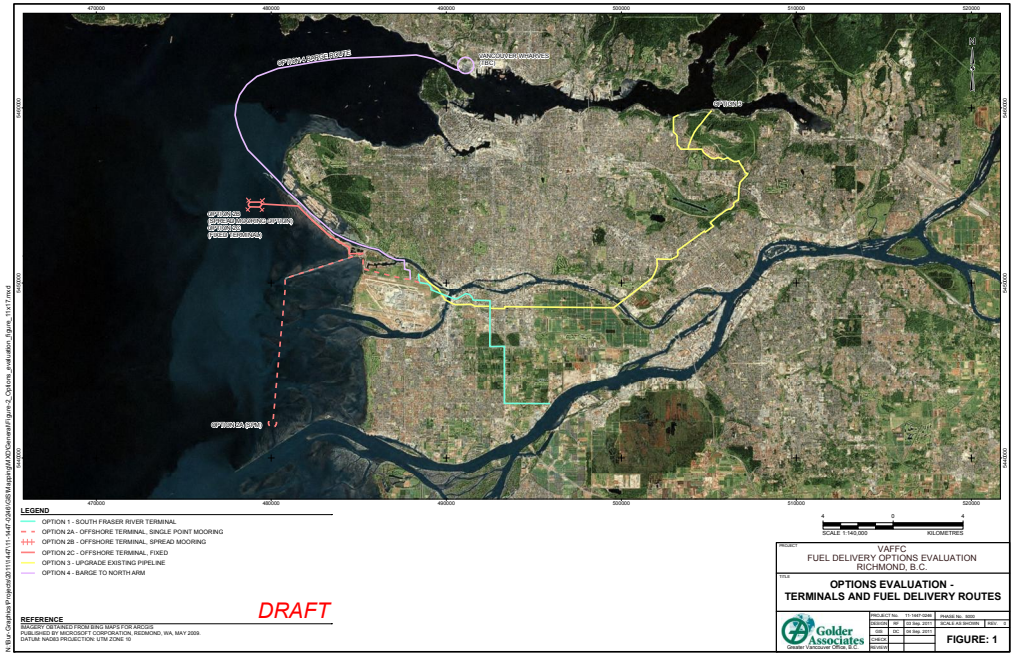
The primary objective of VAFFC's fuel delivery project is to secure a reliable and long-term fuel supply that will meet the future needs of YVR with increased capacity and, at the same time, be able to access diversified fuel supply sources including offshore and international markets.

A number of potentially feasible jet fuel delivery options to YVR have been identified and investigated by VAFFC over the past several years. An initial evaluation process, based on environmental, social, economic and regulatory criteria, resulted in a shortlist of four options that were included in the YVR Master Plan in 2006. One of the feasible options identified during this evaluation involves a marine terminal on the South Arm of Fraser River (north bank), a jet fuel receiving facility close to the terminal, and an underground pipeline connecting to the jet fuel storage facilities at YVR. This option is being proposed by VAFFC, and is the subject of a harmonized provincial-federal environmental assessment and of the detailed Environmental Assessment Certificate (EAC) Application that is currently under review.

In order to address stakeholder concerns and questions raised during the EAC Application review process, VAFFC initiated an independent evaluation of the potentially feasible fuel delivery alternatives. The evaluation includes the currently proposed project (Option 1), two of the other potentially feasibly options identified in the initial 2006 evaluation (Options 2 and 3), and another option recently identified by VAFFC (Option 4). (The fourth option identified in 2006 involved railcar transport from a refinery in Alberta and is no longer considered viable since Alberta is now a net importer of jet fuel.) The following bullets describe the four options that are currently considered feasible, and that are included in this options evaluation:

- Option 1: Modification of an existing deep-water terminal located on the north shore of South Arm Fraser River into a jet fuel offloading terminal, development of a new fuel storage facility (*i.e.,* a tank farm) and a pipeline connecting the facility to the existing YVR tank farm;
- Option 2: Development of a new offshore jet fuel offloading terminal off Sea Island and a pipeline to the existing YVR tank farm, and expansion of the existing tank farm to increase the storage capacity. Three potentially feasible alternatives are evaluated within this option including a single point mooring (SPM) system, a spread mooring (SM) system, and a fixed marine terminal;
- Option 3: Upgrade and/or replacement of the existing TMJFI pipeline delivery system, and expansion of the jet fuel storage capacity at the existing Westridge Terminal; and
- Option 4: Modification of an existing marine terminal to serve as the transhipment terminal for large jet fuel tankers (including development of a new jet fuel tank farm and a new jet fuel barge loading facility in North Vancouver on the north shore of Burrard Inlet), development of a jet fuel barge unloading terminal on the south bank of North Arm Fraser River near YVR, and development of a short pipeline to the existing YVR tank farm.

The terminal and fuel delivery routes of these four options are shown in Figure 1, and detailed descriptions are provided in Section 4.



LEGEND

- OPTION 1 - SOUTH FRASER RIVER TERMINAL
- OPTION 2A - OFFSHORE TERMINAL, SINGLE POINT MOORING
- OPTION 2B - OFFSHORE TERMINAL, SPREAD MOORING
- OPTION 2C - OFFSHORE TERMINAL, FIXED
- OPTION 3 - UPGRADE EXISTING PIPELINE
- OPTION 4 - BARGE TO NORTH ARM

DRAFT

REFERENCE

IMAGERY OBTAINED FROM BING MAPS FOR ARCGIS
PUBLISHED BY MICROSOFT CORPORATION, REDMOND, WA, MAY 2009.
DATUM: NAD83 PROJECTION: UTM ZONE 10

4 0 4
SCALE 1:140,000 KILOMETRES

PROJECT
VAFFC
FUEL DELIVERY OPTIONS EVALUATION
RICHMOND, B.C.

TITLE
OPTIONS EVALUATION -
TERMINALS AND FUEL DELIVERY ROUTES

Golder Associates
Greater Vancouver Office, B.C.

PROJECT No.	11-1447-0246	PHASE No.	8000
DESIGN	RF	22 Sep. 2011	SCALE AS SHOWN REV. 0
GIS	DC	22 Sep. 2011	**FIGURE: 1**
CHECK			
REVIEW			

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3.0 APPROACH

One of the key challenges in conducting the subject options evaluation involves the large number of competing environmental, social, economic and technical priorities. The potential project sites are located in areas with complex environmental interactions, multiple stakeholders, and various First Nations interests. Site conditions are also challenging from an engineering point of view, which affect both the construction and the operation of the project components. The following approach was adopted to complete the subject options analysis:

- Dissect the complex issues to identify the various environmental, social, economic and technical priorities involved and develop a list of criteria or indicators for the priorities;
- Analyze the multiple indicators individually and jointly;
- Evaluate the various indicators and present the process and the results of the evaluation in an open and transparent manner; and
- Present results in a concise and easy to understand manner.

The analysis was carried out using GoldSET, which is a sustainability decision-support tool developed by Golder (www.gold-set.com). GoldSET is based on the established multi-criteria analysis process, and examines project alternatives based on environmental, social, economic and technical criteria. This tool has been applied successfully for a wide range of projects, such as evaluation of site remediation, power line routing, environmental monitoring, and habitat compensation alternatives. The GoldSET process was adjusted to meet the needs of the subject options analysis, including streamlining the analysis to facilitate understanding by a wide range of interest groups.

The options evaluation process involved the following steps, as described in the following sections:

- Establishment of an evaluation panel consisting of a group of experts in the relevant fields;
- Development of an in-depth understanding of the options to be evaluated based on a review of available information and soliciting input from the panel experts;
- Establishment of the evaluation criteria based on input from the panel experts;
- Organization of an options analysis workshop where the panel experts assessed the various key issues and estimated the ratings of the key indicators; and
- Compilation of the options evaluation results.

3.1 Evaluation Panel

A panel of senior environmental, social, economic, engineering, and maritime professionals was assembled for the options analysis. The panel members were selected from Golder's environmental assessment, engineering, and sustainability decision-support teams and from Ausenco's marine engineering team (including external experts). A list of the panel members, along with their technical disciplines and affiliations, is provided in Table 2.

Table 2: Members of the Options Evaluation Panel

Company	Name	Discipline/Role
Golder Associates	Brian Griffin, BASc, PEng	Operational Risk Assessment/Workshop Facilitator
	James Ji, PhD, PEng	Project manager and technical review
	Deborah Chan-Yan, MASc, PEng	Project co-ordinator and technical review
	Upul Atukorala, PhD, PEng	Seismic Specialist
	Mark Johannes, PhD, RPBio	Environment Technical Lead
	Andrew Mason, MA, RPCA	Cultural Heritage Technical Lead
	Dave Munday, BSc, MBA, RPBio	Regulatory Technical Lead
	Evan Jones, MASc, PEng	EHS Management Specialist
	Roxanne Scott, MPA, MEd	Socio-economics Technical Lead
	Shauna McRanor, MAS, PhD Cand	First Nations Technical Lead
	Dicksen Tanzil, PhD, PE	Options analysis and decision support
	Reece Fowler, PhD, MIEMA, CEnv	Project co-ordinator, report production
Ausenco Sandwell	Bill Allen, PEng	Marine Structures Technical Lead/Specialist
	Thomas Lauga, PEng.	Cost and Economics Specialist (external consultant)
	John Swann, Captain, MMFG	Marine Operations Specialist

3.2 Review of Available Information

Information packages were provided to the evaluation panel experts prior to the Options Analysis Workshop. The fuel delivery options review was based on the following documentation:

- Request for Proposal (RFP) - Fuel Delivery Options Evaluation for Vancouver Airport Fuel Delivery Project (VAFFC, 2011);
- Vancouver Airport Fuel Delivery Project. Environmental Assessment Certificate Application (VAFFC, 2011);and
- Background information and baseline studies associated with the Environmental Assessment Certificate Application

Further to the above, the following key information sources pertaining to the project were obtained and reviewed:

- Preliminary Options Summary Table (Golder, unpublished), including review by panel members of independent information sources as a basis for understanding the setting for each option;
  - Independent information sources used for this review also included:
  - BC Conservation Data Center (CDC) Species and Ecosystem Explorer database and associated reports (www.env.gov.bc.ca/cdc);

- Committee on the status on Endangered Wildlife in Canada (COSEWIC) database and Species at Risk Act (SARA) public registry database reports(www.cosewic.gc.ca);
- Ecosystem Classification Information for BC;
- Government agency (Fisheries and Oceans Canada [DFO], BC Ministry of Environment [MOE], and summaries of watercourse distribution, which included search and review of the Habitat Wizard database (www.env.gov.bc.ca/habwiz);
- Fraser River Estuary Management Program habitat classification and mapping for Burrard Inlet and lower Fraser estuary; and
- Cohen Commission of Inquiry reporting on Lower Fraser River Habitats.

- Report – Offshore Marine Facilities Concept Review (Moffatt & Nichol for VAFFC, June 2009);
- TMJ Application for Approval of Tolls (Kinder Morgan, June 2007);
- Final Argument RE: TMJ application for approval of tolls and accelerated depreciation (VAFFC, December 2007);
- Report – Overview of Vancouver Offshore Petroleum Hydrocarbon Movements (Hatch, March 2006);
- GeoBC, "Corporate Applications" Theme, "[First Nations] Consultative Areas Database" Layer (http://geobc.gov.bc.ca/, accessed September 16, 2011); and
- Archaeology Branch, DgRs-17 Site Form and Maps (accessed December 6, 2011).

3.3 Evaluation Criteria

Environmental, social, economic, and technical criteria were developed to evaluate the fuel delivery options. The criteria are organized into a system with five "dimensions," namely Environmental, Socio-economic, First Nations, Operations, and Economic. Evaluation panel members identified broad-level considerations (priorities) or "themes" within each dimension, and then specific "indicators" were identified for each theme. The dimensions, themes, and indicators are depicted in Figure 2.

The indicators were selected to represent the key project-specific criteria with a common understanding based on existing information and professional judgement. These indicators were not intended to be exhaustive. Instead, they were intended to be comprehensive and representative. They were selected based on professional judgment of relevance to the fuel delivery options and to reflect the potential subject of concern to the project interest groups including the various regulatory governing bodies, First Nations, and the proponent (VAFFC). The evaluation dimensions and the related themes and indicators are described in Table 3.

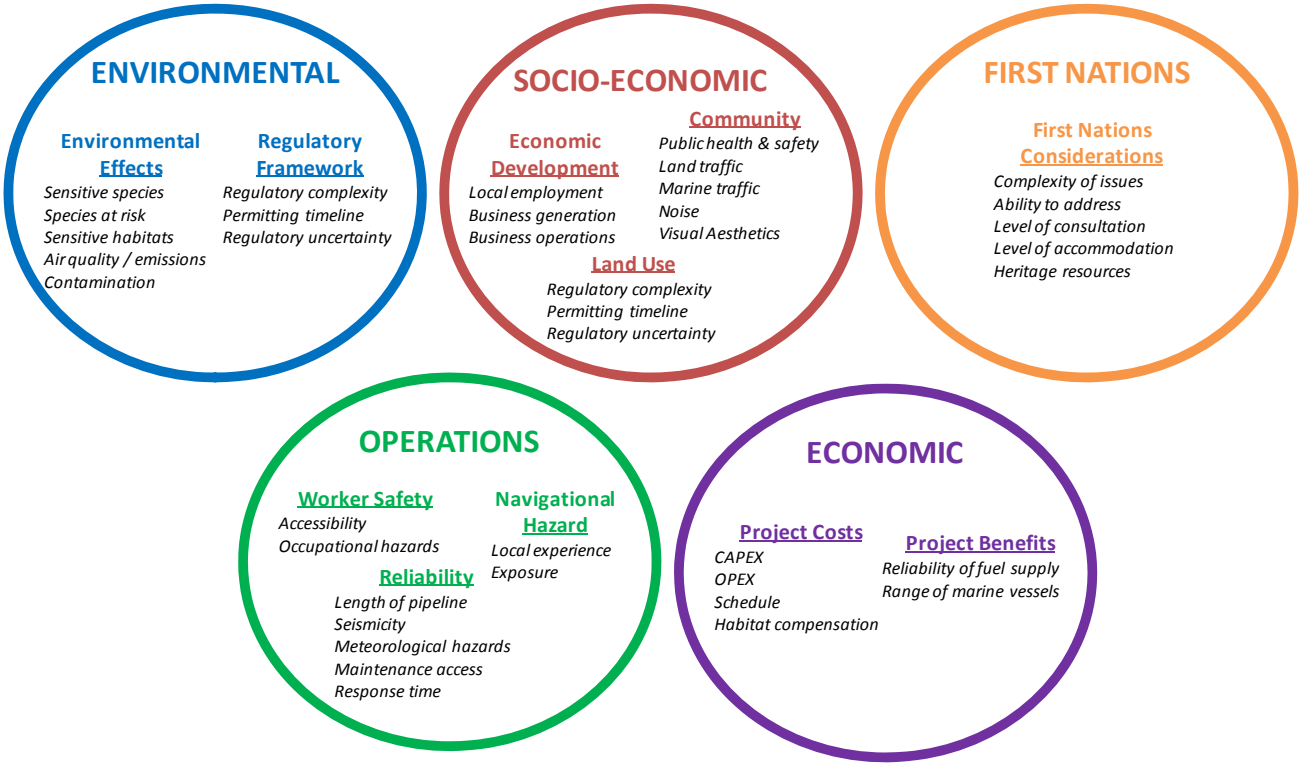


Figure 2: Dimensions, Themes, and Indicators Considered in the Options Evaluation

Table 3: Description of Dimensions, Themes, and Indicators Considered in Options Evaluation

Dimension/Theme	Indicators	Description/Parameters
ENVIRONMENTAL		
Environmental Effects	Sensitive species	Species identified in the project area, which rely on specific habitat conditions that are limited in numbers, restricted in their distribution and habitat use, or are particularly sensitive to disturbance through development (specific to the option).
	Species at risk (SAR)	An endangered, threatened species, or a species of special concern with known distribution and habitat use in the project area (specific to the option). SAR species list generated for the EAC application for the project, and checked against SARA listing and BC red and blue listed species.
	Sensitive habitats	Sensitive habitat areas include, but are not limited to, riparian corridors, wetlands, marine habitats, sea cliffs and shorelines, and habitats supporting rare, endangered, and unique species. Sensitive habitats are any area in which plant or animal life or their habitats are either rare or especially valuable for use by a species, and include the following: a) Habitats containing or supporting "rare and endangered" species as defined by BC species listings, SARA registry and COSEWIC; b) All perennial and intermittent streams, lakes, ponds and tributaries; c) Coastal tidal foreshore lands and marshes; d) Coastal and offshore areas containing breeding or nesting sites and coastal areas used by migratory and resident water-birds and marine mammals; e) Areas used for scientific study and research concerning fish and wildlife; f) Existing wildlife parks and reserves; and g) Existing environmental conditions.
	Air quality and GHG emissions	Air emissions, including greenhouse gas (GHG) from transportation, and vapour loss.
	Soil and water contamination	Risk of fuel spill resulting in soil or water contamination (include community receptors).
Regulatory Framework	Regulatory complexity	Number of authorizations, permits, approvals and licenses required (*i.e.,* federal, provincial, regional, municipal).
	Permitting timeline	Timeline to obtain the authorizations, permits, approvals, and licenses required.
	Regulatory uncertainty	Degree of understanding of the regulatory requirements.

VAFFC - EVALUATION OF FUEL DELIVERY OPTIONS

Dimension/Theme	Indicators	Description/Parameters
SOCIO-ECONOMICS		
Economic Development	Opportunity for direct local employment	Direct employment requirements for construction/operations, defined as full-time equivalents (FTEs).
	Opportunities for local business generation	Project expenditure allocation for purchase of local goods and services.
	Potential effects on business operations (*e.g.,* revenue generation)	Potential effects on business operations (*e.g.,* access restrictions, revenues) based on the number of commercial businesses as potential receptors.
Community Safety & Wellbeing	Potential public health and safety effects from spills and emissions	Public health and safety effects from potential accidental spills and releases and routine emissions.
	Potential effects on land based traffic	Public access and safety effects related to land based traffic.
	Potential effects on marine traffic	Public access and safety effects related to marine traffic.
	Noise	Anticipated acceptance of general construction noise by surrounding receptors.
	Visual Aesthetics	Aesthetic compatibility with local surroundings.
Land Use	Conformity with land use designation/zoning	Potential conflicts with land use designation and zoning.
	Property value effects	Potential effects to property values.
	Foreshore lease	Potential effects on ownership and the right to use the foreshore.

VAFFC - EVALUATION OF FUEL DELIVERY OPTIONS

Dimension/Theme	Indicators	Description/Parameters
FIRST NATIONS		
First Nations Considerations	Complexity of issues	Complexity of First Nations issues (*e.g.*, the number of First Nations involved, type/range of issues/interests).
	Ability to address issues	Degree to which First Nations issues have been/can be satisfactorily addressed by proponent.
	Level of consultation	Level/scope of consultation that the Crown may owe (as a result of its legal obligations), or delegate to proponent. The scope is based on strength of claim/nature of the established right and seriousness of potential new adverse impacts (as distinguished from past/historic impacts). Factors to be considered in informing scope include, for example, proximity to Indian reserves, continuous habitation and use, exclusive occupation/use versus seasonal use/open to others; overlapping claims; and potential reduction of an already limited resource.
	Level of accommodation	Degree of mitigation that the Crown may owe (as a result of its legal obligations) or expect of the proponent. Legal accommodation must be proportionate to the strength of claim/nature of the established right and seriousness of new adverse impacts (accommodation for any past/historic impacts is viewed as outside scope of consultation process).
	Heritage resources	Presence of heritage sites (*e.g.*, archaeological sites, historical sites).

VAFFC - EVALUATION OF FUEL DELIVERY OPTIONS

Dimension/Theme	Indicators	Description/Parameters
OPERATIONS		
Workers Safety	Accessibility	Accessibility of workers to facility.
	Occupational hazards	Exposure to occupational safety hazards (*e.g.*, equipment, water, hazardous materials).
Navigational Hazards	Local experience	Maturity of local experience on transport system.
	Exposure	Exposure to environmental conditions (*e.g.*, wind, tides, currents) and marine traffic hazards.
Reliability	Length of pipeline	Spill exposure based on operating length of pipeline.
	Seismicity	Potential effects of seismicity hazards, including climate and extreme weather evens on project facilities specific to the fuel delivery option.
	Meteorological Hazards	Potential effects of meteorological hazards, including climate an and extreme weather evens on project facilities specific to the fuel delivery option.
	Maintenance access	Access for maintenance, repair, routine inspection.
	Response time for malfunction	Ability to detect spills/malfunction and respond.
ECONOMIC		
Project Cost	CAPEX	Present value of the capital expenditure for the fuel delivery system including the marine terminal, fuel storage, and pipeline facilities.
	OPEX	Present value of the operating expenditure for the fuel delivery system including marine terminal, fuel storage, pipeline facilities, and transhipment costs (assuming 25 years of operational life).
	Schedule	Time to the start of operations.
	Habitat compensation	Habitat compensation (*e.g.*, migratory bird, fishes).
Project Benefits	Reliability of fuel supply	Access to multiple refineries and supplier sources, and continuous fuel supply.
	Accommodate full range of marine vessels	Accommodation for large and small size barges, as well as the Handymax and Panamax class vessels.

3.4 Options Evaluation Workshop

An Options Analysis Workshop was conducted with the evaluation panel on September 27, 2011, with the primary purpose of rating all project options for each of the indicators shown in Table 3. The workshop was undertaken following review of available information by the panel members and in accordance with the approach, procedure and criteria as discussed in the above sections. Each of the identified indicators was analyzed based on the available information and the knowledge/professional judgement of the senior professionals.

Initial ratings for all indicators of each option were obtained from the evaluation panel members during the workshop (see Section 3.5). All evaluation panel members were involved in subsequent discussion and confirmation of the ratings. Rationales for each rating, including evaluation criteria, were identified during the workshop. Follow-up information requirements and other issues and questions were also identified for participants to address subsequent to the workshop.

3.5 Ratings Scales and Compilation of Evaluation Results

Each indicator was rated on a scale of "Negligible Concern" to "Critical Concern" and colour coded for ease of reference, as shown in Table 4. The term "concern" as used in the rating scale refers to potential for impact, risk, or lack of expected benefit to any project interest group (*i.e.*, public, First Nations, regulators, or the proponent). This rating scale allows for both impact/risk and benefit to be rated on a single scale for each indicator. The highest and lowest rating levels are described explicitly, and other rating levels are interpolated between the two extremes.

Table 4: Indicator Rating Scale for the Options Analysis

Rating Level	Description	Score
Negligible Concern	Relatively amongst all 4 options, there is a non-measurable concern to stakeholder groups and First Nations	**5**
Minor Concern	Interpolated between Negligible Concern and Critical Concern	**4**
Moderate Concern		**3**
Major Concern		**2**
Critical Concern	Relatively amongst all 4 options, the concern is unacceptable to one or more of the stakeholder groups or First Nations	**1**

Notes:
(a) "concern" refers to potential for impact, risk, or lack of expected benefit
(b) Stakeholder groups include public, the regulatory institution representing the municipal, provincial and federal governments, and the project proponent.

Each indicator rating level is associated with a "score", also shown in Table 4. Higher scores are generally associated with higher "merit" (*i.e.*, lesser concerns). These scores are used to aggregate the individual indicator scores into theme scores, and subsequently into dimension scores. In each case, higher scores reflect higher merit or larger benefits.

Indicator scores are based on the professional judgement of the panel members drawn from the knowledge, expertise, and experience in their perspective field of practice, and considering the limited amount of information available at the conceptual stage, especially for Options 2, 3 and 4.

Theme scores are derived by aggregating the respective indicator scores, and based on an equal weighting for each indicator. That is, within a given theme, a Negligible Concern with respect to one indicator has the same weight as a Negligible Concern to another indicator. Similarly, a Critical Concern with respect to one indicator has the same weight as a Critical Concern to another indicator (for the same theme). A similar equal weighting approach is used to aggregate theme scores into dimension scores. The procedure is illustrated in Figure 3.

The theme and dimension scores are converted to percentages, with 100% corresponding to the highest possible outcome (highest merit) and 0% corresponding to the lowest possible score (lowest merit).

Results of the evaluation were reviewed by the evaluation panel before being finalized, and are presented in Section 5.

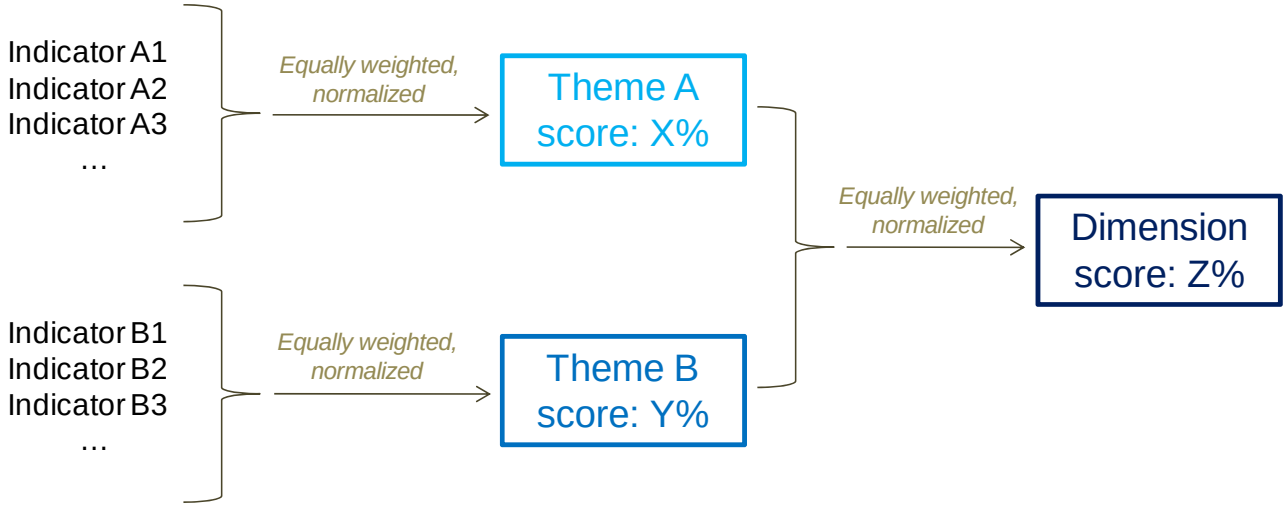


Figure 3: Procedure to Aggregate Indicator Scores into Theme Scores and then Dimension Scores

4.0 OPTIONS DEVELOPMENT

4.1 Option 1 - South Arm Fraser River Terminal with Pipeline to YVR

The South Fraser River Terminal Option will provide a Panamax capable terminal with an adjacent tank farm connected to YVR via a 15 kilometre (km) long underground pipeline (refer to Figure 4).

Operational Control – This option offers complete operational control to VAFFC.

Location – The terminal is located in Richmond on the north shore of the South Arm Fraser River near the eastern end of Williams Road. The site is zoned for industrial use, and an existing partially completed deep-water terminal is present at the site.

Operations – The proposed terminal will be able to accommodate Panamax-size product tankers (up to 75,000 dead weight tonnes (DWT)) and small to large size barges (from 5,000 DWT and up). Product is offloaded via ship or barge pumps and delivered directly into the storage tanks for subsequent transportation to the existing YVR tank farm via a 15 km long pipeline. During a one-year period, an estimated 36 ships and 120 barges (adding to a total of 156 vessel calls) can be expected to deliver 3,000 million litres of product. This number of vessel calls is within the capacity of a single berth.

Navigation to/from Terminal - The South Arm (main arm) of the Fraser River provides a guaranteed draught of 11.5 m, with a mandatory under keel clearance of 1.5 m. Large Panamax product tankers will normally exceed this draught with a full cargo of jet fuel, and therefore, will be restricted to less than full cargo capacity. Handymax vessels will generally be able to carry full jet fuel loads to the terminal, although partial cargoes are more common.

Tankers will navigate to the entrance of Fraser River, pick up a river pilot off Sand Heads, and followed by an approximately 21 km transit along the river channel to the terminal. Waiting for a high tide could potentially be required due to draught limitations depending on the arrival time of the tanker. Two or three tugs of approximately 3,000 hp be required to escort the tanker from Sand Heads to the berth and will assist with bringing the ship alongside the berth. Lines crews will make the vessel fast to the berth and the tugs will then be dispatched. After the ship pumps the cargo ashore and on completion of clearance formalities, a river pilot will board the vessel and tugs will assist the ship's departure from the berth. Tugs will swing the vessel in the channel and provide an escort downstream to Sand Heads where the river pilot will disembark and the tugs will disengage.

Tug and barge combinations will not be restricted by the draught, and tugs operated by experienced masters will likely not require pilots.

Operational Delays – Tidal conditions and reduced visibility may potentially result in delays.

Wave Conditions – The berth is not exposed to adverse wave conditions.

Pipelines - The berth is proposed to be connected to the terminal tank farm by a 500 m long high-capacity pipeline. The terminal tank farm will be connected to the existing YVR tank farm by a 15 km long pipeline, which will be designed to transfer the product at 10 M l/d.

Tank Farm Capacity – The total system tank farm capacity is 132 million litres with 80 million litres in six tanks at the terminal and 52 million litres at YVR.

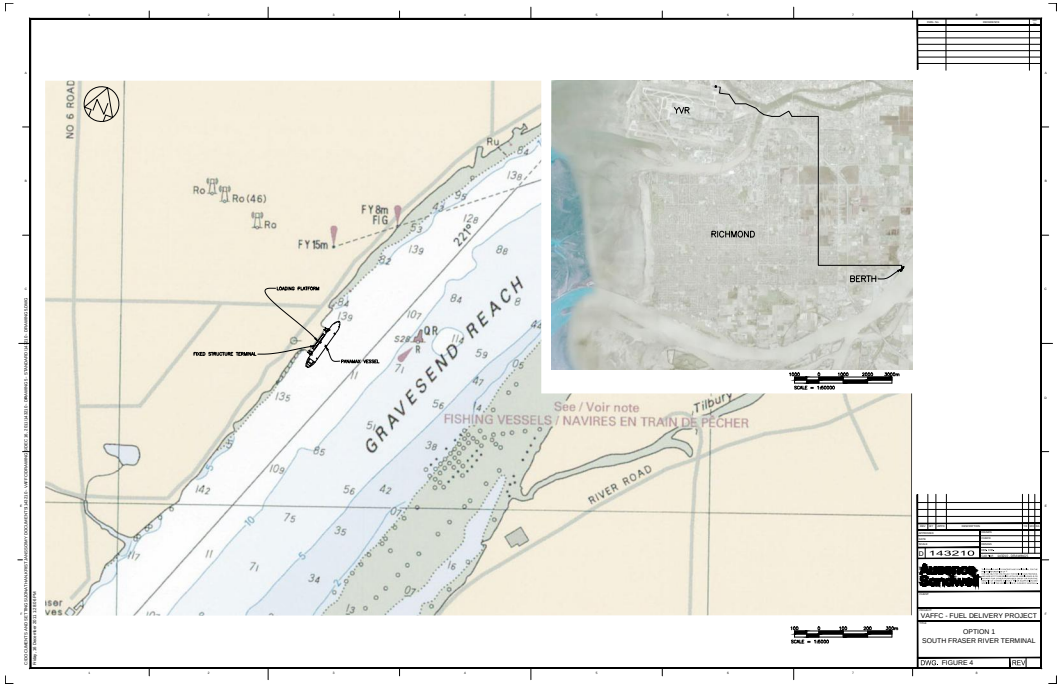
Access – The terminal would have direct road access allowing for unhindered movements to the vessel for supervisory staff, ship's agents, customs and port officials, and crew repatriation.

Maintenance – Terminal facilities are readily accessible from land for maintenance operations.

Duration of Construction Program – Following approval to proceed, the duration of the construction program is estimated to be about 24 months with an active on site work period estimated at 18 months.

Key Risks and Concerns:

- Potential risk of environmental contamination within the Fraser intertidal zone associated with accidental release of products from the operations of jet fuel tankers and the offloading terminal; and
- Potential risk of environmental contamination surrounding the pipeline associated with accidental release of products from the operations of the proposed new jet fuel pipeline through Richmond.


NO 6 ROAD
GRAVESEND REACH
LOADING PLATFORM
FIXED STRUCTURE TERMINAL
PANAMAX VESSEL
See / Voir note
FISHING VESSELS / NAVIRES EN TRAIN DE PÊCHER
RIVER ROAD
Tilbury
YVR
RICHMOND
BERTH
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SCALE = 1:6000
143210
VAFFC - FUEL DELIVERY PROJECT
OPTION 1
SOUTH FRASER RIVER TERMINAL
DWG. FIGURE 4
REV

4.2 Option 2 – Offshore Terminal Facility with Pipeline to YVR

Three potential alternatives were reviewed for an offshore jet fuel receiving terminal located generally west of Sea Island off Sturgeon Bank. These alternatives are presented in the following sections.

4.2.1 Option 2A - Single Point Mooring (SPM)

A single point mooring (SPM) system is an integrated arrangement for bow mooring a tanker and connecting to a submarine pipeline for discharging the product ashore. The vessel weather vanes about the mooring point aligning with current and wind forces. Due to this swinging motion, a large safety zone for exclusion of all other vessels is required while the tanker is moored at the SPM. The Oil Companies International Marine Forum (OCIMF) recommends an exclusion zone of 0.5 nautical miles (nm) (approximately 0.9 km) radius. Figure 5 illustrates the SPM system, and Figure 6 shows the subsea and on land pipeline locations along with connection to the YVR tank farm.

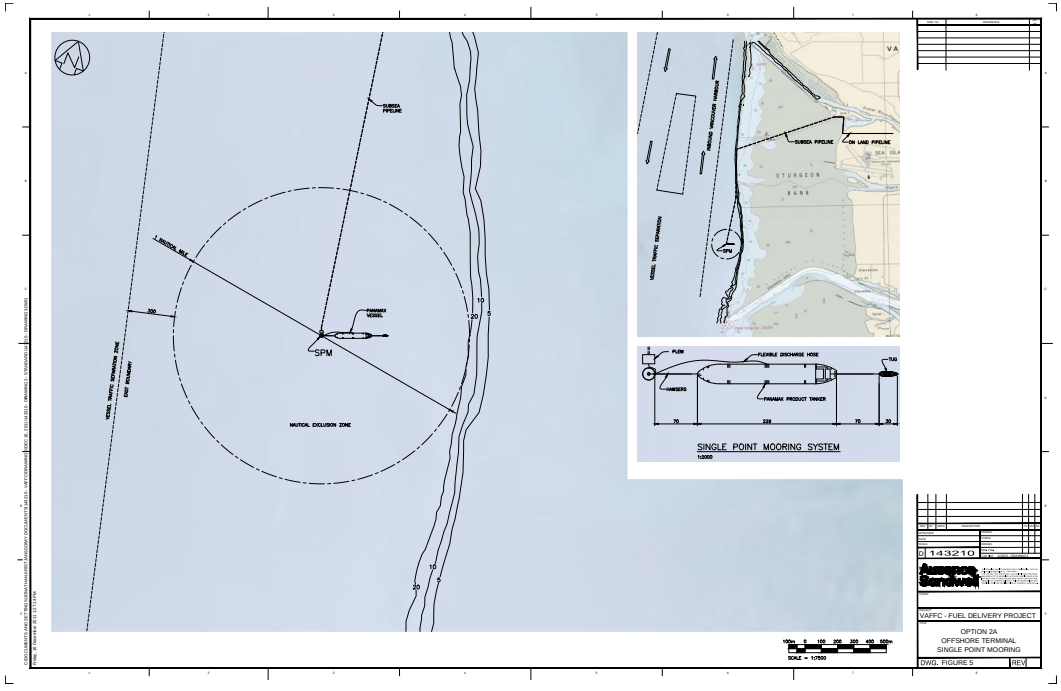
Operational Control – This option offers complete operational control to VAFFC.

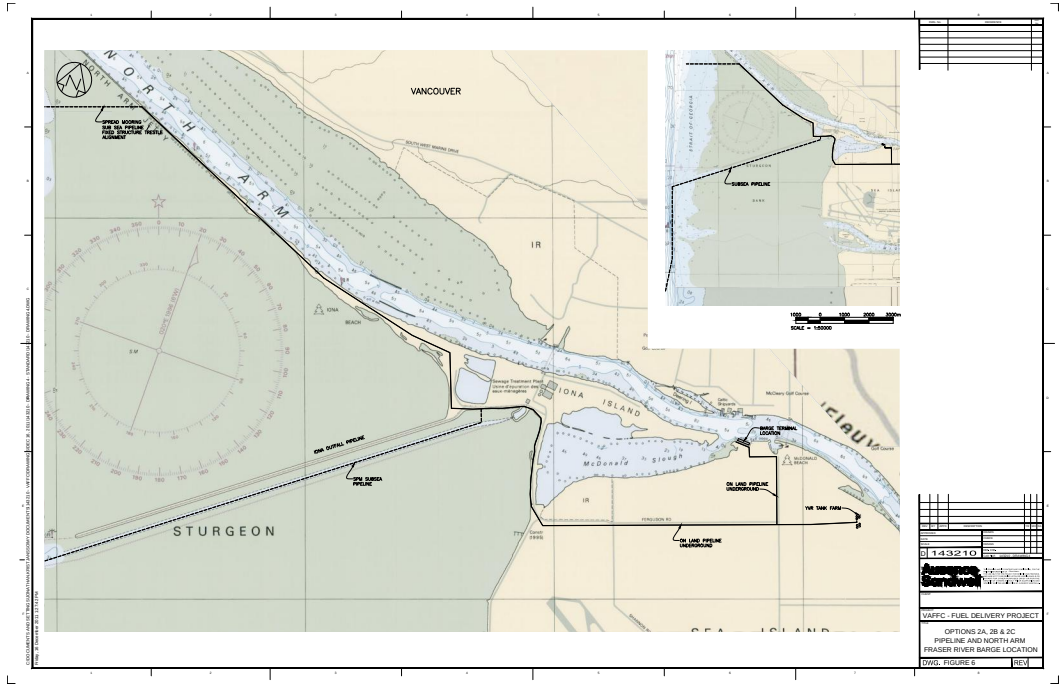
Location – In order to provide the required water depth, necessary exclusion zone, and clearance from the busy marine traffic corridor west of Sturgeon Bank,, the proposed SPM site will be located approximately 4.5 km due north of Sand Heads navigation light. The location is also selected to avoid conflict with the potential future expansion of a YVR runway extending onto the western shore of Sea Island.

Operations – Product tankers (up to Panamax size) would connect to the SPM and the vessel would pump fuel ashore via a combination subsea and onshore underground pipeline to the YVR tank farm. A booster pump station would be required to assist the ship's pumps due to the proposed pipeline length. The SPM will need to accommodate 36 ships per year to handle the 1.8 billion litres from offshore jet fuel suppliers. Barges could not be accommodated at the SPM due to operational constraints and significant potential downtime from adverse wind wave conditions. A separate barge terminal would be required to accommodate barge traffic from the Chevron and Cherry Point refineries. The North Arm barge terminal will offload 120 barge loads assuming that Chevron and Cherry Point jet fuel arrives by small barges (as opposed to the current transport by pipeline). Refer to Section 4.4 for further details of the barge unloading terminal.

Navigation to/from SPM – Ships would be able to approach the SPM system under most tidal conditions (no draught restrictions) and proceed up wind or against the current under guidance of two tugs of approximately 3,500 hp. The tugs would assist manoeuvring the tanker, pass hawsers to the ship's bow, and assist with bringing the floating flexible hose alongside the tanker. The hose would then be brought aboard using the ship's crane and made fast to the manifold. The operation would be under the guidance of a specialized pilot. One tug would remain on station or attached to a towing wire during the entire offloading process. On completion of offloading, the tug would assist with disconnecting the flexible pipeline and detaching the hawsers.

Operational Delays – Delays can be expected due to poor visibility and adverse wave conditions where tugs cannot operate during ship arrivals and departures. However, once the floating line is attached to the ship, SPM systems would be able to offload cargo during most weather conditions. Another potential cause of operational delay is associated with the need to purge the jet fuel pipeline after offloading. If fuel were to remain within a submarine pipeline, environmental damages may occur from a pipeline rupture induced by unforeseeable forces such as a strong earthquake.


SUBSEA PIPELINE
1 NAUTICAL MILE
330
PANAMAX VESSEL
SPM
VESSEL TRAFFIC SEPARATION ZONE
DOF RUNWAY
NAUTICAL EXCLUSION ZONE
10
20
5
SCALE = 1:7500
SUBSEA PIPELINE
ON LAND PIPELINE
HOUND WOODSIDE HARBOUR
VESSEL TRAFFIC SEPARATION
STURGEON BANK
SPM
FLOW
FLEXIBLE DISCHARGE HOSE
TUG
HAWSERS
PANAMAX PRODUCT TANKER
70
229
70
30
SINGLE POINT MOORING SYSTEM
1:2000
143210
VAFFC - FUEL DELIVERY PROJECT
OPTION 2A
OFFSHORE TERMINAL
SINGLE POINT MOORING
DWG. FIGURE 5
REV


VANCOUVER
NORTH ARM
SPECIAL MOORING BUOY STRUCTURE FOR FUEL BARGE DURING INSTALL ALIGNMENT
IR
IONA ISLAND
McDonald Slough
SUBSEA PIPELINE
BARGE SEAWARD LOCATION
ON LAND PIPELINE UNDERGROUND
YVR TANK FARM
STURGEON
SEA ISLAND
143210
VAFFC - FUEL DELIVERY PROJECT
OPTIONS 2A, 2B & 2C
PIPELINE AND NORTH ARM
FRASER RIVER BARGE LOCATION
DWG. FIGURE 6
REV

Wave Conditions – The SPM system would be subject to adverse wave conditions generally from the west and northwest directions. During ship arrivals and departures, tugs can generally operate in significant wave height up to 1.5 m. Above this operational limit the vessel would not be able to attach to the SPM system and would have to wait for weather conditions to moderate. From an analysis of predicted wave conditions, some 200 hours per year can be expected to exceed operating limits, which would result in vessel delays and possible demurrage charges.

Pipeline to Tank Farm – The SPM would be connected to the YVR tank farm via a pipeline end manifold (PLEM), an 11.8 km long subsea pipeline and a 5.2 km long buried onshore pipeline. In order to reduce the impact on Sturgeon Bank, the preferred alignment for the subsea pipeline would run north from the SPM and turn north eastward adjacent to the Iona outfall jetty. The onshore portion of the pipeline will be located within the YVR security fence, to the extent possible.

A barge unloading terminal to be located on the south bank of Fraser River North Arm will be used to handle smaller loads from local suppliers, which will be connected to the YVR tank farm by a 2 km long buried pipeline located along the road right of way.

Tank Farm Capacity – The total system tank farm capacity is proposed to be 132 million litres, with 80 million litres capacity to be added to the existing YVR tank farm which has a current capacity of 52 million litres.

Access – Supervisory staff, customs and port officials, pilots, ship's agents, and crew repatriation would be limited to water access via vessels, which could operate from Steveston, an one-way distance of approximately 15 km (8 nm).

Maintenance – Inspection of the SPM system, mooring chains, anchors, risers, floating hoses, hawsers and associated equipment would be required annually. The offshore maintenance would be scheduled around ship calls and weather windows, and would require significant diving inspection.

Duration of Construction Program – Following approval to proceed, the duration of construction program is estimated to be about 24 months with an active on site work period estimated at nine months.

Key Risks and Concerns:

- Exposed offshore location;
- Proximity to environmentally sensitive foreshore and intertidal habitats, including the land designated as a Regional Park (Iona Beach) and Sea Island Conservation Area;
- Difficult to access from the land and the associated reduced capability to execute an urgent large scale response when required;
- Proximity to a busy marine traffic corridor (the vessel separation zone for Vancouver Harbour);
- Long subsea pipeline;
- Construction of subsea pipeline adjacent to the Iona wastewater outfall pipeline; and
- Seismic event and potential earthquake-induced near-shore or submarine landslides, which may result in significant delay in fuel delivery for YVR associated with the loss of functionality of the facility.

4.2.2 Option 2B - Spread Mooring Alternative

A spread mooring (SM) system comprises a series of eight anchors and buoys located to secure the vessel in a relatively fixed position aligned with the prevailing wind, wave and current conditions (refer to Figure 7). The vessel would then be connected by a flexible hose to a subsea pipeline, which connects to the onshore pipeline and subsequently to the existing YVR tank farm as shown in Figure 6.

Operational Control – This option offers complete operational control to VAFFC.

Location – The proposed spread mooring is located approximately 1.6 km south of the North Arm Jetty navigation light, the location of which provides vessels with adequate water depth and the shortest subsea pipeline route to the onshore pipeline located along the North Arm Jetty as shown in Figure 7. The vessel's orientation would be selected to minimize the anticipated wave-induced motions for this relatively exposed location.

Operations – Product tankers (up to Panamax size) would connect to a flexible hose at the spread mooring system and the vessel would pump ashore via a subsea pipeline and an onshore underground pipeline to the YVR tank farm. A booster pump station would be required to assist the ship's pumps due to the pipeline length. The spread mooring system would need to accommodate 36 ships per year to handle the 1.8 billion litres from offshore jet fuel suppliers. Barges could not be accommodated at the spread mooring system due to operational constraints and significant downtime potential from adverse wind and wave conditions. A separate barge terminal would be required to accommodate barge traffic from the Chevron and Cherry Point refineries. The North Arm barge terminal will offload 120 barge loads assuming that Chevron and Cherry Point jet fuel arrives by small barge (as opposed to the current delivery by pipeline). Refer to Section 4.4 for further details of the terminal.

Navigation to/from Terminal – Ships would approach the terminal on an easterly heading, with the support of three tugs (of approximately 3,000 hp) in attendance. The tugs would be used to guide the vessel into the mooring area and to run lines to buoys, along with support during departure operations. There are no draught restrictions to operations at the terminal.

Operational Delays – Potential delays can be expected due to poor visibility and wave conditions where tugs cannot operate during ships arrival and departure. Wind and wave conditions will dictate the acceptable time for arrival and departure. Similar to that for Option 2A, another potential cause of operational delay is associated with the need to purge the jet fuel pipeline after offloading. If fuel were to remain within a submarine pipeline, environment damages may occur from a pipeline rupture induced by unforeseeable forces such as a strong earthquake.

Wave Conditions – The spread mooring system is subject to adverse wave conditions generally from the west and northwest directions. During ships arrival and departure, tugs can generally operate in significant wave height up to 1.5m. Above this operational limit, the vessel could not approach the spread moorings and would have to wait for weather conditions to moderate. From an analysis of predicted wave conditions, some 200 hours per year can be expected to exceed operating limits. This will result in vessel delays and possible demurrage charges.

Pipeline to Tank Farm – The spread moorings system would connect to the YVR tank farm via a pipeline end manifold (PLEM), a 2.3 km long subsea pipeline and a 9.6 km long buried onshore pipeline. The preferred pipeline alignment is the shortest distance to the onshore pipeline located on the North Arm Jetty, thereby reducing the environmental impact on Sturgeon Bank. The Sea Island portion of the onshore buried pipeline would be located inside the YVR security fence to the maximum extent possible.

A barge unloading terminal, to be located on the south bank of Fraser River South Arm, will be used to handle smaller loads from local suppliers, which will be connected to the YVR tank farm by a 2 km long buried pipeline located along the road right of way.

Tank Farm Capacity – The total system tank farm capacity would be 132 million litres, with 80 million litres capacity to be added to the existing YVR tank farm which has an existing capacity of 52 million litres.

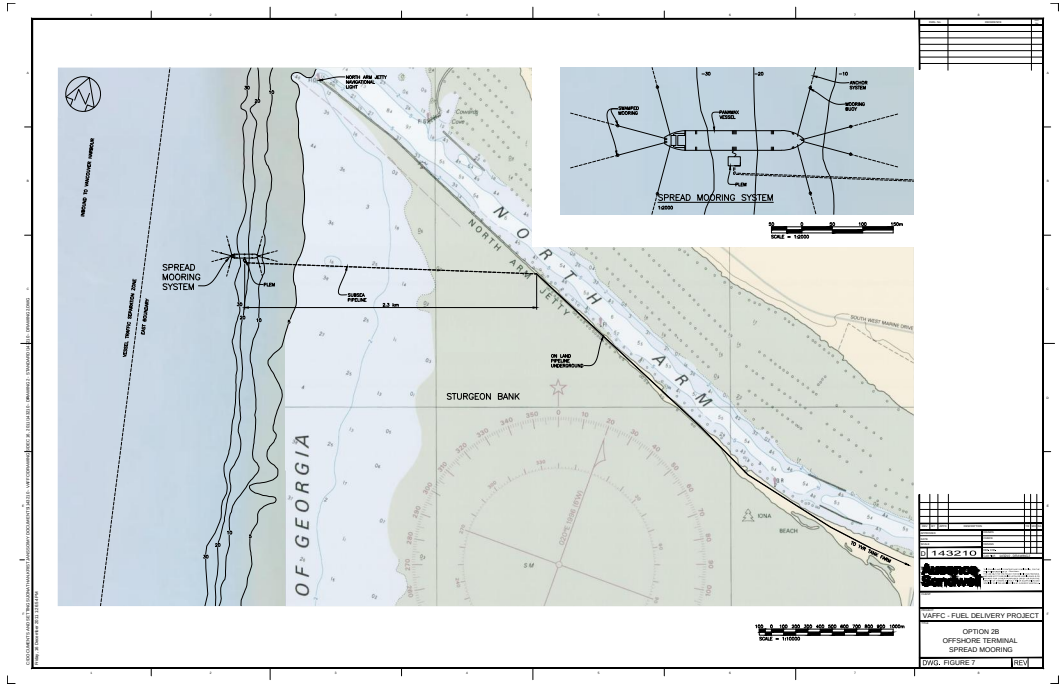
Access – Supervisory staff, customs and port officials, pilots, ship's agents, and crew repatriation would access ships by small vessels, which can be operated out of the North Arm, a distance of some 10 km (5.5 nm).

Maintenance – Annual inspection of the mooring chains, anchors, floating hoses, subsea manifold and associated equipment will require underwater inspection operations. The offshore maintenance would be scheduled around ship calls and weather windows and would require a significant amount of diving inspections.

Duration of Construction Program – Following approval to proceed, the duration of the construction program is estimated to be about 20 months with an active on site work period estimated at 8 months.

Key Risks and Concerns:

- Exposed offshore location;
- Proximity to environmentally sensitive foreshore and intertidal habitats, including the land designated as a Regional Park (Iona Beach) and Sea Island Conservation Area;
- Difficult to access from the land and the associated reduced capability to execute an urgent large scale response when required;
- Proximity to a busy marine traffic corridor (the vessel separation zone for Vancouver Harbour);
- Installation and operation of subsea pipeline within Sturgeon Bank, and
- Seismic event and potential earthquake-induced near-shore or submarine landslides, which may result in significant delay in fuel delivery for YVR associated with the loss of functionality of the facility.


SPREAD MOORING SYSTEM
NORTH ARM JETTY
NORTH ARM
STURGEON BANK
OF GEORGIA
ON LAND PIPELINE UNDERGROUND
SUBSEA PIPELINE
2.2 km
SPREAD MOORING SYSTEM
1:2000
SCALE = 1:2000
SCALE = 1:10000
143210
VAFFC - FUEL DELIVERY PROJECT
OPTION 2B
OFFSHORE TERMINAL
SPREAD MOORING
DWG. FIGURE 7
REV

4.2.3 Option 2C - Fixed Terminal Alternative

The fixed terminal would comprise pile-supported structures to berth and moor vessels up to Panamax class. The structure would also support loading arms which connect to the ship's manifold to allow pumping the jet fuel ashore (refer to Figure 8). The fixed terminal would be connected to shore via a pile-supported trestle which supports the pipeline and provides an access roadway for personnel and maintenance vehicles. Onshore pipeline would connect to the YVR tank farm as shown in Figure 6.

Operational Control – This option offers complete operational control to VAFFC.

Location – The proposed fixed structure terminal will be located 1.6 km south of the North Arm Jetty navigation light to provide adequate water depth and the shortest trestle route to the onshore pipeline. The preliminary orientation of the terminal is selected to minimize operational downtime induced by wave conditions at this relatively exposed location.

Operations – Product tankers (up to Panamax size) would connect to the loading arms on the loading platform and the vessel would pump the jet fuel ashore via a trestle mounted pipeline which is connected to a buried pipeline connecting to the existing YVR tank farm. A booster pump station would be required to assist the ship's pumps due to the pipeline length. Large barges, in the order of 20,000 DWT, could be accommodated at the fixed structure but smaller barges will require a separate North Arm barge unloading terminal. The fixed platform system will need to accommodate 36 ships per year to handle the 1.8 billion litres from offshore jet fuel suppliers. The North Arm barge unloading terminal will offload 120 barge loads assuming that Chevron and Cherry Point jet fuel arrives by small barges (as opposed to the current delivery by pipeline). Further discussions on the North Arm barge unloading terminal are provided in Section 4.4.

Navigation to/from Terminal – Ships would approach the terminal on an easterly heading with three tugs of approximately 3,000 hp in attendance. The tugs would guide the vessel into the berth and may be required to run lines to mooring facilities. Tugs would also be required during departure operations. There are no draught restrictions to operations at this terminal.

Operational Delays – Delays can be expected due to adverse fog conditions and wave conditions where tugs cannot operate during ships arrival and departure. Wind and wave conditions will dictate arrival and departure timing.

Wave Conditions – The fixed structure terminal would be subject to adverse wave conditions generally from the west and northwest directions. During ship arrivals and departures, tugs can generally operate in significant wave height up to 1.5 m. Above this operational limit the vessel cannot approach the terminal and will have to wait for weather conditions to moderate. From an analysis of predicted wave conditions, some 200 hours per year can be expected to exceed operating limits. This will result in vessel delays and possible demurrage charges.

Pipeline to Tank Farm – The fixed terminal would be connected to the YVR tank farm via loading arms linking to a pipeline of which the offshore segment would be supported by a trestle and onshore portion would be buried. The alignment of the 2.1 km long access trestle is selected as the shortest distance to the 9.6 km long onshore pipeline located on the North Arm Jetty. This alignment reduces the environmental impact on Sturgeon Bank. The Sea Island portion of the buried onshore pipeline would be located inside the YVR security fence to the maximum extent possible.

A barge unloading terminal to be located on the south bank of Fraser River South Arm will be used to handle smaller loads from local suppliers, which will be connected to the YVR tank farm by a 2 km long buried pipeline located along the road right of way.

Tank Farm Capacity – The total system tank farm capacity would be 132 million litres with 80 million litres capacity to be added to the existing YVR tank farm which has an existing capacity of 52 million litres.

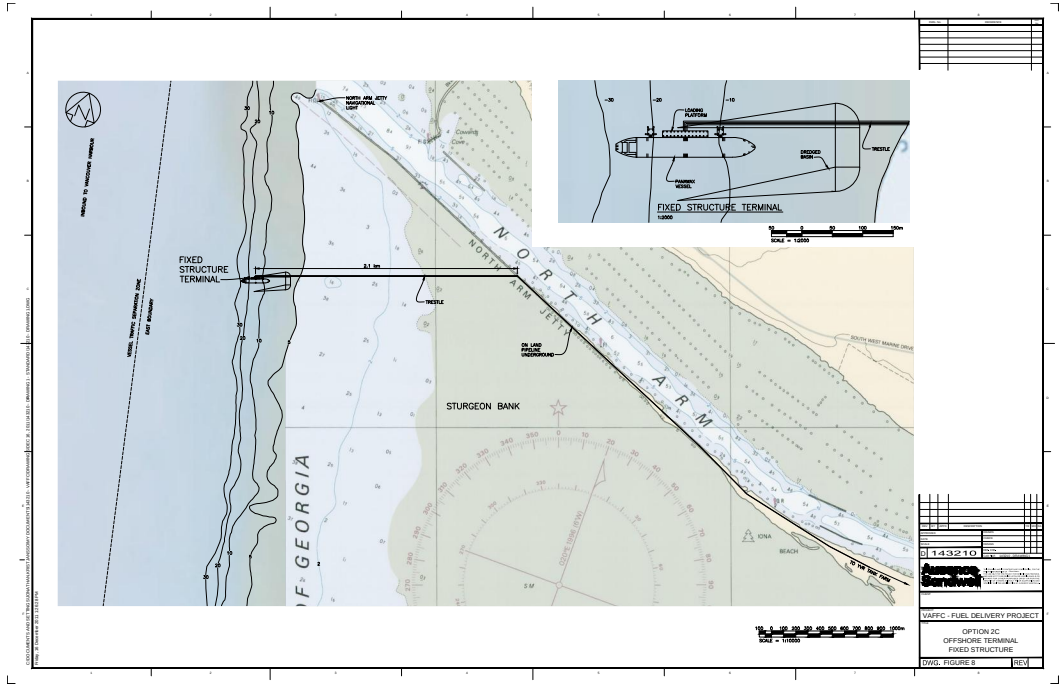
Access – Supervisory staff, customs and port officials, pilots, ship's agents, and crew would access the vessel via the trestle and roadway.

Maintenance – Annual inspection of the mooring facilities, pipeline, loading arms and associated equipment is required. There is direct access via the trestle for maintenance work. Only minimal over the water and subsea inspection and maintenance is necessary.

Duration of Construction Program – Following approval to proceed, the duration of the construction program is estimated to be about 24 months with an active on site work period estimated at 16 months.

Key Risks and Concerns:

- Exposed off-shore location;
- Proximity to environmentally sensitive foreshore and intertidal habitats, including the land designated as a Regional Park (Iona Beach) and Sea Island Conservation Area;
- Proximity to a busy marine traffic corridor (vessel separation zone for Vancouver Harbour); and
- Seismic event and potential earthquake-induced near-shore or submarine landslides, which may result in significant delay in fuel delivery for YVR associated with the loss of functionality of the facility.


FIXED STRUCTURE TERMINAL
2.1 km
TRESTLE
ON LAND PIPELINE UNDERGROUND
STURGEON BANK
NORTH ARM JETTY
NORTH ARM
OF GEORGIA
NORTH ARM JETTY MARGINAL LIGHT
VESSEL TRAFFIC SEPARATION ZONE
CAP STURGEON
IONA
BEACH
SOUTH WEST MARINE DRIVE
LOADING PLATFORM
DECKED BARGE
PASSENGER VESSEL
FIXED STRUCTURE TERMINAL
1:2000
SCALE = 1:2000
SCALE = 1:10000
143210
VAFFC - FUEL DELIVERY PROJECT
OPTION 2C
OFFSHORE TERMINAL
FIXED STRUCTURE
DWG. FIGURE 8
REV

4.3 Option 3 – Upgrading of Trans Mountain Jet Fuel Pipeline

This option envisages upgrading of the existing Trans Mountain Jet Fuel Inc (TMJF) pipeline and provision of a new, higher capacity pipeline between Westridge Terminal on the south shore of Burrard Inlet and the existing YVR tank farm. The approximate alignment of the existing TMJF pipeline is shown in Figure 1. Westridge Terminal marine facilities have recently been upgraded to Aframax-size standards, and can accommodate the smaller Panamax-class vessels.

Operational Control – VAFFC fuel facility operations will be subject to long-term contracts with the pipeline and terminal operators. Even if the pipeline right-of-way were obtained from the present owner, the marine terminal is likely to remain with the current ownership due to other important cargoes being handled at the facility.

Location – Westridge Terminal is located on the south shore of Burrard Inlet, east of Second Narrows Bridge.

Operations – Vessels would offload at the terminal and pump the jet fuel to onshore storage tanks. The jet fuels supplied by the Chevron refinery will be pumped to the storage tanks at Westridge via the existing (or the upgraded) pipeline. The product would then be transported from Westridge storage tanks via the new pipeline through Burnaby and Richmond to YVR. Jet fuel Barges from Cherry Point can be accommodated at Westridge. However, this traffic will increase the demand for berth space at an already busy terminal.

Navigation to/from Terminal – Product tankers would navigate through Vancouver Harbour and under the Second Narrows Bridge to Westridge Terminal. A minimum of three tugs would be required to assist and escort a tanker under the bridge and alongside the berth. The transit is subject to specified tidal conditions. Departure also requires tug assistance and escort.

Operational Delays – Potential delays associated with emergency and/or routine maintenance access to the long pipeline that is located within the densely populated urban areas. Tide conditions and poor visibility may cause delays to shipping. Delays to ships and barges waiting for berth allocation can be expected due to high utilization of the existing berth at Westridge.

Wave Conditions – Burrard Inlet is protected from adverse wave conditions.

Pipeline Alignment – The existing TMJF pipeline from Westridge and Chevron to YVR is approximately 41 km long. The existing 150 mm diameter pipeline will need to be replaced by a larger diameter line to meet the required minimum capacity of 10 million litres per day. In order to provide continuity of fuel supply to YVR, the existing line will need to remain in service during construction of a new pipeline and separation between the operating pipeline and the line under construction is required. Therefore, a significant amount of realignment and right-of-way acquisition will be required for construction of a new pipeline. The old line would be abandoned following a procedure approved by regulatory authorities which may require purging and cleaning, sectionalizing the line, soil remediation, removal of valves and pits, and possibly grout filling the line to meet this requirement.

Tank Farm Capacity – The existing Westridge Terminal JetA1 fuel tank farm capacity is approximately 36 million litres. To accommodate the discharge of Panamax vessels, storage capacity would need to be increased by a minimum of 44 million litres to provide 80 million litres total storage. The system storage capacity will total 132 million litres with a total of 80 million litres at Westridge and 52 million litres at YVR.

Access – Westridge Terminal has direct road access and the berth allows for unhindered movements for supervisory staff, customs and port officials, ship's agents and crew repatriation.

Maintenance - Increased maintenance and inspection requirements for the pipeline due to its close proximity to urban activities. Westridge Terminal is responsible for terminal maintenance, which is expected to be covered in the tariff for this service.

Duration of Construction Program – Following approval to proceed, the duration of the construction program is estimated to be a minimum of three years with an active on site work period estimated at two years.

Key Risks and Concerns:

- Operational and commercial risk of being locked into one delivery source that is beyond VAFFC's control (*i.e.*, loss of operational and cost control);
- Land and right-of-way acquisition;
- Construction of the jet fuel pipeline in residential areas;
- High utilization of Westridge Terminal by other commodities – possible demurrage against jet fuel product tankers and barges; or requirement to obtain priority berthing arrangements; and
- Increased risk of potential pipeline damages due to exposure of the long pipeline to urban development activities, and the difficulties associated with emergency and/or routine maintenance access within the densely populated urban zones.

4.4 Option 4 – Transhipping Facility and North Arm Barge Terminal

This option involves jet fuel being offloaded and stored at a transhipment terminal located on the north shore of Burrard Inlet, and subsequently transported to an unloading (receiving) terminal to be located on the south shore of Fraser River North Arm using purpose-built jet fuel barges. The necessary jet fuel storage capacity will need to be developed at the transhipment terminal together with a jet fuel barge loading terminal.

The barge receiving terminal would be located a short distance north of the existing YVR tank farm, and the fuel would be pumped from the barge unloading terminal to the tank farm via a short pipeline. This North Arm barge unloading terminal is also an integral component of the delivery systems discussed in Option 2 (refer Figure 9).

Interim Development - A combination of the proposed new North Arm Barge Terminal, the existing Westridge Terminal and the TMJF pipeline operating on an interim basis could accommodate increased YVR jet fuel requirements above the current TMJF practical pipeline capacity, while removing tanker trucks from the highways. Jet fuel could continue to be sourced from Chevron, Cherry Point and internationally for this purpose.

Operational and Commercial Control – VAFFC will require long-term contracts for the offsite transhipment terminal on the north shore of Burrard Inlet and transhipping barge operations. Potential transhipment terminals will require additional tank farm capacity to meet the 80 million litres required for offloading Panamax-class vessels. The owner of the transhipment terminal will need to control the development of the new tank capacity; however, VAFFC will likely have to enter long term contracts to allow for recovery of the transhipment terminal's investment in the storage facilities. These costs have been included as operating costs payable by VAFFC over the term of the contract for the purpose of the current options evaluation. Similarly, tug/barge operators will likely seek a long-term and exclusive contract with VAFFC to recover the capital cost of purpose-built jet fuel barges.

Location – A transhipment terminal, a new tank farm, and a jet fuel barge loading terminal is proposed on the north shore of Burrard Inlet. A jet fuel barge unloading (receiving) terminal would be located on the south shore of Fraser River North Arm a short distance (2 km) north west of the existing YVR tank farm.

Operation – The deep-sea vessels would offload product to a storage tank farm at the transhipment terminal. Jet fuel would be loaded onto barges and shipped from the transhipment terminal to the North Arm Barge Unloading Terminal in 10,000 DWT purpose-built shallow draft petroleum barges. The barge unloading terminal will be connected to the existing tank farm by a 2 km long underground pipeline.

Navigation to/from Terminal – Product tankers will be subject to the requirements of pilotage and tug assist specific to the selected transhipment terminal and relevant authorities. Barges will be loaded and transferred to the North Arm Barge Unloading Terminal with approximately 300 barge loads required annually to provide the future requirements of three billion litres of jet fuel per year. Due to the relatively short barge offloading time, a single berth is anticipated to be able to handle the barge traffic. Of the 300 barge loads, approximately 120 loads will come directly from the Chevron and Cherry Point refineries.

Exposure – Towing of barges from the transhipment terminals is subject to wind and wave conditions in the Strait of Georgia which are generally not a significant issue.

Pipeline Alignment – The 2 km long underground pipeline would commence at a previously used barge terminal site located on the south shore of Fraser River North Arm and run along the road right-of-way to the existing YVR tank farm.

Tank Farm Capacity – The total system tank farm capacity will comprise 80 million litres at the transhipment terminal, 20 million litres additional capacity for barge unloading at YVR to be added to the existing tank farm which has an existing capacity of 52 million litres. The total system tank capacity would be 152 million litres.

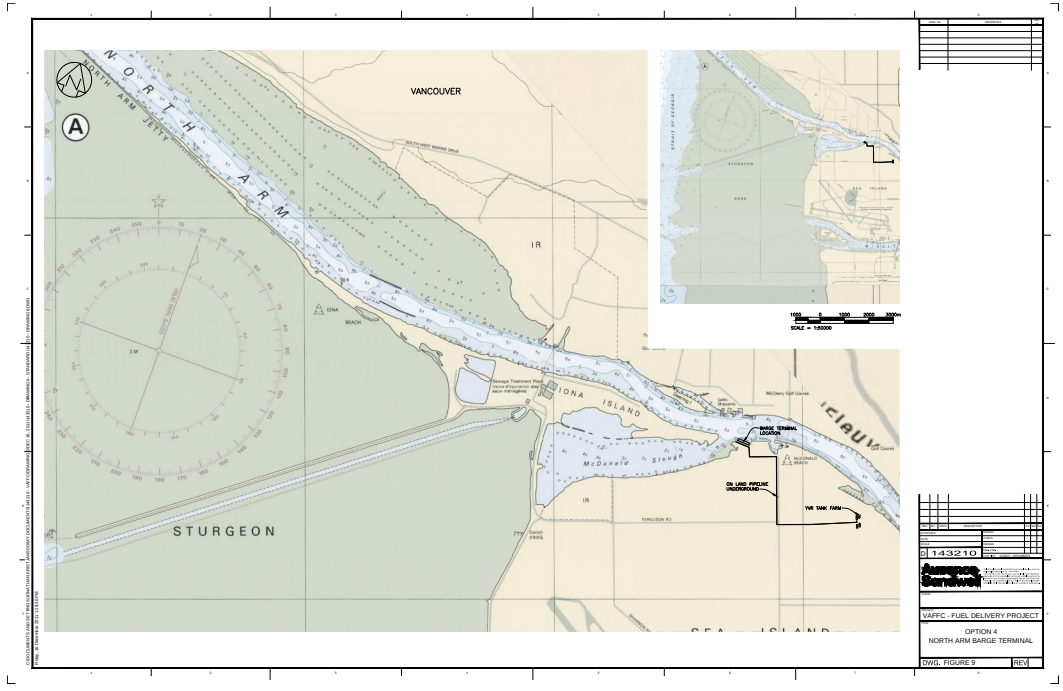
Access – The transhipment terminal and the barge loading terminal on the North shore of Burrard Inlet and the North Arm Barge Unloading Terminal will have direct catwalk access to the vessels.

Maintenance – Transhipment terminal maintenance would be covered by the tariff for tanker offloading, fuel storage, and barge loading operations. The proposed North Arm Barge Unloading Terminal is a relatively minor structure that has ready access for maintenance operations.

Duration of Construction Program – The transhipment terminal on the North Shore of Burrard Inlet may require increased tank farm capacity and possible modification to the existing marine facilities, which could take in the order of 18 months to construct. The transhipment terminal owners would be responsible for this construction. Following approval to proceed, the construction program for the barge terminal is estimated to be about 15 months with an active on site work period estimated at six months.

Key Risks and Concerns:

- Operational and commercial risks associated with long term facility use contract which will have a significant operational cost implication (*i.e.*, loss of operational and cost control);
- Operational and commercial risk associated with long term transhipping contract which will have a significant operational cost implication (*i.e.*, loss of operational and cost control);
- Potential interruption to YVR jet fuel supply from transhipment terminal and tug/barge operations due to reasons that are beyond VAFFC control; and
- Increased potential environmental risk associated with double-handling / transhipping of jet fuel.


VANCOUVER
NORTH ARM
NORTH ARM JETTY
IR
IONA ISLAND
McDonald Slough
STURGEON
SEA ISLAND
BARGE TERMINAL LOCATION
ON LAND PIPELINE UNDERGROUND
YVR TANK FARM
McDonald Beach
McDonald Golf Course
Ferguson Rd
Iona Beach
Sewage Treatment Plant
Lake Sturgeon
Strait of Georgia
SCALE = 1:50000
143210
VAFFC - FUEL DELIVERY PROJECT
OPTION 4
NORTH ARM BARGE TERMINAL
DWG. FIGURE 9
REV

5.0 RESULTS OF OPTIONS EVALUATION

An options analysis workshop on the four potential fuel delivery options for YVR was conducted on September 27, 2011. Results of the workshop are presented in this section for each of the themes and dimensions presented in Section 3.3 of this report.

5.1 Option 1 - South Arm Fraser River Terminal with Pipeline to YVR

5.1.1 Environmental

5.1.1.1 Environmental Effects

Potential environmental effects of the Option 1 have been investigated as part of the EAC Application (VAFFC 2011). Mitigation measures have been developed to reduce the residual environmental effects to acceptable levels based on regulatory requirements and industry best practices. The residual environmental effects are rated below using the indicators identified in Section 3.3, and based on the level of concern relative to other indicators.

A number of sensitive fish species (*i.e.,* as defined by BC species listings, the Species at Rick Act (SARA) registry and Committee on the Status of Endangered Wildlife in Canada (COSEWIC), Fraser River Estuary Management Program (FREMP)), including all five Pacific salmon species, steelhead, eulachon, and white and green sturgeon, are present in the marine transportation corridor along the South Arm of the Fraser River and around the marine terminal. A smaller number of sensitive bird and marine mammal species are also present. While mitigation measures have been identified to minimize potential project-related environmental effects during construction and operations, the species could still be affected during construction and operation life cycles, for example in the event of an accident such as a spill. Thus, Option 1 is rated as a **Moderate Concern** for sensitive species.

Among the fish species present in the area, four species (Interior Coho salmon, Cultus Lake sockeye salmon, white sturgeon and green sturgeon) are considered species-at-risk based on provincial and federal listings. However, the estuary area of the South Arm of the Fraser River serves only as a migratory corridor for these fish species and; therefore, exposure to project-related effects are considered low. Thus, Option 1 is rated as a **Minor Concern** for species-at-risk.

The marine transportation corridor along the South Arm of the Fraser River also crosses sensitive intertidal areas, including marsh areas that could be affected by noise, wave action, and the use of vessels. The fuel pipeline also crosses a number of riparian areas. Thus, Option 1 is rated as a **Moderate Concern** for sensitive habitats.

The use of marine vessels, road vehicles and equipment could also result in an incremental increase in Sulphur dioxide (SO_2). However, all air emissions from marine vessels would be minimized through the implementation of Annex VI of the MARPOL convention. This option is also expected to reduce regional oxides of nitrogen (NO_x) and greenhouse gas (GHG) emissions compared to the current levels, due to the removal of fuel delivery trucks that are currently in operation (VAFFC 2011). Furthermore, a vapour recovery system eliminates the likelihood of vapour loss from the tank farm. Thus, Option 1 is rated as a **Negligible Concern** for air quality and GHG emissions.

In the event of a spill of aviation fuel, the potential consequence is reduced by the inherent physical properties of the fuel (Jet Fuel A1). Due to its high volatility, virtually all of the aviation fuel is expected to evaporate shortly after a spill and would not readily leak into soil or water. Prevention measures, such as the use of double hull tanker vessels, fuel unloading monitoring at the marine terminal and pipeline leak detection system, will also be in place to limit risk to the environment from accidents and spills. Historically, fuel delivery to the Westridge terminal has been performed safely without incident. In the event of a spill, immediate spill response will take place in accordance to the spill response procedures. The pipelines are also assumed to be purged and dried between loads thus reducing the risk of spills when the pipeline is not in operation. Thus, Option 1 is rated as **Minor Concern** for soil and water contamination.

5.1.1.2 Regulatory Framework

The Environmental Assessment Certificate (EAC) Application for Option 1 has been submitted to the BC Environmental Assessment Office (EAO) and is currently under review. Although the review process is currently delayed, the permitting timeline is expected to be approximately two years for similar projects where the project proponent voluntarily opts-in for the provincial environmental assessment process. A small degree of regulatory uncertainty is present due to the Transport Canada TERMPOL review process as the navigation of vessels carrying fuel in the South Arm of the Fraser River has not been previously addressed within this regulatory regime. Thus, Option 1 is rated as a **Minor Concern** for regulatory complexity, permitting timeline, and regulatory uncertainty.

5.1.1.3 Summary

Results of Option 1 analysis for the Environmental dimension are summarized in Table 5. The ratings correspond to 70% of the total possible score for the Environmental Effects theme and 75% for the Regulatory Framework theme, resulting in 73% for the overall Environmental dimension.

Table 5: Analysis of Environmental Dimension for Option 1

Theme	Indicator	Concern	Theme Score	Dimension Score
Environmental Effects	Sensitive species	Moderate	70%	73%
	Species-at-risk	Minor		
	Sensitive habitats	Moderate		
	Air quality and GHG emissions	Negligible		
	Soil and water contamination	Minor		
Regulatory Framework	Regulatory complexity	Minor	75%	
	Permitting timeline	Minor		
	Regulatory uncertainty	Minor		

5.1.2 Socio-Economic

5.1.2.1 Economic Development

Approximately 320 person-years will be employed during the 24-month construction period for Option 1. This option will also provide employment to 14 full-time equivalents (FTEs) per year during operations. VAFFC and its contractors are expected to implement a targeting hiring approach to hire locally from the Lower Mainland of BC. The extent of local direct employment is comparable to similar infrastructure projects in the area. Thus, Option 1 is rated as a **Minor Concern** for the opportunities for direct local employment.

It is expected that 70 to 80% of the $135 million capital expenditure and $66 million operational expenditure will be spent locally in the Lower Mainland. Pilots, tug boat services, and other services are expected to be sourced locally. Thus, Option 1 is rated as a **Minor Concern** for the opportunities for local business generation.

Businesses along the pipeline route could be adversely affected temporarily during construction. Effects include temporary vehicle and pedestrian mobility restrictions, restricted access to driveways, on-site parking, and sidewalks. Approximately 10 and 30% of the pipeline route for Option 1 goes through commercial and industrial areas, respectively, with an estimated total of 20 to 25 businesses potentially affected. However, entire road closures are not expected, thereby complete loss of access to the businesses is not expected. Thus, Option 1 is rated as a **Minor Concern** for the potential effects on business operations.

5.1.2.2 Community Safety and Wellbeing

As discussed in Section 5.1.1.1, Option 1 is expected to result in a small increase in SO_2 emissions and overall reduction in NO_x and GHG emissions compared to the current emissions from the VAFFC fuel delivery system. The tank farm at the marine terminal facility will be located in an existing industrial area. In the event of a fuel spill, the public will be notified following the procedures outlined in the project's spill response plan. Thus, Option 1 is rated as a **Moderate Concern** for the potential public health and safety impacts from emissions and spills.

Most of the 15 km pipeline in Option 1 would go through urban and agricultural areas. Mobility and Access (including motor vehicle access, pedestrian and non-motorized traffic mobility, on and off-street parking access) to approximately seven residential and agricultural properties may be temporarily affected during the construction period. Access to approximately 15 public amenities (such as schools and parks) could also be affected. The construction of the proposed pipeline may temporarily disrupt City and railway right-of-ways that are currently used by pedestrians and cyclists, and other pathways along major city streets. Thus, Option 1 is rated as a **Minor Concern** for the potential effects on land based traffic.

Construction activities for the marine terminal could affect navigation in the South Arm due to floating equipment or pile driving. However, any impact is expected to be short-term during active construction of the marine terminal. During operations, approximately 156 vessel calls are expected annually in the South Arm of the Fraser River, which represent a small increment to the current vessel traffic in the river. Thus, Option 1 is rated as a **Minor Concern** for the potential effects on marine-based traffic.

Noise during construction could also affect properties near the facilities, especially for the pipeline construction as it progresses through urban and agricultural areas. Five households are located within 30m of the Option 1 pipeline route, and approximately 200 to 250 households within 150 m of the pipeline route. Noise may affect these households for a period of a few weeks while construction moves along the pipeline route. Thus, Option 1 is rated as a **Minor Concern** for noise.

Impacts on the visual aesthetics would be minimal. While the construction equipment to build the marine terminal and tank farm will be visible from the Fraser River shorelines, it would not be visually obtrusive as the project site is surrounded by other industrial users. The pipeline will be buried and will have no visual impact during operations. The marine terminal and tank farm will have similar visual impact to the surroundings as currently exists. Thus, Option 1 is rated as a **Minor Concern** for visual aesthetics.

5.1.2.3 Land Use

Option 1 generally complies with existing land zoning and land use guidelines. The Port Metro Vancouver has specified that the marine terminal and tank farm comply with existing Port Land Use Plan Designation for the site. The pipeline route is also consistent and compatible with the existing City of Richmond and Port Metro Vancouver zoning. However, there could be some public concern should some of the utilities corridor require rezoning prior to installation of the pipeline. Thus, Option 1 is rated as a **Minor Concern** for conformity with land use designation and zoning.

There is the potential for perceived changes to property values. Properties located around the pipeline route may have their property values affected. Based on historical precedents, an underground infrastructure such as a pipeline usually results in short-term effects on property values associated with the construction activities. The effects usually decrease over time after construction is completed. Furthermore, the construction activities provide an opportunity to improve amenities such as roads and sidewalk that can improve property values after the completion of the construction activities. The pipeline alignment along the utility corridors will not intrude into surrounding properties. Thus, Option 1 is rated as a **Moderate Concern** for potential effects on property values.

A foreshore lease is not considered an issue for Option 1 as the marine terminal will be constructed at an existing wharf facility. However, modifications to the existing marine terminal may constitute work in a navigable waterway as defined under the Navigable Waters Protection Act (NWPA). An application to obtain a NWPA approval from the Ministry of Transportation authorizing construction of the marine terminal may be required. The marine terminal and tank farm could potentially have some minor visual/landscaping effects to the surrounding community. Thus, Option 1 is rated as a **Negligible Concern** for foreshore lease requirements.

5.1.2.4 Summary

Results of the analysis for Option 1 for the Socio-economic dimension are summarized in Table 6. The ratings correspond to 75% of the total possible score for the Economic Development theme, 70% for the Community Safety and Wellbeing theme, and 75% for the Land Use theme. These scores result in an overall score of 75% for the Socio-economic dimension.

Table 6: Analysis of Socio-Economic Dimension for Option 1

Theme	Indicator	Rating	Theme Score	Dimension Score
Economic Development	Opportunities for direct local employment	Minor	75%	73%
	Opportunities for local business generation	Minor		
	Potential effects on business operations	Minor		
Community Safety and Wellbeing	Potential public health and safety effects from emissions and spills	Moderate	70%	
	Potential effects on land-based traffic	Minor		
	Potential effects on marine-based traffic	Minor		
	Noise	Minor		
	Visual aesthetics	Minor		
Land Use	Conformity with land use designation/zoning	Minor	75%	
	Potential or perceived effects to property values	Moderate		
	Foreshore lease requirements	Negligible		

5.1.3 First Nations

5.1.3.1 First Nations Considerations

The BC EAO identified 12 First Nations in the Section 11 order as potentially affected by Option 1. As reported in the EAC Application (VAFFC 2011), these First Nations cited potential impacts to aboriginal rights, aboriginal title and treaty rights (Chapter 11). Aboriginal rights identified included those related to fishing hunting, and gathering terrestrial foods and medicines. Aboriginal title assertions, including to the village site of *Tl'uqtinus* by First Nations affiliated with the Hul'qumi'num Treaty Group, were also reported, as were potential impacts to treaty rights to fish, hunt migratory birds, and harvest wildlife, plants and berries, particularly as per the Tsawwassen First Nation Final Agreement. Given the range of rights identified and the relatively high number of potentially affected First Nations, Option 1 is rated as a **Major Concern** for the complexity of issues raised by the First Nations identified by the BC EAO.

Based on information presented in the EAC Application, VAFFC appears to have reasonably responded to the issues raised by First Nations; however, some of the actions related to these responses have been deferred to the EAC Application review period or to the Crown and/or its agents. Thus, Option 1 is rated as a **Moderate Concern** for the ability to address issues.

The Crown's duty to consult with First Nations is raised when the Crown has knowledge of established or potentially existing aboriginal and/or treaty rights, and is contemplating conduct that may adversely affect those rights in a novel way. The procedural aspects of this duty can be delegated by the Crown to proponents. The level or scope of consultation is dependent upon both the relative strength of a claim or nature of an established right and the seriousness of potential adverse impacts to the aboriginal or treaty interest. The EAC Application

indicates that no new adverse impacts to aboriginal and/or treaty rights will be created by the land-based components of Option 1, and that the mitigation measures identified for the marine environment will also serve to minimize risks to the exercise of marine-based aboriginal and/or treaty rights. However, there appears to be differing opinions with respect to the location of the village site of *Tl'uqtinus*, and whether the land-based components of Option 1 are in conflict with this location. It further appears that, based on publicly available information (*e.g.,* GeoBC, 2011), the BC EAO does not appear to have identified in its Section 11 order all First Nations with asserted interests in the areas associated with Option 1 (Chapter 3, Section 3.4; compare to First Nations identified in Chapter 7, Section 7.3.4). This may be particularly pertinent if any further Crown conduct is contemplated in relation to this option (*e.g.,* post-EAC permitting), which may result in Crown agencies other than the BC EAO identifying a slightly different or broader set of aboriginal groups for consultation. Thus, Option 1 is rated as a **Moderate Concern** for the level of consultation.

Where the potential to adversely impact aboriginal and/or treaty rights is identified, the Crown is obligated to consider measures that will avoid, minimize or otherwise accommodate likely adverse effects. The degree of accommodation or mitigation that the Crown may owe or expect the proponent to address will vary according to the nature of the established or potential right (*i.e*., aboriginal right, aboriginal title or treaty right) and the extent to which the right may be adversely impacted. For example, the proponent could be expected to adjust operational plans through design changes and/or provide for First Nations participation in financial benefits related to a project (*e.g*., direct employment and contracts). As already stated above, the EAC Application reports that Option 1 is not expected to create new adverse impacts to established or potential aboriginal and/or treaty rights, either because of the "brownfield" condition of the land-based areas or proposed mitigation measures for the marine environment. The EAC Application also indicates that any accommodation ("settlement") of the aboriginal title assertion to the village site of *Tl'uqtinus* is beyond the scope of the project (Chapter 11, Section 11.6.3). The "brownfield" condition of the land-based areas suggests that any adverse impacts to aboriginal title occurred as a result of previous Crown conduct. Thus, Option 1 is rated as a **Minor Concern** for the level of accommodation, as the consultation process for the project is likely not the appropriate means for resolving the issue.

A known archaeological site is present in the vicinity of the marine terminal site for Option 1 (DgRs-17). The extent of the archaeological site is presently unknown and there are also uncertainties on the condition of the archaeological deposits, if present. Based on a review of the EAC Application (Chapter 7) and the provincial record for this site (Archaeology Branch, 2011), the extent and condition of the archaeological deposits at this location cannot be confirmed due to an apparent lack of a detailed historical land use study or evidence of systematic subsurface testing to search for such deposits. Thus, Option 1 is rated as a **Moderate Concern** for heritage resources.

5.1.3.2 Summary

Results of the analysis for Option 1 for the First Nations dimension are summarized in Table 7. The ratings correspond to 50% of the total possible score for the First Nations Considerations theme and 50% for the First Nations dimension.

Table 7: Analysis of the First Nations Dimension for Option 1

Theme	Indicator	Concern	Theme Score	Dimension Score
First Nations Considerations	Complexity of issues	Major	50%	50%
	Ability to address issues	Moderate		
	Level of consultation	Moderate		
	Level of accommodation	Minor		
	Heritage resources	Moderate		

5.1.4 Operations

5.1.4.1 Workers Safety

All Option 1 facilities, including the marine terminal, fuel receiving facility and pipeline will be land-based, which enables easy access to workers and, if necessary, emergency response personnel during construction and operation. Thus, Option 1 is rated as a **Negligible Concern** for accessibility.

The presence of jet fuel at the facilities poses an occupational hazard. This hazard would be present in any option due to the nature of the project and has been historically managed by VAFFC and its contractors through best management practices. Thus, Option 1 is rated as a **Minor Concern** for occupational hazards.

5.1.4.2 Navigational Hazards

Given the nature of navigating the Fraser River south arm, any tankers wishing to traverse upstream must be guided by an experienced Fraser River pilot and escorted by tug boats. Thus, Option 1 is rated as a **Minor Concern** for local experience.

Adverse wave conditions are not expected in the river. Minor issues arising from wind loading and visibility are occasionally expected. Thus, Option 1 is rated as a **Minor Concern** for exposure.

5.1.4.3 5.1.4.3 Reliability

The relatively short 15 km pipeline for Option 1 represents a low spill exposure and is thus rated as a **Minor Concern**.

Richmond, composed of highly liquefiable soil, poses some seismic risk to the pipeline. However, in comparison to other options proposing pipelines offshore in the delta front, this risk is minor. Thus, Option 1 is rated as a **Minor Concern** for seismicity.

Option 1 facilities could be affected by natural hazards, such as extreme storms and other extreme weather events that could affect the marine vessels and marine terminal. However, these facilities would be less susceptible to natural hazards compared to other options considered in this analysis. Thus, Option 1 is rated as **Minor Concern** for the effects of the environment on the project.

As all Option 1 facilities are land-based, there is adequate high maintenance accessibility. Thus, Option 1 is rated as a **Negligible Concern** for maintenance access.

In terms of response time for malfunction, land-based crews can mobilize quickly and respond efficiently to any problems should they arise in the pipeline or at the offloading facilities. For marine spills, tug escorts accompanying the ship are trained to follow standard procedure to mitigate risks, and are equipped to deal with fire, rescue, and pollution control. Thus, Option 1 is rated as a **Minor Concern** for response time for malfunction.

5.1.4.4 Summary

Results of the analysis for Option 1 for the Operations dimension are summarized in Table 8. The ratings correspond to 88% of the total possible score for the Workers Safety theme, 75% for the Navigational Safety theme, and 80% of for the reliability theme. These scores result in an overall score of 81% for the Operations dimension.

Table 8: Analysis of the Operations Dimension for Option 1

Theme	Indicator	Concern	Theme Score	Dimension Score
Workers Safety	Accessibility	Negligible	88%	81%
	Occupational hazards	Minor		
Navigational Safety	Local experience	Minor	75%	
	Exposure	Minor		
Reliability	Length of pipeline	Minor	80%	
	Seismicity	Minor		
	Meteorological Hazards	Minor		
	Maintenance access	Negligible		
	Response time for malfunction	Minor		

5.1.5 Economics

5.1.5.1 Project Cost

Capital expenditures estimated at $135 million are required to enable Option 1. Thus, Option 1 is rated as a **Minor Concern** for CAPEX.

Operating expenditures are expected to reach $67 million per annum incrementally over the next 32 years in step with increases in fuel supply to three billion litres per annum of throughput. Thus, Option 1 is rated as a **Minor Concern** for OPEX. A summary of the estimated costs for the options evaluated and the associated key contributing factors are presented in Appendix A.

After approval has been granted for the project an anticipated 24 months are required for design, construction, and commissioning of the facilities. Although this would not provide an operating alternative to the current supply mode by 2013 (*i.e.,* timeframe for when the current system poses critical limitations to the VAFFC), it is one of the more quickly implementable options. Thus, Option 1 is rated as a **Minor Concern** for schedule.

With an existing terminal facility already located at the proposed offloading site, minimal habitat compensation is expected. Thus, Option 1 is rated as a **Minor Concern** for the financing of habitat compensation.

5.1.5.2 Project Benefits

Constructing a private offloading berth for international fuel vessels greatly increases the accessibility to multiple fuel sources. This accessibility allows for greater reliability of supply, and flexibility in obtaining cheaper fuel, while still maintaining access to local sources. Thus, Option 1 is rated as a **Minor Concern** for reliability of fuel supply.

The proposed berth located on the Fraser River south arm would be able to accommodate vessels ranging from small barges up to Handymax size vessels. Only partially loaded Panamax vessels (the design vessel) would be capable of navigating up the river due to draft limitations. This restriction would have a negligible impact on the ability to deliver sufficient volumes of fuel to port. Thus, Option 1 is rated as a **Minor Concern** for accommodation of a full range of marine vessels.

5.1.5.3 Summary

Results of the analysis for Option 1 for the Economics dimension are summarized in Table 9. The ratings correspond to 75% of the total possible score for the Project Cost theme, 75% for the Project Benefits theme and 75% for the Economics dimension.

Table 9: Analysis of the Economics Dimension for Option 1

Theme	Indicator	Concern	Theme Score	Dimension Score
Project Cost	CAPEX	Minor	75%	75%
	OPEX	Minor		
	Schedule	Minor		
	Habitat compensation	Minor		
Project Benefits	Reliability of fuel supply	Minor	75%	
	Accommodation of a full range of marine vessels	Minor		

5.2 Option 2 – Offshore Terminal Facility with Pipeline to YVR

5.2.1 Environmental

5.2.1.1 Environmental Effects

Sensitive species similar to those identified for Option 1 are associated with all the tidal marsh and bank areas. However, Option 2A (Single Point Mooring) poses a greater concern than the 2B and 2C alternatives due to the length of the 11.8 km subsea pipeline. The potential effects on sensitive species for Options 2B (Spread Mooring, with 2.3 km subsea pipeline) and 2C (Fixed Structure, with no subsea pipeline) are more localized and similar to Option 1. Thus, Option 2A is rated as a **Major Concern** and Options 2B and 2C are rated as a **Moderate Concern** for sensitive species.

A number of species-at-risk are present in the offshore area, including migratory waterfowl, killer whales, and sea lions. The Single Point Mooring for Option 2A is located near the mouth of the South Arm of the Fraser River and could affect the salmon population of the South Arm. Thus, Option 2A is rated as a **Major Concern** and Options 2B and 2C are rated as a **Moderate Concern** for species-at-risk.

The Option 2 alternatives would be located within the Sturgeon Bank Wildlife Management Area and therefore could affect the sensitive habitats within Sturgeon Bank and any of the tidal marshes. Option 2A, in particular, is a higher concern due to the subsea pipeline. Thus, Option 2A is rated as a **Major Concern** and Options 2B and 2C are rated as a **Moderate Concern** for sensitive habitats.

Air emissions, including GHG emissions, for the Option 2 alternatives involve similar sources from Option 1 (*i.e.*, construction and operational equipment, marine vessels, and small number of road vehicles) and therefore are estimated to be similar to Option 1. Thus, Options 2A, 2B, and 2C are rated as a **Negligible Concern** for air quality and GHG emissions.

Potential for soil and water contamination during operations are similar to Option 1 and are similarly minimized by the volatility of the aviation fuel material, spill prevention measures, and spill response procedures. However, the construction of the Option 2 offshore facilities may result in contamination of the marine environment, especially associated with the disturbance of the seabed due to the jetting of the subsea pipeline for Options 2A and 2B. Thus, Options 2A, 2B, and 2C are rated as a **Moderate Concern** for soil and water contamination.

5.2.1.2 Regulatory Framework

The regulatory requirements for the Option 2 alternatives are more complex than land-based configurations such as Option 1. In addition, regulatory agencies have less experience dealing with offshore components. Thus, Options 2A, 2B, and 2C are rated as a **Moderate Concern** for regulatory complexity.

Due to the higher regulatory complexity, the permitting timeline for all Option 2 alternatives is expected to be longer than Option 1 and is estimated at four years or longer. Thus, Options 2A, 2B, and 2C are rated as a **Moderate Concern** for permitting timeline.

The Option 2 alternatives also pose higher regulatory uncertainties compared to Option 1 due to the permitting of the offshore facilities, sediment issues with the subsea pipeline, and habitat compensation issues. Thus, Options 2A, 2B, and 2C are rated as a **Moderate Concern** for regulatory uncertainty.

5.2.1.3 Summary

Results of the analysis for Option 2 alternatives for the Environmental dimension are summarized in Table 10.

Table 10: Analysis of Environmental Dimension for Option 2

Theme	Indicator	Concern			Theme Score	Dimension Score
		2A	2B	2C		
Environmental Effects	Sensitive species	Major	Moderate	Moderate	2A: 45% 2B: 60% 2C: 60%	2A: 48% 2B: 55% 2C: 55%
	Species-at-risk	Major	Moderate	Moderate		
	Sensitive habitats	Major	Moderate	Moderate		
	Air quality and GHG emissions	Negligible	Negligible	Negligible		
	Soil and water contamination	Moderate	Moderate	Moderate		
Regulatory Framework	Regulatory complexity	Moderate	Moderate	Moderate	2A: 50% 2B: 50% 2C: 50%	
	Permitting timeline	Moderate	Moderate	Moderate		
	Regulatory uncertainty	Moderate	Moderate	Moderate		

5.2.2 Socio-Economic

5.2.2.1 Economic Development

The levels of direct employment during construction and operations of the Option 2 alternatives are expected to be similar to Option 1. Targeted hiring approach is also expected to be implemented by VAFFC and its contractors. However, Option 2A (Single Point Mooring) is expected to require specialist services that may not be available locally, while the labour skills needed for Options 2B (Spread Mooring) and 2C (Fixed Structure) are expected to be available locally in the Lower Mainland of BC. Thus, Option 2A is rated as a **Moderate Concern** and Options 2B and 2C are rated as a **Minor Concern** for the opportunities for direct local employment.

Some of the $225 million capital expenditure for Option 2A will be spent on manufacturing of the SPM equipment in manufacturing facilities outside of the Lower Mainland. Most of the $135 million capital expenditure for Option 2B and $185 million for Option 2C, on the other hand, are expected to be spent locally. Most of the operating expenditure for all Option 2 alternatives is expected to be spent locally. Similar to Option 1, the Option 2 alternatives are expected to provide opportunities to local pilots, tugs, and other services. Thus, Option 2A is rated as a **Moderate Concern** and Options 2B and 2C are rated as a **Minor Concern** for local business generation.

Due to the facility locations away from commercial and industrial areas, the construction of Option 2 facilities would have very limited effects to businesses. Only two to three businesses on Sea Island could be affected during the construction of the 9.6 km on-land pipeline for Options 2B and 2C. Thus, Options 2A, 2B, and 2C are rated as a **Negligible Concern** for the potential effects on business operations.

5.2.2.2 Community Safety and Wellbeing

All Option 2 alternatives are expected to have similar emission profiles as Option 1. Procedures could be developed to immediately contain any accidental spill from the offshore facilities, such that the safety of the recreational and commercial fishery users in the offshore area would not be affected. Thus, Options 2A, 2B and 2C are rated as a **Minor Concern** for the potential public health and safety impacts from emissions and spills.

Construction of the offshore facilities for all Option 2 alternatives is expected to have minimal impacts on road traffic. Construction of the 9.6 km on-land pipeline for Options 2B and 2C would also have minimal impacts on road traffic due to its location away from populated residential areas. Thus, Options 2A, 2B and 2C are rated as a **Minor Concern** for the potential effects on land-based traffic.

Recreational and commercial fishery users at Sturgeon Banks could be affected by the movements of vessels to the offshore facilities. However, the volume of vessel movements are expected to be similar to Option 1 (approximately 156 vessel calls annually), which represent a small increment to the current vessel traffic in the area. Thus, Options 2A, 2B and 2C are rated as a **Minor Concern** for the potential effects on marine-based traffic.

Noise during construction of any of the Option 2 facilities could affect users of public parks on Sea Island and Iona. However, the level of noise emitted is expected to be less or comparable to the other options and would be temporary. Residential homes would not be affected due to the facilities' locations. Thus, Options 2A, 2B and 2C are rated as a **Minor Concern** for noise.

The construction and operations of the offshore facilities and pipeline for Option 2A and Option 2B will have virtually no visual impacts. The visual impacts for Option 2C would be similar to Option 1. The view of tank farm at YVR will be compatible with the surrounding airport facilities. Thus, Options 2A and 2B are rated as **Negligible Concern** and Option 2C is rated as a **Minor Concern** for visual aesthetics.

5.2.2.3 Land Use

All Option 2 alternatives will comply with existing land zoning and land use guidelines and there is no rezoning concern. Thus, Options 2A, 2B and 2C are rated as **Negligible Concern** for conformity with land use designation and zoning.

All Option 2 facilities are located away from residential or commercial properties. Thus, Options 2A, 2B and 2C are rated as a **Negligible Concern** for potential or perceived effects on property values.

Foreshore leases could be required for the subsea and on-land pipeline corridors for the Option 2 alternatives. However, there are existing leases on Sea Island that could need to be negotiated and an NWPA may be required for each site. Thus, Options 2A, 2B and 2C are rated as a **Minor Concern** for foreshore lease requirements.

5.2.2.4 Summary

Results of the analysis for the Option 2 alternatives for the Socio-economic dimension are summarized in Table 11. For Option 2A (Single Point Mooring), the ratings correspond to 67% of the total possible score for the Economic Development theme, 80% for the Community Safety and Wellbeing theme, and 92% for the Land Use theme. These theme scores result in an overall score of 80% for the Socio-economic dimension.

For Option 2B (Spread Mooring), the ratings correspond to 83% of the total possible score for the Economic Development theme, 81% for the Community Safety and Wellbeing theme, and 92% for the Land Use theme. The overall Option 2B score is thus 85% for the Socio-economic dimension.

For Option 2C (Fixed Structure), the ratings correspond to 83% of the total possible score for the Economic Development theme, 75% for the Community Safety and Wellbeing theme, and 92% for the Land Use theme. These scores reflect an overall rating of 83% for the Socio-economic dimension.

Table 11: Analysis of Socio-Economic Dimension for Option 2

Theme	Indicator	Concern			Theme Score	Dimension Score
		2A	2B	2C		
Economic Development	Opportunities for direct local employment	Moderate	Minor	Minor	2A: 67%	
	Opportunities for local business generation	Moderate	Minor	Minor	2B: 83%	
	Potential effects on business operations	Negligible	Negligible	Negligible	2C: 83%	
Community Safety and Wellbeing	Potential public health and safety effects from emissions and spills	Minor	Minor	Minor	2A: 80%	2A: 80%
	Potential effects on land-based traffic	Minor	Minor	Minor	2B: 81%	2B: 85%
	Potential effects on marine-based traffic	Minor	Minor	Minor	2C: 75%	2C: 83%
	Noise	Minor	Minor	Minor		
	Visual aesthetics	Negligible	Negligible	Minor		
Land Use	Conformity with land use designation/zoning	Negligible	Negligible	Negligible	2A: 92%	
	Potential or perceived effects to property values	Negligible	Negligible	Negligible	2B: 92%	
	Foreshore lease requirements	Minor	Minor	Minor	2C: 92%	

5.2.3 First Nations

5.2.3.1 First Nations Considerations

The First Nations with interests in Option 2A are likely the same as for Option 1 (GeoBC, 2011), and Option 2A would therefore likely require consideration of the same type and range of established and/or potential aboriginal/treaty rights. For Options 2B and 2C, which are very focused on the North Arm of the Fraser River, the number of potentially affected First Nations would likely decrease (GeoBC, 2011) and treaty rights would likely be eliminated as a consideration (*i.e.,* the area does not appear to be subject to a final agreement or a Douglas treaty). Thus, Option 2A is rated as a **Major Concern** and Options 2B and 2C as a **Moderate Concern** for the complexity of issues.

Apart from the treaty rights that may apply to Option 2A, but not to Options 2B or 2C, the type and range of issues for Options 2A, 2B, and 2C will likely be the same as Option 1 (*i.e.,* aboriginal rights, including aboriginal title). Thus, Options 2A, 2B and 2C are rated as a **Moderate Concern** for the ability to address issues.

There are two Indian Reserves belonging to the Musqueam Indian Band in proximity to all or part of the components for Options 2A, 2B, and 2C, these being one on the north shore of the North Arm of the Fraser River and the other directly south of this location, at the northwest corner of Sea Island. As indicated in Table 3, above, proximity to Indian Reserves is an important consideration with respect to level/scope of consultation, as it tends to place consultation at the deeper end of the consultation spectrum, albeit balanced against the seriousness of potential adverse impacts. This level/scope may be higher than for Option 1, particularly with respect to the Musqueam. Thus, Options 2A, 2B, and 2C are rated as a **Major Concern** for the level of consultation.

Due to the proximity of Musqueam Indian Reserves to all or parts of the components for these options, the mitigation expected of VAFFC could be more involved for Options 2A, 2B, and 2C than for Option 1. Thus, Options 2A, 2B, and 2C are rated as a **Moderate Concern** for the level of accommodation.

Four previously recorded archaeological sites are present in the vicinity of the facilities for Options 2A, 2B and 2C. The extent and condition of the archaeological sites is presently uncertain. However, Option 2 facilities would be farther away from any of the known archaeological sites compared to Option 1 (*i.e.,* DgRs-17), and may not be as archaeologically significant (*i.e.,* likely not as large in extent or associated with documented post-contact use). Thus, Options 2A, 2B and 2C are rated as a **Minor Concern** for heritage resources.

5.2.3.2 Summary

Results of the analysis for the Option 2 alternatives for the First Nations dimension are summarized in Table 12. The theme and dimension ratings correspond to 45% for Option 2A, 50% for Option 2B, and 50% for Option 2C.

Table 12: Analysis of First Nations Dimension for Option 2

Theme	Indicator	Concern			Theme Score	Dimension Score
		2A	2B	2C		
First Nations Considerations	Complexity of issues	Major	Moderate	Moderate	2A: 45% 2B: 50% 2C: 50%	2A: 45% 2B: 50% 2C: 50%
	Ability to address issues	Moderate	Moderate	Moderate		
	Level of consultation	Major	Major	Major		
	Level of accommodation	Moderate	Moderate	Moderate		
	Heritage resources	Minor	Minor	Minor		

5.2.4 Operations

5.2.4.1 Workers Safety

Options 2A and 2B would require water access during construction and operations of the offshore facilities. On the other hand, Option 2C would be more easily accessible through the trestle. Thus, Options 2A and 2B are rated as a **Major Concern**, while Option 2C is rated as a **Negligible Concern** for accessibility.

Construction over water poses an occupational hazard for all Option 2 alternatives. Floating hoses pose an occupational hazard during operations for Options 2A and 2B, along with diving during construction and operations. The presence of the aviation fuel is also an occupational hazard but, as with Option 1, would be managed through best practices. Thus, Option 2A and 2B are rated as a **Major Concern** and Option 2C is rated as a **Minor Concern** for occupational hazards.

5.2.4.2 Navigational Hazards

SPM and spread mooring operations are rare in the local area, and specialized pilots and tug crews are required for safe berthing procedures. Available local expertise may be minimal affecting efficient early operations. Thus, Option 2A and 2B are rated as a **Moderate Concern** for local experience. Alternatively, fixed terminals are very common, and procedures for berthing familiar to local pilots and tug crews. Thus Option 2C is rated as a **Minor Concern** for local experience.

Wave conditions in the Georgia Strait would have a significant effect on options 2A, 2B, and 2C in terms of approach and departure to berth. Tug operational thresholds would be governing for approach and departure of all alternatives. Options 2A and 2B are capable of handling adverse wave conditions during offloading due to their flexible design while Option 2C is restricted to more favourable wave conditions due to the ship-berth interaction. As a means of increasing berth availability at option 2C, MoorMaster™ units (an automated mooring system) are proposed. With MoorMaster™ units applied in Option 2C, all options are expected to experience approximately 200 hours unfavourable wave conditions annually. Further, all three alternatives are located in close proximity to the traffic separation scheme for vessels proceeding to Vancouver Harbour. This proximity may create a potential for conflict. Thus, considering environmental and marine traffic exposure Option 2A, 2B, and 2C are rated as a **Moderate Concern** for exposure.

5.2.4.3 Reliability

Option 2A utilizes a 17 km long pipeline, 11.8 km of which is subsea. Option 2B is comprised of 2.3 km of subsea pipeline and 9.6 km of on land pipeline for a total length of 11.9 km. Option 2C utilizes a 11.7 km pipeline, with 2.1 km being along the trestle. In terms of spill exposure, the lengths are relatively similar to Option 1 and thus Option 2A, 2B, and 2C are rated as a **Minor Concern** for length of pipeline.

Seismic concerns for each of Options 2A, 2B, and 2C are primarily governed by pipeline length and location. Option 2A has a large subsea pipeline component situated on the seismically sensitive delta front. Under significant seismic loading the pipeline could be lost. Thus Option 2A is rated as a **Major Concern** for seismicity. Option 2B has similar concerns as 2A with a subsea pipeline located across Sturgeon Bank, but given a much shorter subsea length the risk factor is lower. Thus, Option 2B is rated as a **Moderate Concern** for seismicity. Option 2C's pipeline is situated entirely on the trestle or underground on land, and would have comparable concerns to Option 1. Thus, Option 2C is rated as **Minor Concern** for seismicity.

All of the offshore facilities for Option 2 alternatives are more susceptible to storm than Option 1. Thus, Options 2A, 2B, and 2C are rated as a **Moderate Concern** for the effects of the environment on the project.

With no land access to Option 2A or 2B, much of the mooring system underwater, and a significant portion of subsea pipeline for Option 2A, routine maintenance access becomes difficult. Thus, Option 2A and 2B are rated as a **Major Concern** for maintenance access. Alternatively, Option 2C has direct access via trestle to land-based maintenance crews, and is comparable to Option 1 with some increases due to diver inspection of the fixed structure and trestle. Thus Option 2C is rated as a **Minor Concern** for maintenance access.

For malfunction response time, land-based crews can mobilize quickly and respond efficiently to any problems should they arise in the on land pipeline for all of the alternatives. For marine spills, tug escorts accompanying the ship are trained to follow standard procedure to mitigate risks, and are equipped to deal with fire, rescue, and pollution control. For Option 2A and 2B, response time may be hindered due to wave conditions and relative location of the berth, making malfunctions harder to contain. Thus, Option 2A and 2B are rated as a **Moderate Concern** for response time for malfunction. With trestle access, and no subsea pipeline, Option 2C has a comparable malfunction response time to Option 1. Thus, Option 2C is rated as a **Minor Concern** for response time for malfunction.

5.2.4.4 *Summary*

Results of the analysis for Option 2A, 2B and 2C for the Operations dimension is summarized in Table 13. The dimension ratings correspond to 40% for Option 2A, 42% for Option 2B, and 73% for Option 2C.

Table 13: Analysis of Operations Dimension for Option 2

Theme	Indicator	Concern			Theme Score	Dimension Score
		2A	2B	2C		
Workers Safety	Accessibility	Major	Major	Negligible	2A: 25% 2B: 25% 2C: 88%	2A: 40% 2B: 42% 2C: 73%
	Occupational hazards	Major	Major	Minor		
Navigational Safety	Local experience	Moderate	Moderate	Minor	2A: 50% 2B: 50% 2C: 63%	
	Exposure	Moderate	Moderate	Moderate		
Reliability	Length of pipeline	Minor	Minor	Minor	2A: 45% 2B: 50% 2C: 70%	
	Seismicity	Major	Moderate	Minor		
	Meteorological Hazards	Moderate	Moderate	Moderate		
	Maintenance access	Major	Major	Minor		
	Response time for malfunction	Moderate	Moderate	Minor		

5.2.5 Economics

5.2.5.1 *Project Cost*

Capital expenditures are estimated at $225, $135 and $185 million for Options 2A, 2B, and 2C, respectively. The estimates include costs associated with building an ancillary barge berth for offloading small barges from Chevron and Cherry Point in conjunction with the main terminal. In comparison to Option 1, Option 2A is 70% more expensive, Option 2B is equivalent, and Option 2C is 40% more expensive. Thus, Option 2A is rated as a **Major Concern**, Option 2B as a **Minor Concern**, and Option 2C as a **Moderate Concern** for CAPEX.

Operating expenditures are expected to reach $67, $ 65 and $ 66 million per annum incrementally over the next 15 years for Options 2A, 2B, and 2C, respectively. These operating costs are in step with increases in fuel supply to three billion litres per annum of throughput by 2027. In comparison to Option 1, Option 2A is $3 million per annum higher, while Option 2B and 2C are comparable. Thus Option 2A is rated as a **Moderate Concern** and Option 2B and 2C are rated as a **Minor Concern** for OPEX. A summary of the estimated costs for the options evaluated and the associated key contributing factors are presented in Appendix A.

Comparable to Option 1, all three alternatives would require design, construction, and commissioning on the order of 2 years after permitting was approved. Thus Option 2A, 2B, and 2C are rated as a **Minor Concern** for Schedule.

Due to the extensive subsea pipeline in Option 2A, significant habitat compensation costs can be expected. In comparison to Option 2B and 2C, Option 2A disturbs approximately 5 times more underwater habitat. Thus, Option 2A is rated as a **Major Concern** and Option 2B and 2C are rated as a **Minor Concern** for habitat compensation.

5.2.5.2 Project Benefits

As with Option 1, a private offshore berth greatly increases the accessibility to international fuel supply. With access to multiple sources, and full operational control, the only reliability issues arise during severe environmental conditions. With the subsea pipelines more susceptible to seismic events than the trestle pipeline, Options 2A, and 2B, become slightly less reliable. Thus, Option 2A and 2B are rated as a **Minor Concern** and Option 2C is rated as a **Negligible Concern** for reliability of fuel supply.

With the implementation of an ancillary barge berth, likely in the north arm of the Fraser River, there are no restrictions on vessel size that can be accommodated for all three alternatives. Thus, Option 2A, 2B, and 2C are rated as a **Negligible Concern** for accommodation of a full range of marine vessels.

5.2.5.3 Summary

Results of the analysis for Options 2A, 2B and 2C for the Economics dimension is summarized in Table 14. The dimension ratings correspond to 66% for Option 2A, 81% for Option 2B, and 84% for Option 2C.

Table 14: Analysis of the Economics Dimension for Option 2

Theme	Indicator	Concern			Theme Score	Dimension Score
		2A	2B	2C		
Project Cost	CAPEX	Major	Minor	Moderate	2A: 44% 2B: 75% 2C: 69%	2A: 66% 2B: 81% 2C: 84%
	OPEX	Moderate	Minor	Minor		
	Schedule	Minor	Minor	Minor		
	Habitat compensation	Major	Minor	Minor		
Project Benefits	Reliability of fuel supply	Minor	Minor	Negligible	2A: 88% 2B: 88% 2C: 100%	
	Accommodation of a full range of marine vessels	Negligible	Negligible	Negligible		

5.3 Option 3 – Upgrading of Trans Mountain Jet Fuel Pipeline

5.3.1 Environmental

5.3.1.1 Environmental Effects

Option 3 involves the use of the existing Westridge Terminal, expansion of the Westridge fuel storage capacity, and upgrading of the existing TMJ pipeline to YVR. The existing Westridge Terminal is located within an existing industrial area. Similarly, the existing TMJ pipeline would be upgraded through an existing corridor in a highly urban and built-up area. The pipeline would pass by Burnaby Lake and through three river crossings, where the new pipeline would be constructed using horizontal directional drilling (HDD). Sensitive species, species-at-risk and sensitive habitat are not expected to be affected. Thus, Option 3 is rated as a **Negligible Concern** for sensitive species and species-at-risk and a **Moderate Concern** for sensitive habitats due to the re-establishment of more natural areas across the existing linear corridor over the past 50 years.

Air emissions, including GHG emissions, from Option 3 are expected to be similar to Option 1. Thus, Option 3 is rated as a **Negligible Concern** for air quality and GHG emissions.

Soil and water could be affected by an accidental fuel spill. Potential consequences to the environment of an accidental spill would be similar to Option 1. In the event of a spill, virtually the entire spill is expected to evaporate shortly after a spill and do not leak into soil or into water because of the high volatility of the aviation fuel (JetA1). Spill prevention measures and spill response procedures similar to Option 1 are expected to be in place. Historically, there has been no significant spill at Westridge. A spill along the pipeline route is not expected to affect habitats due to its location. Thus, Option 3 is rated as a **Minor Concern** for soil and water contamination.

The Westridge terminal and vessels could be affected by natural hazards such as extreme storms and other extreme weather events. However, they are less susceptible compared to the offshore options and is similar to Option 1. Thus, Option 3 is rated as a **Minor Concern** for the effects of the environment on the project.

5.3.1.2 Regulatory Framework

The permitting process for Option 3 is expected to be very complex because of the pipeline route. Since the existing TMJ pipeline was commissioned in 1969, Right-of-Way has not been established. The area around the route has been extensively developed since the pipeline was constructed. The corridor passes through five zoning areas from the Westridge Terminal through Burnaby and Richmond before reaching YVR on Sea Island. Approximately 50% of the route is in residential areas, with approximately 500 properties that could be affected. The use of eminent domain could be necessary. Thus, Option 3 is rated as a **Major Concern** for regulatory complexities.

Due to the regulatory complexity of installing a new pipeline, it is expected that the permitting process would be very lengthy and time consuming. Thus, Option 3 is rated as **Critical Concern** for permitting timeline. In addition, the permitting process would also involve a high degree of uncertainties especially with respect to obtaining private sector approvals for the affected properties in Burnaby and Richmond. Thus, Option 3 is rated as **Major Concern** for regulatory uncertainties.

5.3.1.3 Summary

Results of the analysis for Option 3 for the Environmental dimension are summarized in Table 15. The ratings correspond to 85% of the total possible score for the Environmental Effects theme, 17% for the Regulatory Framework theme, and overall 51% for the Environmental dimension.

Table 15: Analysis of the Environmental Dimension for Option 3

Theme	Indicator	Concern	Theme Score	Dimension Score
Environmental Effects	Sensitive species	Negligible	85%	51%
	Species-at-risk	Negligible		
	Sensitive habitats	Moderate		
	Air quality and GHG emissions	Negligible		
	Soil and water contamination	Minor		
Regulatory Framework	Regulatory complexity	Major	17%	
	Permitting timeline	Critical		
	Regulatory uncertainty	Major		

5.3.2 Socio-Economic

5.3.2.1 Economic Development

Option 3 involves the highest capital expenditure at $280 million, more than twice the capital expenditure for Option 1. Much of the higher capital expenditure is associated with higher construction requirements for the 41 km pipeline. Thus, direct employment during construction is also expected to be considerably higher than Option 1, although direct employment during operations is expected to be similar. VAFFC and its contractors are expected to implement a targeting hiring approach to hire locally from the Lower Mainland of BC. Thus, Option 1 is rated as a **Negligible Concern** for the opportunities for direct local employment (a benefit).

While opportunities for local business generation during operations for Option 3 are expected to be similar to Option 1, opportunities during construction are expected to be greater due to the higher construction requirements. Thus, Option 3 is rated as a **Negligible Concern** for the opportunities for local business generation (a benefit).

However, businesses along the pipeline route could be adversely affected temporarily during construction. Approximately 75 businesses are located within 30m of the pipeline route. More businesses in the area could also be affected by reduced traffic access. Thus, Option 1 is rated as a **Major Concern** for the potential effects on business operations.

5.3.2.2 Community Safety and Wellbeing

As discussed in Section 5.3.1.1, emissions from Option 3 are expected to be similar to Option 1. However, while potential consequences to the environment from an accidental spill are expected to be similar to Option 1, the potential consequences to public safety could raise a more serious concern. The existing corridor has not been fully delineated and is likely to pass within residential properties in proximity to houses. Thus, Option 3 is rated as a **Major Concern** for the potential public health and safety impacts from emissions and spills.

Based on a high level review of municipal mapping data, approximately 300 residences appear within 30m of the pipeline and approximately 200 residences within 6 m of the pipeline. The area is also associated with busy traffic. Access to these properties and the safety of traffic users in the area could be affected. Thus, Option 3 is rated as a **Major Concern** for the potential effects on land-based traffic.

Marine traffic volume for the construction and operations of Option 3 facilities are expected to be similar to Option 1. Thus, Option 3 is rated as a **Minor Concern** for the potential effects on marine-based traffic.

Temporary noise during construction could also affect the residences in proximity of the pipeline. However, noise may affect these households for a period of a few weeks while construction moves along the pipeline route. Thus, Option 3 is rated as a **Moderate Concern** for noise. Impacts on the visual aesthetics would be minimal as facilities will have similar visual impact to its surrounding. Thus, Option 3 is rated as a **Minor Concern** for visual aesthetics.

5.3.2.3 Land Use

Zoning along the pipeline route has changed significantly since the TMJ pipeline was built. As the pipeline passes through residential properties, the upgrade would not meet the current zoning. Thus, Option 1 is rated as a **Major Concern** for conformity with land use designation and zoning.

Construction of the upgraded pipeline could also affect property values, especially as the pipeline is expected to pass adjacent to, and in some cases through some residential properties. Easement agreements with the property owners would be required. Thus, Option 3 is rated as a **Major Concern** for potential or perceived effects on property values. Whereas, a foreshore lease is not an issue for Option 3 as the terminal is an existing facility. Thus, Option 3 is rated as a **Negligible Concern** for foreshore lease requirements.

5.3.2.4 Summary

Results of the analysis for Option 3 for the Socio-economic dimension are summarized in Table 16. The ratings correspond to 75% of the total possible score for the Economic Development theme, 50% for the Community Safety and Wellbeing theme, 50% for the Land Use theme. This results in an overall rating of 58% of for the Socio-economic dimension.

Table 16: Analysis of Socio-Economic Dimension for Option 3

Theme	Indicator	Concern	Theme Score	Dimension Score
Economic Development	Opportunities for direct local employment	Negligible	75%	58%
	Opportunities for local business generation	Negligible		
	Potential effects on business operations	Major		
Community Safety and Wellbeing	Potential public health and safety effects from emissions and spills	Major	50%	
	Potential effects on land-based traffic	Major		
	Potential effects on marine-based traffic	Minor		
	Noise	Moderate		
	Visual aesthetics	Minor		

Theme	Indicator	Concern	Theme Score	Dimension Score
Land Use	Conformity with land use designation/zoning	Major	50%	
	Potential or perceived effects to property values	Major		
	Foreshore lease requirements	Negligible		

5.3.3 First Nations

5.3.3.1 First Nations Considerations

The number of First Nations that may be potentially affected by Option 3 will likely be the fewest of all options, but could include First Nations that have not been or would not be identified by the Crown for Option 1 or Options 2A, 2B or 2C (GeoBC, 2011). Option 3, with respect to the land-based components, is likely similar to Option 1 in relation to potential aboriginal/treaty rights issues, particularly with regard to the use of an existing right-of-way for the pipeline; however, it is uncertain whether aboriginal title assertions would be a consideration for Option 3. The issues relating to fishing are likely to be fewer for Option 3 than Option 1 because of the reliance on a sub-river bed pipeline. Thus, Option 3 is rated as a **Minor Concern** for the complexity of issues.

The ability of VAFFC to address potential issues related to Option 3 is expected to be greater than Option 1 and all other options. Thus, Option 3 is rated as a **Minor Concern** for the ability to address issues.

For reasons already cited, the level or scope of consultation would likely be reduced compared to Option 1 because of the long established “built-up” condition in the areas surrounding the majority portion of the existing pipeline route. Acquisition of additional right of way will potentially be required, and is expected to occur in the close vicinity of the existing right of way. It is assumed that this built-up condition has precluded the continued exercise of aboriginal and/or treaty rights and that any adverse impacts to aboriginal rights, including title, would be historic rather than new. Thus, Option 3 is rated as a **Minor Concern** for the level of consultation.

Mitigation measures that VAFFC may be expected to consider as a result of any new adverse impacts of Option 3 would likely be less than Option 1 and significantly less than Options 2A, 2B, and 2C. Thus, Option 3 is rated as a **Minor Concern** for the level of accommodation.

A large, known archaeological site is present in close proximity of the Westridge terminal, along with other smaller and more distant archeological sites. This archaeological site could be affected by construction activities at the Westridge terminal. The extent and condition of the archaeological sites is presently uncertain. Thus, Option 3 is rated as a **Moderate Concern** for heritage resources.

5.3.3.2 Summary

Results of the analysis for Option 3 for the First Nations dimension are summarized in Table 17. The ratings correspond to 70% of the total possible score for the First Nations Considerations theme and 70% for the First Nations dimension.

Table 17: Analysis of First Nations Dimension for Option 3

Theme	Indicator	Rating	Theme Score	Dimension Score
First Nations Considerations	Complexity of issues	Minor	70%	70%
	Ability to address issues	Minor		
	Level of consultation	Minor		
	Level of accommodation	Minor		
	Heritage resources	Moderate		

5.3.4 Operations

5.3.4.1 Workers Safety

Similar to Option 1, all Option 3 facilities will be land-based, which provide easy access to workers and, if necessary, emergency response personnel during construction and operation. Thus, Option 3 is rated as a **Negligible Concern** for accessibility.

Option 3 also involves occupational hazards identified for Option 1. In addition, pipeline construction for Option 3 involves installation of a new pipeline in close proximity to the existing TMJ pipeline. This introduces additional hazards such as exposure to contamination from historic undetected leaks or spills, possible disruptions due to incorrect or incomplete locate information for the existing line, and other incidents that might be increased in severity due to the presence of the fuel. Thus, Option 3 is rated as a **Moderate Concern** for occupational hazards.

5.3.4.2 Navigational Hazards

As an established practise, navigation to and from the Westridge Terminal through the second narrows poses negligible hazard with no incidents reported in the past 20 years. Thus, Option 3 is rated as a **Negligible Concern** for local experience.

Similar to Option 1 in the Fraser River, adverse wave conditions are not expected in the Burrard Inlet. Minor issues arising from wind loading and visibility are occasionally expected. Option 3 is deemed to be better protected than Option 1. Thus, Option 3 is rated as a **Negligible Concern** for exposure.

5.3.4.3 Reliability

Being triple the length of Option 1, the 41 km pipeline between the Westridge Terminal and YVR poses moderate risks for spill exposure. Thus, Option 3 is rated as a **Moderate Concern** for length of pipeline.

Unlike subsea pipelines situated on liquefiable soils, the Option 3 pipeline runs entirely on land save three river crossings. Seismic concern for Option 3 is similar to Option 1. Thus, Option 3 is rated as a **Minor Concern** for seismicity.

The Westridge terminal and vessels could be affected by natural hazards such as extreme storms and other extreme weather events. However, they are less susceptible compared to the offshore options and are similar to Option 1. Thus, Option 3 is rated as a **Minor Concern** for the effects of the environment on the project.

With good access to the entire pipeline, maintenance does not pose a major problem. Concerns rising from access on residential properties may hinder the activities of maintenance crews, but issues arising are deemed to be minor. Thus, Option 3 is rated as a **Minor Concern** for maintenance access.

The overall length of the pipeline raises some concern regarding malfunction response time. As the entire pipe is underground, locating potential malfunctions may slow response times for containment crews. Thus, Option 3 is rated as a **Moderate Concern** for response time for malfunction.

5.3.4.4 Summary

Results of the analysis for Option 3 for the Operations dimension are summarized in Table 18. The ratings correspond to 75% for the Worker Safety theme, 100% for the Navigational Safety theme, and 65% for the reliability theme. The overall score for the Operations dimension is 80%.

Table 18: Analysis of Operations Dimension for Option 3

Theme	Indicator	Concern	Theme Score	Dimension Score
Workers Safety	Accessibility	Negligible	75%	80%
	Occupational hazards	Moderate		
Navigational Safety	Local experience	Negligible	100%	
	Exposure	Negligible		
Reliability	Length of pipeline	Moderate	65%	
	Seismicity	Minor		
	Meteorological Hazards	Minor		
	Maintenance access	Minor		
	Response time for malfunction	Moderate		

5.3.5 Economics

5.3.5.1 Project Cost

Capital expenditures are estimated at $280 million, which is more than twice the cost of Option 1. Thus, Option 3 is rated as a **Critical Concern** for CAPEX.

Operating expenditures are expected to reach $78 million per annum incrementally over the next 32 years in step with increases in fuel supply to three billion litres per annum of throughput. Being 30% higher than Option 1, Option 3 is rated as a **Major Concern** for OPEX. A summary of the estimated costs for the options evaluated and the associated key contributing factors are presented in Appendix A.

After approval has been granted for the project, an anticipated 36 months are required for design, construction, and commissioning of the facilities. This long lead time before Option 3 could be operable would place a greater strain on VAFFC operations in the interim than other options. Thus, Option 3 is rated as a **Major Concern** for schedule.

With three river crossings, habitat compensation is minimal. Thus, Option 3 is rated as a **Negligible Concern** for habitat compensation.

5.3.5.2 Project Benefits

Option 3 depends entirely on the use of the Westridge Terminal for international fuel import. As the current owners are likely to continue other ventures requiring berth time, Option 3 may result in higher product costs, scheduling conflicts, and vessel demurrage on waiting tankers. Thus, Option 3 is rated as a **Major Concern** for reliability of fuel supply.

Currently at the Westridge Terminal, facilities are in place to accommodate vessels up to Panamax size. Thus, Option 3 is rated as a **Negligible Concern** for accommodation of a full range of marine vessels.

5.3.5.3 Summary

Results of the analysis for Option 3 for the Economics dimension are summarized in Table 19. The ratings correspond to 38% of the total possible score for the Project Cost theme and 63% for the Project benefits theme. The overall score for the Economics dimension is 50%.

Table 19: Analysis of Economics Dimension for Option 3

Theme	Indicator	Concern	Theme Score	Dimension Score
Project Cost	CAPEX	Critical	38%	50%
	OPEX	Major		
	Schedule	Major		
	Habitat compensation	Negligible		
Project Benefits	Reliability of fuel supply	Major	63%	
	Accommodation of a full range of marine vessels	Negligible		

5.4 Option 4 – Transhipping Facility and North Arm Barge Terminal

As discussed in Section 4.4, Option 4 involves jet fuel being offloaded and stored at a transhipment facility and subsequently transported to a barge unloading (receiving) terminal on the North Arm of the Fraser River. The evaluation is based primarily on the barge terminal and short pipeline to the YVR tank farm; however, these components represent only a small component of the overall fuel delivery system. Where appropriate and possible, consideration is also given to the transhipment facility which is assumed to be located on the north shore of Burrard Inlet. These assumptions and considerations, particularly with respect to operating costs, enable a fairer comparison of Option 4 to the other options.

5.4.1 Environmental

5.4.1.1 Environmental Effects

In Option 4, fuel would be delivered by deep sea vessels to a transhipping facility on the north shore of Burrard Inlet before being transported by barges to a barge terminal the North Arm of the Fraser River and by a 2 km pipeline to YVR. The levels of concern with respect to sensitive species and species-at-risk for Option 4 are similar to Option 1. Sensitive species along the marine transportation corridor from the transhipping facility to the North Arm barge terminal include salmon and sturgeon as well as birds on Iona Island. Species-at-risk include certain migratory fish species as in Option 1 as well as certain migratory birds on Iona Island. Thus, Option 4 is rated as a **Moderate Concern** for sensitive species and as a **Minor Concern** for species-at-risk and sensitive habitats.

However, unlike Option 1, the marine transportation corridor from the north shore of Burrard Inlet to the North Arm barge terminal does not cross sensitive intertidal areas. The area is not used by migratory salmons. Potential habitat effects from the 2 km pipeline on Sea Island are also expected to be minimal. Thus, Option 1 is rated as a **Minor Concern** for sensitive habitats.

Option 4 is expected to employ most of the air emission reduction measures used in Option 1. However, the double handling of the fuel cargo through the use of the transhipping facility and the barges would result in higher air emissions, including GHG emissions. Thus, Option 4 is rated as a **Moderate Concern** for air quality and GHG emissions.

The potential effects on soil and water contamination are expected to be similar to Option 1. Although the double handling of the fuel increases the likelihood of a spill from fuel loading and unloading, the potential consequence is expected to be low due to the high volatility of the fuel. Similar spill prevention measures and spill response procedures in place for Option 1 would be developed for Option 4. Thus, Option 4 is rated as a **Minor Concern** for soil and water contamination.

5.4.1.2 Regulatory Framework

Option 4 is the least complex option with respect to regulatory requirements as the types of facilities and activities involved are well understood by the regulatory agencies involved. Thus, Option 4 is rated as a **Minor Concern** for regulatory complexity.

The permitting timeline for Option 4 is estimated at two years, including 12 months for the Transport Canada TERMPOL review process and 12 months for other permits including a screening level CEAA with optional public consultation process. This timeline is similar to Option 1. Thus, Option 4 is rated as a **Minor Concern** for permitting timeline.

There remain uncertainties whether the land use plan on the North Shore of Burrard Inlet can accommodate jet fuel as a stored item. However, once the transhipping facility location and configuration is determined, regulatory requirements for all Option 4 facilities including the transhipping facility would be well understood. Thus, Option 4 is rated as a **Minor Concern** for the regulatory uncertainties.

5.4.1.3 Summary

Results of the analysis for Option 4 for the Environmental dimension are summarized in Table 20. The ratings correspond to 65% of the total possible score for the Environmental Effects theme and 75% for the Regulatory Framework theme. The overall score for the Environmental dimension is 70%.

Table 20: Analysis of the Environmental Dimension for Option 4

Theme	Indicator	Concern	Theme Score	Dimension Score
Environmental Effects	Sensitive species	Moderate	65%	70%
	Species-at-risk	Minor		
	Sensitive habitats	Minor		
	Air quality and GHG emissions	Moderate		
	Soil and water contamination	Minor		
Regulatory Framework	Regulatory complexity	Minor	75%	
	Permitting timeline	Minor		
	Regulatory uncertainty	Minor		

5.4.2 Socio-Economic

5.4.2.1 Economic Development

Direct employment for the construction activities for Option 4 is limited to the construction of a barge berth, the 2 km pipeline and additional tank farm capacity at YVR. Construction labour may be required for the construction or upgrade of the transhipping facility, which will be managed by a third-party. However, employment during operations of Option 4 is likely to be higher than Option 1 because of the additional labour required for the double handling of the fuel cargo. Thus, Option 4 is rated as a **Minor Concern** for the opportunities for direct local employment.

Option 4 would generate opportunities for local businesses including the construction or upgrade of the transhipping facility and the barge services during the entire operational life, which is expected to be provided by independent local businesses. Thus, Option 4 is rated as a **Negligible Concern** for the opportunities for local business generation.

Potential adverse effects to businesses are low due to the minimal land-based components of Option 4. The construction of the 2 km on-land pipeline and the tank farm at YVR is not expected to affect local businesses. Thus, Option 4 is rated as **Negligible Concern** for the potential effects on business operations.

5.4.2.2 Community Safety and Wellbeing

As discussed in Section 5.4.1.1, emissions from Option 4 is expected to be higher than Option 1, thereby resulting in incremental adverse effects to the regional air quality. Increased emissions from a transhipping terminal on the North Shore of Burrard Inlet would be a concern especially to the residents of highly populated areas. The likelihood of a fuel spill is also higher due to the double handling of the fuel cargo, although the potential consequences are low due to the high volatility of the fuel. Thus, Option 4 is rated as a **Moderate Concern** for the potential public health and safety impacts from emissions and spills.

The construction of the 2 km pipeline and additional tank storage facility at YVR would have negligible effects on road traffic. However, the construction of the transhipping facility if located within a populated area could result in some traffic concerns. Thus, Option 4 is rated as a **Minor Concern** for the potential effects on land-based traffic.

Option 4 would result in greater vessel movements compared to all the other options considered in this analysis, due to the barges traffic from the transhipping facility to the North Arm barge terminal. Nevertheless, the additional barge traffic would account only a small increase in North Arm vessel traffic. Thus, Option 4 is rated as a **Moderate Concern** for the potential effects on marine-based traffic.

Noise during construction could affect some residents in the North Arm. Noise during construction at the North Shore facility could also affect residents in the surrounding communities. However, the level of noise is expected to be very low and temporary. Thus, Option 4 is rated as a **Minor Concern** for noise.

Impacts on the visual aesthetics would be minimal. All facilities will have similar visual impact to its surrounding. Thus, Option 4 is rated as a **Minor Concern** for visual aesthetics.

5.4.2.3 Land Use

The 2 km pipeline for Option 4 would pass through a light industrial area and the airport property. Other facilities would be in industrial areas. Thus, Option 4 is rated as a **Negligible Concern** for conformity with land use designation and zoning.

Due to their locations away from residential and commercial areas, all facilities including the 2 km pipeline are expected to have negligible effects on property values. Thus, Option 4 is rated as a **Negligible Concern** for potential or perceived effects on property values.

A foreshore lease may be required for the transhipping facility, and an NWPA may be required for each site. Thus, Option 4 is rated as **Minor Concern** for foreshore lease requirements.

5.4.2.4 Summary

Results of the analysis for Option 4 for the Socio-economic dimension are summarized in Table 21. The ratings correspond to 92% of the total possible score for the Economic Development theme, 63% for the Community Safety and Wellbeing theme, and 92% for the Land Use theme. The overall rating is 82% for the Socio-economic dimension.

Table 21: Analysis of the Socio-Economic Dimension for Option 4

Theme	Indicator	Rating	Theme Score	Dimension Score
Economic Development	Opportunities for direct local employment	Minor	92%	83%
	Opportunities for local business generation	Negligible		
	Potential effects on business operations	Negligible		
Community Safety and Wellbeing	Potential public health and safety effects from emissions and spills	Moderate	65%	
	Potential effects on land-based traffic	Minor		
	Potential effects on marine-based traffic	Moderate		
	Noise	Minor		
	Visual aesthetics	Minor		
Land Use	Conformity with land use designation/zoning	Negligible	92%	
	Potential or perceived effects to property values	Negligible		
	Foreshore lease requirements	Minor		

5.4.3 First Nations

5.4.3.1 First Nations Considerations

The number of First Nations potentially affected by (GeoBC, 2011), and the type and range of issues that may be raised in relation to, Option 4 would likely approximate Option 1, though the specific First Nations involved may slightly differ from Option 1. However, areas subject to treaty rights do not appear to coincide with the areas under consideration, including the transportation of fuel to and from an existing facility on the north side of Burrard Inlet. The issues with proximity to Indian Reserves, as per Options 2A, 2B, and 2C, also apply to Option 4 because of proposed components associated with the North Arm of the Fraser River near two Indian Reserves (of the Musqueam Indian Band), and the transport of fuel to and from the north side of Burrard Inlet where additional Indian Reserves are located (including those of the Squamish Nation and Tsleil-Waututh Nation). Issues relating to the marine environment for the other options (except Option 3) would also likely apply to Option 4. Thus, Option 4 is rated as a **Moderate Concern** for the complexity of issues.

Aboriginal rights and title issues raised for Option 1 would likely also be raised for Option 4, though the title issues may more closely resemble those of Options 2A, 2B, and 2C than those of Option 1 (*i.e.,* proximity to Indian Reserves). Thus, Option 4 is rated as a **Moderate Concern** for the ability to address issues.

While the level or scope of consultation for Option 4 will vary according to the issues raised by First Nations and the extent of potential adverse impacts to aboriginal interests, at the higher end, this scope would likely be deeper than for Option 1 and resemble Options 2A, 2B, and 2C, again because of the proximity to Indian Reserves, not just on the North Arm of the Fraser, but also potentially along the north shore of Burrard Inlet. Thus, Option 4 is rated as a **Major Concern** for the level of consultation.

For reasons cited in the preceding paragraph, mitigation measures that may be expected of VAFFC for Option 4 would also likely resemble those outlined for Options 2A, 2B, and 2C, and therefore would be potentially more involved than Option 1. Thus, Option 4 is rated as a **Moderate Concern** for the level of accommodation.

Similar to Options 2B and 2C, archaeological sites could be affected by the barge traffic associated with Option 4. Thus, Option 4 is rated as a **Minor Concern** for heritage resources.

5.4.3.2 Summary

Results of the analysis for Option 4 for the First Nations dimension are summarized in Table 22. The ratings correspond to 50% of the total possible score for the First Nations Considerations theme and 50% for the First Nations dimension.

Table 22: Analysis of the First Nations Dimension for Option 4

Theme	Indicator	Rating	Theme Score	Dimension Score
First Nations Considerations	Complexity of issues	Moderate	50%	50%
	Ability to address issues	Moderate		
	Level of consultation	Major		
	Level of accommodation	Moderate		
	Heritage resources	Minor		

5.4.4 Operations

Due to significant uncertainties associated with the location and current owner of a potential transhipment facility, the operational factors discussed below were assessed primarily on the barge unloading terminal located on the south bank of the Fraser River North Arm and the short (2 km) pipeline linking the unloading terminal to the existing YVR tank farm. Considerations were made, where feasible, to adjust the scores and account for the transhipment facility which is assumed to be on the north shore of Burrard Inlet, immediately east of the Lions Gate Bridge. The adjustments provide a fairer comparison of Option 4 to the other options.

5.4.4.1 Workers Safety

Option 4 facilities will be land-based and provide easy access to workers and, if necessary, emergency response personnel during construction and operation. Thus, Option 4 is rated as a **Negligible Concern** for accessibility.

The double handling and barge transportation of the fuel pose greater occupational hazards than pipeline transportation of the fuel. Thus, Option 4 is rated as a **Moderate Concern** for occupational hazards.

5.4.4.2 Navigational Hazards

During the construction of YVR runways, barges were used to transfer material up the north arm of the Fraser River to the proposed barge terminal site. Given precedence for barge traffic, Option 4 is rated as a **Minor Concern** for local experience.

With the barge berth located in a very sheltered portion of the north arm, exposure to environmental conditions is minimal during operations. Thus, Option 4 is rated as a **Negligible Concern** for exposure.

5.4.4.3 Reliability

In comparison to the 15 km pipeline in Option 1, the 2 km pipeline proposed for Option 4 has minimal spill exposure based on length. Thus Option 4 is rated as a **Negligible Concern** for length of pipeline.

As with Option 1 and Option 3, the fixed structures in Option 4 are entirely land based. Due to the small length, and minimal seismic concern, Option 4 is rated as a **Negligible Concern** for seismicity.

Marine operations in Option 4 could be affected by extreme storms and other extreme weather events. Both the transhipping facility and barge transportation would be more susceptible to these hazards compared to Option 1. Thus, Option 4 is rated as a **Moderate Concern** for the effects of the environment on the project.

With full land access, similar to Option 1 and Option 3, Option 4 is rated a **Negligible Concern** for maintenance access.

Given such a small terminal and short pipeline, any malfunctions are quickly identifiable. As with other options, any marine incidents can be handled by tug crews who are trained to follow standard response procedures. Thus, Option 4 is rated as a **Minor Concern** for response time for malfunction.

5.4.4.4 Summary

Results of the analysis for Option 4 for the Operations dimension are summarized in Table 23. The ratings correspond to 75% for the Worker Safety theme, 88% for the Navigational Safety theme, and 85% for the reliability theme. The overall rating is 83% for the Operations dimension.

Table 23: Analysis of the Operations Dimension for Option 4

Theme	Indicator	Concern	Theme Score	Dimension Score
Workers Safety	Accessibility	Negligible	75%	83%
	Occupational hazards	Major		
Navigational Safety	Local experience	Moderate	88%	
	Exposure	Negligible		
Reliability	Length of pipeline	Negligible	85%	
	Seismicity	Negligible		
	Meteorological Hazards	Moderate		
	Maintenance access	Negligible		
	Response time for malfunction	Minor		

5.4.5 Economics

5.4.5.1 Project Cost

Capital expenditures are estimated at $35 million for the barge terminal. Capital costs for transhipment terminals have been factored into operational expenditures as operating costs. In comparison to Option 1, Option 4 has been rated as **Negligible Concern** for CAPEX.

Operating expenditures are expected to reach $89 million per annum incrementally over the next 32 years in step with increases in fuel supply to three billion litres per annum of throughput. Being 35% higher than Option 1, Option 4 is rated as a **Major Concern** for OPEX. A summary of the estimated costs for the options evaluated and the associated key contributing factors are presented in Appendix A.

Design, construction, and commissioning of the Fraser River North Arm barge unloading terminal is expected to take 15 months after approval has been granted for the project. The time required to develop the transhipment facility, however, is anticipated to be considerable and is, to a significant extent, beyond the control of VAFFC. Development of a facility will involve selection of a feasible site, negotiation with the current owner, and design and modification of an existing marine facility to accommodate the required range of vessels and necessary fuel storage. Therefore, Option 4 is rates as **a Moderate Concern** for schedule.

The only discernable impacts on marine habitat for Option 4 are found at the barge terminal. With a relatively small footprint that is comparable to Option 1, Option 4 is rated as a **Minor Concern** for financial implications to habitat compensation.

5.4.5.2 Project Benefits

The combination of a transhipment terminal and barge berth allows access to both international and local fuel sources. With minimal interference from log booms on the north arm of the Fraser River, Option 4 becomes very similar to Option 1 for reliability. Thus, Option 4 is rated as **Minor Concern** for reliability of fuel supply.

As the transhipment terminal would accommodate any vessels up to Panamax size, no vessel restrictions would be in place. Thus, Option 4 is rated as **Negligible Concern** for Option 4.

5.4.5.3 Summary

Results of the analysis for Option 4 for the Economics dimension are summarized in Table 24. The ratings correspond to 63% of the total possible score for the Project Cost theme and 88% for the Project benefits theme. The overall score for the Economics dimension is 75%.

Table 24: Analysis of the Economics Dimension for Option 4

Theme	Indicator	Concern	Theme Score	Dimension Score
Project Cost	CAPEX	Negligible	63%	75%
	OPEX	Major		
	Schedule	Moderate		
	Habitat compensation	Minor		
Project Benefits	Reliability of fuel supply	Minor	88%	
	Accommodation of a full range of marine vessels	Negligible		

6.0 KEY FEATURES OF OPTIONS AND EVALUATION RESULTS

6.1 Key Features of the Fuel Delivery Options

Option 1 – South Fraser River Terminal with Pipeline to YVR

Option 1, South Fraser River Terminal is based on the upgrading of an existing marine terminal located in a naturally deeper section of the Fraser River's South Arm and an adjacent tank farm connected to YVR via a 15 km underground pipeline (refer to Figures 1 and 4). This option will provide a Panamax capable terminal that can also accommodate small to large barges. Although Panamax tankers can be accommodated, minimum under keel clearance requirements up the Fraser River may restrict loads to less than full capacity. The berth location is not exposed to adverse wave conditions; however, navigation and schedules may depend on the tides. Direct road access is available to the terminal and along the pipeline route.

In this option, VAFFC would have complete commercial and operational control of the terminal and pipeline to YVR.

Key environmental concerns relate to sensitive fish species (*e.g.*, Pacific salmon, steelhead, eulachon, and sturgeon) that are present in the marine transportation corridor along the South Arm of the Fraser River, as well as a smaller number of sensitive birds and marine mammal species. In terms of sensitive habitats, the marine transportation corridor crosses intertidal areas and the pipeline crosses a number of riparian areas.

From a socio-economic standpoint, Option 1 is associated with moderate concerns for public health and safety from fuel spills and emissions. Most of the pipeline will go through urban and agricultural areas; however, it will follow existing roads and/or utility corridors. There are similar concerns related to potential or perceived effects on property values along the pipeline corridor.

There are a number of First Nations considerations for Option 1. The main considerations relate to: the complexity of issues raised by First Nations, the ability of VAFFC to address the issues, the level of consultation due by the Crown or delegated to VAFFC, and the presence of an archaeological site of unconfirmed extent or condition in the vicinity of the river terminal (DgRs-17).

Operational concerns related to worker safety, navigation, and reliability are considered negligible or minor.

Project costs are estimated at $135 million (CAPEX) and $66 million per annum (OPEX for three billion litres per annum throughput). Following approval to proceed, the construction program is expected to take about 24 months, including an active work period of about 18 months.

Option 2 – Offshore Terminal Facility with Pipeline to YVR

Option 2, Offshore Terminal involves a marine terminal located offshore of Sturgeon Bank and a subsea and onland pipeline connecting the terminal to the YVR tank farm (refer Figures 5 to 8). Three alternatives for the terminal were evaluated: Option 2A single point mooring (SPM), Option 2B spread mooring, and Option 2C fixed structure. The potential locations are constrained by the required water depths, existing marine traffic corridor (for traffic approaching or departing Vancouver Harbour), prevailing wind/wave directions and currents, and a potential airport runway expansion. All the alternatives can accommodate a fully-loaded Panamax vessel; however, they cannot receive barges due to operational constraints and adverse wind and wave conditions. This necessitate a separate barge terminal, which is assumed to be located on the North Arm of the Fraser River and connected to the tank farm via a short underground pipeline.

The terminals can operate under most tidal conditions; however, they are exposed to wind and waves, predominantly from the west and northwest. Operational delays can occur due to poor visibility and adverse conditions when tugs cannot operate during ship arrivals or departures. Once the floating line is hooked up to the vessel, though, offloading could proceed during most weather conditions.

Option 2A (SPM alternative) would include an 11.8 km long subsea pipeline that would run north to the Iona jetty, and then along the jetty to land. Option 2B (spread mooring alternative) involves a 2.3 km long subsea pipeline to the North Arm jetty, and then a buried pipeline along the jetty and on YVR property to the tank farm. In both cases, the jet fuel pipeline will have to be emptied after the vessel has unloaded to minimize risk of fuel release to the marine environment. Due to the off-shore location, access would be restricted to water taxis for the SPM terminal and small vessels for the spread mooring terminal. Option 2C (fixed terminal) would involve an elevated pipeline trestle to the shore, which would also provide a roadway for vehicle access.

In Option 2, VAFFC would have complete commercial and operational control of the offshore terminal and pipeline.

There are considerable environmental concerns associated with the Option 2 alternatives. The alternatives are all located within the Sturgeon Bank Wildlife Management Area, and sensitive species located in the tidal marsh and bank areas could be disturbed during construction. Species at risk in the off-shore terminal areas include migratory waterfowl, killer whales, and sea lions. Environmental concerns are even greater for Option 2A, compared to 2B and 2C, due to the considerably longer length of subsea pipeline involved. Construction of the offshore facilities also has a higher potential than Option 1 for soil and water contamination due to construction of the terminal and pipelines occurring in a marine and underwater environment. Regulatory requirements for Option 2 are expected to be more complex than land-based developments (*e.g.*, Option 1), and are thus potentially subject to longer timelines and uncertainties. Overall, the environmental concerns associated with Option 2 are considered greater than for Option 1.

There are limited socio-economic concerns related to Option 2, due to the off-shore terminal and subsea pipelines being located away from communities, as well as the land pipeline being buried and running to the extent possible within the YVR property boundary. Option 2A poses a slight disadvantage, related to direct local employment and business generation, due to the specialized equipment, operators, and construction that may not be available locally.

Option 2 involves similar First Nations considerations as Option 1. The complexity of issues may be slightly reduced for Options 2B and 2C, since these options are focused near the North Arm of the Fraser River, and may concern a smaller set of aboriginal interests than those identified for Option 1 and possibly for Option 2A. The proximity of Indian Reserves to some or all of the Option 2 components does, however, suggest there could be deeper levels or consultation and/or accommodation involved. Heritage resources are of a lesser concern, as known archaeological sites in the vicinity of Option 2 are farther away than those associated with Option 1.

There are moderate to major operational concerns associated with Options 2A and 2B. They are related to worker safety in a marine environment (*e.g.*, construction over water, access by water, maintenance under water), navigational hazards (*e.g.*, less local experience with the SPM and spread mooring systems), and reliability (*e.g.,* length of pipeline subject to higher seismic risk, difficulty of access for maintenance or response to malfunction). All three alternatives for Option 2 are located in an exposed environment and subject to extreme meteorological conditions. Overall, the operational concerns of Option 2A and 2B are much greater than those associated with Option 1. Option 2C is comparable to Option 1, although it is in a more exposed location.

CAPEX costs for Options 2A, 2B, and 2C are estimated at $225 million, $135 million, and $185 million, respectively. OPEX expenditures are expected to reach $67, $65, and $66 million per annum for Options 2A, 2B, and 2C, respectively. Overall capital and operating costs for Option 2A are much higher than for Option 1; costs for Option 2B are comparable; and capital costs for Option 2C are higher than for Option 1.

Following approval to proceed, design, construction, and commissioning is expected to take about 24 months.

Option 3 – Upgrading of the Trans Mountain Jet Fuel Inc. Pipeline

Option 3, Upgrading of TMJFI Pipeline (refer to Figure 1) would provide a new, higher capacity pipeline between Westridge Terminal and the YVR tank farm. Product tankers and barges would unload at Westridge Terminal, located in Burrard Inlet east of Second Narrows Bridge. The pipeline from Westridge to YVR is approximately 41 km long and passes through Burnaby and Richmond to YVR. In this case, VAFFC will have to enter into long-term contracts with the pipeline and terminal operators and, as such, would not retain complete operational control.

The existing pipeline is located in a fairly urban environment, and environmental considerations are generally less or comparable to Option 1. Because of the urban and residential environment, however, the regulatory complexity is high and associated with uncertainty. Uncertain regulatory procedures and timelines for approval are considered major and critical concerns.

Option 3 is associated with the most significant socio-economic concerns, compared to all the other options. These relate to the long length of pipeline locate through highly urban and residential areas, and the potential for effects on business operations, public health and safety due to spills and emissions, land based traffic during construction, noise, conformity with land use and zoning, and property values.

In general, Option 3 is associated with potentially fewer First Nations considerations than the other options. This reflects, in part, fewer issues related to fishing (typically associated with water-based facilities or activities), and the “built up” nature of the existing pipeline corridor. A large known archaeological site has been noted in proximity to the Westridge terminal.

From an operations standpoint, Option 3 is comparable to Option 1 and Option 2C (and considerably better than Options 2A and 2B). The disadvantages compared to Options 1 and 2C relate to the long length of underground pipeline which results in increased worker exposure to risks during construction and operation/maintenance, effects on system reliability, and increased response time to malfunctions.

Of all the options evaluated, Option 3 has the highest capital cost at $280 million, a high operating cost at $78 million per annum, and the longest construction period at three years. Option 3 would involve a complex regulatory and approvals process, and the time required for concluding permitting is uncertain. From a schedule perspective this is considered a major concern.

Option 4 – Transhipment Facility and North Arm Barge Terminal

Option 4, Transhipment facility and North Arm Barge Terminal, relies on an offsite transhipment facility to receive Panamax size vessels and a barge terminal to receive fuel from the transhipment facility. For the purposes of this evaluation, the transhipment facility is assumed to be located on the north shore of Burrard Inlet (*e.g.*, Vancouver Wharves). The barge terminal is located along the North Arm of the Fraser River near the existing YVR jet fuel tank farm. Barge traffic is limited by the available draught in the North Arm; however, purpose built shallow draught barges with a capacity in the order of 10 million litres are considered feasible, and would be used to transfer fuel from the transhipment facility as well as local refineries.

Option 4 would require long-term commitments from VAFFC to the transhipment organization and tug/barge operators. Operational control would be reduced due to the involvement of these parties.

Potential environmental affects associated with Option 4 are similar to those associated with Option 1, in that sensitive species and species at risk would be affected to a similar degree. The marine transportation route does not cross sensitive intertidal areas, however, and thus has relatively less impact on sensitive habitats.

The socio-economic concerns for Option 4 relate to public health and safety, and potential for spills and emissions in populated areas or the higher risks associated with double handling (at the transhipment facility and then onto barge prior to delivery at YVR). Barges would operate across Burrard Inlet and up the North Arm; however this would reflect only a small increase in marine traffic.

First Nations issues would be similar to those associated with Options 2A, 2B and 2C, given the similar focus on the North Arm of the Fraser River. There is, however, an added complexity in terms of the transhipment terminal location in, and marine transportation route to and from, Burrard Inlet, which would involve additional First Nations not considered under Options 2A, 2B or 2C.

Operational concerns for Option 4 are negligible to minor, with the exception of occupational and seismic hazards associated with barge transportation.

The capital costs for Option 4 is relatively low at $35 million, as it only represents the North Arm barge terminal, pipeline to YVR and increased tank farm facility. Costs associated with the transhipment and fuel storage facility are accounted for as operational costs, which results in high annual expenditures of $ 89 million. This is considered a major concern.

6.2 Results of the Options Evaluation

6.2.1 Summary of Indicator Ratings

Thirty-nine (39) indicators were analyzed as part of the options evaluation. Each was assigned a rating in terms of the level of concern, as summarized in Table 25. Negligible and minor concerns suggest higher merit than those associated with moderate, major, and critical ratings.

In general, the results in Table 25 indicate the following:

- Options 1 and 4 are favourable from an Environmental standpoint, as indicated by primarily “negligible concern” or “minor concern” ratings;
- Options 1 and 4 are also acceptable from a Socio-Economic standpoint, although Options 2B and 2C could be slightly better, based on no “moderate concern” ratings;
- Option 3 is the least favourable option in terms of Socio-Economic considerations based on the multiple “major concern” ratings;
- Option 3 is potentially associated with fewer First Nations considerations than the others;
- Option 1 is most favourable in terms of Operations, as all ratings are “negligible” or “minor”;
- Options 2C and 4 are also favourable in terms of Operations, but are affected by exposure and occupational hazards. Option 3 is similar; however, the long length of pipeline poses challenges for access and maintenance;
- Options 1 and 2B are favourable from an Economic standpoint; and
- Option 3 is least favourable from an Economic standpoint, in terms of both capital and operating expenditures as well as potential impacts on schedule.

Figure 10 provides an illustration of the indicator results in terms of the percentages that were assigned to each rating level. It shows all 39 indicators together, and does not differentiate by theme or dimension. Based on the percentage of negligible and minor concern ratings, Figure 10 suggests that Option 1 has the highest merit compared to the others (80% of indicator being rated as negligible or minor concern). This is followed by Option 4 and Option 2C which are close at about 70% and 65%, respectively.

Table 25: Summary of Indicator Ratings for Options 1, 2, 3, and 4

Dimension / Themes	Indicator	Option 1	Option 2			Option 3	Option 4
			A	B	C		
ENVIRONMENTAL							
Environmental Effects	Sensitive species	Moderate	Major	Moderate	Moderate	Negligible	Moderate
	Species at risk	Minor	Major	Moderate	Moderate	Negligible	Minor
	Sensitive habitats	Moderate	Major	Moderate	Moderate	Moderate	Minor
	Air quality and GHG emissions	Negligible	Negligible	Negligible	Negligible	Negligible	Moderate
	Soil and water contamination	Minor	Moderate	Moderate	Moderate	Minor	Minor
Regulatory Framework	Regulatory complexity	Minor	Moderate	Moderate	Moderate	Major	Minor
	Permitting timeline	Minor	Moderate	Moderate	Moderate	Critical	Minor
	Regulatory uncertainty	Minor	Moderate	Moderate	Moderate	Major	Minor
SOCIO-ECONOMICS							
Economic Development	Opportunity for direct local employment	Minor	Moderate	Minor	Minor	Negligible	Minor
	Local business generation	Minor	Moderate	Minor	Minor	Negligible	Negligible
	Effects on business operations	Minor	Negligible	Negligible	Negligible	Major	Negligible
Community Safety & Wellbeing	Public H&S from spills/emissions	Moderate	Minor	Minor	Minor	Major	Moderate
	Effects on land based traffic	Minor	Minor	Minor	Minor	Major	Minor
	Effects on marine traffic	Minor	Minor	Minor	Minor	Minor	Moderate
	Noise	Minor	Minor	Minor	Minor	Moderate	Minor
	Visual Aesthetics	Minor	Negligible	Negligible	Minor	Minor	Minor
Land Use	Conformity with Land Use Designation/zoning	Minor	Negligible	Negligible	Negligible	Major	Negligible
	Property value effects	Moderate	Negligible	Negligible	Negligible	Major	Negligible
	Foreshore lease	Negligible	Minor	Minor	Minor	Negligible	Minor

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Dimension / Themes	Indicator	Option 1	Option 2			Option 3	Option 4
			A	B	C		
FIRST NATIONS							
First Nations Considerations	Complexity of issues	Major	Major	Moderate	Moderate	Minor	Moderate
	Ability to address issues	Moderate	Moderate	Moderate	Moderate	Minor	Moderate
	Level of consultation	Moderate	Major	Major	Major	Minor	Major
	Level of accommodation	Minor	Moderate	Moderate	Moderate	Minor	Moderate
	Heritage resources	Moderate	Minor	Minor	Minor	Moderate	Minor
OPERATIONS							
Workers Safety	Accessibility	Negligible	Major	Major	Negligible	Negligible	Negligible
	Occupational hazards	Minor	Major	Major	Minor	Moderate	Moderate
Navigational Hazards	Local experience	Minor	Moderate	Moderate	Minor	Negligible	Minor
	Exposure	Minor	Moderate	Moderate	Moderate	Negligible	Negligible
Reliability	Length of pipeline	Minor	Minor	Minor	Minor	Moderate	Negligible
	Seismicity	Minor	Major	Moderate	Minor	Minor	Negligible
	Meterological Hazards	Minor	Moderate	Moderate	Moderate	Minor	Moderate
	Maintenance access	Negligible	Major	Major	Minor	Minor	Negligible
	Response time for malfunction	Minor	Moderate	Moderate	Minor	Moderate	Minor
ECONOMIC							
Project Cost	Capital Expenditure	Minor	Major	Minor	Moderate	Critical	Negligible
	Operational Expenditure	Minor	Moderate	Minor	Minor	Major	Major
	Schedule	Minor	Minor	Minor	Minor	Major	Moderate
	Habitat compensation	Minor	Major	Minor	Minor	Negligible	Minor
Project Benefits	Reliability of fuel supply	Minor	Minor	Minor	Negligible	Major	Minor
	Using a range of vessels	Minor	Negligible	Negligible	Negligible	Negligible	Negligible

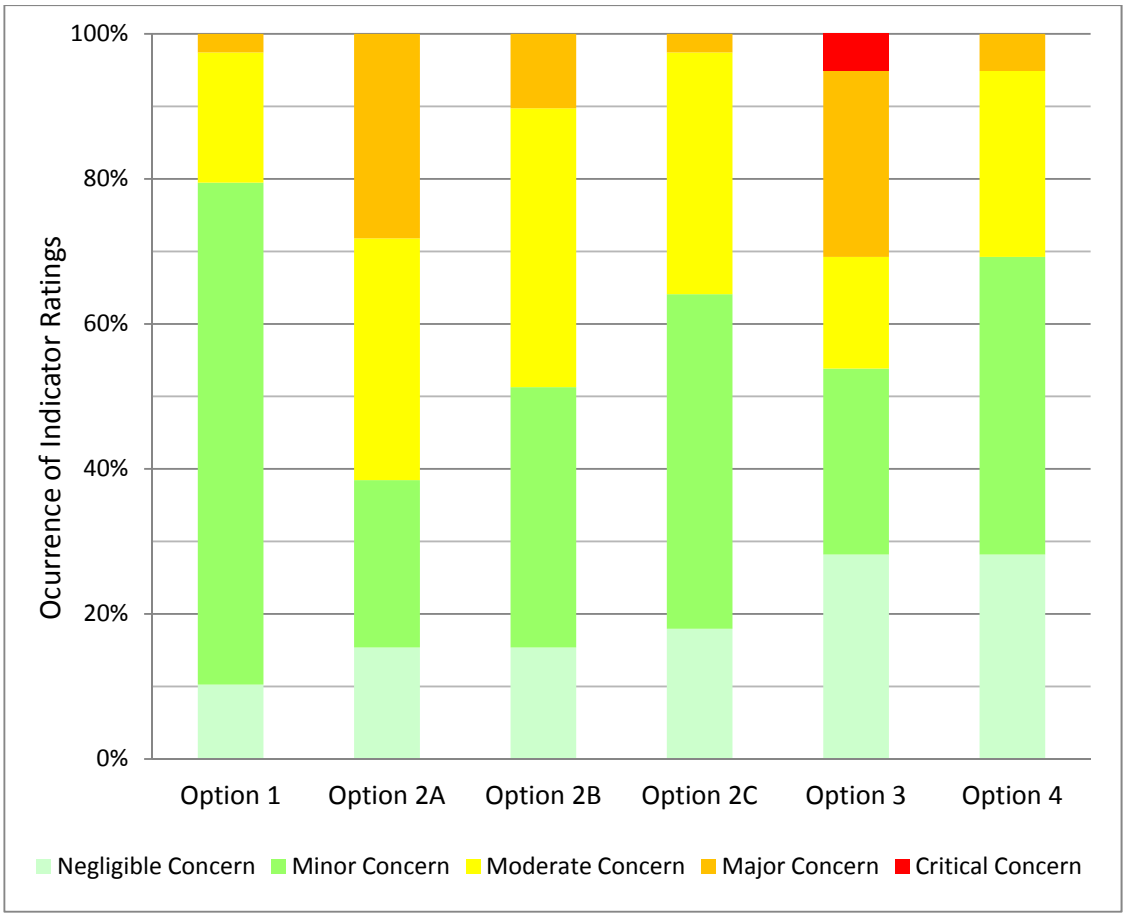

Figure 10: Occurrence of Indicator Ratings by Option

6.2.2 Summary of Results by Dimension and Option

As discussed in Section 3.5, each indicator is assigned a score based on the indicator's concern rating. Higher scores are associated with greater merit (*i.e.*, lesser concerns). The scores are aggregated to theme scores assuming equal weighting of indicators, and then the theme scores are aggregated to dimension scores assuming equal weighting of the themes.

The theme and overall dimension scores are shown in Figure 11 for each option. The graphs allow comparison of options against each other, within a given dimension. They also show the contribution of each theme within a dimension (as shown by the stacked bars that make up each column). The options with the highest and lowest relative merits were identified based on this information, and are shown in Table 26.

Table 26: Merit of Options, by Dimension

Dimension	Highest Merit	Lowest Merit
Environmental	Option 1, Option 4	Option 2A
Socio-Economic	Option 2B, Option 2C, Option 4	Option 3
First Nations	Option 3	Options 2A
Operations	Option 4, Option 1, Option 3	Option 2A, Option 2B
Economic	Option 2C, Option 2B	Option 3

The same data is presented in Figure 12, but is presented by dimension for each Option. The graphs provide a holistic description of each option, considering the five dimensions that were evaluated. Similar to Figure 11, the stacked bars that make up each column represent the themes associated with the given dimension. Based on these figures, overall merits and issues associated with each option were identified. These are summarized in Table 27.

Table 27: Merit in Terms of Dimensions, by Option

Option	Dimensions with Highest Merit[(a)]	Dimensions with Lowest Merit[(a)]
1 – South Fraser Terminal	Environmental, Operations	None
2A – Offshore (SPM)	None	Environment, Economics
2B – Offshore (spread mooring)	Socio-Economics, Economics	Operations
2C – Offshore (fixed terminal)	Socio-Economics, Economics	Operations
3 – Upgrade of TMJF Pipeline	First Nations, Operations	Environment, Socio-Economics, Economic
4 – Transhipping Facility / North Arm Barge Terminal	Environmental, Socio-Economics, Operations	None

Notes: (a) compared to other options; none = none of the dimensions associated with this option scored highest/lowest when compared to the other options.

Consistent with the evaluations of indicator ratings and individual theme and dimension scores, the most favourable options appear to be Option 1 and Option 4. This is illustrated in their similar graphs in Figure 12. The main differences and disadvantages with Option 4 are the additional operational costs and schedule implications associated with the necessary transhipment facility. In addition, VAFFC would not retain full operational control of the system and would be subject to long-term agreements with the transhipping and barge/tug operators. Advantages of Option 4 over Option 1 include lesser operational concerns (with the exception of frequent barge activity and weather hazards) and slightly more favourable socio-economic conditions, primarily associated with less disruption to the community and current land use.

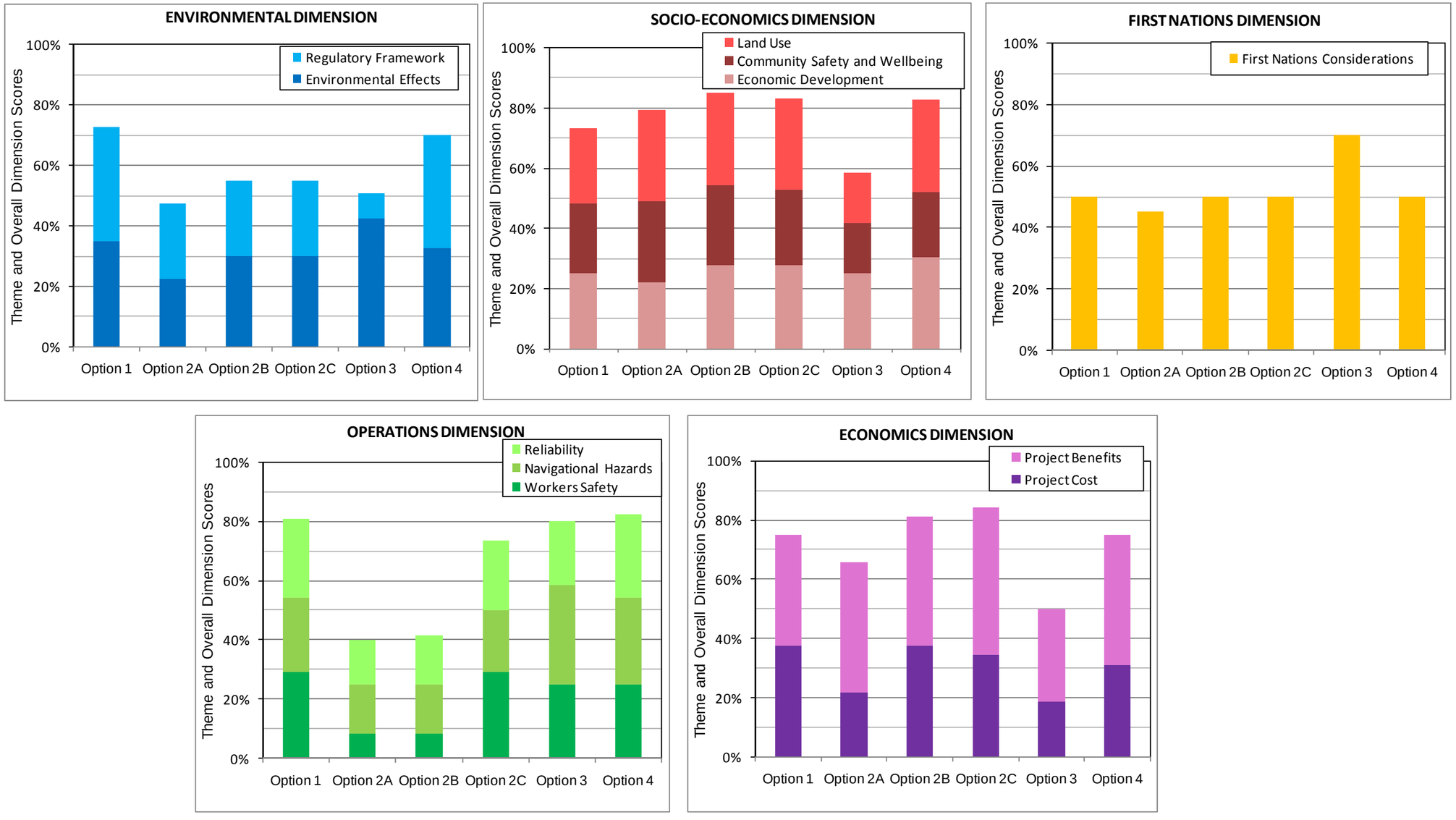

Figure 11: Results by DIMENSION: Contribution of Theme Scores for Each Option

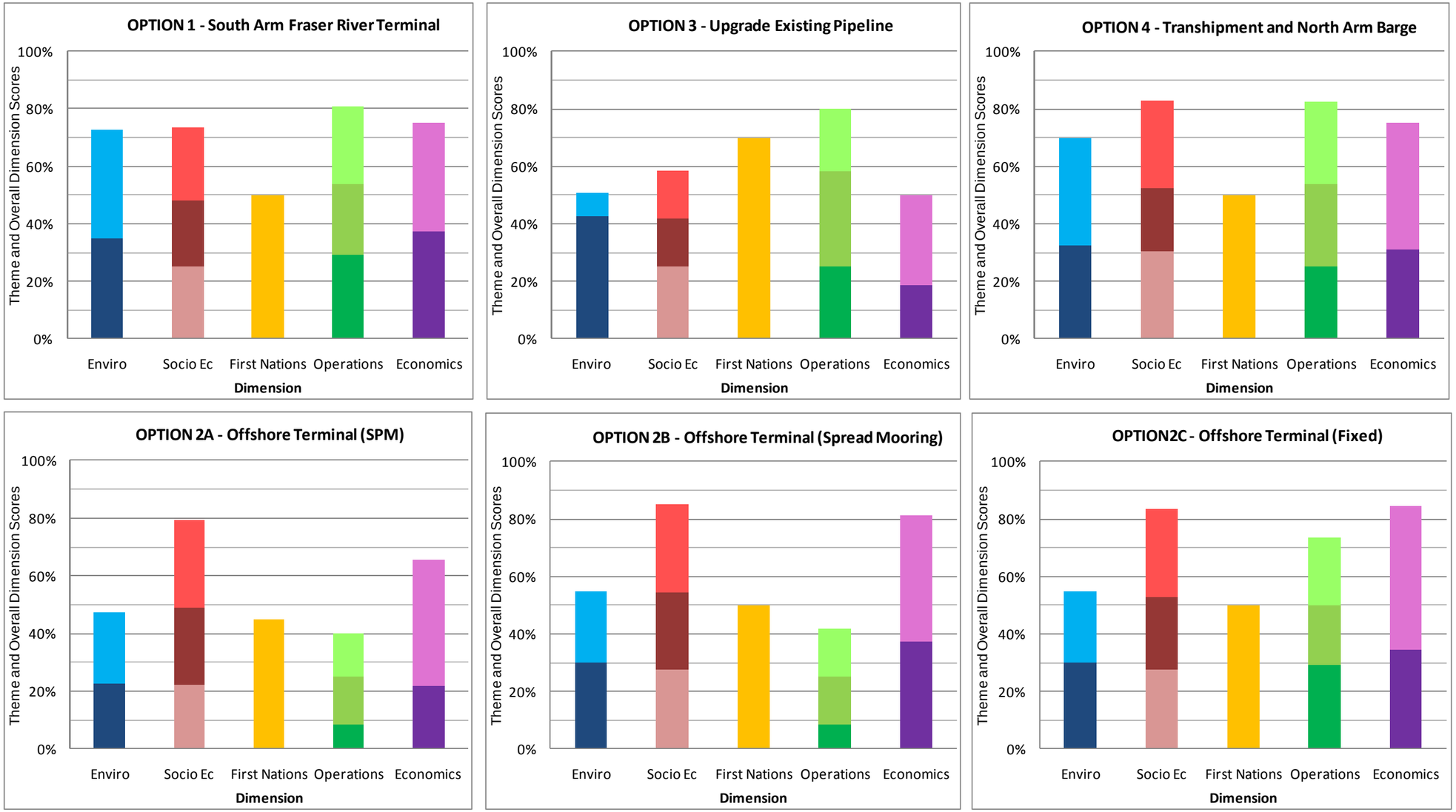

Figure 12: Results by OPTION: Contribution of Theme Scores for Each Dimension

7.0 CLOSURE

We trust that the contents of this report meet with your requirements. Should you have questions or need clarification of the contents, please do not hesitate to contact the undersigned.

Golder and Ausenco are pleased to be granted with this opportunity for participation in this challenging project.

GOLDER ASSOCIATES LTD.

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AUSENCO ENGINEERING CANADA INC.

ORIGINAL SIGNED

William G. Allen, P.Eng.
Senior Specialist Ports & Marine
Ausenco Engineering Canada Inc.

DT/RF/JZJ/BA/UDA/nnv/js

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APPENDIX A

Summary of Estimated Cost

Vancouver Airport Fuel Facilities Corporation
Vancouver Airport Fuel Delivery Project
Evaluation of Fuel Delivery Options

Summary of Cost Analysis
in million $

	Option 1	Option 2a	Option 2b	Option 2c	Option 3	Option 4
	South Fraser	Offshore			Renew Pipeline	North Arm
		SPM	Spread Mooring	Fixed Structure		
Pre Construction	11.8	30.9	13.6	13.0	90.4	7.0
Ship Berth	21.0	49.3	9.1	69.6	-	-
Barge Berth	-	7.1	7.1	7.1	-	7.1
Tank Farm	69.0	65.6	65.6	65.6	36.4	16.4
Pipeline	33.3	72.2	39.6	29.7	153.2	4.5
Capital Costs	135	225	135	185	280	35
Operating Costs	66	67	65	66	78	89

Assumed Annual Fuel Consumption Growth Rate: 2.5%
Assumed Cost of Capital 10%

Net Present Value	408	515	405	463	587	420

Breakdown of Operating Costs
in million $

Ship costs to terminal	48.8	48.0	48.0	48.0	57.0	47.9
Barge costs to terminal	10.8	10.8	10.8	10.8	7.6	21.1
Port charges	1.8	1.6	1.6	1.6	4.2	7.6
Property Taxes	2.5	4.2	2.5	3.4	5.2	0.7
Pipeline and terminal costs	2.1	2.5	2.2	2.1	3.6	1.9
Transhipment terminal costs	-	-	-	-	-	10.0
	66.0	67.1	65.1	65.9	77.6	89.2

Capital Cost Estimates include

Application, review and permitting costs	Application, review and permitting costs	Application, review and permitting costs	Application, review and permitting costs	Application, review and permitting costs	Application, review and permitting costs
Landowner compensation	Habitat compensation	Habitat compensation	Habitat compensation	Landowner compensation	Habitat compensation
Habitat compensation	SPM Manufacturing and Installation	Spread mooring construction	Tanker berth construction	Habitat compensation	barge berth construction
Tanker berth construction	Barge berth construction	barge berth construction	Trestle construction	Tank farm construction	Tank farm construction
Dredging	Tank farm construction	Tank farm construction	Dredging	pump station construction	pump station construction
Tank farm construction	pump station construction	pump station construction	Barge berth construction	on-land pipeline	on-land pipeline construction
pump station construction	on-land pipeline construction	on-land pipeline construction	Tank farm construction		
on-land pipeline construction	subsea pipeline construction	subsea pipeline construction	pump station construction	subsea pipeline construction	subsea pipeline construction
			on-land pipeline construction		
			subsea pipeline construction		

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rosalind.endo@nortonrosefulbright.com

May 22, 2019

Privileged and Confidential
Sent By E-mail

Intergroup Consultants
PO Box 2491 Vancouver Main
Vancouver, BC V6B 3W7

Attention: Patrick Bowman & Melissa Davies

Our reference
19-2668

Dear Mr. Bowman and Ms. Davies:

Vancouver Airport Fuel Facilities Corporation ("VAFFC") – Kinder Morgan Canada (Jet Fuel) Inc. ("KMJF") 2019 Tariff Filing Application – Retainer

We are counsel for VAFFC, who has retained us to advise them on the 2019 Tariff Filing Application filed with the British Columbia Utilities Commission. The 2019 Tariff Filing Application was submitted on November 29, 2018 by Kinder Morgan Canada (Jet Fuel) Inc.

We write to confirm the terms on which we have retained Intergroup Consultants on behalf of VAFFC to assist with this regulatory proceeding.

This retainer contemplates for two separate but related services relevant to this proceeding: (1) advice relating to depreciation, possibly including an expert opinion report, and (2) advice concerning general regulated rates issues, also potentially including an expert report. These services will be provided by Patrick Bowman and Melissa Davies of your office, and Patrica Lee of BCRI Valuations Services. Please maintain separate files for your general advice and for any expert opinion reports that you prepare. This requirement is important and arises from BC litigation practices. BC's Rules of Court are different than in many other provinces. As a result you should be maintaining up to four files.

I. ADVICE

In the course of this matter, we will ask you to assess the strengths and weaknesses of KMJF's case and the positions taken by VAFFC to date. Your duties will extend to standard regulatory milestones information requests drafting and analysis, evidence, cross-examination, and argument.

The discussions that we have with you and any work you complete regarding your advice are strictly confidential and privileged, and will remain so whether or not you are called to give evidence at the hearing. This applies to all advice you provide in relation to any negotiations, as well as any advice you provide for our preparation in the litigation. However, for any expert opinion that you produce, privilege over your file and our discussions in relation to your opinion may be waived (as though in a BC court) before the commencement of the hearing if

May 22, 2019

NORTON ROSE FULBRIGHT

your expert opinion is tendered as evidence. As a result, as noted, it is important that you maintain two separate files, one for advice and one for your expert opinion, and that you ensure that documents are properly separated between those files.

II. EXPERT OPINION REPORT

On the basis of information provided in the litigation, we may ask you to prepare one or two expert reports and to testify at the hearing as an expert witness. We will provide further details, including instructions on the preparation of your report, at a later date if we require you to do so.

III. CONFIDENTIALITY

This matter is confidential. Please do not discuss this matter, except with our office or with VAFFC. Any report that you produce should be addressed to Norton Rose Fulbright Canada LLP, Attention: Matthew D. Keen.

Nothing in this agreement prevents you from corresponding in a general way with the adverse parties or their counsel on unrelated matters. However, we suggest that you refrain from doing so unless it is absolutely necessary. Because you have been retained by VAFFC in this matter, all of your dealings with VAFFC and with this firm are privileged and strictly confidential, and you may not discuss your work with any person other than those who assist you in your work.

If you receive any communication from the plaintiffs or their counsel, or from anyone else on this matter, please contact us before responding.

IV. PRIVILEGE

As noted, your file for any expert report, including all of your notes, working papers, and correspondence, are protected by solicitor-client privilege and not subject to disclosure, unless we tender any expert report you produce as part of the hearing. If we do so, we may be required to produce your file. You may be cross-examined on its contents.

Please take the following steps to protect the privilege over both of your files:

- Write “solicitor-client privileged” on the top of all paper and electronic documents, including notes, that are written as the work is carried out;
- Treat all documents and notes written about the work as confidential by:
    - Not sharing them with anyone except with those who need to know their contents to assist you in completing the work;
    - Not making copies beyond what is needed to do the work;
    - Keeping track of who has copies of the final report and any drafts of it; and
- Keeping all documents relating to the work in a separate file and in a safe, secure place.

Any final expert opinion report is to be addressed and sent to us. You may keep a copy for your file, but it should not be copied without approval from us. You should mark your copy with “Solicitor-Client Privileged / Do Not Copy”.

It is the practice of some experts to retain early drafts of their expert opinion reports, and it is the practice of other experts to routinely dispose of such drafts as they are revised. If it is your practice to dispose of such drafts upon revision, you are entitled to do so. However, please bear in mind that any early drafts that you retain in your file will be subject to disclosure, and you may be cross-examined on them.

May 22, 2019

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V. COMPENSATION FOR EXPERT SERVICES

While we are setting out the terms of reference, and your response should be addressed to us, it will be VAFFC only who will be responsible for payment of your account. Your accounts for this work should be addressed to VAFFC but sent to us. We will then forward each account to VAFFC for payment directly to you.

We confirm that your fees for professional services and disbursements will be paid based on the time you spend on this matter to perform the requested services at hourly billing rate you have quoted, namely $215 (Patrick Bowman), $400 (Patricia Lee) and $128 (Melissa Davies).

VI. SUMMARY

Please confirm that you have no conflict of interest on this retainer and that you are in agreement with the terms set out in this letter.

We look forward to working with you on this matter.

Yours very truly,

Matthew D. Keen

MDK/roe

Baer, Alexander

From: Baer, Alexander
Sent: December 9, 2020 1:31 PM
To: 'Patricia Lee'
Subject: RE: Quick question

Hi Pat,

Yes, that is correct. The Jet Fuel Line is regulated by the BC Oil and Gas Commission, not the CER.

Alex

Alexander Baer
Associate

Norton Rose Fulbright Canada LLP / S.E.N.C.R.L., s.r.l.
1800 - 510 West Georgia Street, Vancouver, BC V6B 0M3 Canada

+1 604.641.4946 F: +1 604.641.4949

alexander.baer@nortonrosefulbright.com
-----Original Message-----
From: Patricia Lee <pattyslee@comcast.net>
Sent: December 9, 2020 12:45 PM
To: Baer, Alexander <alexander.baer@nortonrosefulbright.com>
Subject: Quick question

Quick question Alex. Is the JFL regulated by the BCOGC? It is not regulated by the CER, right?

Baer, Alexander

From: Baer, Alexander
Sent: December 12, 2020 7:19 PM
To: 'Patricia Lee'
Cc: Keen, Matthew
Subject: VAFFC - Comments on Evidence

Hi Pat,

Thanks very much for your new drafts over the past week. With respect to your draft depreciation evidence, we are hoping you could provide a further explanation for the following statement you make on the first page: “PKMJF should not now be rewarded additional depreciation recovery for its failure to implement the depreciation rate design as it professed in 2007”.

Later on in the depreciation evidence, you analyze PKMJF’s 2007 tolls application, its 2009 application, and the 2010 negotiated settlement. When you refer to the “depreciation rate design” in the sentence quoted above, how does this relate to your later analysis, the different applications you consider, and the negotiated settlement? It would be very helpful if you could provide further details.

We have also looked into your question regarding when the *Income Tax Act* was amended to allow deductions for contributions to abandonment trust funds. This took place in 2011, through the *Keeping Canada’s Economy and Jobs Growing Act*, S.C. 2011, c. 24. Section 69 of that *Act* revised the *Income Tax Act* such that contributions to abandonment trusts for pipelines were deductible, starting in the 2012 taxation year.

Best regards,

Alex

Alexander Baer
Associate

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alexander.baer@nortonrosefulbright.com

NORTON ROSE FULBRIGHT

Baer, Alexander

From: Bond, Niles
Sent: May 30, 2019 11:48 AM
To: Keen, Matthew; Patricia Lee; 'Patrick Bowman'; 'Melissa Davies'
Cc: Manhas, Michael
Subject: NEB submissions summary
Attachments: C-26-6B TransCanada Response to Information Requests of NEB (A1H3S6).pdf; C-26-4 TransCanada Written Evidence (A1G7I0).pdf; C-10-12B Enbridge Reply Written Evidence - LMCI Stream 3 (A1I2A8).pdf; C-10-8B Enbridge Responses to NEB IR No. 1 (A1H3T9).pdf; A1I5K3 - Vol.1-TueJan20.09.pdf; A1I5U2 - Vol.4-FriJan23.09.pdf; A1I6E5 - Vol.6-WedJan28.09.pdf; A21835-1 NEB Reasons for Decision - Land Matter Consultation Initiative Stream 3 - RH-2-2008 (5).pdf

Hello all,

As discussed, here is a summary that I prepared at Matt's request of relevant portions from the TransCanada and Enbridge submissions, with regard to collection of abandonment costs and liability, in the NEB proceeding: Land Matters Consultation Initiative (LMCI) Stream 3. The relevant documents these excerpts are taken from are attached, with the excerpted portions highlighted. I also attach a copy of the NEB's decision on stream 3.

Enbridge Responses to NEB IR No. 1, IR 1.8:

> Collecting abandonment costs over a longer period can mitigate some of the risk of intergenerational equity because earlier generations of shippers are required to pay a share of the abandonment costs. This factor militates in favour of a longer time horizon of foreseeability and thus a longer collection period.
>
> Conversely, it must be recognized that over-collection from early shippers would also be inequitable. For example, commencing collection before abandonment is reasonably foreseeable is more likely to make the estimates of abandonment timing and abandonment costs even more speculative and thus less reliable as a basis for tolls. This creates a risk of over-collection from shippers and militates against requiring the collection of abandonment costs to commence in the shorter term.
>
> An unnecessarily long collection period also imposes a higher administrative burden both in absolute terms and relative to the amount of the funds collected – particularly in early years. The practical result can be greater costs with little or no corresponding economic benefit.
>
> Finally, the collection and setting aside of abandonment funds creates an opportunity cost vis-à-vis other, potentially more productive, uses for the capital. An unnecessarily long collection period exacerbates that opportunity cost.
> Deferral of fund collection in appropriate circumstances can mitigate these risks and, conversely, should not increase the risk of under-collection (or of a "death spiral") due to the expected length of the period of reasonable foreseeability.
>
> Deferral of fund collection is unlikely to impact competitiveness since the expected economic lives of competing pipelines (i.e., those that are providing capacity from the same producing regions to similar markets) can be expected to be of a similar length (such that their abandonment fund collection would begin more or less contemporaneously).

Reply Written Evidence of Enbridge Pipelines Inc.:

> Includes, as Appendix A, a report from Wright Mansell Research Limited that provides analysis regarding the appropriate time horizon for accumulating funds to cover the costs of facility abandonment. While this report may be interesting and relevant to consider generally, it specifically addresses issues of rate stability, and fairness and equity amongst intergenerational shippers. For example, "As noted in Section 4.3 above, there are numerous dimensions to [the criterion of fairness and equity]. The principle of 'no acquired rights' would suggest that any

surcharge for abandonment should be applied to all users of a particular component of a system rather than being 'vintaged' (that is, differentially applied to shippers based on whether they used the system on a particular date, over a particular period or for a particular market). Put differently, if this principle was not applied and abandonment costs were differentially applied across shippers it is more likely that other regulatory objectives (such as rate stability) would not be met."

TransCanada written evidence:

A8. Intergenerational inequity arises if pipeline companies are not required to begin setting aside funds to cover abandonment costs. Funds to cover the costs associated with the eventual terminal abandonment of a pipeline should be collected sufficiently in advance of abandonment so as not to unfairly burden those shippers who contract for service on the pipeline towards the end of its economic life. In recovering costs through utility rates, a basic regulatory and financial principle is that the customers who benefit from a required service should bear the cost of providing the service, including terminal abandonment costs. There should be a fair allocation of costs among customer generations.

TransCanada Responses to NEB IR No. 1:

1.2. (b) The circumstances will vary from pipeline to pipeline, but "sufficiently in advance" should in principle be a point for all pipelines whereby:

- the collection of abandonment costs will minimize intergenerational inequity among rate payers; and
- there can be a material accumulation of compounded interest on invested funds.

1.6 With regard to how to address toll settlements that do not contemplate collection for abandonment, TransCanada responded as follows:

Possible options to address this issue are:

- The terms of the settlement are maintained and collection is deferred until after the settlement has expired;
  - The settlement has been negotiated to provide shippers with a greater degree of certainty of costs in the revenue requirement. Deferring the collection of abandonment funds maintains this certainty. Commencing collection of abandonment costs would start after the settlement has expired and could become part of the revenue requirement in a new negotiated settlement.
- The Board mandates the collection of funds for abandonment during the Settlement in the form of an order;
  - If deferring the collection of abandonment funds is deemed to be inappropriate, the Board could order the funds to be collected during the term of any existing settlement and treated as a flow through cost item in the existing settlement. A Board order would preclude the pipeline from having to open an existing settlement and change the terms under which it was negotiated. It would also limit the issue to collection of abandonment funds only and not open other aspects of the settlement that parties might wish to change.

1.7 With regard to questions about the risks of, and caused by, orphaned pipelines:

There will always exist some element of risk that insufficient funds will be collected before a pipeline is abandoned. However, pipelines are tightly regulated and a properly designed framework would allow the Board to review the appropriateness of the amount of funds collected by a pipeline. This should minimize the risk of an orphan pipeline situation.

Any risk faced by landowners, governments and other stakeholders with respect to orphan pipelines must be balanced against the appropriateness of collecting costs from shippers and users of other systems who have received no benefit associated with the orphaned pipeline. Further, this would be a departure from cost causality that is fundamental to rate-making principles. The cost of abandonment is a cost of service that each pipeline incurs. As such, each pipeline is responsible through its collection of tolls to ensure that sufficient funds are collected to cover these costs.

<u>Submissions made in the proceeding's transcripts:</u>

Vol 1, Witnesses for Enbridge:

- P. 47: Insufficient collection for abandonment should be a risk born by the company, not landowners or otherwise. This point is elaborated on at pp. 52-60, 76-79, and 89-90. Enbridge's primary position is that orphan pipelines are more of a theoretical and practical concern, if proper regulatory procedures are in place.

Vol 4, Witnesses for TransCanada:

- A similar position to Enbridge's is by TransCanada expressed at pp. 30-33, 47, 58 and 60.
- At pp. 38-40 TransCanada also spoke to the issues that could be associated with toll settlement agreements, including potential intergenerational risk and inter-pipeline competition issues.

Vol 6, final submissions:

- TransCanada and Enbridge's final submissions, including with regard to the issues of intergenerational equity and risk of under-collection for abandonment at pp. 15-19 and 65.

Best,
Niles

Niles Bond
Lawyer

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NORTON ROSE FULBRIGHT

National Energy Board
Office national de l'énergie

Reasons for Decision

Land Matters Consultation Initiative Stream 3

RH-2-2008

May 2009

Pipeline Abandonment - Financial Issues

Canada

National Energy Board

Reasons for Decision

In the Matter of

Land Matters Consultation Initiative Stream 3

Financial Issues related to Pipeline Abandonment

RH-2-2008

May 2009

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Imprimé au Canada

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Chapter 1

Disposition by the National Energy Board

File ADV-PE-LandMC 02
26 May 2009

To: All Parties to RH-2-2008 and All Pipeline Companies

Hearing Order RH-2-2008 - Land Matters Consultation Initiative Stream 3
Pipeline Abandonment – Financial Issues
Board Decision

Background

In January 2008, the National Energy Board (Board) identified a proposed approach for the Land Matters Consultative Initiative (LMCI), consisting of four distinct topic streams. One of the four topic streams, Stream 3, is "Pipeline Abandonment – Financial Issues". The Board indicated that the key issue to be considered in respect of that topic stream is the following:

> What is the optimal way to ensure that funds are available when abandonment costs are incurred?

For LMCI Stream 3, the Board decided to convene a public hearing to consider the financial issues related to pipeline abandonment. Pursuant to subsection 15(1) of the *National Energy Board Act* (NEB Act), the Board authorized three members to conduct the hearing and to report and make recommendations to the Board in respect of the decision of the Board to be made on the issues in the hearing (the Panel).

The Panel conducted a public hearing, the oral portion of which was heard in January 2009. The Panel's Report and Recommendations were presented to the Board in April 2009, and are attached as Appendix I to this Decision.

Board Decision

The Board, having received and considered the Report and Recommendations, has adopted the Panel's Report and Recommendations, including the Framework and Action Plan set out in the Report, as the decision of the Board in LMCI Stream 3. As a result, all pipeline companies regulated under the NEB Act are directed to comply with the steps set out in the Framework and Action Plan.

The Board will be assessing each filing made by regulated companies, including Group 2 companies, in light of the principles and considerations set out in the Report, as well as the

requirements of the NEB Act. If required, additional information may be sought to aid the Board in its assessment of the filing and further direction may be issued to a regulated company.

The Board has assigned dates to the deadlines set out in the Action Plan, Table 4-1 of the Panel's Report. Accordingly, the Board has attached a revised Action Plan, Table 4-1, as Appendix A.

Next Steps

Regulated companies are directed to serve a notice of this decision and information as to the location of this decision on the Board's Internet Site [www.neb-one.gc.ca, click on the Land Matters Consultation Initiative icon on the right-hand side of the page, scroll down and select Stream 3, and then click on the News Release and Decision dated 26 May 2009] on their shippers and interested parties, including parties to their latest toll decision or settlement.

Regulated companies and Parties to the RH-2-2008 proceeding will be advised by letter of the date of the Technical Conference regarding the Base Case Assumptions. Any other interested persons who wish to be advised of the upcoming Technical Conference are invited to contact Erin Dutcher, Regulatory Officer, at 403-299-2782 or toll-free at 1-800-899-1265 to indicate their interest and provide their contact information.

Yours truly,

Claudine Dutil-Berry
Secretary of the Board

Attachments

Appendix A

Table 4-1
Action Plan

Action	Objective	Participants	Timing
1. RH-2-2008 Decision released	Discussion of principles, high level Framework, Action Plan, Preliminary Base Case	NEB	May 2009
2. Board Technical Conference on Preliminary Base Case	Potential refinements to Preliminary Base Case	Group 1 and Group 2 companies that wish to attend, and any other interested person	November 2009
3. Release of Refined Base Case	Base Case issued for company use	NEB	Feburary 2010
4. (a) Group 1 companies each prepare and file an estimate of abandonment costs and the amount required to be set aside using the Base Case assumptions OR (b) Group 1 companies each prepare and file, **for approval,** an estimate of abandonment costs and the amount required to be set aside using pipeline-specific assumptions or a combination of pipeline-specific and Base Case assumptions	Filing of preliminary estimates using Base Case or pipeline-specific assumptions	Group 1 companies	No later than 31 May 2011
5. NEB consideration of Group 1 companies' preliminary estimates that use pipeline-specific assumptions or a combination of pipeline-specific and Base Case assumptions	NEB decisions on Group 1 companies' preliminary estimates	NEB	By 31 May 2012

6. Group 1 companies each develop and file, **for approval**, a proposal for collection of funds and a proposed process and mechanism to set aside the funds [can be combined with step 4 and filed by 31 May 2011]	Filing of proposed collection mechanisms and proposed set aside mechanisms	Group 1 companies	No later than 30 November 2012
7. Group 2 companies each prepare and file an estimate of abandonment costs and the amount required to be set aside using either the Base Case or pipeline-specific assumptions	Filing of preliminary estimates using Base Case or pipeline-specific assumptions	Group 2 companies	No later than 30 November 2011
8. Group 2 companies that charge tolls each develop and file a proposal for collection of funds [can be combined with step 7 and filed by 30 November 2011]	Filing of proposed collection mechanisms	Group 2 companies that charge tolls	No later than 30 November 2012
9. Group 2 companies each file with the Board a proposed process and mechanism to set aside funds [can be combined with steps 7 or 8, and filed at the earliest applicable date]	Filing of proposed set aside mechanisms	Group 2 companies	No later than 31 May 2013
10. NEB consideration of Group 1 companies' proposals for collection and set aside mechanisms	NEB decisions on Group 1 companies' mechanisms for collection and set aside of funds	NEB	By 31 May 2014

Appendix I

NEB Section 15 Report

National Energy Board

Report and Recommendations Pursuant to Section 15 of the *National Energy Board Act*

In the Matter of

Land Matters Consultation Initiative Stream 3

Financial Issues related to Pipeline Abandonment

RH-2-2008

April 2009

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List of Tables

Abbreviations

Board or NEB	National Energy Board
CAPLA	Canadian Alliance of Pipeline Landowners' Associations
CAPP	Canadian Association of Petroleum Producers
CEPA	Canadian Energy Pipeline Association
Enbridge	Enbridge Pipelines Inc.
KMC	Kinder Morgan Canada Inc.
LMCI	Land Matters Consultation Initiative
NEB Act	*National Energy Board Act*
Panel	National Energy Board members appointed pursuant to subsection 15(1) of the *National Energy Board Act* to prepare a report and recommendations
Pouce Coupé	Pouce Coupé Pipe Line Ltd.
TransCanada	TransCanada PipeLines Limited, Nova Gas Transmission Ltd., Foothills Pipe Lines Ltd., Trans Québec & Maritimes Pipeline Inc., TransCanada Keystone Pipeline GP Ltd.
Westcoast	Westcoast Energy Inc., carrying on business as Spectra Energy Transmission

Glossary of Terms

Abandon	To permanently cease operation such that the cessation results in the discontinuance of service.
Decommission	To permanently cease operation such that the cessation does not result in the discontinuation of service, for example, when a tank is removed from operation on a pipeline and the pipeline continues to operate without the tank.
Depreciation	A non-cash expense charged against earnings to write-off the cost of an asset during its estimated useful life.
Group 1 Company	In general, Group 1 companies are those with more extensive systems and as such are subject to a greater degree of regulatory oversight on financial matters than Group 2 companies.
Group 2 Company	Group 2 companies tend to have smaller systems, with fewer shippers and are subject to a lighter degree of regulatory oversight on financial matters; generally, they are regulated on a complaints basis.
Intergenerational Equity	A broad principle that users in any period are generally required only to pay for the costs of providing them with services in that period.
MH-1-96	NEB proceeding on an application by Murphy Oil Company Ltd. on behalf of Manito Pipelines Ltd. to abandon certain facilities.
Orphan Facility	An oil or gas facility that has, or is deemed to have, no legally responsible and financially viable owner.
Paragraph 74(1)(d)	A paragraph of the NEB Act requiring leave of the Board before a company abandons the operation of its pipeline.
Perpetual Maintenance	The ongoing use of methods to maintain an abandoned pipeline to avoid collapse, subsidence, corrosion or other adverse impacts. This is sometimes referred to as continuing maintenance.
Residual Risk	The risk, remaining at the completion of the pipeline life, related to the adequacy of funding to cover the entire cost of the abandonment activities.

Retirement	An accounting term for when an asset, whether it is replaced or not, is otherwise removed from pipeline service.
Salvage	The value at removal of pipe and facilities.
Stream 4	The stream of the LMCI dealing with physical issues related to pipeline abandonment.
Terminal Negative Salvage	The costs incurred in the abandonment of pipeline facilities less any value realized from the disposition of such facilities.
Zones 1 and 2	Toll zones for Westcoast's gathering and processing facilities.
Zones 3 and 4	Toll zones for Westcoast's transmission facilities.

Recital and Appearances

IN THE MATTER OF the *National Energy Board Act* (NEB Act) and the Regulations made thereunder;

IN THE MATTER OF the Land Matters Consultation Initiative (LMCI) Stream 3, Pipeline Abandonment – Financial Issues; and

IN THE MATTER OF National Energy Board Hearing Order RH-2-2008.

HEARD in Calgary, Alberta on 20, 21, 22, 23, 26 and 28 January 2009;

BEFORE SECTION 15(1) PANEL:

S. Leggett	Presiding Member
K.M. Bateman	Member
L. Mercier	Member

Appearances	**Participants**	**Witnesses**
D. Crowther R. Power	Alliance Pipeline Ltd.	
C. Worthy	BP Canada Energy Company	
D. Crowther M. Yohemas	Enbridge Pipelines Inc.	P. Douvris M. Hrynchyshyn R. Mansell
L.R. Aufricht	Imperial Oil Resources	
P. Forrester M. Novak	Kinder Morgan Canada Inc.	B. McClellan S. Stoness
P. Jeffrey P. Khan	Pouce Coupé Pipe Line Ltd.	P. Robertson
D. Davies R. Sirett	Spectra Energy Transmission (Westcoast)	M. Bootle T. C A. Parmar D. Rae
D. Armstrong	Suncor Energy Marketing Inc.	

S. Denstedt N. Berge M. Keen	TransCanada PipeLines Limited, NOVA Gas Transmission Ltd., Foothills Pipe Lines Ltd., TransCanada Keystone Pipeline GP Ltd., Trans Québec & Maritimes Pipeline Inc.	A. Leong J. Van der Put
P.G. Vogel J. Goudy	Canadian Alliance of Pipeline Landowners' Associations	A. Cheung D. Core K. Habermehl R. Kraayenzen J. Ness C. Storey P. Teevens
N.J. Schultz	Canadian Association of Petroleum Producers	B. Jardine H. Johnson
C. King	Alberta Department of Energy	
J. Saunders P. Johnston	National Energy Board	

Chapter 1

Introduction

1.1 Background

In the fall of 2007, the National Energy Board (the Board or the NEB) announced that, as part of its review of key land issues, it had decided to establish the Land Matters Consultation Initiative (LMCI). The decision resulted from the Board's desire to support continual improvement related to land matters, and confirmed the Board's belief that constructively engaging interested people and organizations would be an effective approach to meet this goal. The Board issued its LMCI Approach on 25 February 2008, which identified potential outcomes that were intended to improve how land matters are appropriately and effectively included in the Board's public interest considerations. The Board also noted that the LMCI would provide a forum for all interested parties and the Board to engage in dialogue and generate options related to land matters for the Board's review.

The Board considered the LMCI topics in four streams:

Stream 1: Company Interactions with Landowners;

Stream 2: Improving the Accessibility of NEB Processes;

Stream 3: Pipeline Abandonment – Financial Issues; and

Stream 4: Pipeline Abandonment – Physical Issues.

For Stream 3, the Board noted two key principles fundamental to its future decisions with respect to the financial matters related to pipeline abandonment. They are:

1. Abandonment costs are a legitimate cost of providing service and are recoverable upon Board approval from users of the system.
2. Landowners will not be liable for costs of pipeline abandonment.

The Board stated that the key issue to be decided related to the financial aspect of abandonment is: What is the optimal way to ensure that funds are available when abandonment costs are incurred? The Board also indicated that the potential outcomes of Stream 3 are:

- *Development of a set of principles which will guide the Board in its future decisions with respect to the financial matters related to pipeline abandonment;*
- *Preliminary mechanism to begin setting aside funds for abandonment costs is identified;*
- *Identification of technical abandonment assumptions to be used to estimate abandonment costs; and*
- *An action plan is developed to move forward on remaining financial issues including issues unique to each pipeline company.*

In March 2008, the Board released a Discussion Paper for Stream 3 that summarized the past relevant documents, discussed practices in other jurisdictions, and identified the proposed financial issues that would need to be decided related to abandonment funding. One of those past documents was the 1985 NEB staff paper entitled "Background Paper on Negative Salvage Value". This paper provides useful background information in the Board's continuing examination of abandonment issues.

1.2 Hearing Process

For LMCI Stream 3, the Board decided to convene a public hearing to consider the financial issues related to pipeline abandonment. In terms of the governance for Stream 3, the Board authorized, pursuant to subsection 15(1) of the *National Energy Board Act* (NEB Act), three members (the Panel) to conduct this hearing and to report and make recommendations to the Board in respect of the decision of the Board to be made on the issues in this hearing.

On 3 March 2008, the Panel issued Hearing Order RH-2-2008 for LMCI Stream 3, setting out the procedures to be followed for a public hearing to begin on 17 June 2008. As part of those procedures, the Panel decided to convene a pre-hearing conference on 3 April 2008 to discuss with interested parties any proposed additions or changes to the List of Issues as well as a number of procedural issues.

On 26 March 2008, the Panel issued a letter to parties indicating that, having received comments on the hearing timetable from parties representing a wide range of interests, the Panel decided to postpone the commencement of the hearing to a later date. The Panel announced that the exact date for the hearing and corresponding revisions to the timetable of events would be discussed at the 3 April 2008 pre-hearing conference.

On 15 April 2008, the Panel issued its Pre-hearing Conference Report to all parties. It issued its ruling on the List of Issues and Timetable of Events on 21 April 2008. In its ruling, the Panel announced that the oral portion of the hearing would commence on 20 January 2009 at a location to be determined later. In response to suggestions by participants at the conference that one or more procedural or technical conferences may be beneficial to the hearing process, the Panel set deadlines by which parties could request additional conferences.

On 8 October 2008, the Canadian Energy Pipeline Association (CEPA), on behalf of itself and its member companies, suggested that the "Mechanics and Governance of establishing Environmental Trusts for pipeline abandonment funds" be part of the agenda for a technical conference. The Panel subsequently scheduled a conference for 30 October 2008 to deal with CEPA's suggestion plus two procedural matters; namely, the location of the hearing and the order of appearances for evidence, cross-examination and final argument. The Panel issued its Conference Report on 5 November 2008 and, on 21 November 2008, the Panel provided its ruling on the procedural issues discussed at the conference.

Five pipeline companies, Enbridge Pipelines Inc. (Enbridge), Kinder Morgan Canada Inc. (KMC), Pouce Coupé Pipe Line Ltd. (Pouce Coupé), TransCanada PipeLines Limited (TransCanada) and Westcoast Energy Inc. (Westcoast), and two associations, the Canadian Alliance of Pipeline Landowners' Associations (CAPLA) and the Canadian Association of

Petroleum Producers (CAPP), submitted evidence in this proceeding. A number of other persons either intervened but did not submit evidence, or participated by submitting a letter of comment.

The Panel heard oral evidence between 20 and 26 January 2009, and final argument on 28 January 2009, in Calgary, Alberta.

1.3 List of Issues

In its RH-2-2008 Hearing Order, as amended, the Panel identified, but did not limit itself to the following issues for discussion in the proceeding:

1. Should the Board require pipeline companies to set aside funds to cover future abandonment costs?
    a. What are the implications on all persons impacted, including shippers, producers, regulated companies, governments, landowners and other members of the public, of requiring or of not requiring pipeline companies to set aside funds to cover future abandonment costs?
    b. If funds are required to be set aside, what mechanisms should be considered and what are the pros and cons of each mechanism?
    c. If funds are required to be set aside, should all pipeline companies under the Board's jurisdiction be required to set aside these funds?

2. If companies are required to set aside funds, what information and assumptions are necessary to create preliminary estimates for future abandonment costs? For example:
    a. What technical and financial assumptions should be used to create preliminary cost estimates?
    b. What process would be appropriate for the Board to consider preliminary estimates for individual pipelines?
    c. What should be the process for refining the estimates over time?

3. If companies are required to set aside funds, when should the collection of funds commence?
    a. Should all pipeline companies under the Board's jurisdiction be required to start collecting funds for abandonment at the same time, (e.g. by calendar date or year of pipeline life)?

4. If companies are required to set aside funds, how should the funds be set aside?
    a. Should they be collected from shippers through annual payments or per unit tolls, or set aside through insurance, or should some other method be used?
    b. If the funds are collected through the tolls of a pipeline company, should they be collected as a component of depreciation or separately?

5. If companies are required to set aside funds, how should the funds be governed? For example:
    a. Should the funds be maintained in a separate trust account, commingled with a company's general corporate revenue, maintained and administered by a third party or maintained in another manner?
    b. Should a portion of the funds be pooled for use across industry (e.g. orphan pipeline fund)?
    c. Should reporting requirements for the funds be established, and if so, what should they be?
    d. Should the regulated portion of a company be insulated from the non-regulated business with respect to abandonment costs, and if so, how?
    e. How would a company access the funds?
    f. What would be the appropriate time to access funds (e.g. only at the end of a pipeline's life or also for interim retirements)?
    g. Who should control access to the funds – a company, a corporate third party, a regulator?
    h. What investment restrictions should be placed on the funds collected, if any?
    i. What taxation issues arise from the collection of funds and how could they be addressed?
    j. What should happen to any funds collected to abandon a pipeline regulated by the NEB which then becomes subject to provincial jurisdiction, either after abandonment or through a transfer to a provincially-regulated company?
    k. Should there be surplus funds collected, what should be the final disposition of those funds?

6. How best should the risks and uncertainties inherent in determining future abandonment costs and revenues be managed or mitigated?
    a. Who should bear the risk/reward of trust account performance?
    b. Who should bear the risk/reward of under/over collection of funds?

7. What is the Board's mandate under the current legislation to require the collection of abandonment costs as a component of a company's revenue requirement?

Chapter 2

Submissions of Parties

This chapter summarizes the submissions of parties and generally follows the order of the List of Issues found in section 1.3.

2.1 Should the Board require that funds be set aside for abandonment?

All of the parties that filed evidence in this proceeding agreed with the key principle in the Board's 25 February 2008 letter, which stated that landowners will not be liable for costs of pipeline abandonment. Enbridge submitted that whatever funding provision was made for abandonment costs and liabilities, it must be sufficient so that landowners and shareholders would not be left bearing any liability. All parties agreed that pipeline companies have an obligation to ensure sufficient funds will be in place to pay for all costs of abandonment.

As a result, all parties who actively participated in the LMCI hearing agreed that abandonment funds should be set aside. There were various opinions on how and when such funds should be collected and set aside.

Enbridge, KMC, Pouce Coupé and TransCanada, as well as CAPLA and CAPP, stated in their evidence that they are in favour of the collection of monies to fund abandonment costs from pipeline users, as these costs are a legitimate cost of providing service and should be recoverable from shippers.

Westcoast submitted that it should not be required to collect and set aside funds to cover future abandonment costs. Westcoast stated that, with respect to its transmission assets (Zones 3 and 4), it would make an application to the Board to collect and set aside funds after recognizing the liability according to accounting rules and standards. In addition, Westcoast made a distinction between its gathering and processing facilities (Zones 1 and 2) and its transmission facilities stating that each should be treated differently. Westcoast submitted that, for competitive reasons, the Board should not require collection for Zones 1 and 2, but rather allow Westcoast to manage its internal accounts appropriately to ensure it can fund its liabilities. While Westcoast did not think collection should be mandated for any of its facilities, it submitted collection could occur on its transmission assets at the same time collection is required on other federally regulated transmission lines. Further discussion of parties' submissions on competitive impacts of collection follows below.

KMC, Pouce Coupé, TransCanada and CAPLA favoured earlier rather than later collection, although the definition of what was meant by "earlier" and "later" varied between the parties. TransCanada proposed that during the time it takes to prepare an abandonment study, collection could begin with a nominal amount based on an agreed-to percentage of each pipeline's annual revenue requirement.

KMC and TransCanada raised concerns regarding the effect of collection on intergenerational equity. KMC stated that a common principle of rate setting is that the pipeline should collect costs such that one generation of customers does not subsidize a different generation of customers. TransCanada submitted that funds to cover abandonment costs should be collected sufficiently in advance of abandonment so as not to unfairly burden those shippers who contract for service towards the end of a pipeline's economic life.

Competitive and Other Impacts of Collection

All pipeline companies and CAPP raised concerns regarding the impacts on competitive dynamics of collection of abandonment funds from shippers. KMC, Pouce Coupé and TransCanada submitted that the framework governing the funding for abandonment should be consistently applied to minimize any economic inefficiencies or material impacts, which could cause competitive advantages or disadvantages. Enbridge stated that the abandonment surcharge alone would not determine competitive impacts. In its view, there are other, often more significant, components than tolls that impact competitiveness, such as market prices. CAPLA suggested that if collection started early enough, changes to competitive dynamics could be avoided.

Westcoast submitted that competition with provincially regulated service providers was the entire justification for its position that it should not be required to collect abandonment funds in its gathering and processing business. Westcoast stated that its gathering and processing business is unique in Canada as it is the only one federally-regulated under the Framework for Light-Handed Regulation[1]. For Zones 1 and 2, the market sets the tolls, not cost-based regulation, and Westcoast negotiates tolls with shippers in a competitive market. Westcoast argued that it bears the full utilization risk associated with these facilities, and does not collect any specific costs in its Zone 1 and 2 tolls. Further, it argued that it could not increase its tolls above market value to collect an additional cost, as this would put it at a competitive disadvantage to others in the gathering and processing business. Westcoast submitted that the Board should not require collection for Zones 1 and 2, but rather allow Westcoast to manage its own accounts appropriately to ensure it can fund its liabilities.

Another concern raised by some industry parties regarding the effect of requiring collection was that collection could result in an increase in costs to shippers. This could lead to a decline in utilization, reducing the ability of the pipeline to collect adequate funds. A decline in use could lead to remaining shippers being charged more and a resulting further decline in use, until the point where the pipeline has few or no shippers to cover the higher and higher tolls required (colloquially called a "death spiral"). However, some parties, such as Enbridge, TransCanada, KMC and CAPP, recognized that this concern could be mitigated by beginning collection earlier. With earlier collection, the increase in costs to shippers could be more modest and thus may prevent a decline in utilization and reduce the risk of creating a death spiral.

1 National Energy Board, RHW-1-98, Key Documents Related to the Board's Decision on the Framework for Light-Handed Regulation, June 1998

2.2 Preliminary Estimates

Many parties indicated that various technical and financial assumptions were required in order to prepare preliminary estimates of the funds required for abandonment. Some of the technical and financial assumptions identified by parties included:

- the physical method of abandonment;
- technology available at the time of abandonment;
- legislative requirements;
- environmental impacts and subsequent remediation requirements;
- estimated salvage value;
- administrative costs;
- cost escalation factors;
- expected investment yield on funds invested;
- timing of abandonment;
- income tax implications; and
- the effect of collection of funds on existing toll settlements.

Enbridge, Pouce Coupé, TransCanada and CAPP all submitted that the income tax treatment of funds collected from shippers and details of a trust fund mechanism with its associated investment policy should be resolved prior to beginning collection of funds. Resolution of these matters would ensure tax efficient use of funds. TransCanada stated that if revenues collected to fund abandonment costs are taxable when collected, then the amount collected has to be increased by the tax component, plus an amount resulting from expenses being non-deductible at the end of the pipeline's life (because there is no taxable income against which expenses can be deducted). TransCanada acknowledged that tax efficient collection issues must be balanced with other factors and principles.

Several parties submitted that the LMCI Stream 4 process would need to be completed before the technical assumptions necessary for cost estimation could be made. CAPLA proposed a default technical assumption of removal of all large diameter pipelines in agricultural land or perpetual maintenance until all abandoned pipelines in a corridor have been removed. CAPLA supported the default abandonment option for the same reasons identified by the NEB in its 1985 staff paper entitled "Background Paper on Negative Salvage Value"; for example, to reduce the risk of subsidence, corrosion contamination and the creation of water conduits. All other parties viewed full removal as an overly conservative assumption.

All parties who filed evidence agreed that estimates should be refined over time. While the frequency of review ranged from every ten years to annually, the most common suggestion for the reviews of estimates was every five years. TransCanada suggested that the frequency of review could be increased as the time of abandonment approaches.

2.3 Timing of Collection

The submissions of parties on the timing for collecting abandonment funds centered on four themes: commencement of collection, deferral, nominal amount and Group 1 vs. Group 2 companies.

Commencement of Collection

Enbridge stated that a number of issues would need to be resolved before any collection for abandonment should occur. These issues included:

- tax status and treatment of abandonment fund contributions and earnings;
- specifics of a trust or other such structure;
- governance and reporting;
- investment guidelines;
- access to funds;
- assumptions regarding the requirement for, and method of, facility abandonment; and
- collection monitoring and adjustment mechanisms.

Enbridge also proposed that the Board establish a methodology that incorporated flexibility for companies to apply for the deferral of collection.

KMC supported an expeditious process that would have the recovery of abandonment costs commence at the earliest opportunity, with all pipelines beginning collection within three years following the conclusion of LMCI Stream 4. In KMC's view, this would provide adequate time for companies to prepare preliminary estimates on abandonment costs and prepare the mechanisms for administering, collecting, managing and reporting on the funds. This would also allow affected regulatory authorities to establish and provide the necessary regulatory oversight associated with abandonment fund collection. KMC was of the view that even if the tax issues are not resolved, funds should be collected.

Pouce Coupé stated that the collection of funds should commence immediately for all pipeline companies, subject to the reasonable time required to conduct the requisite assessment. This assessment would include an indication of the steps that would have to be taken for abandonment, the costs of those steps and the toll surcharge required to cover the costs. According to Pouce Coupé, earlier collection would provide the company with a longer collection period and perhaps more surety that the funds required would be collected.

TransCanada suggested that collection should begin as soon as practical. TransCanada defined "as soon as practical" as the time required to put a trust mechanism in place, address tax efficiency, prepare abandonment cost estimates, and deal with issues such as existing toll settlements.

According to Westcoast, collection should not occur until the amount of costs and the time when the costs will be incurred can be reasonably determined. Westcoast stated that its NEB-regulated

gathering, processing and transmission assets have an indeterminate life and submitted, as a result, that collection should not be required by Westcoast at this time.

CAPLA stated that collection of abandonment reserves should begin immediately, so that landowners do not bear the risk of pipelines being abandoned before sufficient reserves have been established. CAPLA stated that "immediately" means, "as soon as a decision is made at this hearing".

CAPP submitted that all pipelines should be subject to the same requirements and the commencement of collection of funds should not be based on the vintage of a pipeline. In addition, the collection of funds should not begin until the Department of Finance amends the *Income Tax Act* (discussed further in Section 2.5).

Deferral

According to Enbridge, collection of abandonment funds should commence when a reasonably foreseeable date of abandonment and an estimate of costs can occur. Many pipeline assets have sufficiently long economic lives and their abandonment is not reasonably foreseeable within a timeframe that has any practical consequence. As a result, Enbridge suggested that any abandonment funding collection mechanism incorporate flexibility to accommodate differences among pipeline facilities in key parameters, such as expected economic life, and permit the Board to authorize deferral of fund collection by a pipeline.

Enbridge submitted that deferrals would not cause competitive impacts as competing pipelines would have similar supply and market demand fundamentals and would therefore be in a similar position to receive a deferral from the Board.

KMC submitted that deferred collection would be inconsistent with the regulatory principle of intergenerational equity, could cause potential competitive disadvantages between pipelines and could pose a greater risk of leaving taxpayers, landowners and government with the costs of abandonment. It disagreed with waiting until abandonment was reasonably foreseeable because there is significant risk that the pipeline life could be truncated and there would not be monies available to remove the facilities at that time. KMC cited potential changes in American or Canadian government energy policy as adding to the risk of pipeline life truncation.

KMC and Pouce Coupé argued that there is the potential for competitive impacts with the use of a deferral. Pipelines that collect would be put at a competitive disadvantage to those that do not.

CAPLA submitted that the Board should not provide flexibility, such as a deferral, in the abandonment collection process, as landowners need to be protected. Immediate commencement of collection reduces risk for landowners because it spreads the burden of abandonment funding over the remaining economic life and allows companies to take greater advantage of compounding interest on the funds.

In addressing the risks of a deferral raised by other parties, Enbridge acknowledged that collection over a longer period could mitigate some of the risk of intergenerational inequities. However, it submitted that a longer collection period leads to other costs and risks. The first is increased risk of over-collection from early shippers as a result of estimates being less reliable at

that time. Second, a longer collection period can lead to a higher administrative burden with little or no corresponding benefit. Third, the benefits of compound interest from a longer collection period would need to be weighed against the opportunity cost to shippers of putting those funds to alternative uses.

In response to concerns that deferral could result in the under-collection of funds, Enbridge stated that while a deferral would shorten the time of collection, the real issue would be whether there would be a sufficient period remaining to collect the appropriate amount of abandonment funds. Enbridge envisioned a process to allow a company to apply for a deferral that would include adequate checks and balances under Board oversight so that it would not lead to greater risk of insufficient abandonment funds.

Enbridge argued that the concept of deferral should not be dismissed based on hypothetical situations. Instead, individual applications for deferral should be evaluated on a case-by-case basis.

Nominal Amount

TransCanada envisioned the need for an abandonment cost study to be completed after Stream 4, in order to estimate abandonment costs. In the meantime, TransCanada recommended beginning collection with a nominal amount in order to commence collection of abandonment funds before LMCI Stream 4 is complete. This nominal charge would not be based on any specific assumptions regarding the scope of pipeline abandonment and would be intended to get the process of collecting abandonment funds started in order to make a meaningful step towards addressing the issue of pipeline abandonment funding. The benefit of the nominal charge is that steps could be taken in parallel with Stream 4. However, TransCanada suggested that three issues would need to be resolved before any collection (including collection of a nominal amount) begins. These issues are: toll settlements in which shippers have agreed to a toll; the establishment of a mechanism to set aside funds; and tax efficiency of collections.

Enbridge submitted that it does not believe that a nominal collection is the appropriate starting point, as collection should be based on some reasonable understanding of the assumptions underpinning the collection amount. Westcoast submitted that any surcharge, whether nominal or not, would be premature.

KMC was also of the view that nominal collection was not appropriate because abandonment can be dealt with in a timely manner. It suggested that there was no need for the collection of a nominal amount as it was unaware of the imminent abandonment of any pipeline. Instead, collection should be established in an orderly fashion.

CAPP stated that there was no need to rush into a temporary collection scheme or collect some nominal amount of money on an interim basis. Moreover, to do so could undermine the goal of establishing a sound and economically efficient trust structure. CAPP expressed concern that if abandonment fund collection started before tax efficiency was achieved, it would be more difficult to achieve tax efficiency (discussed further in section 2.5). Enbridge, KMC, Pouce Coupé and the Alberta Department of Energy supported this position.

CAPLA did not support the collection of a nominal amount as this provides an opportunity for pipeline companies to delay the establishment of abandonment cost estimates by claiming that something is being done in the interim.

Group 1 vs. Group 2 Companies

KMC submitted that there are some issues generic to both Group 1 and Group 2 companies and others that are likely to be specific to Group 2 and that these should be examined separately. In its view, Group 2 companies should develop a recommended mechanism to deal with the specific issues, which could include opting into the Group 1 mechanism.

Pouce Coupé stated that the distinctions between Group 1 and Group 2 companies are not helpful in determining whether to set aside money for abandonment purposes. Pouce Coupé submitted that while it is not necessary to have a separate dialogue with all Group 2 companies, it would make sense that Group 2 companies not be subject to the same rigorous process that may be required of a Group 1 pipeline entity.

CAPP suggested that the Board should have a dialogue with each Group 2 company regarding any requirement for the funding of abandonment costs before imposing a funding mechanism on these pipelines. Group 2 companies should have the opportunity to propose alternatives to the generic model set out for Group 1 companies.

2.4 Method of Collection

All parties who filed evidence submitted that, should the Board decide that pipeline companies are required to set aside funds to cover future abandonment costs, those funds should be collected through tolls. The main reason given for this position was that customers who benefit from the service provided by the pipelines should also bear the costs associated with the service. It was the position of Enbridge, KMC and Pouce Coupé that any collection should be through a toll surcharge.

Enbridge, KMC, Pouce Coupé, Westcoast, TransCanada and CAPP stated that if funds are collected through tolls, they should be collected separately from depreciation expense in order to keep the funds identifiable and distinct.

2.5 Fund Governance

Several parties made submissions related to aspects of governance of funds set aside for future abandonment activities. Submissions of parties are grouped under the following topic headings:

- segregation of funds;
- pooling;
- management of funds;
- access to abandonment funds;
- reporting requirements;

- tax treatment of funds; and
- leaving federal jurisdiction.

Segregation of Funds

Most parties submitted that any abandonment funds collected should be set aside and maintained in segregated accounts. Parties recommended that there be a specific account or trust for each pipeline, which would segregate the funds from creditors and from non-regulated businesses. Most indicated that the provisions of the trust and its reporting will make this segregation automatic so that it does not need to be addressed specifically.

Enbridge, CAPLA, and TransCanada suggested that funds should be maintained in separate trust accounts for each pipeline and that trust accounts be administered and maintained by the pipeline company with third party oversight or audit. CAPP submitted that any collected funds should be maintained in a separate trust account for each pipeline, administered by a third party, to ensure that the funds would be available when abandonment costs are incurred. Westcoast was not opposed to the use of dedicated trust accounts administered by a third party.

KMC proposed that the Board ensure the funds are:

- held in trust and used only for abandonment purposes;
- in a trust that is prudently managed;
- invested in a reasonably prudent way and that speculative investments and direct investments in a pipeline's own assets are prohibited;
- in a trust that is audited annually to ensure proper collection and investment;
- reviewed and adjusted for accuracy every five years; and
- attached directly to the pipeline asset, such that they remain available regardless of the solvency or existence of the underlying pipeline company.

Enbridge proposed that the funds collected for future abandonment costs could be insulated from non-abandonment purposes through a combination of segregated accounts, compliance reporting and regulatory oversight.

CAPP suggested that funds in the regulated portion of a company could be "ring-fenced" in a manner that would preclude access from creditors of the non-regulated portions of the company as well as from creditors of the regulated entity. It further noted that a third party trustee, with appropriate legislated requirements for allowing withdrawals, would help to "creditor proof" the funds.

Pooling

Pooling of collected abandonment funds, or a portion thereof, was one potential mechanism of setting aside funds mentioned in the Board LMCI Stream 3 Discussion Paper. The Board also asked information requests on the merits of pooling to address the risk of there being insufficient funds to cover a company's abandonment costs, for example, from under-collection or from

under-performance of invested funds. Pooling could also address the risk of orphan pipelines, that is, pipelines where the responsible pipeline company has become insolvent and cannot cover the abandonment costs.

There was a consensus among the pipeline companies that there is only a small probability of insufficient funding for pipeline abandonment. TransCanada indicated that the risk is very small that abandonment would occur before sufficient funds are in place. Most pipelines and CAPP submitted that there should be no pooling or partial pooling of abandonment funds. Many parties raised a concern that pooling leads to cross-subsidization of companies that may have been less prudent in abandonment fund collection by those who have ensured they have sufficient funds. Consequently, in their view, pooling would be inconsistent with regulatory principles of cost causation.

Dr. Mansell, an expert witness for Enbridge, also opposed pooling. He acknowledged that a benefit of pooling could be the creation of economies of scale in administrative oversight, and even, potentially, some market power in investing the funds accumulated. However, he warned that there were significant reasons not to pool, such as concerns about creating a moral hazard,[2] asymmetric information[3] and cross-subsidization.

Dr. Mansell acknowledged that there could be merit in pooling for some small component of the eventual costs, such as the residual risks[4], but indicated that the merit of an orphan fund mechanism may depend on how an abandonment fund collection system works over time. If the risk of orphaned pipelines is greater at the time the system is reviewed than it is now, then that might be the time to look at an alternative mechanism as opposed to designing a system upfront with that risk as a given (which may result in a different system and different behaviour). Other parties (for example, Enbridge, Pouce Coupé) submitted that the residual risk of under-funding was not large enough to warrant the use of pooling for even a portion of the funds.

CAPLA supported the use of pooling as an additional safeguard but emphasized the need for sufficient collection to fund abandonment obligations on a pipeline-specific basis.

Management of Funds

According to TransCanada, governance of a trust involves establishing its management and a framework under which it is managed. The pipeline company would be responsible for developing and governing any trust fund established, while day-to-day management of the trust would be left to fund managers who would act according to governance documents and be subject to trust law. With respect to investment restrictions on funds accumulated, TransCanada

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2 Dr. Mansell defined moral hazard in the pipeline abandonment context as ‘the creation of an incentive for companies in designing their pipeline to ignore, or worry less about, the relatively higher abandonment costs of a particular option because they can fall back on a pooled fund to cover any additional costs.’ More generally, moral hazard refers to the possibility that the behavior of an individual or company will change if they are protected from the consequences of their action.

3 Dr. Mansell defined asymmetric information as referring to the situation where the managers of an orphan fund do not have as good as information as the companies that actually operate them in order to properly assess risks and uncertainties associated with abandonment, so as to properly assess the cost, or charge, to each contributor to the fund.

4 Residual Risk –The possibility that abandonment funds remaining at the completion of the pipeline life are not sufficient to cover the entire cost of the abandonment activities.

suggested the appropriateness of various investment instruments should be determined on the following principles: minimizing the cost burden, through maximization of fund growth opportunities within acceptable risk tolerances; and optimal governance of funds.

Pouce Coupé recommended that investments of accumulated funds should be restricted to low risk vehicles, comparable to the restrictions on pension funds. CAPP recommended that investment restrictions should be similar to those applicable to pension funds, which are set out in the federal *Pension Benefits Standards Act, 1985*. KMC also noted the similarities to pension fund guidance, and further suggested a prohibition on direct investments in the pipeline owner's debt or equity.

Enbridge suggested two potential guidelines for investment policies. The first alternative would be a restriction to low risk vehicles from the outset (for example, Treasury-bills or short-term notes). The other alternative could allow for a more balanced portfolio at the outset, with a gradual shift to a portfolio more heavily weighted in low risk investments as abandonment approaches. Enbridge suggested a further generic procedure could serve as an appropriate means of establishing investment policy guidelines.

CAPLA stated that the Board ought to have an oversight committee that would oversee all pipeline collections and that landowners be represented on such a committee. One role of the committee would be to ensure funds are collected and invested properly.

Pouce Coupé recommended that arm's length professional fund managers should administer the fund. Selection from qualified service providers should be by competitive tender process. Landowner groups and shippers should not participate in overseeing the trust. Other industry parties also did not see a role for landowners with respect to the governance of any funds collected.

Access to Funds

Most parties submitted that the Board should control access to abandonment funds. CAPP, Enbridge, KMC and TransCanada suggested an application to the Board, such as a leave to abandon application, pursuant to paragraph 74(1)(d) of the NEB Act, should be required before funds are withdrawn. KMC proposed that access to abandonment funds would be subject to an application to the Board indicating:

- facilities to be abandoned;
- forecast cost of abandonment project;
- environmental issues to be addressed;
- consultation activities undertaken by the company;
- technical and engineering issues; and
- commercial issues.

CAPP agreed that the time to access funds would generally be at the end of a pipeline's life, however some abandonment activities may take place over time and access to the funds for these

would be appropriate. CAPP, Enbridge, Pouce Coupé and KMC recommended that access to the funds would be at the end of the pipeline's life. CAPP, Enbridge and Pouce Coupé also indicated that access to the abandonment funds should take place as abandonment occurs.

TransCanada submitted that abandonment would occur over time, and so funds may be required prior to actual physical abandonment, but access would be pursuant to a 'leave to abandon' order. It suggested that this would defer the question of whether interim retirements or only final abandonments could access the abandonment funds to consideration of individual paragraph 74(1)(d) applications.

Enbridge suggested access to funds would be through an order of the Board upon receipt of an application for abandonment. Access to funds would occur when the abandonment costs are incurred and this could be at one time or over a period of time. Enbridge agreed with TransCanada that large, complex pipeline abandonments would be a process over time, not one taking place at a point in time. Enbridge did not propose that pipelines have access to these funds for other purposes, such as for capital projects, operating and maintenance expenditures or during insolvency.

Pouce Coupé submitted that, at least for Group 2 companies, access to abandonment funds should be at the discretion of the pipeline company, and in accordance with the terms of the trust's constating documents and any regulatory requirements. It further recommended that companies should be required to report annually to the Board all such uses and be subject to the Board's audit process. Pouce Coupé described Board regulatory oversight as including: assessing the reasonableness of abandonment costs over time through periodic reviews; using existing regulatory approval processes; and being subject to a stakeholder complaints process.

Reporting Requirements

Some parties recommended that there be standard reporting requirements with respect to funds collected. Enbridge, KMC and Pouce Coupé each recommended requirements with basic information reporting, such as trust or account opening and closing balances; collections, income and other additions to the trust or account; and withdrawals or payments from the trust or account.

CAPP recommended standard basic reporting requirements and any additional reporting requirements agreed to between pipeline companies and stakeholders, for example:

- annual or semi-annual reports to the Board and to the stakeholders of the pipeline company;
- amount of funds collected over the reporting period;
- a report from the trustee including the cumulative amount in the trust, the earnings in the trust, the investments of the trust accounts (similar to what a pension manager would provide);
- gains or losses in the account;
- approximate percentage of amounts in trust or account relative to the most recent estimate of ultimate cost of abandonment; and

- amount of funds withdrawn or sought to be withdrawn together with NEB approval order or application number.

Tax Treatment of Funds

All industry parties noted that current tax laws do not allow a tax deduction for funds set aside in a reserve account for future abandonment costs. For full costs to be recovered from users of a pipeline system, a grossing up to a pre-tax basis for any dollar set aside for future abandonment costs would be required. For example, CAPP stated that, at a 33 per cent tax rate, tolls would need to collect $1.49 for every dollar put into a trust or account unless the *Income Tax Act* is changed.

TransCanada suggested that the Board request the Department of Finance put in place an efficient tax treatment such that the funds collected to cover the cost of pipeline abandonment and contributed to a fund be allowed as a tax deduction in the year contributed. Money withdrawn from the fund would be included in taxable income, offset by tax deductions of abandonment costs incurred during the year.

CAPP recommended a model similar to Qualifying Environmental Trusts as defined in the *Income Tax Act* for mining and waste management companies required by their regulator to set aside funds for reclamation. CAPP further argued that the Board had a statutory obligation, under Part II of the NEB Act, to pursue changes to the *Income Tax Act* to increase the tax efficiency of collecting and setting aside funds for abandonment. CAPP argued that abandonment has a safety aspect to it. In its view, Part II of the NEB Act, paragraphs 26(1)(b) and 26(1.1)(b) imposes requirements on the Board to study, to keep under review the safety of pipelines, and to "report …such measures within the jurisdiction of Parliament as it considers necessary or advisable in the public interest for…the safety of pipelines…"

Westcoast submitted that it supported the tax relief proposal by CEPA.[5] According to Westcoast, under CEPA's proposal, withdrawals from the trust would be taxable at the time taken but would be offset by asset retirement expense. Income earned within the trust would be tax deferred until withdrawn from the trust.

KMC submitted that taxation issues could be addressed by seeking tax-exempt status for both the funds collected in a qualifying fund and earnings on the fund. While recognizing that tax issues are beyond the Board's jurisdiction, Pouce Coupé stated that the Board could play a role in facilitating legislative change.

Leaving Federal Jurisdiction

In the List of Issues, the Panel identified the issue of the handling of any funds collected to abandon a pipeline regulated by the NEB if the pipeline became subject to provincial jurisdiction, either after abandonment or through a transfer to a provincially regulated company.

5 Canadian Energy Pipeline Association submission dated August 14, 2007 to the House of Commons Standing Committee on Finance entitled "A Proposal to Grant Current Tax relief for Pipeline Abandonment Funding."

All parties who made submissions on this topic submitted the funds should follow the pipeline, and if a pipeline moves to provincial jurisdiction, a Provincial regulator should then have discretion over the funds.

Pouce Coupé noted that the NEB could handle abandonment decisions in such a way that it would not lose jurisdiction before abandonment funds are deployed, and that terms and conditions could be placed on a trust to ensure funds can only be used for specific purposes. Finally, it argued that the Board would not necessarily lose jurisdiction over a federal pipeline after an abandonment order is effective, and cited sections 49, 51.1 and 12 of the NEB Act as authority.

CAPLA submitted that MH-1-96[6] and other cases decided by the Board are clear that the Board will no longer have jurisdiction after abandonment and cannot address post-abandonment impacts.

2.6 Risk and Uncertainty

The List of Issues set out a number of questions related to risk and how best to manage or mitigate the risks and uncertainties inherent in determining future abandonment costs and revenues. This topic included consideration of who should bear the risk and reward of trust account performance, and the risk and reward of under- or over-collection of funds.

CAPLA emphasized the need for "sufficient resources" to be available, stating that it is landowners who bear the risk of potential liability and costs resulting from under-collection unless other provision is made. CAPLA contended that the purpose of this proceeding is to ensure that the residual risk of a funding deficiency has been addressed, in order that landowners do not continue to bear this risk. CAPLA emphasized that steps must be taken to ensure that there is zero risk for landowners and that these steps must be taken to eliminate the risk to landowners irrespective of the cost and impact that taking those steps might have on pipelines and their shippers. It further noted that commencement of collection now rather than later reduces risk for landowners because it spreads the burden of funding over the remaining economic life and allows for the compounding of interest on the funds.

Most of the pipeline companies submitted that regular reviews of the estimates of the funds required for abandonment and the amount of funds collected would mitigate the risk of inaccurate estimates and insufficient funding. These parties testified that regular reviews were sufficient mitigation for the uncertainties related to funding future activities, as long as the pipeline is in operation. Residual risk was expected to be very minor.

CAPP submitted that addressing risks and uncertainties would be an ongoing process as the methods for physical abandonment are developed and refined, and technology is advanced. As a pipeline approaches the point of abandonment, the forecast of the cost to abandon the pipeline would become more accurate. The amount to be collected through the tolls to pay for the abandonment would be adjusted, pursuant to regular reviews. Therefore, the funds collected

6 National Energy Board, MH-1-96, Reasons for Decision, Manito Pipelines Ltd. (Facilities Abandonment), July 2006, page 21.

would approximate the forecast cost and the difference should not be significant. As a result, CAPP contended it was unnecessary to address this risk now.

Enbridge proposed that a suitable periodic assessment and adjustment process would mitigate risk of trust fund performance by re-evaluating underlying assumptions. Enbridge also submitted that it is not practical to eliminate risk 100 per cent. Enbridge contended that there is not sufficient cause for the Board to require pooling even of a portion of abandonment funds, to address the minute residual risk.

KMC recommended conducting reviews at least every five years for changes in abandonment technology, regulatory requirements, inflation, materials, labour and other cost-related factors. TransCanada submitted that periodic reviews to update expected terminal abandonment costs and abandonment timing and to take stock of the realized returns on fund investments would allow for adjustments to the funds collected. This would minimize any surpluses or deficits at the time of terminal abandonment.

Generally, parties submitted that there should be symmetry regarding the risk of under-collection and the reward of over-collection, that is, the party that is accountable for the risk of inadequate funding would also benefit from any over-funding.

Pouce Coupé proposed that the risk or reward associated with under- or over-collection of abandonment funds (that is, the short-term variations) should be to the account of the shippers. Further, over- or under-funding (that is, the long-term uncertainty) should be to the account of the pipeline company. Contending that abandonment costs are operating and not owning costs, TransCanada proposed that abandonment funds be managed in a manner similar to pension funding, where the normal practice is for shippers to bear the inter-year risk and reward (beyond the test year forecast risk) and pipeline companies to bear the intra-year risk and reward (within the test year forecast risk). Deviations from standard risk sharing would be permitted by the NEB, in a similar manner as deviations related to pension costs.

According to CAPP, if any trust accounts established for abandonment are required to have investment restrictions to minimize the downside risk, then any reward generated by the trust should remain in the trust and be part of the funds available to pay for pipeline abandonment.

In Enbridge's submission, the pipeline company should bear the risk and reward of trust account performance, as it is responsible for the abandonment liability and is well positioned to manage and mitigate the risk. The shippers on the pipeline should bear the risk and reward of under- or over-collection of funds.[7]

7 Enbridge defined under- or over-collection of funds as circumstances in which a pipeline company collects less or more on an annual basis than is required to be collected, as determined by the annual contributions to the abandonment fund that are necessary to fulfill the ultimate abandonment cost obligation.

2.7 Jurisdiction

Issue 7 of the List of Issues asked:

> What is the Board's mandate under the current legislation to require the collection of abandonment costs as a component of a company's revenue requirement?

Many of the parties provided brief submissions on the jurisdiction issue. No party argued that the Board did not have authority to require the collection of abandonment costs as a component of a company's revenue requirement.

Citing subsection 48(2) of the NEB Act, KMC stated that the NEB has the mandate to require collection of abandonment costs as a component of a company's revenue requirement.

Pouce Coupé submitted that under Part IV of the NEB Act, including sections 59 and 62, the Board has broad discretion in the setting of tolls and tariffs for companies it regulates and that discretion is broad enough for the Board to require collection of abandonment costs by those companies. While stating that differing methods could be used for the determination of just and reasonable tolls, it submitted that the Board should adopt a single consistent method for any requirement to collect abandonment costs by those companies. Such an approach is least likely to impair the competitive position of any individual pipeline company relative to others.

Pouce Coupé further submitted that the Board has authority to direct that funds collected through tolls "be deposited into an abandonment trust fund or segregated account" and to set or require "any necessary terms of such trusts". However, in its view, the Board does not have jurisdiction to oversee pooled funds, including managing an orphan fund or directing surplus funds flow outside the scope of the Board's jurisdiction.

Westcoast submitted that the Board was mandated by its public interest obligation to balance conflicting interests and arrive at a judgment that is the best or most favourable for the overall public interest.

TransCanada stated that a fundamental premise of the Board's regulatory mandate is that all costs of service should be borne by those parties using the service, and the ultimate abandonment of facilities is part of that service. Further, TransCanada stated that based on the Board's clear jurisdiction over abandonment and the unrestricted definition of "tolls", it seems clear that the collection of abandonment costs is within the Board's jurisdiction and mandate. In addition, TransCanada adopted the submissions from Westcoast concerning the Board's public interest obligation.

CAPLA submitted that it was clear that the Board not only has jurisdiction over the abandonment of pipeline facilities but it also has the discretion to implement regulations that govern the abandonment of pipeline facilities for the protection of landowners from both safety and financial perspectives.

Chapter 3

Views of the Panel

3.1 Jurisdiction

During the RH-2-2008 proceeding, few parties addressed in detail the issue of the Board's jurisdiction to require collection of abandonment costs as a component of revenue requirement (thus making it possible for companies to apply to collect these costs from shippers through their tolls). As summarized in the previous chapter, many took no issue with the Board's jurisdiction to require collection of abandonment costs as a component of a company's revenue requirement. Several parties noted the Board's broad mandate set out in Part IV of the NEB Act, citing the following provisions in the NEB Act.

Section 59:

> The Board may make orders with respect to all matters relating to traffic, tolls or tariffs.

Section 62:

> All tolls shall be just and reasonable, and shall always, under substantially similar circumstances and conditions with respect to all traffic of the same description carried over the same route, be charged equally to all persons at the same rate.

The Panel notes that the Board's authority to determine just and reasonable tolls is not limited by any statutory directions. Courts have interpreted the provisions above to give the Board a very broad mandate to act on matters relating to traffic, tolls and tariffs.

> Under it [Part IV of NEB Act], tolls are to be just and reasonable and may be charged only as specified in a tariff that has been filed with the Board and is in effect. The Board is given authority in the **broadest of terms to make orders** with respect to all matters relating to them [tolls]. Plainly, the Board has authority to make orders designed to ensure that the tolls to be charged by a pipeline company will be just and reasonable. But its power in that respect is not trammeled or fettered by statutory rules or directions as to how that function is to be carried out or how the purpose is to be achieved.[8]

In the Panel's view, the authority set out in Part IV of the NEB Act is sufficiently broad to allow the Board to embark on the inquiry, and issue a decision on whether the Board should require the collection of abandonment costs as a component of a company's revenue requirement. If the answer is in the affirmative, the Board would then be able to determine whether the collection of

8 *British Columbia Hydro & Power Authority v. Westcoast Transmission Co.*, [1981] F.C.J. No. 32, (FCA), at para 17, recently affirmed in *TransCanada Pipelines Ltd. v. Canada (National Energy Board),* [2004] F.C.J. No. 654 (FCA) at para 30.

specific abandonment costs through tolls is a necessary component or requirement of just and reasonable tolls for a particular pipeline company.

Pouce Coupé also argued that the Board continues to have post-abandonment jurisdiction over pipelines. CAPLA argued that the Board does not have jurisdiction post-abandonment. The Panel notes that the Board is dealing with this issue in Stream 4 of the LMCI, and has released an advisory letter clarifying the Board's jurisdiction post-abandonment, dated 2 February 2009.

3.2 Key Principles and Considerations

Upon consideration of all the evidence in this proceeding, the Panel finds that it is an appropriate time for the Board to deal with abandonment funding in a principled manner. The sections that follow discuss key principles and considerations and a framework for moving forward.

In its 25 February 2008 letter regarding the LMCI Approach, the Board indicated that one of the potential outcomes of Stream 3 is that the Board would develop a set of principles that would guide it in its future decisions with respect to financial matters related to pipeline abandonment. The Panel reaffirmed this potential outcome in its first ruling on amendments to the List of Issues and Timetable of Events, dated 21 April 2008.

Also in its February 2008 letter, the Board set out two key goal-oriented principles as being fundamental to its future decisions with respect to financial matters related to pipeline abandonment. After careful consideration of the record in this proceeding, this Panel has reaffirmed these goal-oriented principles and has recommended additional key principles.

The Panel believes that the following principles and considerations will provide guidance to the Board in its future decisions in these matters. They are also intended to guide companies in addressing financial aspects of abandonment. Furthermore, all of these goal-oriented principles and considerations have been taken into account in the Panel's development of the Framework (described below) for setting aside of funds to cover the costs of abandonment and, as a result, the Framework strives to meet the goals set out in the principles.

The Panel is of the view that the implementation of the proposed Framework will be a significant step towards attaining these goals, in particular, through the regular review processes recommended therein.

The Panel recommends the following as key principles and considerations:

1. It is in the public interest that all pipelines regulated by the NEB be abandoned safely and effectively.

2. Pipeline companies are ultimately responsible for the full costs of constructing, operating and abandoning their pipelines, and the Board will hold the regulated company responsible for these costs.

3. The Board regulates using a goal-oriented, risk-based lifecycle approach; it does not subscribe to the concept of elimination of risk.

4. Landowners will not be liable for costs of pipeline abandonment.

5. At this time, the use of pooling as a general mechanism for setting aside funds to cover the costs of abandonment is not efficient from a regulatory or economic perspective.

6. Timing of abandonment of a pipeline for the purpose of estimating future abandonment costs should be the shorter of anticipated economic life or physical life.

7. The removal of all large-diameter abandoned pipe from agricultural land is not a prudent or effective approach for the purpose of establishing preliminary abandonment cost estimates.

8. Abandonment costs are a legitimate cost of providing service and are recoverable upon Board approval from users of the system.

9. Funds for abandonment costs should be collected and set aside in a transparent manner.

10. Funds for abandonment costs should not be collected as part of depreciation and should be a separate element of cost of service.

11. Any funds set aside for abandonment must be held in such a manner that they can only be used for the purposes of abandonment and abandonment planning.

12. The Board, as an independent and quasi-judicial tribunal, does not promote the development of tax policies or initiatives.

3.3 Discussion of Key Principles and Considerations

3.3.1 Principles relating to the Board's General Mandate

In order to have all pipelines regulated by the NEB abandoned safely and effectively, regardless of ownership of the facilities, there must be adequate funds set aside to cover all abandonment activities. In the Panel's view, pipeline companies are ultimately responsible for the full costs of constructing, operating and abandoning their pipelines. The Board will hold the regulated company responsible for these costs.

There are a number of methods by which the Board could hold a company responsible and seek to ensure that adequate funds are set aside for abandonment. For example, in addition to the Board's jurisdiction under Part IV of the NEB Act previously discussed, in the Panel's view, the Board also has a broader mandate within which it may consider funding of future abandonment costs. This consideration may fall within the Board's consideration of the present and future public convenience and necessity when a company seeks approval for a project under Part III of the NEB Act. It may also fall within the Board's authority with respect to providing for the protection of property and the environment. As a result, the Panel is of the view that the Board has regulatory authority to ascertain whether there are adequate funds set aside for the

abandonment of facilities it regulates, and to impose or enact additional regulatory requirements that endeavor to ensure such funding.

While these key principles apply to all companies regulated by the NEB, the details on how each company collects or sets aside funds for abandonment activities may differ. For example, Group 1 and Group 2 companies may have different methodologies for setting aside funds, and certain Group 2 companies may not collect funds from users if they do not have third-party shippers. Should a Group 2 company that does not charge tolls propose a methodology other than collecting future abandonment costs through tolls, the Panel recommends that the Board consider whether the alternative methodology ensures that adequate funds are set aside for abandonment costs and meets the goal of holding the pipeline company responsible for the full costs of abandoning its pipeline system.

The Panel notes Westcoast's submissions, which are summarized in Chapter 2, on excluding, at a minimum, Westcoast from any regulatory requirements to set aside abandonment funds for its gathering and processing facilities. There was no evidence presented at the hearing that persuaded the Panel that Westcoast, or any other company, would be unable to provide a preliminary estimate of abandonment costs. It is clear that the provision of preliminary estimates requires the use of a number of assumptions, some of which will be refined over time. This may result in adjustments to the estimates and, potentially, the collection methodology. However, the need to use assumptions rather than actual numbers is not sufficient rationale for not embarking on the exercise. In order to assist companies, the Panel recommends that companies use the Base Case assumptions set out in the Framework, discussed below, if companies are not able to determine reasonable pipeline-specific assumptions to calculate their own specific preliminary estimates.

The Panel notes that companies may have different proposals for collection or setting aside of funds. The Panel recommends that the Board remain open to companies submitting different proposals based on the facts of their particular facilities. It is also recommended that the Board exercise its discretion whether to approve or deny such proposals, including proposals regarding the timing of collection or setting aside of funds. The Panel recommends that the discretion be based on pipeline-specific information before the Board, including estimated costs to abandon those particular facilities, rather than estimates that rely extensively on the Base Case assumptions. This will provide the Board with the best information upon which it can make its determination.

3.3.2 Principles relating to Risk

The Board's regulatory oversight role applies to the entire lifecycle of a pipeline or facility. Using a goal-oriented approach to regulation, the Board defines desired outcomes, but allows companies to decide how best to achieve these outcomes throughout the lifecycle of the pipeline or facility. Companies are accountable for their own performance and are expected to identify and manage risk throughout a facility's lifecycle.[9]

[9] This approach is more fully described in the Board's Annual Report 2008, available at http://www.neb-one.gc.ca/clf-nsi/rpblctn/rprt/nnlrprt/nnlrprt-eng.html at pages 5 and 6

The Panel does not believe that it is practicable for regulated companies to eliminate all risk no matter what the cost, as was submitted by CAPLA. At some point on the continuum of possible risks, a point of diminishing returns is reached, where the cost of trying to eliminate all risk is out of proportion to the incremental benefits that might result. However, the Panel reiterates that one of the goals reflected in the principles of the Framework is that landowners will not be liable for the costs of pipeline abandonment.

The Panel recognizes that currently there may be some risk of unfunded or underfunded abandonment. However, with respect to the risk of unfunded abandonment, no evidence was submitted during the proceeding that persuaded the Panel there were pipeline systems anticipated to be abandoned in the foreseeable future. As a result, it is not necessary for abandonment funds to be set aside immediately; there is time to establish a proper framework. Concerning the risk of underfunded abandonments, the Panel is of the view that over time these risks can largely be mitigated. As discussed in the Framework, there will be appropriate mechanisms in place to review abandonment cost estimates, and the accumulation of funds and growth of funds over time. These regular reviews will also mitigate the over-collection of funds from users, thereby ensuring a responsible approach to funding abandonment. The Panel also recommends that there be appropriate ongoing oversight by the Board of abandonment funding. In addition, the Panel notes that pipeline companies have an incentive to set aside and recover sufficient funds from their users so that they, and their shareholders, are not left with the responsibility for any shortfalls. All of these factors will help mitigate the risks of underfunded or unfunded abandonment.

The concept of pooling was raised during the hearing as a possible mechanism for setting aside abandonment funds or to address residual risk. After considering the views of parties, the Panel finds that the use of pooling, as a general method of setting aside the full costs of abandonment, would not be a prudent regulatory instrument at this time. In addition, using current resources to develop an appropriate pooling mechanism as a method of managing any small residual risks associated with unfunded or underfunded pipelines would not be efficient from a regulatory or economic perspective.

In the Panel's view, Board and company resources would be better directed to addressing other fundamental aspects, such as determining preliminary estimates and developing appropriate mechanisms to set aside adequate funds for abandonment. The Panel does not consider that there is currently a need to develop a stand-alone pooling mechanism to address either abandonment funding as a whole or residual risk. However, the Panel notes the Board's broad authority over abandonment funding and recommends that the Board not foreclose the possibility of implementing pooling mechanisms or contingency planning of some sort in the future.

3.3.3 Principles relating to Assumptions

One of the fundamental aspects to be determined by all companies is their preliminary estimates of the amount of funds needed to be set aside now, and on an ongoing basis, to cover the costs of abandonment. The assumed timing of abandonment of a pipeline is critical to this estimate. In the Panel's view, using a range of reasonable timeframes within which abandonment could occur may be a way to address uncertainties surrounding timing of abandonment, although there are likely other ways to deal with these uncertainties as well. Notwithstanding the various ways

abandonment timing could be dealt with, in the Panel's view, based on the evidence heard in the proceeding, economic life should generally be used to determine the timing (or ranges of timing) of abandonment rather than physical life. In the current market environment and given the ability of existing technology to extend physical life, it would be unlikely for physical life of a pipeline to be the determining timing factor. However, to accommodate those cases, the Panel recommends that timing for the purpose of calculating preliminary estimates on the amount of funds needed to be set aside should be based on the shorter of a pipeline's anticipated economic life or physical life.

Another key aspect critical to calculating preliminary estimates is the method of abandonment. As noted in the September 1985 Background Paper on Negative Salvage Value, there are three basic pipeline abandonment options available. These are removal, abandonment in place with continuing maintenance, and outright abandonment in place. In order to prepare their preliminary estimates of abandonment costs, many pipeline companies indicated that they needed guidance from the Board on the most appropriate abandonment standard to use. Several parties were of the view that it would not be possible to prepare their preliminary estimates until the LMCI Stream 4 process was completed, while CAPLA argued that its default technical assumption should be used for agricultural land.

The Panel recommends that the Board not wait until the Stream 4 process is completed before implementing the Framework discussed below. This Report sets out a number of high-level, goal-oriented principles related to certain technical assumptions to provide guidance to companies. In addition, the Framework is sufficiently robust to allow companies to begin work on their preliminary estimates, either by using the Base Case assumptions or their own pipeline-specific assumptions. The outcomes from LMCI Steam 4 may inform this process and feed into the ongoing processes for review over time, but it is not necessary to wait until the Stream 4 process is completed before any action is taken. The Panel is of the view that the preparation of preliminary estimates and the work planned for Stream 4 can proceed in parallel.

With respect to CAPLA's default technical assumption, the Panel was not persuaded on the evidence that removal of all large-diameter pipelines from all agricultural land is a necessary assumption. The Panel is of the view that in the absence of case-specific considerations, such as environmental, cost-related or risk-related considerations, mandated use of this assumption is not appropriate. Such a broad and general assumption would be neither prudent nor effective for establishing preliminary estimates of the costs of abandonment.

As a result, the Panel does not recommend use of this assumption as a Base Case assumption. However, it is within companies' discretion to use this assumption as they consider appropriate in preparing preliminary estimates of abandonment costs. Companies should use assumptions that make sense for the particular circumstances of their systems. The Panel recommends that pipeline companies be required to justify to the Board any assumptions used to calculate pipeline-specific preliminary estimates.

3.3.4 Principles relating to Collecting and Setting Aside Funds

With respect to a pipeline company's ability to collect funds to cover abandonment costs from its users, the Panel has stated in the key principles that abandonment costs are legitimate costs of

providing service and are recoverable upon Board approval from users of the system. In order to receive Board approval to collect future costs from users, pipeline companies are to come forward in a timely manner with a proposal for the collection of just and reasonable tolls, of which future abandonment costs will be a component. In each case, the Board will determine whether the funds sought to be collected are appropriately part of just and reasonable tolls for the regulated facility. For those Group 2 companies that do not charge tolls, alternative methods for setting aside abandonment funds must be developed and filed with the Board.

If companies do not submit proposals to collect these future costs from tollpayers or otherwise set aside abandonment funds in a timely manner, the Panel recommends that the Board identify other regulatory requirements that could ensure coverage of abandonment costs. Examples of other options may include the posting of bonds or letters of credit.

In order to meet the goal of ensuring that there are adequate funds to safely and effectively abandon pipelines, it is a fundamental principle that any funds set aside for abandonment must be held in such a manner that they will only be used for the purposes of abandonment and abandonment planning, and will not be available to third parties. To allow otherwise could increase the risk of underfunded or unfunded abandonments. Accordingly, the Panel recommends that all companies develop an appropriate mechanism to set aside funds to meet this principle. During the hearing, a number of possibilities were discussed, including a trust that provides restrictions in its constating documents and setting up restricted access accounts. In their filings to the Board, as further discussed in the Framework, companies may propose any mechanism that, in their opinion, appropriately meets this goal, even if these mechanisms were not discussed during this proceeding.

The tax treatment of the funds collected and set aside for abandonment received considerable attention during the hearing. The Panel notes that parties raised no other proposals, other than changes to the *Income Tax Act*, that would result in a tax treatment satisfactory to industry parties for these funds. The Panel acknowledges that the tax treatment of abandonment funds will impact the amount of funding required to cover the costs of future abandonment activities.

Some parties suggested that the Board take a lead role in initiating changes to the *Income Tax Act*. CAPP went further and argued that the Board has a statutory obligation to increase the tax efficiency of collecting and setting aside funds for abandonment. It submitted that this statutory obligation stemmed from the Board's advisory functions with respect to safety of pipelines, pursuant to Part II of the NEB Act.

What was not clear from CAPP's argument was how the tax treatment of funds collected affects the *safety* of pipelines, particularly if the Board mandates collection of abandonment funds regardless of the tax treatment of such funds. Further, the Panel notes that no party, including CAPP, presented evidence that a safety impact is possible or might be realized in the absence of income tax changes. While the tax treatment may affect the willingness of the pipeline industry to collect funds or the amount that may be required to be set aside, based on the evidence presented to the Panel, there is no basis to make a finding that there is a connection between tax treatment of the funds and the safety of the pipelines themselves. Safety of pipelines is dependant upon physical aspects of the pipeline, and is overseen by the Board already through its regulation of the construction, operation, maintenance and abandonment of pipelines throughout

their life. Accordingly, the Panel was not persuaded that the Board is statutorily obligated to assist industry on this matter.

Furthermore, the Panel is of the view that the Board, as an independent and quasi-judicial tribunal, should not promote the development of tax policies or initiatives. Tax treatment of the abandonment funds that will be collected is an issue for the pipeline companies, working with others in industry, to pursue with the Department of Finance. As industry has submitted that changes in tax treatment are necessary, parties should endeavour to seek such change in a timely manner. However, as already noted, the funding of abandonment costs remains the responsibility of each pipeline company, regardless of tax implications. Tax efficiency is a goal of, not a deterrent to, the collection of funds for pipeline abandonment.

3.4 Framework

Given the above key principles and discussion, the Panel is of the view that it is now an opportune time to develop a framework to meet the goal of having adequate abandonment funds available for abandonment and abandonment planning when required. Setting aside of abandonment funds is required; however, it need not begin until some fundamental issues have been addressed and a framework has been implemented. This will allow accumulation of abandonment funds to proceed in an orderly fashion. The Panel is of the view that there is time to address certain outstanding issues and to implement a framework that will work for all pipeline companies regulated by the Board.

In reaching this conclusion, the Panel considered the following factors:

- No pipeline systems are anticipated to be abandoned in the foreseeable future.
- Applying the concept of risk management, as opposed to the concept of zero risk, parties did not present any evidence at the hearing that persuaded the Panel that time is of the essence in terms of the Board needing to require immediate collection or setting aside of funds.
- It would not be prudent from an economic efficiency perspective to implement a framework that results in the over-accumulation or under-accumulation of abandonment funds.
- In the Panel's view, the immediate collection or set aside of a nominal amount would divert resources away from tackling the fundamental aspects of abandonment funding.

Notwithstanding the recommendation to implement a framework applicable across the industry, pipeline companies are not precluded from filing an application with the Board to begin the collection or setting aside of funds for abandonment while the Framework is being implemented. If this should occur, the Panel recommends that the Board consider the application on its merits at that time.

In addition, the Panel notes that the Board is not precluded from considering the full costs of constructing, operating and abandoning a pipeline as part of its consideration of the present and future public convenience and necessity of a project when a company seeks approval under Part

III of the NEB Act, should the Board determine that doing so is appropriate based on the case before it.

Overview of Framework and Action Plan

It is essential that all regulated companies accept the responsibility for the full costs of their facilities, including abandonment costs. In the Panel's view, a fundamental element of accepting responsibility is the quantification, albeit approximate at this stage, of that responsibility.

Consequently, the Panel finds that pipeline companies are responsible for coming forward to the Board with estimates of funds needed for abandonment, justifying any assumptions used, and with proposals for the mechanisms and timing of the collection and setting aside of those funds. The ultimate goal is to have all companies begin to set aside funds to cover future abandonment costs no later than five years from the date of the decision of the Board. To achieve this goal, a number of steps must be completed within this five-year period, including the Board's assessment of filings. These steps are described below and summarized in Chapter 4, Action Plan and Base Case Assumptions.

The Panel recognizes that, should the Board adopt the proposed Framework and Action Plan, there will be increased regulatory interaction between stakeholders and the Board. This includes increased filings by companies within the next five years, resulting in increased assessments, and potentially hearings, by the Board over that same period with respect to those filings. Additional resources to hold and participate in at least one further technical conference will also be required. While these resources are not insignificant, the Panel is of the view that in order to progress on the issue of financial aspects of abandonment, an increased regulatory role, at least in the short to mid-term, is inevitable.

The Panel encourages all stakeholders to identify ways to increase efficiency, while respecting the key principles, the goals set out therein and ultimate goal of the Framework and Action Plan to ensure that funds are available when abandonment costs are incurred. Further, the Panel recommends that the Board also remain open to, and itself seek out, opportunities to increase regulatory efficiencies, even if acting on those opportunities results in refinements to the Framework and Action Plan.

<u>Preliminary Estimates</u>

As an essential first step, the Panel recommends that the Board direct each company under NEB jurisdiction (Group 1 and Group 2) to submit a preliminary estimate of its total future abandonment costs and the amount required to be set aside using basic assumptions regarding economic life and the method of abandonment.

To facilitate these submissions, the Panel has provided Base Case assumptions in this Report that companies may use to develop these preliminary estimates. A technical conference will be held to assess and discuss these assumptions. Following the discussion of these assumptions, and the issuance of a revised set of Base Case assumptions as necessary, each company will be expected to prepare and file an estimate of abandonment costs and the amount required to be set aside using the Base Case assumptions. Alternatively, should it not wish to rely on the Base Case assumptions, a company may file with the Board its pipeline-specific estimate of abandonment

costs for its pipeline system. The pipeline-specific estimate should be accompanied by discussion and supporting evidence for any assumptions the company is using that differ from the Base Case assumptions.

If a Group 1 company is using all of the Base Case assumptions, or if a Group 2 company is using either the Base Case or pipeline-specific assumptions, no approval is necessary for its preliminary estimates. If a Group 1 company is using any pipeline-specific assumptions, Board approval of the preliminary estimates is required.

The Panel recommends that Westcoast be required to calculate preliminary estimates for abandonment costs for its transmission (Zones 3 and 4) and its gathering and processing (Zones 1 and 2) facilities.

Collection of Funds

Group 1 companies would be required to file, for approval, a proposal for collecting the amount of funds required. Group 2 companies that charge tolls would file their proposals for collecting funds for abandonment. These proposals should contain discussion and justification of the time horizon and methodology for collecting future abandonment costs from users of the pipeline system.

Group 2 companies that do not charge tolls need not complete this step, but would be required to file with the Board their proposals for setting aside the amount of funds required (as discussed in the next step).

Concerning the method of collection, the Panel agrees with many of the parties who indicated that collecting abandonment funds should be transparent and this can be achieved for Group 1 or Group 2 companies that charge tolls through either tolls or a toll surcharge. However, there may be other transparent methods that companies wish to propose to the Board. The Panel is also of the view that abandonment funds should be separate from depreciation as an element of cost of service and that the funds should be segregated by pipeline.

Concerning negotiated toll settlements, the Panel's view is that within the timeframe established in the Action Plan, the majority of toll settlements will have expired. In the interim, in entering into new toll settlements, parties will be aware of this Framework and Action Plan. The Panel expects that parties will ensure that any new toll settlements address abandonment funding matters resulting from the Framework and Action Plan.

Setting Aside Funds

All Group 1 companies would be required to file, for approval, a proposed process and mechanism to set aside the funds. All Group 2 companies would file with the Board a proposed process and mechanism to set aside the funds.

The Panel recommends that any process and mechanism for setting aside the funds for abandonment have the following attributes:

- funds must be maintained in a segregated account and not be commingled with a company's general corporate funds;
- funds must be managed by an independent, third party;
- funds collected must be protected from creditors;
- funds must be protected from misuse or use for a purpose other than abandonment;
- regular reviews (at least every five years) of the amount of funds set aside and disbursed from the segregated account must be incorporated, and regular reporting to the Board and stakeholders must be built in;
- funds must be segregated by pipeline;
- funds must be subject to Board audit, as appropriate;
- companies must develop a sound investment policy for abandonment funds as ultimately, accountability for the collection and governance of the funds rests with each pipeline company; and
- the process for accessing the funds must be clearly set out in the mechanism.

Pipeline companies are expected to demonstrate to the Board how the mechanism they have chosen meets the goal of ensuring that adequate funds will be set aside to cover all pipeline abandonment activities. In the Panel's view, it is not necessary to use a one-size-fits-all approach. The market may play a role in determining the appropriate mechanism that a particular company may decide to adopt.

The Panel does not see a need to comment on the merits of the concept of deferral of collection or exemptions from collection or setting aside of funds. In the Panel's view, this is a level of detail beyond the scope of this proceeding, and is best addressed on a case-specific basis. As a result, this concept may form part of a company's proposal for collection and setting aside funds. However, as noted above in the Key Principles section, the Panel recommends that, as a prerequisite to considering any proposals to defer collection or set aside of funds, companies be required to submit information on a pipeline-specific basis, rather than using the Base Case assumptions. This will allow the Board to have before it the best information possible, upon which it may exercise its discretion to approve or deny such a proposal.

The Panel was not persuaded by CAPLA's submissions advocating the involvement of landowners in an oversight committee role to review abandonment funding. A role of such a committee requires a significant amount of time, resources and financial expertise. Further, given the key principles noted above, the ongoing Board oversight of this matter and that interested parties may participate in future NEB abandonment-related proceedings, the Panel does not recommend the establishment of an external oversight committee.

Access to Funds

As noted in Chapter 2, many parties in the hearing indicated that Board guidance on accessing the funds would be needed. In the Panel's view, funds should be accessible only for abandonment purposes. "Abandonment purposes" may include the development of an abandonment plan, as well as the undertaking of activities (for example, surveys and studies) to prepare an abandonment plan or to carry out an abandonment, and the continuation of post-physical abandonment activities (for example, monitoring or perpetual maintenance).

Pouce Coupé initially submitted that access to accumulated funds should also be permitted for decommissioning of facilities. Others argued that access should be restricted to covering abandonment, and abandonment process activities (such as pre-planning). The Panel notes that both deactivation and decommissioning contemplate continuation of system service. Provided service continues, revenue will be generated from the collection of tolls, from which funds should be available to cover these costs. Consequently, the Panel recommends that access to the funds should generally not be permitted for decommissioning or deactivation of facilities, unless the Board authorizes the access on the facts of a particular case before it.

Accordingly, in order to access the funds to cover costs of physically abandoning facilities and the costs for undertaking abandonment planning activities, companies will generally require a Board order, for example, pursuant to paragraph 74(1)(d) of the NEB Act.

As summarized in Chapter 2, Pouce Coupé argued that at least Group 2 companies should be able to access funds without a Board order. Instead, it submitted that Board oversight of the funds could be exercised through annual reporting of a company's access to the funds and audits by the Board of the funds. The Panel notes the expansive definition of "abandonment purposes" proposed herein, the requirement under the NEB Act to seek leave to abandon, and the recommendation that the Board exercise its discretion to authorize access in other circumstances as appropriate. Consequently, the Panel was not persuaded there is a need for a broad exception to the access procedure, such as the exception proposed by Pouce Coupé for Group 2 companies.

While the Board cannot mandate the process for accessing funds for abandonment of facilities that have fallen outside of the Board's jurisdiction, the Panel would recommend that companies consider, in the development of any mechanisms for setting aside the funds, the conditions for accessing funds should the related facilities fall within provincial or territorial jurisdiction at a later date. This may require sufficiently broad provisions or specifically-drafted provisions for access to encompass this potential situation. Exercising foresight on this issue now while developing appropriate mechanisms may save time and complications at a later date.

Chapter 4

Action Plan and Base Case Assumptions

4.1 Action Plan

Table 4-1 below summarizes the recommended steps going forward, along with the objectives, expected participants and timing of each step. The ultimate goal is to have all companies begin to set aside abandonment funds no later than five years from the date of the Board's decision. Companies that charge tolls would begin to collect funds for future abandonment costs no later than the first toll year following five years from the Board's decision. The deadlines proposed in the table are targets, and may be amended if the Board determines that circumstances require an adjustment.

Table 4-1
Action Plan

Action	Objective	Participants	Timing
1. RH-2-2008 Decision released	Discussion of principles, high level Framework, Action Plan, Preliminary Base Case	NEB	T (T equals release of NEB decision)
2. Board Technical Conference on Preliminary Base Case	Potential refinements to Preliminary Base Case	Group 1 and Group 2 companies that wish to attend, and any other interested person	T + 6 months
3. Release of Refined Base Case	Base Case issued for company use	NEB	T + 9 months
4. (a) Group 1 companies each prepare and file an estimate of abandonment costs and the amount required to be set aside using the Base Case assumptions OR (b) Group 1 companies each prepare and file, **for approval,** an estimate of abandonment	Filing of preliminary estimates using Base Case or pipeline-specific assumptions	Group 1 companies	No later than T + 24 months

costs and the amount required to be set aside using pipeline-specific assumptions or a combination of pipeline-specific and Base Case assumptions			
5. NEB consideration of Group 1 companies' preliminary estimates that use pipeline-specific assumptions or a combination of pipeline-specific and Base Case assumptions	NEB decisions on Group 1 companies' preliminary estimates	NEB	No later than T + 36 months
6. Group 1 companies each develop and file, **for approval**, a proposal for collection of funds and a proposed process and mechanism to set aside the funds [can be combined with step 4 and filed at T + 24 months]	Filing of proposed collection mechanisms and proposed set aside mechanisms	Group 1 companies	No later than T + 42 months
7. Group 2 companies each prepare and file an estimate of abandonment costs and the amount required to be set aside using either the Base Case or pipeline-specific assumptions	Filing of preliminary estimates using Base Case or pipeline-specific assumptions	Group 2 companies	No later than T + 30 months
8. Group 2 companies that charge tolls each develop and file a proposal for collection of funds [can be combined with step 7 and filed at T + 30 months]	Filing of proposed collection mechanisms	Group 2 companies that charge tolls	No later than T + 42 months
9. Group 2 companies each file with the Board a proposed process and mechanism to set aside funds [can be combined with steps 7 or 8, and filed at the earliest applicable date]	Filing of proposed set aside mechanisms	Group 2 companies	No later than T + 48 months
10. NEB consideration of Group 1 companies' proposals for collection and set aside mechanisms	NEB decisions on Group 1 companies' mechanisms for collection and set aside of funds	NEB	Within T + 5 years

4.2 Preliminary Base Case Assumptions

The Panel recommends that the Base Case assumptions in Table 4-2 form the basis for preparing preliminary cost estimates for each pipeline company. If pipeline companies choose to file their own pipeline-specific estimates of future abandonment costs, they should be prepared to justify any deviations from the Base Case assumptions that have been used in coming to these pipeline-specific estimates. These Base Case assumptions will be considered at a technical conference in approximately six months time, and all interested persons are invited to attend the conference. The Base Case assumptions will be refined shortly thereafter, if appropriate. The input of all parties will be considered in refining these Base Case assumptions.

Table 4-2
Base Case Assumptions

Method of Abandonment	See Table 4-3 below
Abandonment Cost Information	Use information in Oil and Gas Journal Survey filed by TransCanada[10]. Parties should explain how they used the data in this survey.
Economic Life	40 years (based on recommendations in the Canadian Institute of Chartered Accountants Handbook for estimating life of long-term capital assets)
Estimated Salvage Value	As no data was filed in this proceeding, and to be conservative, the Board has assumed zero
Inflation Rate	2 per cent (reflects Bank of Canada inflation target and approximates historical rolling averages)
Return on Funds Collected	4.5 per cent (based on Bank of Canada long-term bond yields, using those years between 2000-2009 when inflation averaged 2 per cent per year)[11]

Table 4-3
Method of Abandonment Assumptions

Land Use		**Pipeline Diameter**	
		Less than or equal to 203 mm (8”)	**Greater than 203 mm (8”)**
Agricultural	Crop	Assume 90% abandoned in place with no maintenance; 10% removed	Assume 80% abandoned in place with perpetual maintenance; 20% removed
	Pasture	Assume 90% abandoned in place with no maintenance; 10% removed	Assume 80% abandoned in place with perpetual maintenance; 20% removed
All Other		Assume 100% abandoned in place; 50% with perpetual maintenance, 50% with no maintenance	

10 Exhibit C-26-12, dated 29 January 2009, available at https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=546537&objAction=browse

11 This 4.5 per cent per year is a nominal rate; combined with the 2 per cent inflation, it is 2.5 per cent per year in real dollars.

The above table is provided solely to start the discussion on these Base Case assumptions and the Panel expects that the numbers on this table will be debated in the forthcoming technical conference. While it recognizes that the number of categories for land use and pipeline diameter may be expanded and refined in the future and that every abandonment plan and pipeline-specific estimate will be case-specific, the Panel has recommended a simplified approach at this time due to the lack of information on the record of this proceeding. The split of agricultural land between crop and pasture recognizes that there will likely be different assumptions when those refinements are made.

Chapter 5

Recommendation

The section 15 Panel recommends that the Board accept the Panel's report, including the key principles, Framework and Action Plan.

S. Leggett
Presiding Member

K.M. Bateman
Member

L. Mercier
Member

Calgary, Alberta
April 2009

Land Matters Consultation Initiative (LMCI) Stream 3
Pipeline Abandonment – Financial Issues
RH-2-2008

Responses to
National Energy Board
Information Request No. 1 to Enbridge Pipelines Inc.

1.1 **Reference:** Written Evidence of Enbridge, Page 3, A1

Preamble: Enbridge states that the NEB should require all pipelines that it regulates to begin, at the appropriate time, collecting funds from their shippers to be used to finance future abandonment costs.

Request: Please explain in detail what Enbridge considers "an appropriate time" and the criteria for determining it.

Response: As explained beginning at page 7 of the Written Evidence of Enbridge Pipelines Inc. ("Enbridge Evidence"), Enbridge Pipelines Inc. ("Enbridge") considers that collection of funds should commence when a reasonably accurate estimate of future abandonment costs can be made. No such estimate is possible until abandonment is reasonably foreseeable.

See also the responses to NEB-Enbridge-1.8(c) and (d).

1.2 **Reference:** Written Evidence of Enbridge, Page 3, A4 (Introduction)

Preamble: Enbridge states it is confident that it will have more than sufficient financial means to satisfy its pipeline abandonment obligations.

Request: Please explain in detail how Enbridge will ensure it has sufficient financial means to satisfy future obligations.

Response: As explained in the Enbridge Evidence, Enbridge is of the view that the National Energy Board ("Board" or "NEB") should require all pipelines that it regulates to begin, at an appropriate time, collecting funds from their shippers that will be used to finance future abandonment costs. Enbridge thus expects to collect sufficient funds from shippers on its NEB-regulated pipelines to be able to satisfy its pipeline abandonment obligations. Enbridge also expects that such funds would be segregated for use only to satisfy its pipeline abandonment obligations. In the unlikely event that there were to be a shortfall in the amount of funds collected from shippers, Enbridge could draw upon its substantial assets to pay for the balance of the costs incurred in satisfying its abandonment obligations.

1.3 **Reference:** Written Evidence of Enbridge, Pages 3-4, A1a

Preamble: Enbridge states that shippers may see higher transportation costs and pipeline companies may experience a decline in utilization of their facilities as a consequence of higher tolls.

Request: Please explain why Enbridge predicts a potential decline in utilization under the assumption that all NEB-regulated pipelines would be required to collect higher tolls.

Response: The assumption that all NEB-regulated pipelines would be required to collect higher tolls does not necessarily imply that all pipelines would be impacted to the same degree. Each pipeline would likely charge a different level of tolls for abandonment fund collection dependent on its unique circumstances. This could result in declining utilization of some pipelines but not others. Higher tolls could also place NEB-regulated pipelines and the producers that they serve at a competitive disadvantage globally. This could also result in reduced utilization of some pipelines.

1.4 **Reference:** Written Evidence of Enbridge, Pages 3-4, A1b

Preamble: Enbridge lists the details that it views as important when deciding if a trust account approach would be suitable.

Request: Please provide the rationale for including each of these details and Enbridge's position on each one if not already provided in its evidence.

Response: The portion of the Enbridge Evidence that is referenced in the request was intended to serve two purposes. First, to highlight the fact that establishing trust accounts for abandonment costs would not be an uncomplicated exercise and would require the resolution of numerous details. Second, to express the view that, until at least the more important details can be resolved, neither the Board nor stakeholders can completely assess whether the trust approach would be suitable. A trust is a complex legal arrangement and therefore it is essential that affected parties have a thorough understanding of the details and complexities involved.

The list of details in the Enbridge Evidence was not intended to be exhaustive. Rather, it identifies some of the issues and complexities associated with a potential trust structure. As explained in the Enbridge Evidence, Enbridge would not oppose a trust approach so long as it were designed to meet the objective of providing funds to cover abandonment costs and did not create an undue administrative burden or cost. Enbridge does not currently have a "position" in respect of the details that were listed in the Enbridge Evidence other than in a broad sense. For example, Enbridge is of the view, generally speaking, that the tax treatment should be fair and efficient, the pipeline operator should be assured of access in appropriate circumstances to the trust funds for the payment of abandonment costs, the trustees should be afforded appropriate protection from liability, and that any such trust should be established so as to make the funds as secure as may reasonably be possible in the context of proceedings against the pipeline. Enbridge has not yet considered all aspects of these broader issues or the details of the ways in which they can best be addressed.

1.5 **Reference:** Discussion Paper for LMCI Stream 3 – Land Matters Consultation Initiative, Pages 3-4

Preamble: The terms "abandon" and "decommission" are defined in the reference.

Requests:

(a) Based on these definitions, please describe Enbridge's understanding of how any abandonment fund should be used. In particular, please explain how Enbridge would differentiate between normal business practices and end of life abandonment with regards to the use of funds collected.

(b) What would be the distinguishing criteria between pipeline abandonment as part of a "normal practice" verses an abandonment for which funds would be available? If a pipeline abandons large pieces of its mainline, would this be a normal practice of an ongoing business? Please explain in detail using criteria; for example, size of pipe, location, percentage of capacity remaining, etc.

Response:

(a) and (b) Assuming for the purposes of this response that the terms "abandon" and "decommission" are defined as outlined in the LMCI Stream 3 Discussion Paper referenced in the request, then Enbridge is of the view that, whenever a pipeline asset, regardless of size, is permanently removed from service and its productive capacity is not replaced, the costs of such abandonment should be funded through accumulated abandonment funds. This would be an end of life abandonment. Conversely, when an asset is permanently removed from service, but its productive capacity is replaced, then such activity would constitute a normal business practice and the associated costs would not be paid from accumulated abandonment funds – but rather recovered through tolls as part of the pipeline's cost of service.

1.6 **Reference:** Written Evidence of Enbridge, Page 5, A1c

Preamble: Enbridge states funds should not be pooled among pipeline companies.

Requests: If there is no pooling of funds:

(a) Who will be liable for costs related to orphan pipelines, should there be any?

(b) Is there a risk to landowners, governments and other stakeholders if there isn't a pooled fund to cover abandonment costs of orphaned pipelines?

(c) If so, how could landowners, governments and other stakeholders be provided with the same level of assurance that a pooled fund may provide? What measures could be taken to prevent any burden of abandonment costs ending up being covered by them?

(d) Should financial assurances or security for abandonment be required until future abandonment costs are fully covered?

Response:

(a) - (d) Given that all pipelines under NEB jurisdiction would be subject to the same regulatory requirements and oversight, it is unclear why there should be any so-called "orphan pipelines". More particularly, as explained in the Enbridge Evidence, Enbridge is of the view that the Board should require all pipeline companies that it regulates to begin, at an appropriate time, collecting funds from their shippers that will be used to finance future abandonment costs. If such an approach were to be adopted, then Enbridge would expect that all pipeline companies regulated by the Board would begin collecting and segregating funds over an appropriate time horizon based on proper assumptions (as approved by the Board) as to the timing and cost of abandonment. Those assumptions would be periodically reviewed and updated and abandonment cost collection requirements would be adjusted accordingly. No further risk mitigation should be necessary.

1.7 **Reference:** Written Evidence of Enbridge, Page 6, A2a

Preamble: Enbridge stated that it is of the view that, for the purposes of making preliminary estimates of abandonment costs, abandonment in place should be assumed to be the required method of abandonment.

Requests:

(a) Please explain why Enbridge takes this view and discuss whether abandonment in place should be the assumed method for all types of land use and diameters of pipeline.

(b) Please discuss the rationale of this assumption as it relates to:
   i. shippers;
   ii. pipeline companies;
   iii. landowners;

   including a discussion of the effect on tolls, assurance of funds to pay for abandonment and potential risks and long-term consequences to each party.

Responses:

(a) To clarify, Enbridge is of the view that abandonment in place should be assumed to be the required method of abandonment for the purposes of making preliminary estimates of abandonment costs until the conclusion of the LMCI Stream 4 process at which time Enbridge expects that the NEB will provide appropriate guidance on this issue.

(b) The assumption regarding abandonment in place is intended to be temporary (i.e., until the conclusion of the LMCI Stream 4 process) and thus there should be no long-term consequences for any parties.

1.8 **Reference:** Written Evidence of Enbridge, Page 7, A3

Preamble: Enbridge suggests that if the expected economic life of a pipeline were to be of such a length that the time of abandonment is not yet reasonably foreseeable then the NEB could authorize a deferral of funds collection for that facility.

Requests:

(a) Who would accept liability for the abandonment costs if the pipeline is abandoned before costs are reasonably determined? Should financial guarantees or security be required until the time when estimates are to be reasonably estimated?

(b) What is the risk to affected stakeholders (landowners, governments, shippers, etc) in delaying the start-up of collection?

(c) How would Enbridge define when the abandonment date for a facility is reasonably foreseeable?

(d) Please discuss this proposal with respect to:
- Intergenerational fairness
- User-pay principle
- Risk of under-collection of funds by collecting at the end-of-life
- Competitiveness of pipeline companies that are required to collect fund versus those that are not
- Risk of death spiral

Responses:

(a) As explained in the Enbridge Evidence, each pipeline is responsible for the abandonment of its individual facilities. The scenario posited in the request is highly unlikely and no financial guarantees or security should be required especially recognizing the underlying financial strength, capacity and assets of most, if not all, of the pipeline companies that are subject to regulation by the Board.

(b) Since deferred fund collection would be available only if the Board were to be satisfied, on the balance of probabilities, that the expected economic life of a specific facility is of such duration that the time of abandonment is not reasonably foreseeable, collection deferral should not create additional risk for stakeholders.

(c) An abandonment event that could reasonably be expected to occur within a time horizon established by the NEB would be reasonably foreseeable. The NEB would establish the time horizon based on a

consideration and appropriate balancing of the factors outlined in the response to NEB-Enbridge-1.8(d) below.

(d) Collecting abandonment costs over a longer period can mitigate some of the risk of intergenerational equity because earlier generations of shippers are required to pay a share of the abandonment costs. This factor militates in favour of a longer time horizon of foreseeability and thus a longer collection period.

Conversely, it must be recognized that over-collection from early shippers would also be inequitable. For example, commencing collection before abandonment is reasonably foreseeable is more likely to make the estimates of abandonment timing and abandonment costs even more speculative and thus less reliable as a basis for tolls. This creates a risk of over-collection from shippers and militates against requiring the collection of abandonment costs to commence in the shorter term.

An unnecessarily long collection period also imposes a higher administrative burden both in absolute terms and relative to the amount of the funds collected – particularly in early years. The practical result can be greater costs with little or no corresponding economic benefit.

Finally, the collection and setting aside of abandonment funds creates an opportunity cost vis-à-vis other, potentially more productive, uses for the capital. An unnecessarily long collection period exacerbates that opportunity cost.

Deferral of fund collection in appropriate circumstances can mitigate these risks and, conversely, should not increase the risk of under-collection (or of a “death spiral”) due to the expected length of the period of reasonable foreseeability.

Deferral of fund collection is unlikely to impact competitiveness since the expected economic lives of competing pipelines (i.e., those that are providing capacity from the same producing regions to similar markets) can be expected to be of a similar length (such that their abandonment fund collection would begin more or less contemporaneously).

1.9 **Reference:** Written Evidence of Enbridge, Page 8, A4a

Preamble: Enbridge suggests collecting abandonment costs through a toll surcharge.

Request: Please discuss the rationale of collecting abandonment costs as a surcharge to tolls.

Response: Enbridge is of the view that pipeline companies should be required to collect funds through a separate and transparent tolling mechanism, *which may or may not be structured as a surcharge*.

A surcharge would offer transparency and security to stakeholders because it would enable them to review and analyze the funds as a separate item in the pipeline's revenue requirement. A surcharge may also facilitate a volume and distance based collection mechanism in accordance with the principles of user-pay and cost causation.

Other methods, such as annual shipper payments, or insurance mechanisms, do not provide the same level of transparency and are less consistent with cost causation.

1.10 **Reference:** Written Evidence of Enbridge, Page 8, A4b.

Preamble: The above reference states that funds should be recovered as a separate item in tolls and not as a component of depreciation.

Requests:

(a) Please discuss Enbridge's view on whether the economic life for the collection of funds to cover future abandonment costs should be the same as the economic life used by companies in depreciation studies.

(b) In Enbridge's view, should abandonment funding include an estimate for ongoing maintenance for a period of time after the assets are abandoned? If yes, for how long?

Responses:

(a) Enbridge is of the view that the economic life for the collection of abandonment funds would often not be the same as the life used for the purposes of depreciation studies. There are at least two reasons. First, a pipeline system will have an economic life that is principally dependent on supply and market fundamentals. Conversely, the individual assets that comprise the system will have economic lives that are principally limited by their physical lives and that are therefore often shorter than the economic life of the system as a whole. Second, one objective of depreciation studies is to establish depreciation rates that will provide for the orderly and full recovery of invested capital. Such studies are therefore prepared on a category-by-category or asset-by-asset (e.g., pipe, station equipment, etc.) basis using estimates of the economic life of each category or asset.

(b) Yes. Abandonment funding should include an estimate of the costs for on-going maintenance where such on-going post-abandonment maintenance is part of the abandonment plan approved by the Board. It is expected that the time period for ongoing maintenance would be determined by the abandonment plan.

1.11 Reference: Written Evidence of Enbridge, Page 8, A4a

Preamble: Enbridge comments that a toll surcharge would be one possibility. Canadian toll methodologies are typically based on the best estimate of a year's costs of service and allocated over that year's throughputs, or that year's contracts, by volume. That leaves a potential of rising unit tolls if and when volumes decline.

Requests:

(a) Does Enbridge recommend a surcharge computed according to traditional toll methodology?

(b) At some point in the future, would this expose abandonment funding to increasing risk of requiring significant surcharge adjustments at a time when volumes are declining?

(c) Are there alternatives?

Responses:

(a) Yes.

(b) Abandonment funding, like other components of a pipeline company's revenue requirement, will be exposed to a certain level of increasing risk of requiring tolling adjustments at a time when volumes are declining. However, Enbridge considers pipeline companies to be positioned to, and capable of, properly managing this risk.

In addition, collection of abandonment costs will commence when abandonment is reasonably foreseeable – which should be well in advance of a pipeline experiencing a decline in volumes. Further, the collection period will be of sufficient duration as to substantially mitigate the risk of requiring significant surcharge adjustments later.

(c) See the response to NEB-Enbridge-1.9.

NATIONAL ENERGY BOARD

Land Matters Consultation Initiative Stream 3
RH-2-2008
Pipeline Abandonment – Financial Issues
File ADV-PE-LandMC 02

Reply Written Evidence
of
Enbridge Pipelines Inc.

December 17, 2008

Q1. What is the purpose of this Reply Written Evidence?

A1. This Reply Written Evidence replies to certain of the positions advanced by the Canadian Alliance of Pipeline Landowners' Associations ("CAPLA") in the document entitled "Second Evidence Filing of the Canadian Alliance of Pipeline Landowners' Associations" dated November 5, 2008 ("CAPLA Round 2 Evidence") that was filed with the National Energy Board ("Board" or "NEB") in this proceeding.

Q2. What are the CAPLA positions to which Enbridge wishes to reply?

A2. The first such position relates to the timing of the commencement of collection of funds to cover abandonment costs. In this regard, CAPLA argues (at page 8 of the CAPLA Round 2 Evidence) that ". . . the industry [including Enbridge] advances proposals . . . for the timing of collections, which place landowners at risk for abandonment costs".

CAPLA also asserts that "[i]ndustry participants recognize that . . . delaying commencement of collection of abandonment funds until termination of the economic life of the pipeline can be determined create[s] a risk of underfunding of abandonment costs which will be borne by landowners" (see CAPLA Round 2 Evidence, at pages 9-10), that "[i]n order for landowners not to bear the risk of pipelines being abandoned before sufficient reserves have been established to address abandonment costs, collection of abandonment reserves should begin now" (CAPLA Round 2 Evidence, at page 15) and that the Board ". . . must require the commencement of collection of funds sufficient to finance the default option immediately" (CAPLA Round 2 Evidence, at p. 17).

The second CAPLA position to which Enbridge wishes to reply at this time concerns landowner participation in the "governance" of funds collected in respect of future abandonment costs (see CAPLA Round 2 Evidence, at p. 19).

There are other positions that CAPLA has advanced with which Enbridge disagrees. However, Enbridge has determined that it is not necessary to reply to those positions in this Reply Written Evidence.

Q3. What is the Enbridge reply to the CAPLA positions respecting the immediate commencement of the collection of abandonment funds?

A3. As explained beginning at page 7 of the Written Evidence of Enbridge Pipelines Inc. ("Enbridge Evidence"), Enbridge is of the view that collection of funds for the payment of future abandonment costs should commence when a reasonably accurate estimate of future abandonment costs can be made. Further, if the expected economic life of a pipeline were to be of such a length that the time of abandonment is not yet reasonably foreseeable then the NEB could authorize a deferral of funds collection in respect of that facility. The NEB could establish the time horizon based on a consideration and balancing of various factors including those enumerated in the responses to NEB-Enbridge-1.8 (c) and (d).

Q4. Are there ways in which the Board could evaluate alternative funding horizons?

A4. Yes. Enbridge requested Wright Mansell Research Ltd. ("WMR") to undertake an analysis to evaluate the issue of the appropriate time horizon for accumulating funds to cover the costs of facility abandonment.

WMR has prepared a report of its study entitled "Evaluation of Alternative Funding Horizons for Facility Abandonment" ("WMR Report"). A copy of the WMR Report is attached as Appendix "A" to this Reply Written Evidence.

Q5. For what purpose does Enbridge recommend that the NEB consider the WMR Report?

A5. The WMR Report provides a framework and analysis that would be of assistance to the Board in evaluating various funding horizons against a series of regulatory criteria such as rate stability, fairness and equity, and the encouragement of efficiency. This will, in turn, inform the discussion in this proceeding concerning the issues of appropriate collection commencement date and fund accumulation period.

Q6. What is the Enbridge reply to the CAPLA position respecting landowner participation in fund "governance"?

A6. Enbridge does not consider landowner participation in fund "governance" to be necessary. In some circumstances, it would also be inappropriate.

Q7. Why would landowner participation in fund "governance" be unnecessary?

A7. CAPLA asserts that landowners must have a direct role in fund governance because landowners bear the risk of potential liability and costs resulting from under collection, the selection of inappropriate technical options, or the improper implementation of those options (see CAPLA Round 2 Evidence, at page 19).

Enbridge disagrees for two principal reasons.

First, as discussed in the Enbridge Evidence, landowners will not be responsible for abandonment of pipeline facilities nor for the associated costs.

Second, the NEB will select the appropriate "technical option" for abandoning any particular pipeline facility and the pipeline company will then be required to satisfy the Board that both its abandonment plan and its ability to execute that plan are acceptable having regard to the prevailing facts and circumstances and all applicable statutes, regulations and regulatory requirements.

Q8. CAPLA takes the position that landowners must participate in the distribution of abandonment funds. Does Enbridge agree?

A8. No. Enbridge has recommended that access to the funds would be gained through an order of the Board or as otherwise permitted by the terms under which the funds/accounts are established (e.g., if the relevant facility were not to be subject to NEB regulation). There would be no need for landowners to participate in the distribution of abandonment funds.

Landowners could, of course, participate in NEB abandonment proceedings. In the great majority of cases (i.e., in all but those in which the relevant facility is no longer subject to NEB jurisdiction – say, as a consequence of a sale of the facility) those proceedings would establish the requirements for accessing the abandonment funds. In the few remaining cases, access to the abandonment funds would proceed according to the terms under which the funds/accounts were established. Those terms would themselves be determined by the Board and most probably in proceedings in which landowners could participate.

Q9. Why would landowner participation in fund "governance" be inappropriate?

A9. CAPLA suggests, in the response to NEB-CAPLA-2.1, that one possibility for a direct role for landowners in fund governance would be membership on the boards of directors that oversee the funds. There has also been some discussion in this proceeding about the option of abandonment funds being accumulated in trust funds or accounts. The Qualifying Environmental Trust ("QET") has been cited as one potential model – although it is understood that, under the current legislation, QETs are not available to the pipeline industry. QETs are also not tax efficient – among some other disadvantages.

Of particular relevance in the present context is the fact that, in order for a trust to meet the requirements of a QET, it can have no trustees other than the federal or provincial Crown or a Canadian trust company. It is reasonable to expect similar requirements to be imposed in respect of any trust vehicle for the collection of pipeline abandonment funds that would be afforded the desired income tax status. Landowner participation in the governance of any such trust fund would not only be inappropriate but likely also prohibited by statute.

Q10. Does that conclude this Reply Written Evidence?

A10. Yes.

APPENDIX "A"
TO
REPLY WRITTEN EVIDENCE
OF
ENBRIDGE PIPELINES INC.

Evaluation of Alternative Funding Horizons For Facility Abandonment

Prepared For:

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By:

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December 17, 2008

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Executive Summary

In its submission re: NEB Hearing Order RH-2-2008, Enbridge Pipelines Inc (Enbridge) proposed that:

- Funds to cover abandonment costs should be accumulated through some separate mechanism such as a toll surcharge;
- Funds should be set aside in a separate account for the specific purpose of funding future abandonment costs; and,
- Each pipeline company should be responsible for abandonment of its facilities and should collect the funds necessary to cover abandonment costs.

In this context, and subsequent to filing its submission, Enbridge asked Wright Mansell Research Ltd. (WMR) to undertake an analysis to evaluate the issue of the appropriate time horizon for accumulating funds to cover the costs of facility abandonment.

1. Objective

- The specific objective in this study is to quantify and evaluate the tradeoffs and considerations for the purpose of informing discussions and decisions on the issue of the appropriate commencement date and fund accumulation period.

2. Methodology

- The probable date of abandonment will vary substantially for different lines and in most cases it cannot be accurately predicted far into the future.

- Further, many key variables such as the expected costs of abandonment cannot be reasonably estimated until decisions are taken regarding the required nature of abandonment. Similarly, there remains uncertainty about the types of funds that will be approved, how they will be taxed and many other such details that will have a bearing on the appropriate time horizon for fund accumulation.

- In light of these unknowns, the approach taken is to develop a 'generic' or 'representative' case and then simulate the implications of alternative approaches under a variety of scenarios to capture the main interrelationships and uncertainties. The results of these simulations are then evaluated using standard regulatory criteria such as rate stability, fairness and equity, and the encouragement of efficiency.

3. Key Assumptions for the Base Case

The generic model employs the following assumptions for the Base Case:

- there is a stable annual revenue requirement of $1 billion;
- the terminal value of the abandonment fund of $1 billion;
- the fund is collected through a fixed percentage toll surcharge;
- the rate of return earned by the fund is 6% before income tax but after a 0.5% fee to cover management costs;
- the income tax rate remains constant at 33.9%, the contributions to the fund and income earned by the fund are taxable and tax deductions at abandonment are fully used;
- the rate of inflation is zero and, as such, revenue requirements, tolls and abandonment costs remain stable over time; and,
- the fund is expended in one year to cover abandonment costs.

4. Simulation Results for the Base Case and Alternative Scenarios

The results for the various cases are compared using a benchmark surcharge equal to 5% of the toll.[1] That is, the calculations show the number of years required to accumulate a given size for the abandonment fund under various conditions or assumptions, including the restriction on the size of the toll surcharge to a level equal to 5% of existing tolls.

The results for the various cases are summarized below.

[1] This benchmark is consistent with generally applied regulatory criteria. However, the results are presented in a manner that allows lower or higher benchmarks to be used.

Number of Years to Accumulate an Abandonment Fund with a 5% Toll Surcharge under Various Assumptions

	Variation from Base Case	Years to Accumulate Fund
Base Case, with $1.0 billion Fund	* no variation; i.e. with assumed base parameters	15
	* with no income taxes	13
	* with no final cost deductibility for income tax	20
	* with lower, 3% rate of return earned by fund contributions	17
	* with higher, 12% rate of return earned by fund contributions	12
	* with Inflation of 2%/yr in size of fund and revenue requirement	15
	* with Inflation of 2%/yr in size of fund but not in revenue requirement	17
Base Case Parameters	* smaller fund of $0.5 billion	9
Base Case Parameters	* larger fund of $1.5 billion	20
Source: Figures in Report, Section 3		

- The main determinant of the time horizon required to accumulate a fund to cover abandonment costs is the size of the fund (which is assumed equal to the size of the abandonment costs) in relation to the annual revenue requirement for the pipeline. Assuming a toll surcharge of 5%, this time horizon varies between 9 years in the case of a $0.5 billion fund (equal to one half of the annual revenue requirement) to 20 years in the case of a $1.5 billion fund (equal to 1.5 times the annual revenue requirement).

- In the Base Case where the annual revenue requirement and the terminal value of the fund is $1 billion, the number of years required to accumulate $1 billion with a 5% toll surcharge varies from 13 years if the fund contributions and interest are not taxed, to 15 years if the fund contributions and interest are taxed and the tax deduction at abandonment is fully utilized, to 20 years if the contributions and interest are taxed but the tax deduction at abandonment cannot be utilized.

- The long term average real returns on the funds invested will depend to a large degree on the mix between fixed income and equity instruments in the investment portfolio and on the overall level of risk exposure in both portfolio components. Compared to the Base Case where the real rate is 6% before income tax and the accumulation period is 15 years, a higher real return of 12% reduces this period to 12 years and a lower rate of 3% increases it to 17 years.

- In a situation where the fund earns 3% but an alternative use of that financial capital would provide a risk-adjusted 12% return, there is likely to be a loss of economic benefits. In this example the opportunity cost, using the 5% surcharge as the benchmark, is roughly equivalent to five years of accumulation or about $250 million. Put differently, in cases where there is a large opportunity cost, the net economic cost of extending the accumulation period could be quite significant.

- It is shown that the required accumulation period is largely unaffected by inflation if the revenue requirement (and tolls) and the abandonment costs are similarly affected by inflation. If only the abandonment costs increase over time the effect is to lengthen the required accumulation period by 2 years in the case of a 2% per year inflation of abandonment costs.

5. Qualifications

- There are substantial variations across pipelines in terms of these and other variables. The required accumulation period to meet any given

abandonment costs will vary across systems and will depend to a significant degree on the particular circumstances of each system.

- The results presented above and the discussion based on those results should be interpreted as indicative for the purpose of evaluating options rather than definitive for the purpose of designing a specific approach applicable to all pipelines.

- It is unreasonable to expect that abandonment costs and abandonment date could be known three or more decades in advance. The results presented here are based on an assumption that the date and costs would be determined 10-20 years in advance. This is an appropriate assumption given the analytical objectives in this report and what would appear to be a reasonable ability in practice to foresee changes in the economic life of a pipeline. However, it must be recognized that the analysis here abstracts from the very real issues arising from the fact that at present in most cases these future costs and abandonment dates are highly uncertain.

6. Evaluation

Rate Stability

- The benchmark used in comparing the various cases amounts to a 5% increase in tolls. This amount would not likely be considered ‘rate shock’ under most circumstances.

- Because the percentage surcharge is constant over time, it would not significantly increase or decrease the underlying stability of tolls. A surcharge at this level would not, by itself, seem likely to change the overall toll (that is, the base toll plus surcharge) sufficiently to cause dramatic changes in demand of the type associated with a ‘death spiral’.

- It would not seem that the introduction of a 5% increase in tolls would demand a lengthy transition period since required adjustments by shippers are unlikely to be major.

- For the generic case, an accumulation period of about 15 years is required, with an approximate range of +or- 5 years, depending on assumptions. So long as the abandonment fund could be put in place between 10 and 20 years in advance of abandonment and given the assumptions underpinning the analysis, the orderly accumulation of abandonment funds while maintaining rate stability would be possible.

- If the accumulation period in advance of abandonment was significantly shortened the toll impact would be considerably larger and it may not be as clear that the criterion of rate stability would be met.

- If it was determined by the regulator that the maximum surcharge had to be significantly less than 5% to meet other objectives, a longer accumulation period in advance of ultimate abandonment would be required. For example in the Base Case, if this maximum surcharge was set at 2.5% then the accumulation period would have to be increased from 15 years to 25 years.

Fairness and Equity

- The principle of 'no acquired rights' would suggest that any surcharge for abandonment should be applied across all users of a particular component of the system rather than being 'vintaged' (that is, differentially applied to shippers based on whether they used the system on a particular date, over a particular period or for a particular market).

- The principle of 'cost causality' would seem to be met under a case such as the generic Base Case that has been modelled. The argument would be that abandonment costs, once their size and timing are identified, are part of the life cycle costs for any system and, conceptually, are really no different from any other known capital expenditures on the system. As such, these abandonment costs should be reflected in tolls just as in the case of depreciation or other capital recovery costs.

- A system-specific surcharge of the type modelled in this study would be consistent with the principle of 'equal tolls for equal service'.

- In the context of intergenerational equity or fairness, front-end loaded tolls may mean that early shippers pay too much and the later shippers pay too little. However, the relevant issue is whether the imposition of an abandonment cost surcharge of the type modelled in this study would increase or decrease intergenerational equity relative to what it would be in the absence of such a surcharge or compared to a different surcharge. It is concluded that it is unlikely to increase or decrease any underlying intergenerational equity embodied in existing toll structures.

Efficiency

- The efficiency or overall optimality issue is similar in broad terms to that concerning the determination of the optimal depreciation pattern. Using this as a guide, a case for higher abandonment surcharges in earlier years (front-end loading) would require some combination of: expectations that unit transmission costs will decline over time; the threat of new entrants with lower costs; expectations of declining throughput due to decreasing supply or declining markets; and, expectations that abandonment costs will escalate over time relative to pipeline revenues. The case for higher abandonment surcharges in later years (back-end loading) would require, among other things, the expectation that future oil and gas prices will be higher and throughputs of product can be maintained at high levels for most of the remaining life of the facilities.

- While there may be specific cases where a front-end or back-end loaded surcharge may be justified, it would seem that in most circumstances a constant percentage surcharge would be most consistent with the results in the literature on optimal toll patterns.

- The imposition of a fixed percentage surcharge that remains constant over time would not significantly alter the toll pattern for a pipeline. As such it would not make an existing toll structure more or less efficient than it already was.

- Any pipelines where the imposition of an abandonment surcharge would be imminent under the Enbridge proposal would be quite mature. As such any high front-end load in their initial years would be long past and, except for rate changes associated with periodic expansion, the tolls would be fairly stable over time as most of the original investment would have already been recovered.

1. INTRODUCTION

1.1 Background

Under Hearing Order RH-2-2008, LMCI Stream 3: Pipeline Abandonment, the National Energy Board (NEB) outlined a series of issues concerning the funding of future abandonment costs for pipeline companies operating under NEB jurisdiction.[2] These concern whether or not pipeline companies should be required to set aside funds to cover future abandonment costs, the estimation of these costs, when the collection of funds should commence if companies are required to set aside funds, how the funds should be collected and set aside, the governance of any such funds, and the best way to manage risks and uncertainties with respect to future abandonment costs and revenues.

In response to the Hearing Order, Enbridge Pipelines Inc. (Enbridge) filed written evidence[3] which outlined an approach to these issues. It recommended that, among other things:

> "…the NEB should require all pipelines that it regulates to begin, at an appropriate time, collecting funds from their shippers that will be used to finance future abandonment costs".[4]

Further, Enbridge suggested that:

> "Collection of funds should commence when a reasonably accurate estimate of future abandonment costs can be made."

and that:

> "If the expected economic life of a pipeline were to be of such a length that the time of abandonment is not yet reasonably foreseeable then the NEB could authorize a deferral of funds collection in respect of that

[2] See National Energy Board, *Hearing Order RH-2-2008 regarding LMCI Stream 3 Pipeline Abandonment – Financial Issues,* Proposed List of Issues, Appendix I. For background see: National Energy Board, *Background Paper on Negative Salvage Value,* September 1985 and National Energy Board, *Land Matters Consultation Initiative Stream 3: Financial Issues Related to Pipeline Abandonment, Discussion Paper,* March 2008.
[3] *Written Evidence of Enbridge Pipelines Inc.*, September 5, 2008 re: Land Matters Consultation Initiative Stream 3, RH-2-2008, Pipeline Abandonment-Financial Issues, File ADV-PE-LandMC 02.
[4] A1 of *Written Evidence of Enbridge Pipelines Inc., September 5, 2008.*

> facility. Deferred fund collection would be available if the Board were to be satisfied, on the balance of probabilities, that the expected economic life of a specific facility is of such duration that the time of abandonment is not reasonably foreseeable."[5]

Enbridge has also suggested that:

- funds should be recovered through a separate mechanism such as a surcharge on tolls;
- funds should be set aside in a separate account for the specific purpose of funding future abandonment costs; and,
- each pipeline company should be responsible for abandonment of its facilities and should collect the funds necessary to cover abandonment costs.[6]

In response to a NEB IR, Enbridge has outlined the factors which should be considered in determining when abandonment is reasonably foreseeable and when collection of funds should therefore be initiated. Specifically:

> "Collecting abandonment costs over a longer period can mitigate some of the risk of intergenerational equity because earlier generations of shippers are required to pay a share of the abandonment costs. This factor militates in favour of a longer time horizon of foreseeability and thus a longer collection period.
>
> Conversely, it must be recognized that over-collection from early shippers would also be inequitable. For example, commencing collection before abandonment is reasonably foreseeable is more likely to make the estimates of abandonment timing and abandonment costs even more speculative and thus less reliable as a basis for tolls. This creates a risk of over-collection from shippers and militates against requiring the collection of abandonment costs to commence in the shorter term.
>
> An unnecessarily long collection period also imposes a higher administrative burden both in absolute terms and relative to the amount

[5] A3 of *Written Evidence of Enbridge Pipelines Inc., September 5, 2008.*
[6] A4a, A5a and A5b of *Written Evidence of Enbridge Pipelines Inc., September 5, 2008.*

of the funds collected – particularly in early years. The practical result can be greater costs with little or no corresponding economic benefit.

Finally, the collection and setting aside of abandonment funds creates an opportunity cost vis-à-vis other, potentially more productive, uses for the capital. An unnecessarily long collection period exacerbates that opportunity cost.

Deferral of fund collection in appropriate circumstances can mitigate these risks and, conversely, should not increase the risk of under-collection (or of a "death spiral") due to the expected length of the period of reasonable foreseeability.

Deferral of fund collection is unlikely to impact competitiveness since the expected economic lives of competing pipelines (i.e., those that are providing capacity from the same producing regions to similar markets) can be expected to be of a similar length (such that their abandonment fund collection would begin more or less contemporaneously)." [7]

1.2 Study Objective

As indicated in the foregoing there are numerous tradeoffs and considerations that must be taken into account in deciding the appropriate commencement date and term for the development of funds to cover facility abandonment costs. Before a well-considered decision can be made it will be important to have a better understanding of the size and nature of these tradeoffs.

In this context, Enbridge asked Wright Mansell Research Ltd. (WMR) to undertake an analysis to evaluate the issue of the appropriate time horizon for accumulating funds to cover the costs of facility abandonment.

The main objective in this study is to quantify and evaluate these tradeoffs and considerations for the purpose of informing discussions and decisions on the issue of appropriate commencement date and fund accumulation period.

[7] *Enbridge Responses to NEB IR No.1, pp. 8-9.*

1.3 Approach

The economic life of individual pipelines is highly variable and subject to the particular supply source and market circumstances. However, the economic life of most mainline transmission systems of the type regulated by the NEB is typically very long and the point when they are no longer economically viable is highly uncertain. The economic life of most such facilities in Canada has steadily increased for a number of reasons. These include:

- the increase over time in estimates of conventional oil and gas reserves as more information has been accumulated, as technology has advanced and real energy prices have risen

- the development and growth of unconventional gas and oil resources

- shifts in supply sources for various domestic and export markets which, for example, have provided opportunities to reverse and reconfigure pipelines to serve different markets or transport different commodities or products

- anticipation of new supply sources such as offshore and northern oil and gas or imported supplies of LNG and condensates

The expectation of higher future energy prices and strong market demands for Canadian oil and gas translates into the expectation of further extensions of the economic life of many, if not most, NEB-regulated pipelines.

However, it remains that the probable date of abandonment will vary substantially for different pipelines and in most cases cannot be accurately predicted many decades in advance. Further, key variables such as the expected costs of abandonment cannot be reasonably estimated until decisions are taken regarding the required nature of abandonment. Similarly, there remains uncertainty about the types of funds that will be approved, how they will be managed and many other such details that will have a bearing on the appropriate time horizon for fund accumulation.

In light of these unknowns, the approach taken in this study is to develop a 'generic' or 'representative' case and then simulate the implications of alternative approaches under a variety of scenarios to capture the main uncertainties. The results of these simulations are then evaluated using standard regulatory criteria such as rate stability, fairness and equity, the encouragement of efficiency and revenue sufficiency.

2. METHODOLOGY

2.1 A Generic Model of a Representative Pipeline

A representative pipeline has been defined and modeled under various scenarios to capture the impact of different time horizons and differences in key assumptions and parameters. For analytical purposes, and for showing graphical results, the horizons considered range from 5 to 40 years. In each case it is assumed that a toll surcharge is imposed to accumulate varying amounts in a fund to cover abandonment costs. The latter is related to the capital invested and the nature of required abandonment. The analysis assumes a generic fund. The particulars of the fund arrangement (for example, whether it is to be a segregated corporate fund or a trust fund) are not specified but key differences related to such things as differences in tax treatment are reflected in the analysis.

The scenarios also capture differing assumptions with regard to the tax treatment of fund contributions and abandonment expenditures and with regard to differing rates of inflation and returns on capital and fund investments. The results from the analysis indicate the nature and extent of the interdependencies: for example, between the size of the surcharge required under each time horizon, the magnitude of the abandonment costs and the tax treatment of contributions to the fund.

2.2 Parameters of a Generic Model

Based on existing and proposed pipelines, it appears that, as a rule of thumb, a typical annual revenue requirement for an operating pipeline might be about 1/5 of the net value of assets in place. In other words, a pipeline with net assets of $5 billion might operate with an annual revenue requirement of around $1 billion. The assumption used in the Base Case is that the abandonment cost is equal to the annual revenue requirement.

For purposes of analysis a Base Case is employed which has a stable annual revenue requirement of $1 billion[8] and which calls for a $1 billion abandonment fund.

[8] Enbridge 2007 Annual Report, pages 37 and 105 show total revenues for all liquids pipelines of $1.09 billion, and the 2007 annual revenue requirement for the incentive tolled mainline was $743 million.

The Base Case incorporates a zero rate of inflation, meaning that, for example, there is no difference between real and nominal dollar amounts, or rates of return. As shown later, in most cases the incorporation of modest rates of inflation (say, having revenues and abandonment costs increase at 2% per year, with a difference between real and nominal rates of return of approximately 2%[9]) does not lead to significantly different results for the accumulation horizon.

The model and analysis concentrates on the essence of the problem rather than on the many detailed, real and practical problems surrounding the establishment and operation of a pipeline abandonment fund or funds. It assumes that a fund is established for each pipeline company, that a toll surcharge is introduced and not varied over time, and that the size of the required fund is known and not varied over time.

These are simplifications to allow the determination and highlighting of the fundamental factors affecting the funding horizon for abandonment costs. In reality, parts of a pipeline system will be expanding, parts will be in decline and other parts may be stable. As may be expected for most large pipeline operations, the abandonment of assets is piecemeal and incremental. In addition it might be expected that there would be periodic revisions and adjustments of any surcharges for abandonment costs, as information becomes more complete and circumstances change. Abandonment expenditures are also likely to be spread out over several years whereas the modelling in this report assumes that the fund is spent in a single year.

Bearing in mind the limitations of a generic model, the analytical results will reasonably show the relative scope of effects on tolls arising from varying factors such as length of time the fund is in place, the earnings of the fund, income taxes, and most important the size of the required abandonment fund.

[9] If r is the real interest rate, i is the nominal interest rate and e is the expected rate of inflation, then the exact relationship is $i = r + e + r.e$. For example, if r=.06 and e=.02, the nominal interest rate would be 8.12. It can be seen that for relatively low rates of inflation using $i = r + e$ provides a good approximation for the difference between nominal and real rates of interest or return.

3. SIMULATION RESULTS

3.1 The Base Case

The parameters of the Base Case are as follows:

- there is a stable annual revenue requirement of $1 billion;
- the terminal value of the abandonment fund of $1 billion;
- the fund is collected through a fixed percentage toll surcharge;
- the rate of return earned by the fund is 6% before income tax but after a 0.5% fee to cover management costs;
- the income tax rate remains constant at 33.9%, the contributions to the fund and the income earned by the fund are taxable and the tax deductions at abandonment are fully used;
- the rate of inflation is zero and, as such, revenue requirements, tolls and abandonment costs remain stable over time; and,
- the fund is expended in one year to cover abandonment costs.

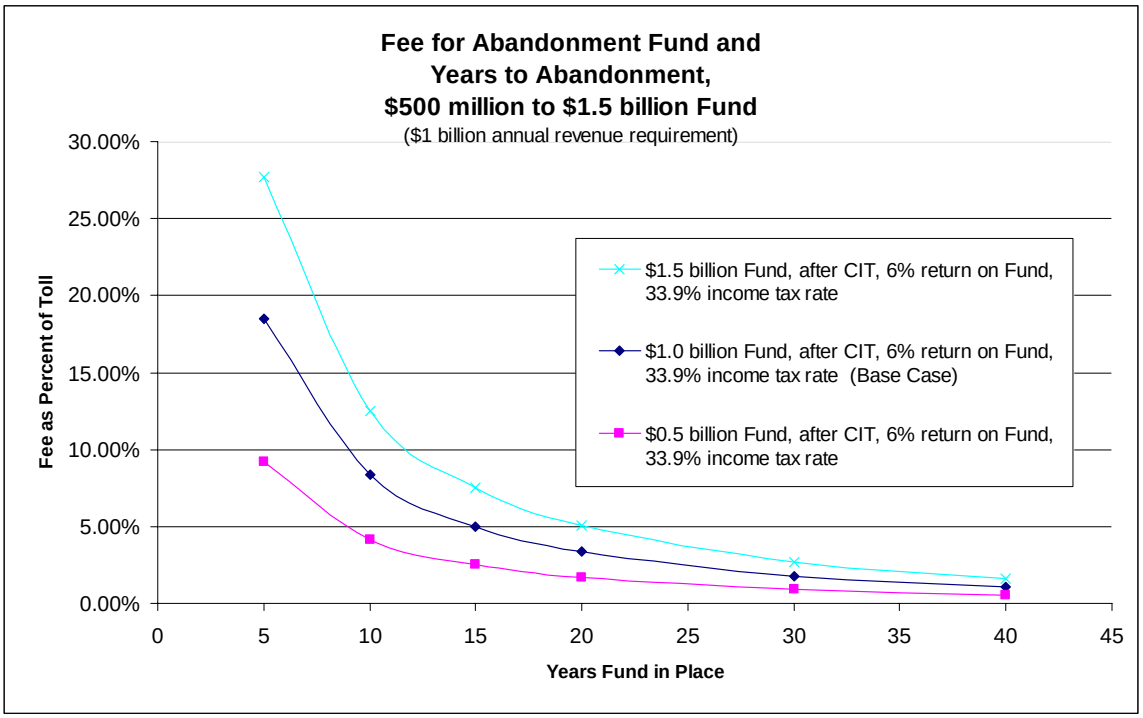
3.2 The Effect of the Size of the Abandonment Fund

Given the parameters, the cash flow modelling solves for the number of years over which the fund has to be collected and the consequent percentage impact on the toll over that period, as shown in Figure 3.1. For purposes of making comparisons, a toll impact of 5% is used as a benchmark in evaluating the results.

At the level of the 5% toll impact it can be seen that shifting from a $1 billion fund to a $1.5 billion fund means the fund would have to be collected over 20 years rather than 15 years if the toll impact is to be kept under 5%. A smaller fund of $0.5 billion requires only about 9 years in place under this same 5% toll impact restriction.

It is apparent that the size of the abandonment fund relative to the annual revenue requirement is critical in determining the years over which the surcharge must be collected in order to avoid a toll impact of more than 5%.

Figure 3.1: Impact of Size of Abandonment Fund on Tolls under Varying Accumulation Periods



This relationship is additionally of interest because a fund the same size as the annual revenue requirement, as in the Base Case where it is $1 billion, requires an accumulation period of around 15 years in order to avoid a toll impact greater than 5%. This provides a useful metric because, given the other parameters in the calculation, a general result is that if the fund (before tax) is the same as the annual revenue requirement then the results in terms of life span and toll impact are the same for any twinning of fund and revenue requirement. For example, they would be the same for a case where the annual revenue requirement and the abandonment fund were both equal to $500 million or where they were both equal to, say, $2 billion.

This also means, given the other parameters, that a fund larger than the annual revenue requirement needs to be in place more than 15 years given the assumed maximum 5% toll impact and conversely a fund smaller than the revenue requirement needs to be in place less than 15 years.

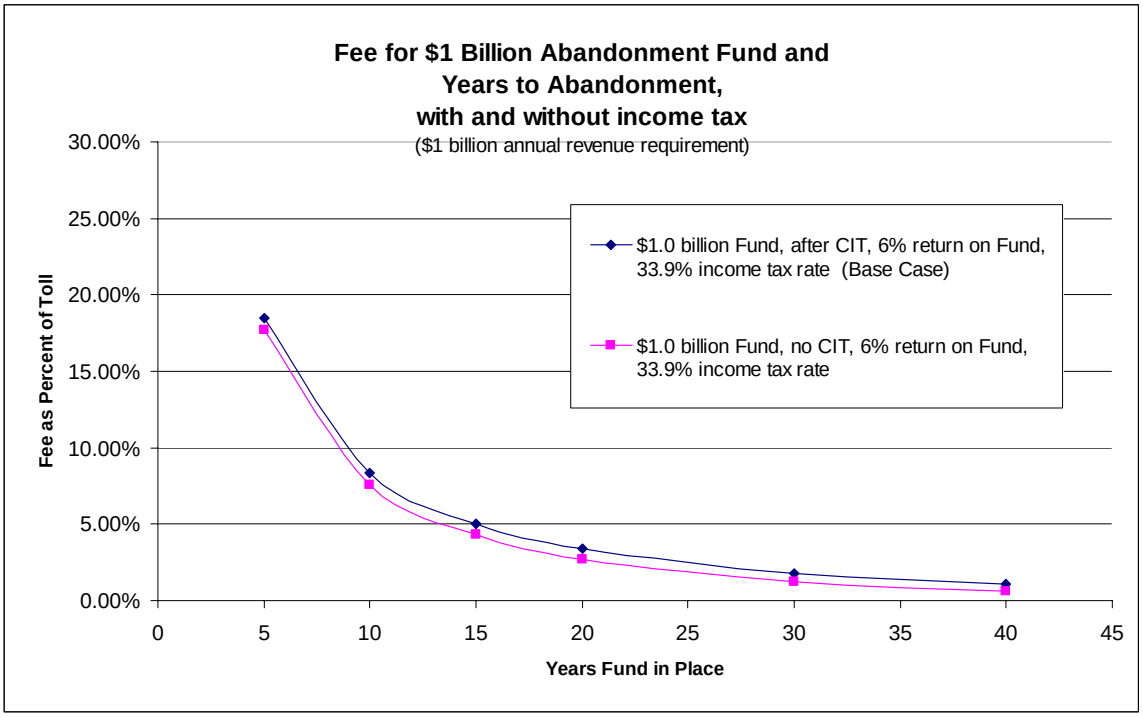
3.3 The Effect of Tax Treatment

The Base Case incorporates an average (combined) corporate tax rate of 33.9%. Taxes are assumed to be paid by the pipeline company on the contributions to the fund, on the earnings of the fund and then a taxable income deduction is realized when the final expenditures are made.

It may be possible to set up an abandonment fund in such a way that the contributions and earnings would not be subject to corporate income tax.[10] The effect would be to slightly shorten the period of time the fund would have to be in place to accumulate to $1 billion.

As indicated in Figure 3.2, if no income taxes were applicable to the fund,

Figure 3.2: Impact of Tax Treatment on Tolls under Varying Accumulation Periods



the curve would be changed only slightly from the Base Case which assumes full tax on payments and full tax deductions on abandonment costs. Given the 5% toll impact benchmark, the collection term for a $1 billion fund shifts

[10] This may require legislation to change federal and provincial tax provisions.

from 15 years in the Base Case to 13 years in the case where the fund is not subject to corporate income taxes.

In other words, the application of income taxes, all other things equal and provided that the tax deduction at abandonment can be realized, would make relatively little difference to the number of years the fund would have to be in place to avoid a toll impact of greater than 5%.

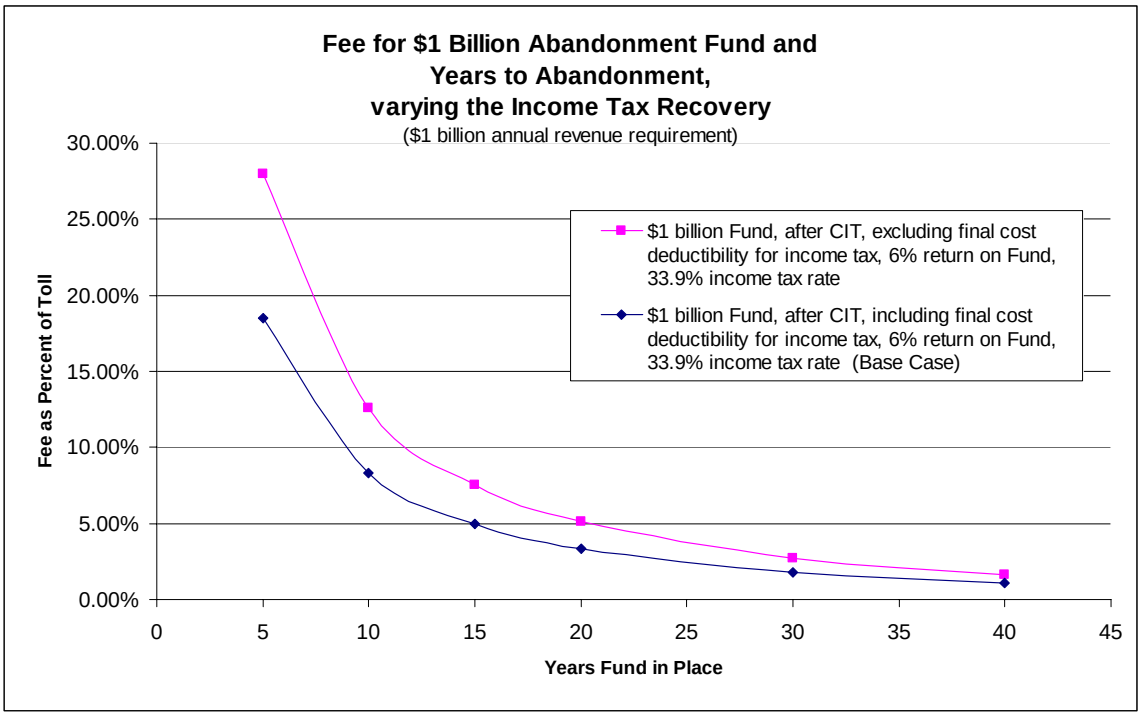
A key consideration in regard to the impact of income taxes on accumulation periods is whether the expenditures for abandonment can actually be used for reduction of income taxes at the time of abandonment. While there are carry back provisions in the Income Tax Act, these may not be sufficient to allow for full recovery of expenditure credits.

In the Base Case, income tax is paid on the contributions to the fund and on the earnings of the fund and then a tax deduction is realized when the final expenditures are made. In the alternative case shown in Figure 3.3, it is assumed that the tax deduction on the final expenditures cannot be fully used.

The results show that the effect of not being able to use the final income tax deduction pushes the curve to the right. At the level of a 5% toll impact, the years the fund needs to be in place increases by about 5 years; i.e. from 15 years to 20 years.

It is useful to note that a combination of changes (not shown in the graph) of not being able to realize the final income tax deduction and obtaining a lower earnings yield on the fund (that is, a yield of 3% vs. 6%) pushes the number of years the fund needs to be in place up to 25 years.

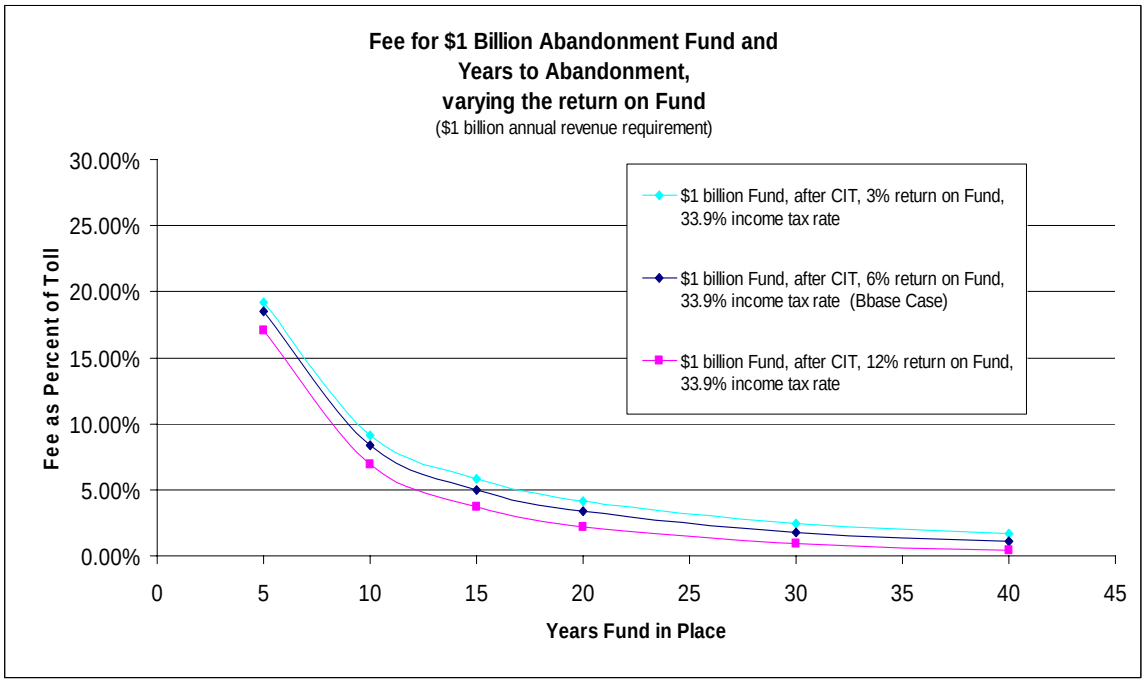
Figure 3.3: Impact of Tax Recovery at Abandonment on Tolls under Varying Accumulation Periods



3.4 The Effect of Variations in the Return on Financial Investments

To test the impact of changes in financial rates of return, this case examines the effect of rates higher and lower than the 6% assumed in the base case. That is, one case is where the rate of return earned on contributions to the fund is increased to 12% (before income tax but net of management costs) and the other is the case where the rate of return is decreased to 3%. The results are shown in Figure 3.4.

Figure 3.4: Impact of Changes in Fund Rate of Return on Tolls under Varying Accumulation Periods



The variations in the return on the fund make less difference to the required accumulation period than might be expected. This follows from the fact that the change in return earned by the fund necessarily has a rather small effect in the early years as the fund is being built up through annual contributions.

At the 5% toll impact level, if the return earned by the fund increases from 6% to 12% then the years the fund needs to be in place decreases 3 years, from 15 to 12 years. A reduction of the fund's earnings to 3% increases the contribution period for the fund by about 2 years.

This case can also indicate the implications of higher opportunity costs associated with the accumulated funds. Supposing the fund is restricted to investments in low risk, fixed income instruments, while the funds used to pay the surcharge would otherwise earn a higher return comparable to hurdle rates used for private sector investments. In such a situation where the fund might earn 3% but the alternative use of the funds provides a risk adjusted 12% return, the opportunity cost, using the 5% surcharge as the benchmark, is roughly equivalent to five years of accumulation (or about $250 million in the example shown). Put differently, in cases where there is a large

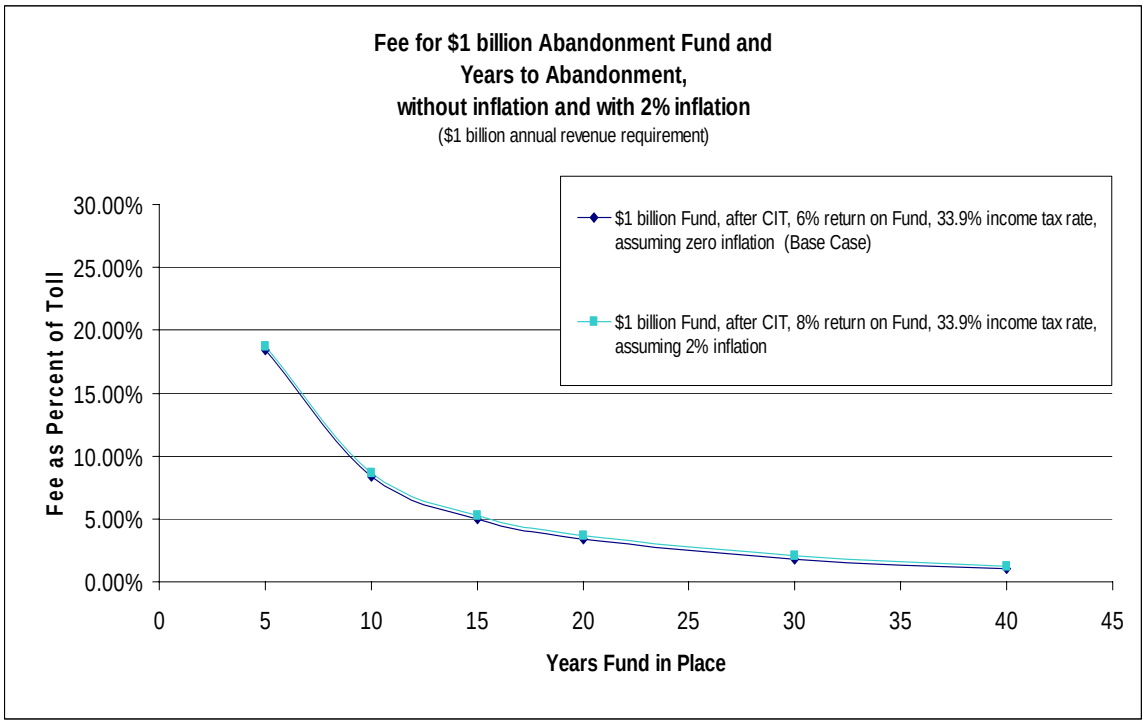
opportunity cost, the net economic cost of extending the accumulation period could be quite significant.

3.5 The Effects of Inflation

In the first case considered to evaluate the effects of inflation it is assumed that both the revenue requirement and abandonment costs escalate at 2% per year, the same rate of inflation assumed for the economy as a whole. Also, with the incorporation of this inflation, the nominal return on investments in the fund is now assumed to be 8% (versus 6% in the Base Case).

The effects of these changes relative to the Base Case are shown in Figure 3.5.

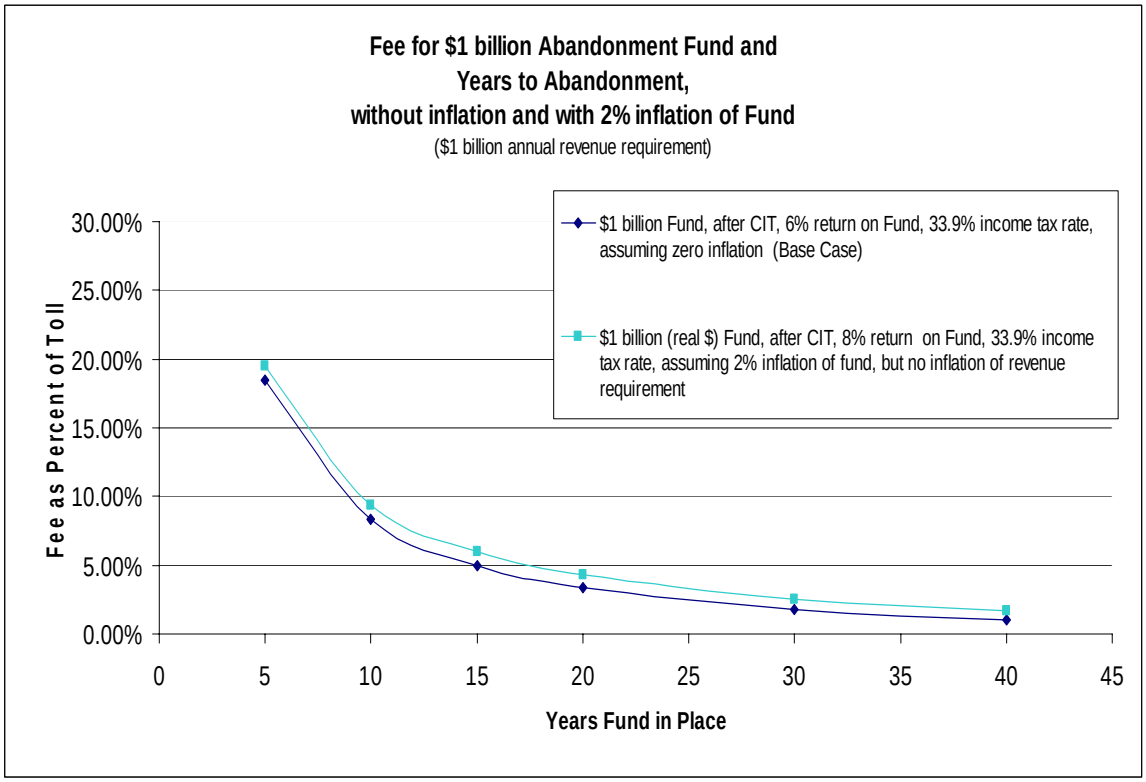
Figure 3.5: Impact of Changes in Inflation Rate on Tolls under Varying Accumulation Periods



As shown, under these assumptions the curves are almost the same and using a more precise nominal rate of 8.12% (rather than the approximation of 8%) would make them even closer.

To consider the effects of inflation a further case is examined where it is assumed that the abandonment costs increase over time at 2% per year while the revenue requirement remains constant in nominal terms (and therefore declines at about 2% per year in real or constant dollar terms). The return on the fund is assumed to be 8%. The results are shown in Figure 3.6.

Figure 3.6: Impact of Differential Inflation Rates on Tolls under Varying Accumulation Periods



In this case, it can be observed that, relative to the Base Case, the accumulation period associated with a 5% toll impact is shifted by about two years or from 15 years to 17 years. In general, increasing the rate of inflation for abandonment costs relative to the rate of increase in the pipeline revenue requirement leads to an increase in the number of years a fund must be in place to meet any particular toll impact constraint. This effect is similar to the effect of increasing the abandonment fund as outlined in Section 3.2.

A corollary to this is that decreasing the revenue requirement over time relative to the abandonment fund will increase the number of years the fund must be in place, at any given toll impact level.

4. EVALUATION OF RESULTS AND CONCLUSIONS

4.1 Summary of Simulation Results

Section 4 is focused on an evaluation of the key issues concerning the length of the collection/accumulation period for an abandonment fund based on the various simulation results already presented and standard regulatory criteria applicable to tolling issues. It is convenient to begin with a summary of the simulation results. This is provided below in Table 4.1.

Table 4.1: Number of Years to Accumulate an Abandonment Fund with a 5% Toll Surcharge under Various Assumptions

	Variation from Base Case	Years to Accumulate Fund
Base Case, with $1.0 billion Fund	* no variation; i.e. with assumed base parameters (footnote11)	15
	* with no income taxes	13
	* with no final cost deductibility for income tax	20
	* with lower, 3% rate of return earned by fund contributions	17
	* with higher, 12% rate of return earned by fund contributions	12
(footnote 12)	* with Inflation of 2%/yr in size of fund and revenue requirement	15
(footnote 13)	* with Inflation of 2%/yr in size of fund but not in revenue requirement	17
Base Case Parameters	* smaller fund of $0.5 billion	9
Base Case Parameters	* larger fund of $1.5 billion	20
Source: Figures in Report, Section 3		

Footnotes: Base Case[11] General Inflation Case[12] Differential Inflation Case[13]

[11] Assumes: annual Revenue Requirement remains constant over time; abandonment fund is the same size as the annual Revenue Requirement; corporate income taxes are applicable to fund contributions and investment income and tax deduction at abandonment is fully realized; and, a 6% real return on the fund.
[12] Assumes revenue requirement and abandonment costs increase at 2% per year and the rate earned on fund investments is 6% real or 8% in nominal terms.
[13] Assumes revenue requirement remains constant in nominal terms (i.e., tolls fall in real terms at the rate of 2% per year) while abandonment costs increase at 2% per year and the rate earned on fund investments is 6% real or 8% in nominal terms.

As indicated, the main determinant of the time horizon required to accumulate a fund to cover abandonment costs is the size of the fund (which is assumed equal to the size of the abandonment costs) in relation to the annual revenue requirement for the pipeline. Assuming a toll surcharge of 5%, this time horizon varies between 9 years in the case of a $0.5 billion fund to 20 years in the case of a $1.5 billion fund.

Further, in the Base Case where the annual revenue requirement and the terminal value of the fund is $1 billion, the number of years required to accumulate $1 billion with a 5% toll surcharge varies from 13 years if the fund contributions and interest are not taxed, to 15 years if the fund contributions and interest are taxed and the tax deduction at abandonment is fully utilized, to 20 years if the contributions and interest are taxed but the tax deduction at abandonment cannot be utilized.

The long term average real returns on the funds invested will depend to a large degree on the mix between fixed income and equity instruments in the investment portfolio and on the overall level of risk exposure in both components. Compared to the Base Case where the real rate is 6% and the accumulation period is 15 years, a higher real return of 12% reduces this period to 12 years and a lower rate of 3% increases it to 17 years.

These results also highlight the importance of the opportunity cost of the fund if it is restricted to low risk, low return investments. For example, if the fund was restricted to investments generating a 3% return while the opportunity cost of funds used to pay the surcharge is a risk-adjusted 12%, the overall opportunity cost translates into about 5 years of contributions to the fund – still using the benchmark of a 5% toll impact. Expressed differently, this opportunity cost amounts to about $250 million in the Base Case. In such situations it is clear that the overall opportunity cost will increase as the contribution period is extended.

Finally, it is shown that the required accumulation period is largely unaffected by inflation if the revenue requirement (and tolls) and the abandonment costs are similarly affected by inflation. If only the abandonment costs increase over time the effect is to lengthen the required accumulation period; for example by 2 years in the case of a 2% per year inflation of abandonment costs.

4.2 Qualifications

The model and these results are believed to reasonably represent the relationships between the required accumulation period under a fixed (5%) toll surcharge and variables such as size of fund, rates of return, tax treatment and so on. However, it must be emphasized that there are substantial variations across pipelines in terms of these and other variables. Consequently, the required accumulation period to meet any given abandonment costs will vary across pipelines and will depend to a significant degree on the particular circumstances of each system.

Given this, the results presented above and the discussion below based on those results should be interpreted as indicative for the purpose of evaluating options rather than definitive for the purpose of designing a specific approach applicable to all pipelines. It must also be emphasized that the results presented here are based on an assumption that the abandonment date and costs are known at least 10-20 years in advance. This is an appropriate assumption given the analytical objectives in this report. However, it must be recognized that the analysis here abstracts from the very real issues arising from the fact that at present in most cases these future costs and abandonment dates are highly uncertain.

Also note that throughout the discussion of the simulation results a benchmark toll impact of 5% has been used to compare accumulation periods under different assumptions. If a lower toll surcharge is used it should be clear that the accumulation period will be extended while a benchmark with a higher toll surcharge would entail shorter accumulation periods. The impacts associated with using a surcharge lower or higher than 5% can be determined from the graphs provided in Section 3.

4.3 Regulatory Criteria

There are a number of standard regulatory criteria typically used in the context of pipeline tolling and related regulatory decisions.[14] These include:

[14] For a summary see R. Mansell and J. Church, *Traditional and Incentive Regulation*, Van Horne Institute, 1995.

- Rate Stability. This is usually taken to mean that rates should be reasonably stable and predictable and that there should not be 'rate shock'. As a rule of thumb, rate shock refers to situations where rates of increase in tolls are in 'double digits.[15] The criterion of rate stability also embodies the notion that there should be a gradual transition to higher tolls if the increase is large to avoid hardships on particular groups with limited ability to adjust in the short run.

- Fairness and Equity. This usually encompasses the requirements that tolls be just and reasonable and that they not constitute 'unjust discrimination'. Such terms embody the notions that tolls should be equal for equal service, that tolls should be based on cost causality, that tolls be consistent with the principle of 'no acquired rights', and that tolls should not unjustly discriminate against any party.[16]

- Encouragement of Efficiency. There are often numerous elements involved under this criterion, including encouraging the producer/shipper to operate at least-cost and to supply volumes at an efficient level, for the consumer to receive product efficiently, and for the pipeline to adopt cost-reducing technologies and introduce new products and services when they can be justified on a cost benefit basis and to supply a quality of service (for example, with respect to reliability) and type of service that is socially optimal in that the benefit of an increment in quality or type of service is equal to the cost of providing that increment. More broadly, and particularly in the context of the long term pattern of pipeline tolls, the intertemporal toll pattern should provide consistent and efficient market signals reflecting optimization by consumers and producers especially with respect to the use and recovery of capital. This issue is discussed below in section 4.4.

- Revenue Sufficiency and Stability. This refers to the requirement that the tolls provide adequate revenues to meet all necessary costs and provide a fair return to pipeline investors, while maintaining

[15] However, the context could be important. For example, a 10% increase in tolls in a situation where tolls have been rising might be viewed quite differently than a 10% increase applied in a situation where tolls have been falling.

[16] Cost causality refers to the principle that tolls should reflect the costs caused by the provision of services to the particular customers. The principle of 'no acquired rights' means that customers do not acquire ownership or other special rights to facilities simply because they have used the services provided by those facilities in the past.

appropriate levels of safety and service. It also concerns the desirability of a reasonably predictable revenue stream.

- Consistency with Other Policies and Regulation. This would include other policies and agreements dealing with trade, taxation and the regulatory environment. For example, in the context of deregulated oil and gas pricing it is important that the tolls provide proper market signals so that such deregulated markets operate efficiently.

- Practicality, Administrative Simplicity and General Acceptance. This means that the toll methodology is well understood, that the methods used to set the tolls should be as logical and straightforward as possible and that the tolls and methodology should be as free as possible from controversy.

In light of the objective of this study, issues such as consistency with other policies and regulation, and issues such as practicality, administrative simplicity and general acceptance, are not examined here. Rather the focus is more on the evaluation of alternative funding horizons in the context of the first three regulatory criteria listed above.

4.4 Optimal Intertemporal Toll Patterns

In the analysis to this point a fixed percentage toll surcharge has been assumed as the benchmark. That is, the increase in the toll as a result of the imposition of a surcharge to accumulate an abandonment fund would be roughly constant over the accumulation period. However, in the case where the surcharge is in place for a relatively long period of time it is reasonable to ask whether it would be better to have a front-end or back-end loading of the surcharge.[17] To address this issue it is helpful to review the literature on optimal toll patterns.

Given the highly capital intensive nature of pipelines, one of the most important determinants of toll patterns over time is the return on and return of capital. The latter is typically based on an estimate of average service life of the facilities and the use of straight line depreciation methodology. This methodology leads to front-end loading where the tolls in the early years are

[17] For example, with a front-end load, the surcharge would be higher in the earlier years and decline over time.

higher than in later years when the facilities are fully depreciated.[18] However, it has been argued in the literature that such a toll pattern may not be efficient and that it would be desirable to smooth out or levelize the tolls, for example, through the use of some other depreciation methodology.

The objective in this section is to highlight some of these arguments because, at least to some extent, they do inform the discussion of the optimal way of recovering funds to cover abandonment costs. The means by which abandonment costs are recovered may be viewed as the mirror image of the issue of recovering initially invested capital.[19]

It was shown by Navarro, Petersen and Stauffer (1981)[20] that fairly standard utility-type ratemaking methodologies in oil pipeline regulation sometimes includes a 'Formula Bias' and often generate an 'Intertemporal Bias'. The former exists if the formula does not actually provide the regulated firm with the stipulated rate of return even when all of the parameters are correctly specified and all expectations are correct. An intertemporal bias refers to time patterns of tolls that do not represent the opportunity cost of the economic resources and therefore the tolls do not provide the correct market signals to investors in regulated projects and to the purchasers of the services these projects provide. These standard utility formulas most often embody strong front-end loading whereas in most cases a more level pattern of tolls over time would be more efficient.

Given that the time pattern of tolls for pipelines is largely determined by the depreciation or capital recovery schedules, most of the research relevant to optimal intertemporal tolls on pipelines has focused on defining optimal depreciation schedules.[21] This work begins with the Invariance Proposition which, simply stated, shows that it is possible to have many different depreciation schedules consistent with ensuring congruence between the Internal Rate of Return for the firm and the allowed or regulated rate of return. The research then derives the optimal depreciation or capital

[18] Of course, with the addition of facilities over time and the use of rolled –in-tolling, this pattern may be modified somewhat.
[19] Recognizing, however, that there are differences, including the fact that an initial capital investment in facilities and minimum economic life is considerably more certain than the abandonment costs and end of economic life of the facilities.
[20] See Navarro, Peter, Bruce Petersen and Thomas Stauffer, *Bell Journal of Economics*, 12, Autumn 1981.
[21] An exception is the earlier work by Baumol, W. and D. Bradford, "Optimal Departures from Marginal Cost Pricing", *American Economic Review*, 60, 1970 which focused on the optimally smoothing the expenditures of consumers/shippers over time.

recovery over time under various conditions involving technological change, changes in demand and costs over time, taxation changes and changes in the regulator's objectives.[22] Within these models it can be shown that there are conditions under which a strong front-end loading of tolls arising from traditional straight line depreciation is optimal and efficient. For example, Crew and Kleindorfer (1992) show that such front-end loading is appropriate when there is significant technological change that lowers the costs for new entrants.[23] Further, it should be noted that in some jurisdictions there may be accounting standards which constrain the ability to deviate very far from front-end loading.[24] Uncertainty, including that involving financial risk, would also lead to incentives for faster rather than slower capital recovery.

These issues aside, the research on optimal depreciation would suggest that under common conditions the optimal depreciation schedule and toll structure would be closer to one that is level or back-end loaded rather than front-end loaded. For example, Burness and Patrick (1992) show that back-end loading is efficient under a broad range of conditions, for example when demands are stable and when quasi rents (the difference between revenues and operating costs) are fairly stable or increasing as a result of technological change or other factors.

It may be argued that the recovery pattern for capital costs at the end of the life of a long-lived asset such as a pipeline should be viewed in a similar light as the recovery pattern of capital costs at the beginning of the life of such an asset. Accepting this argument and drawing on the results regarding optimal capital recovery patterns, it would seem that, a priori, the case for higher abandonment cost surcharges in earlier years would require evidence of one or more of the following: that unit costs will decline over time and there will be new entrants with lower costs; there is a significant probability that throughput will decline substantially over time due to decreasing supply or declining markets; and / or a high probability that abandonment costs will escalate over time relative to pipeline revenues.

[22] See, for example: Rogerson, William, "Optimal Depreciation Schedules for Regulated Utilities", *Journal of Regulatory Economics*, 4, 1992; Burness, H.S. and R.H. Patrick, "Optimal Depreciation, Payments to Capital and Natural Monopoly Regulation", *Journal of Regulatory Economics*, 4, 1992; Crew, M. and P. Kleindorfer, "Economic Depreciation and the Regulated Firm under Competition and Technological Change", *Journal of Regulatory Economics*, 4, 1992; and, Awerbuch, S., "Depreciation and Profitability Under Rate of Return Regulation", *Journal of Regulatory Economics*, 4, 1992.
[23] A standard example is the case of utilities providing communication services.
[24] For example, in the U.S. the application of Financial Accounting Standards Board rules has required that capital recovery in any given period not be more than that in the previous period.

While there may be specific cases where these conditions hold, in most situations they would not. In the more common cases it is probably easier to make the case for levelized surcharges (that is surcharges that remain constant over time). It may be possible to make a case for back-end loaded surcharges (that is where the surcharge increases over time) but this would require, among other things, the expectation that future oil and gas prices will be higher and throughputs of product (which might be different than the product the lines were originally designed for) can be maintained at high levels for most of the remaining life of the facilities.

In summary, while there may be specific cases where a front-end or back-end loaded surcharge may be justified, it would seem that in most circumstances a constant percentage surcharge would be most consistent with the results in the literature on optimal toll patterns.

4.5 Evaluation of Results Using Regulatory Criteria

The objective in this section is to evaluate the simulation results in the context of standard regulatory criteria, with a focus on those concerning rate stability, fairness and equity and overall efficiency.

Rate Stability

The benchmark used in comparing the various cases summarized in Table 4.1 involved the imposition of a surcharge equal to 5% of the toll and the maintenance of that 5% surcharge over time. The effect would therefore be to raise overall toll levels by 5%. This amount would not likely be considered ‘rate shock’ under most circumstances (given that it is well under the common ‘two digit’ criterion). Further, because the surcharge is constant over time, it should not significantly increase or decrease the underlying stability of tolls. To put it differently, a surcharge at this level would not, by itself, be sufficient to cause dramatic changes in demand for pipeline services of the type associated with a ‘death spiral’. In addition, it would not seem that the introduction of a 5% increase would require a lengthy transition period because major adjustments by shippers are unlikely.

As illustrated by the simulation results for the generic case used in this study, an accumulation period of about 15 years is required, with an

approximate range of + or - 5 years, depending on assumptions. In other words, so long as the abandonment fund could be put in place between 10 and 20 years in advance of abandonment and given the assumptions underpinning the analysis, the orderly accumulation of abandonment funds while maintaining rate stability would be possible.

If the accumulation period in advance of abandonment was significantly shortened then, as shown by the graphs in Section 3, the toll impact would be considerably larger and it may not be so clear that the criterion of rate stability would be met. On the other hand, if it was determined by the regulator that the maximum surcharge had to be significantly less than 5% to meet other objectives, a longer accumulation period in advance of ultimate abandonment would be required. For example as shown in Figure 3.1, if this maximum surcharge was set at 2.5% then, for the Base Case with abandonment costs of $1 billion, the accumulation period would have to be increased from 15 years to 25 years.[25] The impacts of other changes, such as larger or smaller abandonment costs, or differences in fund structure and tax treatment, can be read from the graphs in Section 3.

Fairness and Equity

As noted in Section 4.3 above, there are numerous dimensions to this criterion. The principle of 'no acquired rights' would suggest that any surcharge for abandonment should be applied to all users of a particular component of a system rather than being 'vintaged' (that is, differentially applied to shippers based on whether they used the system on a particular date, over a particular period or for a particular market). Put differently, if this principle was not applied and abandonment costs were differentially applied across shippers it is more likely that other regulatory objectives (such as rate stability) would not be met.

The principle of 'cost causality' would seem to be met under a case such as the generic Base Case that has been modelled. The argument would be that abandonment costs, once their size and timing can be determined, are part of the life cycle costs for any system and, conceptually, are really no different from any other known capital expenditures on the system. As such, once the

[25] It must be underlined once again that this result is for a case where the abandonment cost is equal to the assumed constant annual revenue requirement.

abandonment costs are known they should be reflected in tolls just as in the case of depreciation or other capital recovery costs.

Similarly, it would seem that a pipeline-specific surcharge of the type modelled in this study would be consistent with the principle of 'equal tolls for equal service'. In other words, all users of a facility facing an expected abandonment in a given number of years would pay the same toll, all other things equal. To the extent that there are significant differences in the expected remaining life of competing systems and one system is subject to abandonment tolls but the other is not, one could argue that both provide similar service. However, this is the same as the differences in tolls across competing systems arising from such things as the percentage of the original capital investment that has already been depreciated / recovered. The same argument would apply in the case where there is competition among systems serving similar supply and market areas. Under existing tolling structures, a system that is more fully depreciated may have a toll advantage. The earlier imposition of a surcharge on such a system in the event that the end of its economic life becomes reasonably foreseeable, may reduce that competitive advantage.

Although it is not well defined, the notion of intergenerational equity or fairness is sometimes raised in the context of tolling decisions. The front-end loaded tolls may mean that the early shippers pay too much and the later shippers pay too little. Whether or not such an argument carries weight will depend, among other things, on there being significant shifts over time in the makeup of shippers, being able to determine the true incidence of the tolls at each point in time[26] and being able to suspend the principle of 'no acquired rights'.

However, in any event the relevant issue is whether the imposition of an abandonment cost surcharge of the type modelled in this study would increase or decrease intergenerational equity relative to what it would be in the absence of such a surcharge or compared to a different surcharge. There are several reasons why it is unlikely to increase or decrease any underlying intergenerational equity embodied in existing toll structures. First, unless the accumulation period was substantially shortened from the accumulation periods for the 5% toll impact cases considered in this study, the required

[26] That is, being able to determine to what extent the tolls paid/costs incurred by a shipper were actually passed back to the producer or shifted forward to the consumer.

surcharge would be fairly small in relation to the tolls. Second, the surcharge modelled in this study remains constant over time (as a percentage of the toll) and, as such, does not cause a significant change in the intertemporal toll pattern. Third, while a constant surcharge over time is assumed in this report, it would add complexity but it would be possible to vary that surcharge somewhat if it was deemed that the surcharge should be larger or smaller in the early accumulation period compared to the later accumulation period.

Efficiency

As noted above, the imposition of a percentage surcharge that remains constant over time would not significantly alter the toll pattern for a pipeline. As such it would not make an existing toll structure more or less efficient than it already was.

Following the discussion in Section 4.4, the efficiency or overall optimality issue is similar in broad terms to that concerning the determination of the optimal depreciation pattern. In this context, however, it should be noted that any pipelines where the imposition of an abandonment surcharge would be imminent under the Enbridge proposal would be quite mature. That is, any high front-end load in the initial years would be long past and, except for rate changes associated with periodic expansion, the tolls would be fairly stable over time as most of the original investment would have already been recovered.

Further, as noted in the previous section, there could be specific circumstances for a particular pipeline that would support arguments for a front or back-end load to the abandonment surcharge. However, on balance, in most circumstances a constant percentage surcharge would be most consistent with the requirements for overall efficiency.

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SENT BY ELECTRONIC MAIL

Ms. Claudine Dutil-Berry
Secretary
National Energy Board
444 - 7th Avenue S.W.
Calgary, AB T2P 0X8

Dear Ms. Dutil-Berry:

Hearing Order RH-2-2008
LMCI Stream 3 Pipeline Abandonment - Financial Issues

We act as legal counsel for Foothills Pipe Lines Ltd., NOVA Gas Transmission Ltd., TransCanada Keystone Pipeline GP Ltd. and TransCanada Pipelines Limited ("TransCanada"). As per the National Energy Board's letter dated April 21, 2008, please find enclosed the Initial Written Evidence of TransCanada concerning the above noted matter. If you have any questions or concerns please do not hesitate to contact the undersigned.

Yours truly,

Shawn H.T. Denstedt
SHTD:Sln

Enclosure
c: N. Berge, TransCanada Pipelines Limited

NATIONAL ENERGY BOARD

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

AND IN THE MATTER OF National Energy Board Proceeding RH-2-2008

WRITTEN EVIDENCE OF
TRANSCANADA PIPELINES LIMITED
NOVA GAS TRANSMISSION LTD.
FOOTHILLS PIPE LINES LTD.
TRANSCANADA KEYSTONE PIPELINE GP LTD.

September 5, 2008

1.0 BACKGROUND AND SUMMARY OF EVIDENCE

Q1. Please describe the nature and purpose of TransCanada PipeLines Limited, NOVA Gas Transmission Ltd., Foothills Pipe Lines Ltd. and TransCanada Keystone Pipeline GP Ltd's ("TransCanada") evidence.

A1. TransCanada is submitting this evidence to provide its views on the National Energy Board ("NEB" or "Board") List of Issues provided as Appendix I to the NEB's letter dated April 21, 2008 regarding the financial issues related to pipeline abandonment ("Stream 3 Issues").

TransCanada is the owner and operator of a number of existing natural gas transmission systems regulated by the Board. As well, TransCanada will be the operator of the jointly-owned Keystone oil transmission system, scheduled to go into service at the end of 2009. This evidence was developed from TransCanada's perspective as an owner and operator of multiple pipeline systems.

Stream 3 Issues in Canada are important to TransCanada and the outcome of this proceeding will have a significant impact on TransCanada's Canadian pipeline business.

TransCanada's evidence discusses pertinent factors that TransCanada feels the Board should consider in addressing Stream 3 Issues.

Q2. What are the overarching principles which frame TransCanada's evidence regarding Stream 3 Issues?

A2. The following high-level principles provide the basis for a framework to address the Stream 3 Issues in the current proceeding:

- Abandonment costs are a legitimate cost of providing service and are recoverable upon Board approval from users of the system[1];

- Landowners will not be liable for costs of pipeline abandonment[2];

- Funds to cover the costs associated with the eventual terminal abandonment of pipeline facilities should be collected during the economic life of the pipeline to minimize intergenerational inequities between shippers who contract for service on the pipeline at different points during the economic life of the pipeline;

- Any funds collected by a pipeline to provide for its eventual terminal abandonment should be used for that purpose;

- The framework governing the collection of funds to cover abandonment costs should be consistent among pipelines that transport similar products, including assumptions, scope of the physical abandonment activities, accounting for funds, management of funds, and access to funds;

- The collection of funds to cover terminal abandonment costs should not result in economically inefficient outcomes. That is, such collection should not result in material changes in the competitive position of a pipeline relative to other pipelines it competes with for access to supplies and markets, potentially resulting in inefficient expansions or new construction, and stranded existing capacity; and

- Terminal abandonment should be recognized as a process rather than an event. Abandonment of specific facilities and the associated cost of abandonment will vary between pipelines and can occur during the economic life of a larger system.

[1] NEB letter dated January 17, 2008, page 5.
[2] *Ibid*.

Q3. Please describe the principal issues that TransCanada believes will require further discussion between the participants in this proceeding in order to come to agreement on the framework to address the Stream 3 Issues.

A3. TransCanada's evidence discusses the following issues, which it views as matters necessary for participants and the Board to consider:

- When the collection of funds to cover the costs associated with the eventual terminal abandonment of a pipeline should commence;
- Whether the same fundamental framework governing the collection of funds to cover abandonment costs can be applied to both gas transmission pipelines and oil transmission pipelines;
- How best to ensure the efficient tax treatment of the funds collected to cover the costs of terminal pipeline abandonment;
- Whether the funds should be paid into individual accounts for each of the pipelines, a single account for all pipelines regulated by the Board, or a hybrid of the two approaches;
- The need to distinguish between interim retirement costs and terminal abandonment costs to ensure that pipelines are able to access the abandonment funds to cover legitimate terminal abandonment costs, some of which may be incurred before the end of the economic life of the pipeline; and,
- Whether the pipeline or shippers will bear the risk of fund over/under-collection.

Q4. What outcomes does TransCanada expect from this proceeding?

A4. TransCanada believes that the objective of this proceeding should be to develop a conceptual framework to provide for the funding of costs related to the eventual terminal abandonment of all natural gas, oil and other transmission pipelines regulated by the Board. The conceptual framework would include principles governing how and when the funds would be collected. TransCanada also believes that an outcome of this proceeding should be a direction to begin collection as soon as practical.

Q5. Please provide an overview of TransCanada's assets.

A5. TransCanada's wholly-owned natural gas transmission systems currently regulated by the Board include the following:

- Canadian Mainline: Comprises approximately 15 000 km of pipelines extending from a point just inside the Alberta border through Saskatchewan, Manitoba, Ontario and Québec, with various connections to domestic pipelines and at the international border.

- Foothills System: Comprises approximately 1 240 km of pipelines extending from central Alberta (near Caroline) to the United States border near Monchy, Saskatchewan and Kingsgate, British Columbia.

TransCanada and Gaz Métro Limited Partnership jointly-own a natural gas transmission system, the Trans Québec & Maritimes ("TQM") system, currently regulated by the Board. The TQM system comprises approximately 620 km of pipelines extending from the Québec-Ontario border near St-Lazare to St-Nicolas, near Québec City, and to East Hereford at the Canada-U.S. border.

TransCanada also wholly-owns NOVA Gas Transmission Ltd., which in turn owns and operates the Alberta System, which is currently regulated by the Alberta Utilities Commission. On June 17, 2008, TransCanada applied to the Board for a

Certificate of Public Convenience and Necessity under section 52 of the National Energy Board Act and related approvals for TransCanada's Alberta System. The Alberta System comprises approximately 23 500 km of pipelines located within Alberta and transports natural gas destined for markets within Alberta, within Canada outside Alberta, and in the United States. It connects with the Canadian Mainline at Empress, Alberta and with the Foothills System at Caroline, Crowsnest, and McNeill, Alberta.

TransCanada is currently constructing and will be the operator of the jointly-owned Keystone oil transmission system, which is scheduled to go into service at the end of 2009. The Canadian portion of the Keystone System regulated by the Board will comprise approximately 1 235 km of pipelines and 23 pump stations extending from Hardisty, Alberta to the Canada – U.S. border near Haskett, Manitoba.

As well, TransCanada is currently in the process of applying for the Keystone XL expansion, the Canadian portion of which will comprise of approximately 525 km of pipelines and 8 pump stations extending from Hardisty, Alberta to the Canada-U.S. Border near Monchy, Saskatchewan.

Q6. How is TransCanada's evidence organized?

A6. TransCanada addresses each issue in the Board List of Issues in order and provides recommendations and/or points for the Board to consider.

2.0 NEB ISSUE 1

Q7. What is TransCanada's view on whether the Board should require pipeline companies to set aside funds to cover future abandonment costs?

A7. TransCanada agrees with the following Board statement:

> Two key principles the Board believes are fundamental to its future decisions with respect to the financial matters related to pipeline abandonment are outlined below:
>
> 1. Abandonment costs are a legitimate cost of providing service and are recoverable upon Board approval from users of the system.
>
> 2. Landowners will not be liable for costs of pipeline abandonment.[3]

As such, it would be appropriate for the Board to require pipeline companies to collect and have funds set aside for future terminal abandonment costs at the appropriate time during the course of the economic life of the pipeline.

In its September 1985 paper entitled *Background Paper on Negative Salvage Value*, the Board reviewed U.S. precedents for decisions on requests by utilities to collect the costs associated with terminal abandonment of assets prior to the costs being incurred. The decisions reviewed support the concept of recovering terminal abandonment costs from the current customers who benefit from the use of the assets. In some cases it was held that the magnitude of the decommissioning allowance should increase over time so that inflation will not reduce the burden on future customers at the expense of existing customers.

[3] NEB letter dated January 17, 2008, page 5.

Since terminal abandonment costs are usually based on estimates, periodic reviews and revisions were advocated in the 1985 paper.[4]

TransCanada finds the following criteria that have been considered in U.S. decisions to provide useful guidance in this proceeding:

1. Assurance of availability of funds;
2. Cost borne by ratepayers;
3. Flexibility to adapt to changing costs; and
4. Equity among ratepayers.

Q8. What are the implications of requiring or not requiring pipeline companies to set aside funds to cover future abandonment costs?

A8. The implication of requiring or not requiring pipeline companies to set aside funds is that it may result in economic inefficiency, intergenerational inequity and/or an unfunded liability.

In requiring pipelines to set aside funds to cover future abandonment costs, the Board should consider the possible impact such action could have on the competitive dynamics between pipeline companies to ensure that economically inefficient outcomes are avoided. The abandonment costs could have a material impact on tolls if not properly addressed, and could be a factor in shippers' decisions whether or not to contract for service on certain pipelines. Underutilization of pipeline assets caused by a decreased ability to compete increases the risk of under-collecting the funds required to cover the cost of terminal pipeline abandonment. Further, this could lead to the early abandonment of pipe in favour of expansions on other pipelines or new pipelines, which could be economically inefficient.

[4] page 4.

The individual circumstances facing each pipeline will be different, but the framework governing the funding of abandonment costs should be consistently applied so that differences in the collection of abandonment funds for specific pipelines do not lead to material changes in the competitive positions of pipelines accessing the same supplies and markets to the extent that such changes lead to economically inefficient outcomes.

Intergenerational inequity arises if pipeline companies are not required to begin setting aside funds to cover abandonment costs. Funds to cover the costs associated with the eventual terminal abandonment of a pipeline should be collected sufficiently in advance of abandonment so as not to unfairly burden those shippers who contract for service on the pipeline towards the end of its economic life. In recovering costs through utility rates, a basic regulatory and financial principle is that the customers who benefit from a required service should bear the cost of providing the service, including terminal abandonment costs. There should be a fair allocation of costs among customer generations.

If funds were not set aside for abandonment costs, the pipeline could be left at risk for these costs. If there is no fund and/or no pipeline company left after abandonment, landowners or government could be at risk. Again, this contravenes the principle that customers who benefit from a service should bear the cost of providing the service and the principle that landowners should not be liable for the costs.

Q9. If funds are to be set aside, what mechanisms should be considered and what are the pros and cons of each mechanism?

A9. TransCanada understands “mechanisms” to mean alternative means of collecting and managing the funds required to cover the costs of terminal pipeline abandonment. Any mechanism considered should minimize additional risks to pipelines while ensuring funds collected are appropriately managed and readily accessible when terminal abandonment costs are to be incurred. In addition, the

mechanism should reflect the most efficient and cost effective form of collection and management of funds to minimize costs to shippers.

A principal consideration regarding the collection and management of funds is whether the funds should be paid into individual accounts for each of the pipelines, a single account for all pipelines regulated by the Board, or a hybrid of the two approaches. After weighing the merits of each option, TransCanada supports the collection of funds to be paid into individual accounts for each pipeline. Factors supporting this option include:

- focus and accountability;
- assurance to landowners that specific funds are being set aside;
- consistency with the cost causation principle;
- a simpler means of transferring the funds if there were a change in the jurisdiction of a pipeline (e.g. from federal to provincial jurisdiction);
- avoidance of "the tragedy of the commons" where individual pipelines could under-collect expecting to have access to funds collected by other pipelines;
- elimination of the risk that a disproportionate share of the funds collected would be used to cover the costs of pipelines abandoned earlier to the detriment of those pipelines with longer economic lives; and
- less complex administration.

Q10. If funds are required to be set aside, should all pipeline companies under the Board's jurisdiction be required to set aside these funds?

A10. Yes.

Q11. Are there any other points TransCanada wishes to make with regards to this issue?

A11. Yes. TransCanada believes the Board should also consider the impact of the collection of abandonment costs on the national energy infrastructure. The integrated nature of the North American pipeline network creates a situation whereby the impact of collection on any one pipeline could have an effect on all the pipes connecting the same supply, or delivering into the same market. A pipeline regulated under one jurisdiction could potentially price its capacity out of the market if the collections were too high relative to other pipelines regulated by another provincial or international jurisdiction and not subject to these charges. TransCanada would encourage the Board to work with other regulators to set forth a consistent set of regulations.

3.0 NEB ISSUE 2

Q12. If companies are required to set aside funds, what information and assumptions are necessary to create preliminary estimates for future abandonment costs?

A12. The conclusions from Stream 4 of the Land Matters Consultation Initiative ("LMCI") will allow for a more accurate estimate for future abandonment costs. Costs will largely depend on the scope of the required physical abandonment activities (i.e. abandon in place, removal, or combination thereof), which in turn will be influenced by factors such as environmental regulations and standards, as well as the state of the technology which can be employed to effect the abandonment of pipelines.

In the absence of conclusions from Stream 4 of the LMCI, TransCanada, at this time, believes the following information and assumptions would be necessary to create preliminary cost estimates:

- assumptions on cost escalation;
- assumptions on value of salvaged assets;
- assumptions on the scope of abandonment;
- assumptions on the effects of technology to affect costs of abandonment; and
- a retirement study to determine expected economic life of a pipeline and when facilities will need to be abandoned.

Any resulting abandonment costs will differ from the total amount that will need to be collected. TransCanada, at this time, believes that the following information and assumptions will have an effect on the total amount that will need to be collected:

- assumptions for the interest return on the funds collected;
- assumptions on tax treatment that the funds will receive; and
- assumptions on how pipeline abandonment will occur (immediately after sections of pipelines reach the end of their economic life or all at once at the end)

These are not exhaustive lists and as the issue is better understood and more information becomes available these assumptions may change. Likewise, after more information becomes available through the conclusion of Stream 4, the estimates can be refined for greater accuracy.

4.0 NEB ISSUE 3

Q13. If companies are required to set aside funds, when should the collection of funds commence?

A13. The collection of those costs should commence for all pipelines as soon as practical. However, under the principle that the framework for the collection of the funds should be consistent among pipelines that transport similar products, the magnitude of those collections could differ between groups of pipelines. This could be due to fundamental differences between the groups in terms of types of products transported and factors that govern economic life of facilities (e.g., supply reserves, demand forecasts, competition from alternative fuel sources).

One situation which may also affect the timing for commencement of abandonment funds collection is where pipelines and shippers have agreed to fix the revenue requirements which are to be recovered from shippers for one or more years through a settlement. The Board will have to the approach in cases where a settlement does not address the issue of abandonment cost recovery or instances where the language of the settlement agreement may preclude the adjustment of the revenue requirement to account for such costs.

5.0 NEB ISSUE 4

Q14. If companies are required to set aside funds, how should the funds be set aside?

A14. Please refer to A9.

Q15. Should the funds be collected from shippers through annual payments, or per unit tolls, or set aside through insurance, or should some other method be used?

A15. The funds should be collected so that customers who benefit from the service should also bear the costs associated with that service. This principle leads to a method of collection that should not contribute to intergenerational inequity while providing for the most direct link between the amount of abandonment funds to be collected from specific shippers to the volume of gas transported by those shippers. Based on this, TransCanada proposes a method of collection based on per unit tolls.

Q16. If the funds are collected through tolls of a pipeline company, should they be collected as a component of depreciation or separately?

A16. There are a number of reasons why these funds should not be collected as a component of depreciation. By including the collection amount as part of depreciation expense, it does not provide sufficient transparency in order to properly monitor the expense being charged to customers. Funds collected via depreciation expense could be used to cover interim retirement costs, which may increase the risk of insufficient funds for abandonment. Collecting funds for abandonment costs as part of depreciation expense could also lead to negative rate base well before the pipeline reaches the end of its economic life.

Further, a fund which would be kept separate from the general revenues collected by pipeline companies would provide the necessary transparency and help ensure that adequate funds would be available to cover the costs associated with terminal abandonment of the pipelines. The Board expressed a similar preliminary view in its February 19, 1986 letter:

> Negative salvage should be separated from depreciation as an element of cost of service, and that funds collected on

account of negative salvage should be segregated from general corporate funds.[5]

6.0 NEB ISSUE 5

Q17. If companies are required to set aside funds how should the funds be governed?

A17. The funds should be segregated from general corporate funds to ensure that contributions to the fund will be used for the eventual terminal abandonment of pipelines. Such funds should be auditable by representatives of the regulator, the shippers and the pipeline company so that all stakeholders can ensure that their interests are being protected. However, there are many further details that need to be determined regarding the management of abandonment funds. Further determinations are required on issues such as the tax treatment of the funds and investment governance applied to the funds.

Q18. Should a portion of the funds be pooled for use across industry?

A18. No. Please refer to A9.

Q19. Should the regulated portion of a company be insulated from the non-regulated business with respect to abandonment costs, and if so, how?

A19. As stated in A7, the cost associated with providing for the eventual terminal abandonment of a regulated pipeline is a reasonable cost of providing service to the shippers who contract for transmission service on the pipeline. As such, those costs should not be borne by the shareholders of the company which owns the pipeline and which may also own other assets. This can be facilitated by establishing a fund which is specific to the regulated pipeline and is only

[5] NEB letter dated February 19, 1986 to Pipeline Companies under Board Jurisdiction and Other Interested Parties. File No.: 1100-10.

accessible for the purpose of covering terminal abandonment costs incurred specifically for that pipeline.

Q20. How would a company access the funds?

A20. Funds would be accessed through a Section 74 application under the *National Energy Board Act* (*"NEB Act"*).

Q21. What would be the appropriate time to access funds?

A21. Funds would be accessed following a Section 74 approval.

Q22. Who should control access to the funds?

A22. Please refer to A20.

Q23. What investment restrictions should be placed on the funds collected, if any?

A23. There is no single answer to this question that could serve as a "blanket" policy for all pipelines. The appropriateness of various investment instruments for each individual fund should be determined based on a number of principles.

For that purpose, TransCanada suggests the following principles:

- Minimization of cost burden on each pipeline's shippers through maximization of growth within acceptable risk tolerance of investments within a fund; and
- Optimal governance of funds.

The long history of investment policies of other retirement funds, such as pension plans, could provide guidance in establishing appropriate investment portfolios for pipeline abandonment funds.

Q24. What taxation issues arise from the management of funds and how could they be addressed?

A24. The income tax impact of collecting funds was succinctly explained in the NEB *Background Paper on Negative Salvage Value* (1985) wherein it states:

> Under the current income tax laws, revenues and expenses related to negative salvage would be treated as follows:
>
> 1. Depreciation charges on account of negative salvage, to the extent that they are collected before they are spent, are taxable in the year collected.
> 2. Income earned on funds pre-collected on account of negative salvage is taxable in the year earned.
> 3. Plant removal costs are deductible for income tax purposes in the year(s) those costs are actually incurred.[6]

In the last few years of a pipeline's economic life, the revenues collected and consequent taxable income are expected to be low because of diminishing rate base. In this situation, the abandonment costs would be incurred and would be tax deductible at a time when the company has declining revenues. Therefore, the company may not have sufficient taxable income during the years against which the abandonment costs could be deducted.

TransCanada believes that the Board should request that the Department of Finance put in place an efficient tax treatment such that the funds collected to cover the cost of pipeline abandonment and contributed to a fund should be allowed as a tax deduction in the year contributed. The funds subsequently withdrawn would be included in taxable income in the year withdrawn from the

[6] pages 25-26.

fund. The subsequent inclusion in taxable income would most likely be offset by tax deductions of abandonment costs incurred during the year.

Making such collections tax-deferred would help minimize costs to shippers and avoid unnecessarily tying up capital that could be deployed more productively in the economy. As well, this approach would deal with the possibility that there may be no revenues against which to credit the abandonment costs at the end of the pipeline's economic life.

Q25. What should happen to any funds collected to abandon a pipeline regulated by the NEB which then becomes subject to provincial jurisdiction, either after abandonment or through a transfer to a provincially-regulated company?

A25. The funds should follow the pipeline.

Q26. Should there be surplus funds collected, what should be the final disposition of those funds?

A26. Periodic reviews to update expected terminal abandonment costs, abandonment timing, and to take stock of the realized returns on fund investments would allow for adjustments or true-ups to the funds collected in order to minimize any surpluses or deficits at the time of terminal abandonment. However, should a surplus or deficit exist, given that abandonment costs are operating and not owning costs, the risk/reward associated with under/over-collection of abandonment funds should be for the account of the shippers.

7.0 NEB ISSUE 6

Q27. How best should the risks and uncertainties inherent in determining future abandonment costs and revenues be managed and mitigated?

A27. Please refer to A26.

Q28. Who should bear the risk/reward of trust account performance?

A28. Please refer to A26.

Q29. Who should bear the risk/reward of under/over collection of funds?

A29. Please refer to A26.

8.0 NEB ISSUE 7

Q30. What is the Board's mandate under the current legislation to require the collection of abandonment costs as a component of a company's revenue requirement?

A30. While there is no specific mandate under the *NEB Act* that requires the collection of abandonment costs as a component of a company's revenue requirement, a fundamental premise of the Board's regulatory mandate is that all costs of service should be born by those parties using the service, and the ultimate abandonment of facilities is part of that service. Further, the Board has a broad mandate under the *NEB Act* and can make orders with respect to all matters relating to traffic, tolls or tariffs. It is clear that the Board has authority over abandonment as it is charged under the *NEB Act* with certain powers relating to abandonment (e.g., Section 74). "Tolls" is defined to include a variety of things, but is not limited to those enumerated items. Based on the Board's clear jurisdiction over abandonment and the unrestricted definition of "tolls" it seems clear that the collection of abandonment costs is within the Board's jurisdiction and mandate.

Q31. What other concerns with the collection of abandonment costs, legislation and jurisdiction does TransCanada have?

A31. TransCanada has the following general concerns:

- Present definitions relating to discontinuance of service may exclude some legitimate terminal abandonment costs from being recovered from the fund set aside to cover these expenses. Some abandonment may take place over the economic life of a pipeline, not just at the end. As well, it is possible that identical facility retirement on two different pipeline systems may not both be terminal retirements depending on the usage of the facilities. The LMCI Stream 3 process should review and, if appropriate, revise these definitions so they provide better clarity in the application of the conceptual framework of the terminal abandonment process, due to ambiguity in the definitions of “abandon” and “decommission” provided in the Discussion Paper for Stream 3 and the practical application of those terms;

- Whether the collection of abandonment costs, as directed by the Board, will account for other federal regulatory requirements outside of the Board’s jurisdiction (*Canadian Environmental Assessment Act*, etc.) or provincial regulatory rules. The concern is that having paid for abandonment through the NEB, TransCanada could be subject to additional provincial regulatory requirements. TransCanada wishes to clarify that the Board’s mandate extends to abandoned pipelines.

- Whether the collection and management of the funds collected for abandonment costs would include funds necessary for compliance with regulatory requirements relating to pipeline abandonment that are outside the Board’s jurisdiction, and whether such funds would require oversight from other regulatory bodies.

- Whether a Section 74 approval would permit access the funds for abandonment costs set forth by a provincial or other federal regulator.

- Whether the abandonment of gathering pipelines (e.g. portions of the Alberta System) is fundamentally different from the abandonment of trunklines;

- When the NEB would need to consider potential amendments to *Gas Pipeline Uniform Accounting Regulations* and *Oil Pipeline Uniform Accounting Regulations* as a result of requiring pipeline companies to set aside funds to cover future abandonment costs; and

- Whether there are any potential impacts as a result of pending changes to Generally Accepted Accounting Principles.

NEB 1.1

Reference: (i) Written Evidence of TransCanada, Page 5, A4, lines 70-74

(ii) Written Evidence of TransCanada, Page 9, A8, lines 162-167

Preamble: TransCanada discusses the implications of requiring or not requiring pipeline companies to set aside funds. With regards to economic efficiency, TransCanada states that even though the individual circumstances facing each pipeline will be different, the framework should be consistently applied so that differences in the collection of abandonment funds do not lead to economically inefficient outcomes.

Request:

Please explain in detail what TransCanada sees as the framework that can be consistently applied. What elements need to be addressed in designing a framework that can be consistently applied?

Response:

The framework set out by the National Energy Board ("NEB" or "Board") should be reflective of the principles that TransCanada presented in its evidence[1].

The following should also be part of the framework:

- In calculating the amounts required to be collected to cover the cost of pipeline terminal abandonment, consideration must be given to the cost of setting up, maintaining, and managing the funds in which the monies would be invested;
- Funds should be collected on an individual pipeline basis;
- Taxation on funds collected should be structured in the most tax efficient manner possible; and
- Periodic review should occur to ensure the right amounts are being collected.

[1] RH-2-2008 Written Evidence of TransCanada Pipelines Limited, NOVA Gas Transmission Ltd., Foothills Pipe Lines Ltd., and TransCanada Keystone Pipeline GP Ltd. Q/A2, pages 2-3, lines 23-46.

NEB 1.1

In order for a framework to be consistently applied, it must be generic enough to account for different situations between pipelines that transport different products, or under substantially different circumstances.

NEB 1.2

Reference: (i) Written Evidence of TransCanada, Page 5, A4

(ii) Written Evidence of TransCanada, Page 9, A8, lines 169-173

Preamble: In reference (i), TransCanada believes an outcome of the proceeding should be direction to begin collection of abandonment funds as soon as is practical.

In reference (ii), TransCanada stated that funds should be collected sufficiently in advance of abandonment.

Request:

(a) What should the criteria be to determine when it is practical to begin collection?

(b) Please explain what TransCanada means by "sufficiently in advance".

Response:

(a) The criteria to determine when it is practical to begin collection would be part of the framework determined by the Board. It should be generic enough to account for different situations between pipelines that transport different products, or under substantially different circumstances.

Examples of the factors the Board may want to consider in determining when it is practical to begin collection include:

- There will be a significant amount of time and effort required to establish a mechanism, such as a trust, for the collection and management of abandonment funds;
- Pipeline companies will require a reasonable amount of time to prepare terminal abandonment cost estimates and an outlook of when those costs would be incurred through a retirement study. Accordingly, collection should not begin until a company is given sufficient time to complete these estimates;

NEB 1.2

- Collection of abandonment costs may impact currently effective settlements. For further discussion, please refer to the response to NEB 1.6; and
- Resolution of the taxation issue should facilitate the timely commencement of collection.

(b) The circumstances will vary from pipeline to pipeline, but "sufficiently in advance" should in principle be a point for all pipelines whereby:

- the collection of abandonment costs will minimize intergenerational inequity among rate payers; and
- there can be a material accumulation of compounded interest on invested funds.

NEB 1.3

Reference: Written Evidence of TransCanada, Page 8, A8, lines 151-161

Preamble: In the above reference, TransCanada stated that in setting funds aside, the Board should consider the possible impact on the competitive dynamics between pipelines to ensure economic inefficiencies are avoided.

Request:

(a) How does Trans Canada propose that this potential impact to the competitive dynamics between pipelines be addressed?

(b) What factors should be considered in addressing this issue and how should those factors be considered?

Response:

(a) & (b):

Similar pipelines transporting similar products under similar circumstances should be collecting abandonment costs under the same framework, in a similar time frame with a similar unit of cost.

The factors that the Board may want to consider in addressing this issue include and are not limited to:

- The economic inefficiency that may result if collection of abandonment costs causes one pipeline serving a supply area to be offloaded while another pipeline serving the same supply area expands;
- The impacts of collection of abandonment funds on NEB-regulated pipelines in terms of competition in relation to Federal Energy Regulatory Commission ("FERC") regulated and provincially-regulated pipelines;
- Long-term impacts on the viability of greenfield projects and attraction of capital to the Canadian energy infrastructure; and
- Impacts on the price of natural gas to consumers and netbacks to producers.

NEB 1.4

Reference: (i) Written Evidence of TransCanada, Page 12, A12

(ii) Written Evidence of TransCanada, Page 14, A16

Preamble: In reference (i), TransCanada states that assumptions used to develop a preliminary cost estimate should include a retirement study to determine the expected economic life of a pipeline and when the facilities will need to be abandoned. It is stated in reference (ii) that funds should not be collected as a component of depreciation.

Request:

(a) Please discuss TransCanada's view on whether the economic life for the collection of funds to cover future abandonment costs should be the same as the economic life used by companies in depreciation studies.

(b) In TransCanada's view, should abandonment funding include an estimate for ongoing maintenance for a period of time after the assets are abandoned? If yes, for how long?

Response:

(a) The period over which funds are collected to cover future abandonment costs may not be the same as the period over which invested capital is recovered through depreciation. A depreciation study focuses on useful lives of individual assets or asset groups; while recovery of future abandonment costs focuses on the life of the pipeline system as a whole. Additionally, factors or assumptions used in determining the useful lives of individual assets or asset groups for the purpose of a depreciation study may not be the same as those used in determining the life of the pipeline system for the purpose of recovery of future abandonment costs.

(b) The amount of funds to be collected for abandonment should reflect the total cost of abandonment including, if applicable, costs of setting up and maintaining trusts, and the costs of meeting any additional regulatory requirements. If it is determined that it is appropriate to abandon pipes in a manner that would require ongoing maintenance for a defined period of time, then the funds collected should reflect this.

NEB 1.5

Reference: (i) Written Evidence of TransCanada, Page 20, A31

(ii) Discussion Paper for LMCI Stream 3 – Land Matters Consultation Initiative, Pages 3-4

Preamble: The terms "abandon" and "decommission" are defined in reference (ii). In reference (i), TransCanada states that the LMCI Stream 3 process should review, and if appropriate, revise these definitions so they provide better clarity in the application of the conceptual framework of the terminal abandonment process.

Request:

(a) Please define "abandon" and "decommission" in terms of TransCanada's understanding of them.

(b) Based on the definitions in (a), please describe TransCanada's understanding of how any abandonment fund should be used. In particular, please explain how TransCanada would differentiate between normal business practices and end of life abandonment with regards to the use of funds collected.

(c) What would be the distinguishing criteria between pipeline abandonment as part of a "normal practice" verses an abandonment for which funds would be available? If a pipeline abandons large pieces of its mainline, would this be a normal practice of an ongoing business? Please explain in detail using criteria; for example, size of pipe, location, percentage of capacity remaining, etc.

Response:

(a) There is no definition for "abandon" or "decommission" provided in the *National Energy Board Act ("NEB Act")* or the *National Energy Board Rules of Practice and Procedure, 1995*. Reference (ii) and the recently amended *Onshore Pipeline Regulations, 1999* defines "abandon" as "to permanently cease operation such that the cessation results in the discontinuance of service" and "decommission" as "to permanently cease operation such that the cessation does not result in the discontinuance of service."

NEB 1.5

TransCanada's understanding of these terms is based on the above definitions provided by the NEB. Further, TransCanada understands that 'service' is defined as the ability of a pipeline, as a whole, to transport hydrocarbons to an end point.

Based on this guidance provided by the NEB, TransCanada interprets abandonment as those terminal or final retirements of major components of the pipeline system caused by economic obsolescence, such as the depletion of supply reserves and /or loss of market demand. By contrast, decommissioning would entail interim retirements of components of the pipeline system where the pipeline continues to be economically viable.

(b) & (c):

The abandonment fund should be used for the costs associated with the setup and maintenance of the fund as well as for situations where abandonment, as defined by the NEB, occurs. Such abandonment and access to the abandonment funds should occur through the course of a Section 74 application for abandonment.

In its consideration of a Section 74 application, the factors that the Board may take into account in determining whether the application constitutes abandonment may include such pipeline system specific factors such as the size, location and percentage of pipe proposed to be abandoned. TransCanada also understands that the factors referred to in (a) would also form part of the Board's considerations.

NEB 1.6

Reference: Written Evidence of TransCanada, Page 13, A13

Preamble: TransCanada discusses toll settlements where pipelines will not have flexibility to add abandonment costs into the revenue requirement and suggests the Board will need to address this issue.

Request:

Please discuss the options available to address this issue.

Response:

Possible options to address this issue are:

- The terms of the settlement are maintained and collection is deferred until after the settlement has expired;
  - The settlement has been negotiated to provide shippers with a greater degree of certainty of costs in the revenue requirement. Deferring the collection of abandonment funds maintains this certainty. Commencing collection of abandonment costs would start after the settlement has expired and could become part of the revenue requirement in a new negotiated settlement.
- The Board mandates the collection of funds for abandonment during the Settlement in the form of an order;
  - If deferring the collection of abandonment funds is deemed to be inappropriate, the Board could order the funds to be collected during the term of any existing settlement and treated as a flow through cost item in the existing settlement. A Board order would preclude the pipeline from having to open an existing settlement and change the terms under which it was negotiated. It would also limit the issue to collection of abandonment funds only and not open other aspects of the settlement that parties might wish to change.

NEB 1.7

Reference: Written Evidence of TransCanada, Page 15, A18

Preamble: TransCanada does not support the pooling of a portion of funds for use across the industry.

Request:

If there is no pooling of funds:

(a) Who will be liable for costs related to orphan pipelines, should there be any?

(b) Is there a risk to landowners, governments and other stakeholders if there isn't a pooled fund to cover the abandonment costs of orphaned pipelines?

(c) If so, how could landowners, governments and other stakeholders be provided with the same level of assurance that a pooled fund may provide? What measures could be taken to prevent any burden of abandonment costs ending up being covered by them?

(d) Should financial assurances or security for abandonment be required until future abandonment costs are fully covered?

Response:

(a) through (d):

There will always exist some element of risk that insufficient funds will be collected before a pipeline is abandoned. However, pipelines are tightly regulated and a properly designed framework would allow the Board to review the appropriateness of the amount of funds collected by a pipeline. This should minimize the risk of an orphan pipeline situation.

Any risk faced by landowners, governments and other stakeholders with respect to orphan pipelines must be balanced against the appropriateness of collecting costs from shippers and users of other systems who have received no benefit associated with the orphaned pipeline. Further, this would be a departure from cost causality that is fundamental to rate-making principles. The cost of

NEB 1.7

abandonment is a cost of service that each pipeline incurs. As such, each pipeline is responsible through its collection of tolls to ensure that sufficient funds are collected to cover these costs.

NEB 1.8

Reference: Written Evidence of TransCanada, Page 16, A23, Lines 348-350

Preamble: TransCanada stated that the investment policies of other retirement funds, such as pension funds, could provide guidance in establishing appropriate investment portfolios for pipeline abandonment funds. The Board would like further details regarding the governance of potential environmental trusts, in particular in relation to the representation of beneficiaries in the oversight of such trusts.

Request:

(a) If the Board were to decide to require environmental trusts, does TransCanada have comments regarding who or what groups should be represented in governing such trusts?

(b) Does TransCanada have any recommendations regarding the role of such beneficiaries in the governance of trusts?

Response:

(a) & (b):

TransCanada sees the question of governing the trust to involve 1) management of the trust and 2) a framework under which that management should be conducted.

The pipeline should be responsible for the development and governance of the trust applicable to the pipeline. However, the day to day management should be performed by fund managers subject to trust law and governance documents. TransCanada would propose to bring forward for approval to the NEB a governance plan regarding the management of the trust.

NEB 1.9

Reference: Written Evidence of TransCanada, Page 16, A23, Lines 348-350

Preamble: Several parties mention company pensions as a model to reference for funding for pipeline abandonment.

Request:

Please discuss whether there is a difference in data requirements and in assumptions in the context of comparing pension modelling and modelling of pipeline abandonment costs.

Response:

Some data requirements for pipeline abandonment are similar to the data requirements for employee pensions.

The base assumptions for funding requirements for pipeline abandonment may include some of the following:

1. expected cost of abandonment;
2. timing of abandonment; and
3. future expected return on investments.

The base assumptions for funding requirements for employee pensions may include the following:

1. expected cost of payments to retirees;
2. average life expectancy of employees and current average age of employees; and
3. future expected return on investments.

The specific data requirements are generally different between pension costs and abandonment costs. For example pension costs rely on statistical analysis for a large number of the population, while abandonment costs rely on the retirement profiles of asset groups. However as noted above, the base assumptions used in the modeling of pension and pipeline abandonment costs are similar.

NEB 1.10

Reference: Written Evidence of TransCanada, A12, Pages 11-12

Preamble: TransCanada lists certain information and assumptions that would be necessary to create preliminary cost estimates. One factor not specifically mentioned is the use of construction costs per km. Benchmarking of pipeline construction costs is sometimes published by third party firms or by journalists.

The Board would like to understand the extent to which labour portions of such costs would provide some approximate generic parameters to use in creating preliminary cost estimates for those portions of pipe which maybe removed.

Request:

(a) Is TransCanada aware if information is published on average North America pipeline construction costs on a cost per km basis?

(b) If so, please cite specific references, and provide the publications, if available.

(c) Does such information contain sufficient detail for estimating average (current) costs of removal of pipeline sections? (i.e., is the labour construction cost information separated from costs of pipe?)

(d) Would such costs provide a reasonable starting point for preliminary estimates of future abandonment costs if applied to appropriate estimates of kilometres of pipe to be removed?

Response:

(a) Yes.

(b) The Oil and Gas Journal publishes a report on the construction costs of pipelines. TransCanada is currently in the process of obtaining the permission to provide a copy of the report to the NEB.

NEB 1.10

(c) & (d):

The costs included in the reference identified in the response to part (b) are broken down into categories and expressed in terms of average cost per mile. TransCanada notes that the average costs provided in the report can vary greatly from year to year for the same diameter of pipe. As such, even for preliminary estimations it would be inappropriate to use this data as there is a risk that the average cost chosen may be too high / too low relative to actual costs resulting in inefficient collection of abandonment funds.

It would be more appropriate to develop estimates that are reflective of site-specific factors such as topography, type of terrain (e.g. farmland, rock, muskeg, etc.) the frequency of water crossings and proximity to transportation infrastructure and services.

NEB 1.11

Reference: Written Evidence of TransCanada, A24, Page 17

Preamble: TransCanada stated that it believes the Board should request the Department of Finance put in place an efficient tax treatment such that funds collected to cover the cost of pipeline abandonment and contributed to a fund should be allowed as a tax deduction in the year contributed.

Request:

(a) In the event that alternative tax treatment is not available in the long term, does TransCanada know of other funding mechanisms available to address TransCanada's concern?

(b) In the event that alternative tax treatment is not available in the short term, are there other funding mechanisms available to address TransCanada's concern?

Response:

(a) & (b):

TransCanada has not investigated a large variety of other funding mechanisms to address the concern of having funds available to cover the cost of pipeline abandonment as other funding mechanisms would not have such funds segregated from general corporate revenue. Given that funds should be set aside, the question remains as to the quantum that should be set aside every year to achieve the goal of having enough money to cover the cost of pipeline abandonment. Two factors in determining the quantum are 1) whether the amount contributed to the fund is deductible for tax purposes, and 2) the expected return on investments in the fund.

If the contributions are not tax deductible, then the quantum collected has to be increased by the tax component, plus an amount that may result in a non-deductible component at the end of the pipeline's life, because there is no taxable income to deduct against.

NEB 1.12

Reference: Written Evidence of TransCanada, A31, Page 21

Preamble: TransCanada raises as a concern "whether the abandonment of gathering pipelines (e.g. portions of the Alberta System) is fundamentally different from the abandonment of trunklines".

Request:

Please provide TransCanada's views on the question of whether abandonment of gathering pipelines is fundamentally different from the abandonment of trunklines.

Response:

The abandonment of gathering pipelines may be different than mainlines. Gathering pipelines generally consist of smaller diameter pipelines than mainlines and are located in supply basins that may themselves have different physical conditions than the areas traversed by mainlines. This may result in different physical abandonment activities with different cost implications arising out of Stream 4 of the LMCI. As well, the life of a gathering line is determined by the life of the resource, while a trunk line is governed by the economics of the supply source and market.

NEB 1.13

Reference: Written Evidence of TransCanada, A31, Page 21

Preamble: TransCanada raises as a concern "whether there are any potential impacts as a result of pending changes to Generally Accepted Accounting Principles".

Request:

(a) Please confirm that the pending changes referred to relate to the implementation of International Financial Reporting Standards (IFRS), which will be adopted in 2011.

(b) Please explain how these pending changes will impact on the financial issues related to pipeline abandonment under consideration in this proceeding.

Response:

(a) Confirmed.

(b) Based on TransCanada's preliminary assessment, one of the changes to generally accepted accounting principles with the adoption of IFRS will be the introduction of the concept of "constructive obligation". This concept, along with the assessment of other criteria under IFRS, may result in the recognition of additional asset retirement obligations or earlier recognition of asset retirement obligations for financial reporting purposes. In the event that asset retirement obligations are used in determining estimates of future abandonment costs, any future changes in accounting in this area will impact the determination of pipeline abandonment costs.

NATIONAL ENERGY BOARD
OFFICE NATIONAL DE L'ÉNERGIE

Hearing RH-2-2008
Audience RH-2-2008

Land Matters Consultative Initiative (LMCI) Stream 3
Pipeline Abandonment - Financial Issues

Troisième volet de l'Initiative de consultation relative aux questions financières (ICQF)
Cessation d'exploitation de pipelines - Questions financières

VOLUME 1

Hearing held at
L'audience tenue à

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Calgary, Alberta

January 20, 2009
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HEARING /AUDIENCE
RH-2-2008

IN THE MATTER of the Land Matters Consultative Initiative (LMCI)
Stream 3 - Pipeline Abandonment - Financial Issues

HEARING LOCATION/LIEU DE L'AUDIENCE

Hearing held at Calgary (Alberta), Tuesday, January 20, 2009
Audience tenue à Calgary (Alberta), Mardi, le 20 janvier 2009

BOARD PANEL/COMITÉ D'AUDIENCE DE L'OFFICE

S. Leggett	Chairperson/Présidente
K. Bateman	Member/Membre
L. Mercier	Member/Membre

APPEARANCES/COMPARUTIONS

Companies/Compagnies

Alliance Pipeline Ltd.
- Mr. D. Crowther
- Mr. R. Power

BP Canada Energy Company
- Ms. C. Worthy

Enbridge Pipelines Inc.
- Mr. D. Crowther
- Ms. M. Yohemas

Foothills Pipe Lines Ltd.
- Mr. S. Denstedt
- Ms. N. Berge
- Mr. M. Keen

Imperial Oil Resources
- Ms. L. Ofrech (ph)

Kinder Morgan Canada Inc.
- Mr. P. Forrester
- Ms. M. Novak

NOVA Gas Transmission Ltd.
- Mr. S. Denstedt
- Ms. N. Berge
- Mr. M. Keen

Pouce Coupé Pipe Line Ltd.
- Mr. P. Jeffrey
- Mr. P. Khan

Spectra Energy Transmission (Westcoast Energy Inc.)
- Mr. D. Davies
- Ms. R. Sirett

APPEARANCES/COMPARUTIONS

Companies/Compagnies

Suncor Energy Marketing Inc. (SEMI)
- Mr. D. Armstrong

TransCanada Keystone Pipeline GP Ltd.
- Mr. S. Denstedt
- Ms. N. Berge
- Mr. M. Keen

TransCanada PipeLines Limited
- Mr. S. Denstedt
- Ms. N. Berge
- Mr. M. Keen

Trans Québec & Maritimes Pipeline Inc.
- Mr. S. Denstedt
- Ms. N. Berge
- Mr. M. Keen

Associations

Canadian Allliance of Pipeline Landowners' Association (CAPLA)
- Mr. P.G. Vogel
- Mr. J. Goudy

Canadian Association of Petroleum Producers (CAPP)
- Mr. N.J. Schultz

Governments/Gouvernements

Alberta Department of Energy
- Mr. C. King

National Energy Board/Office national de l'énergie
- Mr. P. Johnston
- Ms. J. Saunders

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--- Upon commencing at 8:57 a.m./L'audience débute à 8h57

1. **THE CHAIRPERSON:** Good morning, ladies and gentlemen. Bonjour, mesdames et messieurs.

2. My name is Sheila Leggett and I will be chairing this hearing. My fellow Panel Members are, to my right, Kenneth Bateman and, to my left, Lyne Mercier.

3. The National Energy Board issued Hearing Order RH-2-2008 on March 3rd, 2008 setting out the procedures to be followed for a public hearing on Land Matters Consultative Initiative Stream 3. Stream 3 concerns financial matters related to pipeline abandonment.

4. This Hearing Panel was designated pursuant to section 15(1) of the *National Energy Board Act*, and will report and make recommendations to the Board in respect of the decisions to be made by the Board on the issues being considered in this hearing. The Board will adopt or otherwise deal with the report recommendations as it considers advisable.

5. As communicated by the Board in Ruling Number 1 on April 21st, 2008, the following are some of the potential outcomes of Stream 3:

6. Development of a set of principles which will guide the Board in its future decisions with respect to the financial matters related to pipeline abandonment;

7. Identification of a preliminary mechanism or mechanisms to begin setting aside funds for abandonment costs;

8. Identification of technical abandonment assumptions to be used to estimate abandonment costs;

9. Development of an action plan to move forward on remaining financial issues, including issues unique to each pipeline company;

10. And commencement of collection of some funds for abandonment as a starting point from which future collection may proceed.

11. At this point, I would like to introduce the Board staff involved in this hearing.

12. We have our Project Manager, Mr. Barry Branston. If you could just maybe raise your hand so people will know who you are. Legal counsel, Ms. Jody Saunders and Mr. Paul Johnston; Economics & Financial Regulation, Dr. Sharp;

Financial Regulatory Analyst, Mr. Rubie and Ms. Parkinson; Economists, Ms. Baker and Ms. Moffat, and our Communication Officer is at the back of the room, Mr. Cameron, on the right-hand side.

13. As well, we have our Regulatory Officers assisting us, and today at the front of the room we have Ms. Dutcher and Ms. Dubé and Louise Niro will also be helping.

14. There will also be other technical service providers here.

15. Before we begin, I would like to welcome everyone and give you a brief account of the procedures we will follow during this hearing.

16. The Board will follow the procedure as stated in Ruling #7 of November 21st, 2008 in respect of the presentation of evidence and argument by the parties.

17. First, the Board will call upon parties who have registered an appearance at the oral portion of the hearing in the following order. We will start with pipelines and other companies, then deal with associations and then governments.

18. Each subgroup will be called in alphabetical order. Parties will empanel their witnesses to adopt their pre-filed written evidence and be cross-examined.

19. After the evidentiary portion of the hearing is complete, the Board will receive final argument.

20. For final argument, the Board will hear from companies, associations and governments, all of whom have registered an appearance, but following a "top down, bottom up" approach. This means that the parties will be called on from the top of the order of appearances through to the bottom, and then starting from the bottom of the order of appearances, and in reverse order, parties will be called upon for reply argument, should they wish to present any.

21. Prior to the completion of the hearing, the Board will determine whether it will be beneficial to allow the option of filing written argument as an alternative to or to supplement oral argument. If you anticipate making final argument in writing, please advise Board counsel. We note that to date no parties have made such a request.

22. I would like to remind everyone that the Board is committed to ensuring that stakeholders are effectively engaged in the Board processes. My role as Chair of this Panel is to ensure that the proceedings unfold in an efficient and respectful manner and I look forward to everyone's full cooperation in this regard.

23. During this proceeding, the Board will be viewing the exhibits electronically. As parties refer to a document by its exhibit number, it will be produced electronically on the screens at the sides of the room. In order to ensure an efficient process, parties must identify each document to which they refer by its exhibit number.

24. In addition, in advance of cross-examining other parties, please provide the regulatory officers at the front with a list of exhibit numbers to which you intend to refer to so that these documents may be retrieved expeditiously. This information must include the exhibit numbers, including a sub-number if that is included on the exhibit list and the Adobe page number.

25. A list of pre-filed exhibits is available on the exhibit table at the back of the hearing room. We would ask that you check the list before you register your appearance, and if you wish to file a document which does not appear on the list, you must seek leave to do so when you come forward to register.

26. Please note that if you file an exhibit during the hearing, you must also file the document through the Board's electronic document repository, if you have the ability to file documents electronically. Parties need not tender for filing copies of exhibits which are already included in the Exhibit List.

27. When filing an exhibit at this time or during the proceeding, please provide six copies to the Regulatory Officer, ten copies to Board counsel, and leave sufficient copies in the hearing room for all other interested parties.

28. At the back of the room you will find a number of other documents including the Order of Appearances and Procedural Directive.

29. The Procedural Directive provides full information on the electronic exhibit procedure, filing of new exhibits, receiving undertakings, obtaining transcripts, the sitting hours, accessing the online broadcast of the hearing, information on written argument and the availability of internet access.

30. If any parties are uncertain of the process or require information concerning the entering of exhibits or other hearing-related matters, we would ask that you would speak with our Board counsel, either Ms. Saunders or Mr. Johnston.

31. The Board will sit today until 1:30 and anticipates taking a break at mid-morning and then another short break at noon. For the remainder of the hearing, the Board intends to sit from 8:30 until 1:30 daily, unless it advises otherwise. On those

days, we will break at an appropriate time mid-morning for 20 minutes and again at noon for five minutes.

32. As always, we are concerned that the hearing time be used effectively and efficiently. We remind parties that the principal purpose of cross-examination in our proceedings is to clarify and test the evidence that has already been filed. Parties should not reiterate their own evidence nor repeat cross-examination questions that have already been asked.

33. The Board reminds parties that, generally, only parties who are adverse in interest may cross-examine each other.

34. We will begin with the registration of appearances. Parties will be called in the order in which they appear on the Order of Appearances. The order for the presentation of evidence and cross-examination will also generally follow the Order of Appearances.

35. When registering your appearance, please inform the Board whether you are represented by legal counsel or someone else, whether you wish to be called for the purpose of cross-examination, whom you wish to cross-examine, whether you will have witnesses yourself, and whether you wish to present final argument.

36. As well, please indicate whether you have any preliminary matters that you wish to raise before we proceed with the evidentiary portion of the hearing. All preliminary matters will be dealt with following the registration of appearances.

37. I will now ask Board counsel to assist in the registration of appearances and the filing of exhibits. When your name is called, please come forward to register your appearance.

38. Mr. Johnston, please.

39. **MR. JOHNSTON:** Thank you, Madam Chair.

40. I'll begin alphabetically with companies.

41. Alliance Pipeline Ltd. ...?

42. **MR. CROWTHER:** Good morning, Madam Chair and Members. Douglas Crowther appearing on behalf of Alliance Pipeline Ltd. Mr. Robert Power from Alliance is also in the room today.

43. Alliance does not currently intend to cross-examine any witnesses.

However, I will advise or Mr. Power will advise Board counsel if those plans should change as the proceeding unfolds.

44. Alliance will not be presenting any witnesses. It may present final argument, and I will so advise Board counsel in due course. Alliance has no preliminary matters.

45. Thank you.

46. **MR. JOHNSTON:** Thank you.

47. ATCO Pipelines …?

--- (No response/Aucune réponse)

48. **MR. JOHNSTON:** BP Canada Energy Company …?

--- (No response/Aucune réponse)

49. **MR. JOHNSTON:** ConocoPhillips Canada Limited …?

--- (No response/Aucune réponse)

50. **MR. JOHNSTON:** Enbridge Pipelines Inc. ...?

51. **MR. CROWTHER:** Douglas Crowther appearing for Enbridge Pipelines Inc. I also have with me today and likely throughout the proceeding Ms. Marnie Yohemas, regulatory counsel for Enbridge Pipelines Inc.

52. Enbridge may wish to cross-examine other panels, including potentially CAPLA, Kinder Morgan and TransCanada PipeLines. However, I will advise Board counsel in due course once those plans are firmed up.

53. Enbridge will be presenting witnesses this morning and it does intend to present final argument.

54. I would appreciate being called upon to make submissions in respect of the matter dealing with clarification of definitions. Other than that, I have no preliminary matters. Thank you.

55. **MR. JOHNSTON:** EnCana Corporation ...?

--- (No response/Aucune réponse)

56. **MR. JOHNSTON:** Export Users Group ...?

--- (No response/Aucune réponse)

57. **MR. JOHNSTON:** Foothills Pipe Lines Ltd. ...?

58. **MR. DENSTEDT:** Good morning. Shawn Denstedt here, representing Foothills Pipe Lines, TransCanada Keystone Pipeline Ltd. and Trans Québec & Maritimes Pipeline Inc.

59. We'd asked to be called in the batting order as TransCanada PipeLines Limited and here with me today are Matthew Keen and Nadine Berge.

60. We would ask to be called for cross-examination. At this time we only contemplate asking questions of CAPLA. We will be presenting evidence and we will be making final argument. We'd also ask to be called in respect of the clarification of definitions.

61. **MR. JOHNSTON:** And do you have any witnesses, sir?

62. **MR. DENSTEDT:** Yes, sir, we do.

63. **MR. JOHNSTON:** And could you please state their names for the record?

64. **MR. DENSTEDT:** Sorry. John Van der Put, V-A-N D-E-R P-U-T, and Amy Leong, L-E-O-N-G.

65. **MR. JOHNSTON:** Thank you.

66. Imperial Oil Resources …?

67. **MS. OFRECH:** Good morning, Madam Chair. Lindsay Ofrech (phonetic) appearing for Imperial Resources.

68. We do not intend to call any witnesses nor to conduct any cross-examinations. Imperial Oil Resources may seek leave to file a written argument. Thank you.

69. **MR. JOHNSTON:** And you have no preliminary matters, I take it?

70. **MS. OFRECH:** We do not. Thank you.

71. **MR. JOHNSTON:** Kinder Morgan Canada Inc. ...?

72. **MR. FORRESTER:** Good morning, Madam Chair, Members of the Board. My name is Peter Forrester. I'm assistant general counsel with Kinder Morgan. Also in attendance with me is Ms. Novak, Michelle Novak, who is legal counsel with Kinder Morgan.

73. We do intend to present witnesses today: our Scott Stoness who is Vice-President of Regulatory and Financial Affairs with Kinder Morgan and also Brenda McClelland who is Director of Regulatory Affairs with Kinder Morgan.

74. We are also representing the TransMountain Pipeline Inc. system and the Express Pipeline Ltd. system. We will be presenting a panel. We may cross CAPLA and Enbridge and we will present final argument.

75. Subject to that, we have no preliminary matters.

76. **MR. JOHNSTON:** Maritimes & Northeast Pipeline Company…?

--- (No response/Aucune réponse)

77. **MR. JOHNSTON:** Montreal Pipe Line Ltd. ...?

--- (No response/Aucune réponse)

78. **MR. JOHNSTON:** NOVA Gas Transmission Ltd. …?

--- (No response/Aucune réponse)

79. **MR. JOHNSTON:** Pouce Coupé Pipe Line Ltd. ...?

80. **MR. JEFFREY:** Good morning, Madam Chair, Members of the Board.

81. My name is Paul Jeffrey, appearing on behalf of Pouce Coupé Pipe Line Ltd.

82. Representing Pouce Coupé, along with me, towards the back of the hearing room is Mr. Parvez Khan.

83. The Board will be pleased to hear that you'll see Mr. Khan's face more than mine through the course of this proceeding. It is Pouce Coupé's intention to cross-examine Westcoast Energy, Enbridge Pipelines and CAPLA.

84. And as we've indicated in pre-filed material, we will present a witness by the name of Mr. Peter Robertson to respond to questions with respect to Pouce Coupé's evidence.

85. We have no preliminary matters and we wish to be asked to present final argument. Thank you.

86. **MR. JOHNSTON:** Shell Canada Energy …?

--- (No response/Aucune réponse)

87. **MR. JOHNSTON:** Shell Energy North America (Canada) Inc. ...?

--- (No response/Aucune réponse)

88. **MR. JOHNSTON:** Spectra Energy Transmission?

89. **MR. DAVIES:** Good morning, Madam Chair and Members. My name is Don Davies. With me is Robin Sirett, S-I-R-E-T-T, and we are appearing for Westcoast Energy Inc. which carries on business as Spectra Energy.

90. Westcoast will be presenting evidence. The direct evidence for the witnesses will be filed later today. The Westcoast witnesses will be Tim Curry, Amarjit Parmar, Duane Rae and Matt Bootle, B-O-O-T-L-E.

91. We do wish to be called for cross-examination of other parties, though we may not end up cross-examining all other parties. We will as well be presenting argument.

92. We have no preliminary matters but do have some comments on the definitions issue. Thank you.

93. **MR. JOHNSTON:** Suncor Energy Marketing Inc. ...?

94. **MR. ARMSTRONG:** I'm David Armstrong for Suncor Energy.

95. We have no preliminary matters. We do not intend to present witnesses. We do not intend to cross-examine and we'll reserve the right to provide final argument. Thank you.

96. **MR. JOHNSTON:** And you have no preliminary matters?

97. **MR. ARMSTRONG:** No, sorry. I forgot that one. No preliminary matters.

98. **MR. JOHNSTON:** Thank you, sir.

99. Terasen Gas Inc. ...?

--- (No response/Aucune réponse)

100. **MR. JOHNSTON:** And then the next name is TransCanada Keystone Pipeline GP Ltd. which is part of TransCanada and then TransCanada PipeLines Ltd., the same.

101. Trans-Northern Pipelines Inc. ...?

--- (No response/Aucune réponse)

102. **MR. JOHNSTON:** Trans Québec & Maritimes Pipeline Inc. which again is -- counsel has mentioned that's part of TransCanada.

103. Union Gas Limited…?

--- (No response/Aucune réponse)

104. **MR. JOHNSTON:** All right. Starting with associations alphabetically, the Canadian Alliance of Pipeline Landowners' Association?

105. **MR. VOGEL:** Good morning, Madam Chair, Board Members.

106. My name is Paul Vogel. I appear on behalf of CAPLA and with me is John Goudy.

107. We do intend to -- CAPLA does intend to cross-examine the industry participant panels, Enbridge, KMC, Pouce Coupé, Spectra, TCPL and CAPP. And CAPLA will be presenting a panel of witnesses, as advised in our correspondence to the Board. CAPLA will present final argument and I have no preliminary matters.

108. **MR. JOHNSTON:** And just for the record, can we have the name of the witnesses that CAPLA will be presenting?

109. **MR. VOGEL:** Yes. Patrick Teevens, Aggie Cheung whose CVs have both been pre-filed with the Board; Dave Core who is President of CAPLA and there are a number of landowner representatives representing various CAPLA associations

and their names are as per the correspondence that we've filed with the Board.

110. **MR. JOHNSTON:** Thank you.

111. **MR. VOGEL:** Thank you, Madam Chair.

112. **MR. JOHNSTON:** The Canadian Association of Petroleum Producers...?

113. **MR. SCHULTZ:** Good morning, Madam Chair, Members of the Board. My name is Nick Schultz and I represent the Canadian Association of Petroleum Producers.

114. We do have a panel of witnesses and, as indicated in the pre-filed evidence, the witnesses are Barry Jardine and Hugh Johnson.

115. We do not need to be called for cross-examination but if that changes, I will advise your counsel and of course the affected party.

116. I have no preliminary matters. We do wish to be called for argument and I do wish to be called in regard to the definitional issue that will be discussed after the appearances.

117. I think I've got the checklist.

118. Thank you, Madam Chair.

119. **MR. JOHNSTON:** Canadian Energy Pipeline Association...?

--- (No response/Aucune réponse)

120. **MR. JOHNSTON:** Industrial Gas Users Association...?

--- (No response/Aucune réponse)

121. **MR. JOHNSTON:** Turning then to governments, Alberta Department of Energy...?

122. **MR. KING:** Good morning, Madam Chair. My name is Colin King. I'm with the Alberta Government Department of Energy.

123. We have no preliminary issues. We will not be presenting any witness panels. We do wish to be called for cross-examination of the panels and we may give final argument.

124. Thank you.

125. **MR. JOHNSTON:** British Columbia Oil and Gas Commission...?

--- (No response/Aucune réponse)

126. **MR. JOHNSTON:** Government of the Northwest Territories, Department of Industry, Tourism and Investment...?

--- (No response/Aucune réponse)

127. **MR. JOHNSTON:** Procureur général du Québec...?

--- (No response/Aucune réponse)

128. **MR. JOHNSTON:** Saskatchewan Ministry of Energy and Resources...?

--- (No response/Aucune réponse)

129. **MR. JOHNSTON:** And then, lastly, to register counsel for the National Energy Board; to my left Jody Saunders and myself Paul Johnston.

130. We do have one preliminary matter to address and, just very briefly, the Board has received four opening statements from Kinder Morgan, CAPLA, Enbridge and TransCanada. These opening statements will be transcribed into today's records. There's no need for parties to read the opening statements and copies of the statements are available at the back of the room.

131. And that concludes registration.

132. **THE CHAIRPERSON:** Thank you, Mr. Johnston.

133. I've been made aware that we're having some interference with the webcast. So this could be a hard thing for many in this room to do but I would ask you if you'd turn off your Blackberries. Apparently, they're interfering with the system. So if you could do that, because the webcast just will not be clear unless we do that, so I appreciate all of your assistance in that matter.

134. Thank you very much for the clarity with respect to the registration process. My recollection is that we have no preliminary matters other than dealing with the definitions. If there is anybody who does have a preliminary matter that they

wish to raise at this point before we deal with that would you please come forward?

--- (No response/Aucune réponse)

135. **THE CHAIRPERSON:** Thank you very much.

136. So we'll move now to dealing with the definitions.

137. On January 13th, the Board issued a letter, Exhibit A-40A, in response to definitions that were received as a result of our IR request dated December 17th, 2008, Exhibit A-31.

138. In that letter the Board asked parties to make any comments on the definitions received as a preliminary matter at this hearing. We will proceed with that process now and thank you to those who identified that you wish to be called at this but I will go through the list of parties who've registered just to make sure we don't lose anyone.

139. So we'll start with Alliance Pipeline. Do you have any -- do you wish to come forward?

--- (No response/Aucune réponse)

140. **THE CHAIRPERSON:** Enbridge Pipelines...?

141. **MR. CROWTHER:** Thank you, Madam Chair.

142. I must say that Mr. Johnston let me off easy because I neglected to identify the Enbridge witnesses whom you will meet very shortly, I expect. For the record they are Dr. Robert Mansell, Mr. Michael Hrynchyshyn and Mr. Peter Douvris.

143. And it might have also been easier for other parties entering appearances to respond to all the questions if I hadn't stolen the list as the first one up. Let me turn then to the submissions regarding the issue of definitions.

144. As you mentioned, Madam Chair, the Board indicated in its January 13th, 2009 letter that before providing direction to the parties it would give them an opportunity to indicate whether they adopt or object to the definitions that were proposed by TransCanada, Kinder Morgan and Westcoast.

145. To be candid, Madam Chair, it is not clear to Enbridge what direction the Board may be thinking of providing. In its response to NEB TransCanada 3.1(a),

which I have as part of Exhibit C-26-10, TransCanada suggested that it would be beneficial to have consistent definitions and applications for certain terms in this proceeding.

146. It also indicted that direction from the Board regarding the definition of terms would help to ensure that all parties share a common understanding when using those terms. I don't know exactly what TransCanada had in mind but I suppose that the Board's "direction" could take the form of some sort of glossary to which parties could or could be required to make reference during the oral portion of this hearing.

147. Enbridge certainly does not understand that the Board's direction would indicate that for instance definitions of terms such as abandon, deactivate or decommission, as they appear in the Onshore Pipeline Regulations will be amended to conform with the definitions that have been proposed here, although one might interpret some of Kinder Morgan's suggestions for modified definitions in that way.

148. In the respectful submission of Enbridge, one potential problem that should be recognized is that parties have not had the benefit of any glossary that the Board may now develop in preparing their pre-filed evidence or responses to information requests. The same is true of at least the Enbridge witnesses so far as their preparation for their oral testimony is concerned.

149. Enbridge certainly agrees that as this hearing proceeds it will be important that all parties and the Board be able to communicate effectively, and as part of that, to understand what they mean when they use particular terms or expressions but, with respect, it may not be either a practical or a productive exercise to attempt to develop a single set of definitions for that purpose.

150. Now, having said all of that, Enbridge offers the following few comments respecting the definitions that have been proposed:

151. TransCanada proposes that the expression "terminal retirements" be understood to mean:

> *"Retirements where the major components of a system are abandoned due to economic obsolescence. Such retirements are not expected to occur all at once. Rather, it is anticipated that there will be a relatively restricted period during which these major retirements will occur."* (As read)

152. It is not clear to Enbridge what TransCanada means by either "major components of a system" or "relatively restricted period". Clarification would be required in those respects before Enbridge could say whether it adopts or objects to

the definition that TransCanada has proposed.

153. As to the Kinder Morgan suggestions, first, Kinder Morgan recommends that the definition of abandon be amended to acknowledge the fact that pipeline abandonment can only occur with the approval of this Board. The term "abandon" is of course defined in the Onshore Pipeline Regulations and it isn't clear whether Kinder Morgan is proposing that the Regulations be amended.

154. But in any event, Enbridge doesn't see the need to add the proposed qualifier to the definition of abandon. If the Board were to disagree, however, then logic would suggest that a similar qualifier should also be added to the definition of decommission.

155. Kinder Morgan also proposes a definition for "abandonment life". I stand to be corrected but I'm not aware that the expression "abandonment life" has yet been used by Kinder Morgan or any other party and so there is no context in which to evaluate the appropriateness of the definition.

156. Further, concerning Kinder Morgan's proposed definition of abandonment life, it is unclear to Enbridge what is meant by a complete set of pipeline system assets. Clarification in that regard would be required before Enbridge could say whether or not it adopts or objects to that portion of the proposed definition.

157. More importantly, the concept that "all assets are simultaneously retired" would be unlikely to apply to a system such as the Enbridge system where it is more likely that abandonment will occur in respect of specific assets, not the entire system. Therefore, Enbridge objects to that aspect of the proposed definition.

158. Madam Chair, those are my submissions.

159. **THE CHAIRPERSON:** Thank you, Mr. Crowther.

160. **MR. CROWTHER:** Thank you.

161. Imperial Oil Resources...?

--- (No response/Aucune réponse)

162. **THE CHAIRPERSON:** Kinder Morgan...?

--- (No response/Aucune réponse)

163. **THE CHAIRPERSON:** Pouce Coupé...?

164. **MR. JEFFREY:** Thank you, Madam Chair.

165. Pouce Coupé would agree with the submissions of Enbridge on the point that nailing down certainty now with respect to various terms may be more restrictive and counterproductive given that evidence has been filed and parties will not have had those concepts in mind that you might determine after this discussion.

166. I think it is helpful that parties have had the opportunity to, and some have availed themselves of that opportunity to bring clarity to what they think terms ought to mean, and by that I take it that they have also communicated what they have meant when they've used those terms.

167. But it is open to parties during cross-examination if there is a sense there is some uncertainty about how a term is being used to try and bring that certainty for the sake of understanding, and then at the close of the proceeding if parties wish to recommend consideration of a change to a definition and regulation or the addition of some, I think that's the appropriate time.

168. Those would be all of our submissions.

169. **THE CHAIRPERSON:** Thank you, Mr. Jeffrey.

170. Suncor Energy Marketing Inc. ...?

--- (No response/Aucune réponse)

171. **THE CHAIRPERSON:** TransCanada Pipelines...?

172. Sorry, Mr. Davies. Spectra Energy Transmission first.

173. Thank you for your patience, Mr. Denstedt.

174. **MR. DAVIES:** I thought maybe you'd changed us to Westcoast Energy Inc., and that would be fine with us, Madam Chair.

175. **THE CHAIRPERSON:** I have to admit, it is a little confusing at times. So thank you for standing up.

176. **MR. DAVIES:** Westcoast has not suggested any definitions of terms. All that we advised in our response to Board question 3.1 was that we have used the terms

abandon and retire interchangeably to mean the permanent cessation of operations of a pipeline or part of a pipeline.

177. I do have a few comments to make about the definitions put forward by others, particularly in respect of the definitions of the terms abandonment life and appreciation life as suggested by Kinder Morgan.

178. Let me say, first of all, that I would be very hesitant to adopt the definition of any term without having a very clear understanding of the context in which the term is being used. And, frankly, I'm not sure exactly where the terms abandonment life and appreciation life appear in the record of this proceeding. I didn't see them in the Kinder Morgan evidence but perhaps I missed them.

179. I'm personally not familiar with the term depreciation life. I know that in previous rate cases where depreciation has been an issue the Board has used the term service life and has defined service life estimate as:

> *"An estimate of the probable life of an asset for the purpose of determining the time period over which the total purchase price of the asset will be depreciated."* (As read)

180. Kinder Morgan may be using the term depreciation life in the same way that the Board uses the term service life, but I don't know that. And, in any event, I don't know why we would be trying to define the term depreciation life in this proceeding anyways. This proceeding isn't about depreciation; it's about abandonment.

181. Which brings me to the term abandonment life; the term itself seems to be a bit of an oxymoron. Abandonment is the end of life; so it's the end of life life, which is not a concept that is readily understandable.

182. If Kinder Morgan is referring to abandonment timing and is suggesting that the timing of abandonment is an important issue to be considered then we agree, but I really don't think that we would be furthering discussion of that issue by trying to define a term like abandonment life.

183. So, Madam Chair, those are my brief comments. Thank you.

184. **THE CHAIRPERSON:** Thank you, Mr. Davies.

185. Mr. Denstedt...?

186. **MR. DENSTEDT:** Thank you, Madam Chairman.

187. Good to get my first mistake out of the way early. I failed to mention that we're here representing NOVA Gas Transmission as well.

188. Just briefly on the definition, first of all let me deal with my friend's comments from Enbridge.

189. TransCanada believes that one of the things that might be confusing during the course of this process is the interchange of terms from a regulatory perspective and an accounting perspective when there are slightly different definitions or meanings that may apply.

190. So I'd agree with my friend from Enbridge that we should be cautious in the process to make sure that when we're using terms we identify and it's clear to all parties whether those terms are being used in a regulatory context or in an accounting context, because they are slightly different.

191. To the extent there is confusion, it will be incumbent upon the witnesses to make sure their position and evidence is clear, but it's equally incumbent upon the cross-examiners to ensure they're not misleading the witnesses by the use of terms that can be used interchangeably.

192. In respect of terminal retirements, TransCanada's hope in using that definition was to identify that abandonment is not an event that occurs mysteriously on any given day but it's an event -- it's a process that occurs over a length of time and that major components of an entire system may be phased into abandonment over a number of years so that, again, not an event but a process.

193. And that brings me to my only comment on the definitions that were put forward by Kinder Morgan, and it's in respect of their definition in their IR 2.1 in respect of abandonment life.

194. Again, the only words that TransCanada really takes some concern with is the use of simultaneously retired. We don't think that is either practical or realistic in the context of a major transmission system like TransCanada's where, in fact, abandonment will occur over a longer period of time and certainly not simultaneously.

195. Those are all my comments. If there are any questions I'd be happy to respond.

196. **THE CHAIRPERSON:** Thank you, Mr. Denstedt.

197. Canadian Alliance of Pipeline Landowners Association...?

--- (No response/Aucune réponse)

198. **THE CHAIRPERSON:** Canadian Association of Petroleum Producers...?

199. **MR. SCHULTZ:** Thank you, Madam Chair.

200. CAPP doesn't believe that adding to the sort of rubric of definitions at this point is going to contribute meaningfully to the proceeding. We've all worked with the definitions that were in the Board's discussion paper and that are grounded in the Board's Regulations.

201. I think we all understand more or less what they're meant to mean, recognizing that even those definitions allow for some interpretation in particular situations.

202. So I don't think adding a suite of new definitions that have a bunch of terms buried in them that in themselves require some judgment as to whether it is or isn't a major component of a pipeline or what is or isn't economic obsolescence or whether things that we do for depreciation are really appropriate for what we're trying to do in this case in relation to an abandonment fund are going to help us.

203. And just to illustrate that a little bit, I mean, if one thinks about what we're trying to do here in terms of creating a mechanism to create an abandonment fund, one is looking at that in the context of a concern that you don't have a pipeline that is itself a going concern, that can fund its ongoing activities, which may include additions, subtractions. And if you have a going concern that can do those things, then you don't need to worry about what's in the abandonment fund. The going concern will take care of it.

204. And so you can have a large, complicated system that might retire something that might meet TransCanada's definition of a terminal retirement, take a system like NOVA which has multiple branches, and in that sense it might be a terminal retirement, but it might not require dipping into an abandonment fund.

205. So I think there is a bunch of complexity out there when it comes to actually working out what's part of the fund and what's dealt with through normal depreciation and, of course, our view is the fund should be a separate trust fund, separate from normal depreciation.

206. So I'm not sure that these definitions that people are suggesting really contribute to something that, in itself, is easy to grasp conceptually, and then when you get down to actually working out the details, gets a bit more complicated.

207. Thank you, Ma'am.

208. **THE CHAIRPERSON:** Thank you, Mr. Schultz.

209. Alberta Department of Energy...?

--- (No response/Aucune réponse)

210. **THE CHAIRPERSON:** Just to make sure that we benefit from the receipt of everybody's knowledge, I'm just going to go back up and see if there's anybody who wants to add comments on the way back up.

211. So I'll go to TransCanada Pipelines. Anything to add?

--- (No response/Aucune réponse)

212. **THE CHAIRPERSON:** Spectra...?

--- (No response/Aucune réponse)

213. **THE CHAIRPERSON:** Pouce Coupé...?

--- (No response/Aucune réponse)

214. **THE CHAIRPERSON:** Kinder Morgan...?

215. **MR. FORRESTER:** Madam Chair, just for clarification, when Kinder Morgan used the terms they weren't suggesting that the Board adopt those as definitions. They were -- we were attempting to clarify the terms that we had used in our evidence and how we had used them, and we agree with most of my learned friends who have suggested that it's not intended to be a glossary that the Board would then rely on, and we will clarify them further in our evidence.

216. **THE CHAIRPERSON:** Thank you, Mr. Forrester.

217. Imperial Oil...?

--- (No response/Aucune réponse)

218. **THE CHAIRPERSON:** Enbridge...?

--- (No response/Aucune réponse)

219. **THE CHAIRPERSON:** Alliance...?

--- (No response/Aucune réponse)

220. **THE CHAIRPERSON:** Thank you very much.

221. If you'll excuse us for a minute?

--- (A short pause/Courte pause)

222. **THE CHAIRPERSON:** The Board thanks everyone for their input on these definitions and we'll now proceed with Enbridge's panel, if you'd like to proceed, Mr. Power?

223. Thank you.

224. **WRITTEN OPENING STATEMENT OF ENBRIDGE PIPELINES INC.:**

National Energy Board
Hearing Order RH-2-2008
Land Matters Consultation Initiative Stream 3

Opening Statement of Enbridge Pipelines Inc.
(January 16, 2009)

1. In its letter of 17 January 2008, the National Energy Board ("Board") stated that one of the potential outcomes of the Land Matters Consultation Initiative ("LMCI") would be the development of a set of principles that will guide the Board in its future decisions with respect to the financial matters related to pipeline abandonment [Ex. A-2C, "Land Matters Consultation Initiative Stream 3: Financial Issues Relating to Pipeline Abandonment Discussion Paper", section 2.1 (p. 7 - 1st bullet)]. Enbridge Pipelines Inc. ("Enbridge") agrees that that should be the outcome of this proceeding.

2. The collection of funds for the purposes of pipeline facility abandonment requires the resolution of highly complex issues and therefore implementation of any principles that the Board may develop would require very careful consideration and

execution by the affected pipelines. For example, if the Board were to require pipelines that it regulates to collect and set aside pipeline abandonment funds, it would first be necessary for those pipelines to address and work out numerous details including, among others, the following:

- *tax status and treatment of abandonment fund contributions and earnings*
- *specifics of trust or other such structure*
- *governance and reporting*
- *investment guidelines*
- *access to funds*
- *assumptions regarding the requirements for, and methods of, facility abandonment*
- *collection monitoring and adjustment mechanisms.*

Substantial resources would be required to resolve these complexities and it would be essential that the Board afford the affected pipelines with sufficient time to do so.

3. Issues concerning the method of abandonment should be resolved in Stream 4 of the LMCI process rather than in this proceeding. Stream 4 must also provide the necessary guidance regarding the technical assumptions relating to abandonment that are required to be made for purposes of estimating abandonment costs.

4. It is fundamental to the Enbridge position that: (a) abandonment costs are a legitimate cost of providing service and as such should be recovered, with the Board's approval, from shippers through tolls; and, (b) landowners are not, and will not be, responsible for the abandonment of Enbridge's pipelines.

5. Collection of abandonment funds should commence when a reasonably accurate estimate of future abandonment costs can be made [Ex. C-10-12A, "Written Evidence of Enbridge Pipelines Inc.", A3 (p.7)]. However, no such estimate is possible until abandonment is reasonably foreseeable [Ex. C-10-8B, NEB-EPI-1.1]. An abandonment event that could reasonably be expected to occur within a time horizon established by the Board would be reasonably foreseeable. The Board would establish the time horizon based on consideration and appropriate balancing of several factors including fairness and equity (e.g., intergenerational equity), efficiency (e.g., administrative cost/burden and opportunity cost), and rate stability (e.g., toll impacts including whether just and reasonable) [Ex. C-10-8B, NEB-EPI-1.8(c) and NEB-EPI-1.8(d). See also Ex. C-10-12B, "Reply Written Evidence of Enbridge Pipelines Inc.", Appendix "A", "Evaluation or Alternative Funding Horizons for Facility Abandonment" by Wright Mansell Research Ltd.].

6. In order to make an abandonment funds collection mechanism sufficiently robust as to warrant endorsement by the Board, it must incorporate flexibility to accommodate differences in key parameters (such as expected remaining life) among

pipeline facilities. In this regard, Enbridge proposes that, if the expected life of a pipeline were to be of such a length that the time of abandonment is not foreseeable within the time horizon established by the Board, then deferral of funds collection in respect of that facility could be authorized by the Board.

225. **WRITTEN OPENING STATEMENT OF KINDER MORGAN CANADA INC.:**

National Energy Board Hearing Order RH-2-2008
Kinder Morgan Canada Inc., operator of
Trans Mountain Pipeline Inc., and
Express Pipeline Ltd.

("Kinder Morgan")

Good Morning Madam Chairperson and Members of the Board. My name is Peter Forrester, Assistant General Counsel with Kinder Morgan Canada Inc., operator of the board regulated Trans Mountain Pipeline and Express Pipeline systems. Ms. Michelle Novak, Legal Counsel with Kinder Morgan is also here representing Kinder Morgan.

The Board has asked industry and stakeholders in this Stream 3 proceeding, in essence, what is the most efficient way to deal with the financial matters surrounding the eventual and inevitable abandonment of federally regulated pipelines. Kinder Morgan is of the view that this is an extremely important question. It is happy to participate through its evidence filed to date, and through its witness panel in this hearing composed of Kinder Morgan's Vice President of Regulatory Affairs and Finance, Mr. Scott Stoness, and its Director of Regulatory Affairs, Ms. Brenda McClellan.

Kinder Morgan's evidence is, and will be, that it is reasonably foreseeable that pipeline systems have a certain economic life, and at the end of that economic life the system will have to be abandoned. This is an outcome which requires planning, absent which the pipeline systems may very well be inadequately prepared for abandonment, exposing government, the public, pipeline companies and its shareholders, shippers and those with overlapping interests in land to abandonment costs. To prevent this exposure, Kinder Morgan urges the Board to use this Hearing, and the related processes, to implement policies and procedures to allow for the efficient collection of abandonment funds which will ultimately ensure that the funds are available at the time of the terminal abandonment of the pipeline system in question.

Kinder Morgan recognizes that there are a number of ways to achieve the end goal of ensuring that sufficient abandonment costs are available upon terminal abandonment, and recognizes that reconciling the competing interests is not an easy task. However, Kinder Morgan advocates a number of high level principles which from its perspective are fundamental to making abandonment efficient and workable:

1. While there may not currently be a clear line of sight as to when economic abandonment of any of the major pipelines regulated by the Board will occur, it will eventually occur. It is better to deal with it sooner, rather than later, to reduce or eliminate the future liability by ensuring funds are collected during the viable economic life of the pipeline systems, and from the current and future users of the pipelines.

Kinder Morgan has and will advocate a process whereby reasonable estimates can be made via Stream 4. It is of the view that a reasonable time frame for starting collection is 3 years following the conclusion of Stream 4, which will provide sufficient time for reasonable estimates and the preparation and implementation of the necessary administration mechanisms.

2. That the abandonment funds should be collected from the shippers of the system in the most transparent way possible, which means clearly as part of a toll or an abandonment surcharge. This includes dealing with the important matter of ensuring the new funds being collected address issues related to common carrier and contract systems. Our evidence will discuss details of how we propose this be achieved.

3. That the funds be secured to ensure they are available for actual abandonment when necessary. Kinder Morgan's evidence will advocate a trust fund mechanism based on its' particular suitability in this regard.

4. It is of the utmost importance that the collection of abandonment costs does not cause any unforeseen or unintended competitive inequities between pipeline companies and or pipeline systems.

5. Kinder Morgan will advocate that the Board issue draft guidelines at the end of the Hearing and give industry sufficient time to set up polices and procedures necessary to implement the eventual directives.

In closing, Kinder Morgan thanks the Board for considering industry and stakeholder input and looks forward to participating in the Hearing.

226. **WRITTEN OPENING STATEMENT OF "TRANSCANADA" - Foothills Pipe Lines Ltd., TransCanada PipeLines Limited, NOVA Gas Transmission Ltd., TransCanada Keystone Pipeline GP Ltd.:**

National Energy Board Hearing Order RH-2-2008

TransCanada PipeLines Limited
Foothills Pipe Lines Ltd.
NOVA Gas Transmission Ltd.
TransCanada Keystone Pipeline GP Ltd.
("TransCanada")

Opening Statement

Good morning Madam Chair and Board members. We are pleased to be here today on behalf of TransCanada PipeLines Limited. TransCanada PipeLines directly or indirectly owns and operates the Canadian Mainline, the Foothills Pipe Line System, the NOVA Gas Transmission Ltd. Alberta System and is currently constructing the Keystone Pipeline Project, all of which we will refer to as TransCanada.

The mandate of Stream 3 of the Land Matters Consultation Initiative ("LMCI") process is to consider the financial issues related to pipeline abandonment. This is an important matter. It is important to TransCanada because it owns and operates approximately 40,000 km of pipelines that span the country and the ultimate abandonment costs of these pipelines will be significant.

In its evidence TransCanada has identified key principles that should guide the Board and parties in this process. These are:
• Landowners must not be held liable for the costs of pipeline abandonment;
• The tolling principles of user-pay and cost causation mean that abandonment costs are a legitimate cost of providing transportation service and should be recovered through rates;
• Because this is a cost of service item and to minimize intergenerational inequity, collection should begin as soon as is practical;
• Funds collected for abandonment should be used for abandonment and managed in a way that minimizes the amount of capital that must be collected;
• The framework to collect abandonment costs should be applied consistently among pipelines that transport similar products under similar circumstances;
• Abandonment should be recognized as a process rather than an event; and
• Finally, the commencement of collection should be done in an efficient and cost-effective manner that does not result in material changes in the competitive landscape.

TransCanada believes that the outcome of the Stream 3 process should be a set of formal guidelines issued by the Board that reflect these principles, and that pipeline companies will follow in applying to recover abandonment costs as a toll component. These guidelines should prescribe the creation of independently managed trust funds, into which pipeline companies will direct the abandonment cost component of tolls. These guidelines should also address how the Board will oversee and periodically review the management of and contributions to these trust funds.

Stream 4 of the LMCI process will consider abandonment requirements in technical detail. Estimates of abandonment costs therefore require that the outcomes of the LMCI Stream 4 process be known before abandonment cost estimates can be properly prepared. Once the technical guidelines on abandonment contemplated by Steam 4 are determined, pipeline companies can proceed with an estimate of abandonment costs.

TransCanada also recognizes that it may take some time for each pipeline company to develop an abandonment study. Because TransCanada proposes collecting as soon as practical, TransCanada proposes that in the interim a nominal amount be collected based on, for example, an agreed-to percentage of each pipeline's annual revenue requirement. This nominal charge would not be based on any specific assumptions regarding the scope of pipeline abandonment and would be intended to get the process of collecting abandonment funds started in order to take a meaningful step towards addressing the issue of pipeline abandonment funding.

The purpose of Stream 3 is to consider the financial issues related to pipeline abandonment. TransCanada has proposed an approach to collect abandonment costs as a component of rates that, in its view, balances the interests of pipeline companies, shippers and landowners, and protects the public interest. In closing, TransCanada wants to express its appreciation for the opportunity to present its views on this important issue.

227. **WRITTEN OPENING STATEMENT OF CANADIAN ALLIANCE OF PIPELINE LANDOWNERS' ASSOCIATION (CAPLA):**

National Energy Board
Hearing Order RH-2-2008

Land Matters Consultation Initiative
Stream 3

Written Opening Statement
Canadian Alliance of Pipeline Landowners' Association

Opening Statement of the
Canadian Alliance of Pipeline Landowner Associations (CAPLA)

January 20, 2009

In accordance with directions provided by the Board upon the establishment of LMCI, this hearing is to determine "the optimal way to ensure that funds are available when abandonment costs are incurred" to fulfill the Board's fundamental principle that "landowners will not be liable for costs of pipeline abandonment." Outcomes to be achieved by the Board in this proceeding include "identification of technical abandonment assumptions to be used to estimate abandonment costs" to relieve landowners of this potential liability.

In its Stream 3 Discussion Paper, the Board proposed establishing a default methodology "to streamline the calculation of appropriate charges." Accordingly, CAPLA has proposed in this proceeding the following "default option" technical assumption for preliminary estimates of abandonment costs:

> *"... removal of large diameter pipelines in agricultural lands where all pipelines in a common corridor have been abandoned. Where one or more pipelines continue to be operated adjacent to abandoned pipelines that have not been removed, those adjacent abandoned pipelines must be maintained as though operating until removal is triggered by the cessation of operation of all pipelines in the corridor … Only in this way can the Board address the concern of all parties 'that financial reserves are available … to cover the costs of the necessary work' and ensure that landowners do not bear the risk of post-abandonment liabilities and costs".*

The removal/perpetual maintenance technical assumption proposed by CAPLA is based upon expert pre-filed evidence which establishes that pipelines simply abandoned in place will inevitably corrode resulting in land use, environmental contamination and safety impacts. Both these conclusions and CAPLA's proposed removal/perpetual maintenance technical assumption are consistent with similar Board and industry conclusions in their analysis of pipeline abandonment issues since 1985. The Board's loss of jurisdiction to address abandonment issues which may arise post-abandonment, and the potential disappearance or insolvency of the company, leaves landowners with the risk of abandonment liabilities and costs for which they may have no regulatory remedy and, in any event, no financial recourse. All of the analysis of these abandonment issues conducted to date endorses removal of large diameter pipes from agricultural lands in default of perpetual maintenance as the only technical option which will provide protection to landowners from this risk.

CAPLA's proposed removal/perpetual maintenance technical assumption as the basis for estimating abandonment costs in Stream 3 is independent of the Board's LMCI Stream 4 consideration of "principles defining the end state of land post-abandonment". Adoption by the Board in Stream 3 of this removal/perpetual maintenance technical assumption will not predetermine the result of either Stream 4 or future abandonment applications, but only assures the availability of sufficient funds for this purpose upon abandonment. In addition to relieving landowners of the risk of abandonment liabilities and costs, such funding provision also addresses the companies' regulatory obligation for abandoned pipeline removal at the time many existing pipelines were constructed (and easement rights acquired), and equivalent legal obligations which continue to exist in other jurisdictions, under recent NEB landowner settlements and as proposed by CAPLA in LMCI Stream 1 as mandatory minimum easement agreement provisions. Again, the expert evidence pre-filed by CAPLA in this proceeding establishes the regulatory feasibility of recovery of such costs.

Therefore, the end result of LMCI Stream 3 and any subsequent related process must be the collection by pipeline companies of funds sufficient to cover the cost of the removal/perpetual maintenance abandonment option. All pipeline companies regulated by the Board must be included and CAPLA proposes that the amounts necessary to fund abandonment costs be collected beginning as soon as possible as tolls by pipeline companies from their shippers. The longer the period of time in which funds can be raised to cover the costs of abandonment, the lesser the impact the collection of costs will have on the parties providing the funds and the lesser the risk to landowners that funds in place at the time of abandonment will be insufficient to cover the costs of abandonment. Immediate commencement of the collection of funds also addresses the risk of intergenerational inequity for shippers.

Preliminary cost estimates should be established through an additional regulatory process immediately following the conclusion of the LMCI Stream 3 process. The Board should require pipeline companies to provide the company specific information identified by the Board as "essential to develop estimates for standard cost elements" regarding the future costs of the removal/perpetual maintenance abandonment option. This secondary process could be established as a generic hearing to design and institute an industry-wide methodology for the estimation of future abandonment costs that would be applicable to all Board-regulated pipeline companies, whether or not they chose to participate in the proceeding. This process could also design and institute a methodology by which the amount of the annual contribution toward the future cost of abandonment would be calculated (based on the estimated remaining life of an individual pipeline). Pipeline companies would then be required to submit to the Board abandonment cost estimates based on the generic method as part of their tolls filings.

Contributions toward a pipeline company's estimated future cost of abandonment would be collected on an annual or more frequent basis as part of the tolls charged to its shippers and as a component separate from depreciation. The amounts collected in respect of future abandonment costs would be accumulated in trust funds to be maintained and administered by an independent third-party trustee. A separate fund would be established in respect of each individual pipeline. The Board would have oversight of the fund collection and management process, and annual or bi-annual reporting on fund performance would be required. Landowners must have a role in the oversight and management of abandonment funds, which may include membership on the boards of abandonment funds and must include funded participation in Board regulatory processes involving the collection and management of abandonment funds.

In addition to its ongoing oversight of fund collection and management, the Board must also institute a process for the regular periodic review of abandonment cost assumptions to ensure that the incremental amounts being collected will be sufficient to cover the future cost of abandonment taking into consideration changes in various factors affecting that cost. Landowners must play a key role in this review process and their participation must be fully funded. The review of the generic cost assumptions established by the Board could be conducted as part of a generic hearing every three to five years. As part of the separate fund performance reporting obligation and review process (including tolls applications), pipelines companies would be required to demonstrate on a regular basis that their pipeline-specific application of the generic cost assumptions remains correct and that their collection of funds remains on target.

Amounts collected in an abandonment fund to cover the future cost of abandonment would be available only to cover the costs of abandonment activities which have been approved by the Board as a result of a s.74 abandonment application. As with all other Board regulatory processes in which the interests of landowners are directly affected, landowners must have a full and meaningful role in the abandonment application process and their participation must be fully funded. CAPLA submits that the cost of landowner engagement in the abandonment regulatory process is a proper cost of abandonment that should be included in the Board's determination of abandonment cost estimates. Access to amounts in abandonment funds required to cover Board-approved abandonment costs would require Board assent and compliance with any other conditions established as part of the trust underlying the fund.

To address the very real possibility that one or more pipeline companies in the future may be financially unable to address abandonment funding shortfalls (where the amounts collected are insufficient to cover the cost of abandonment at the time the

cost is incurred), in which case landowners will be left at risk for the costs and liabilities associated with abandonment, the Board must also institute an alternative source of funding available to cover "orphan pipelines". CAPLA suggests that this alternative source of funding could be an orphan pipeline fund created by the Board to which each regulated pipeline company would be required to contribute (including the contribution of surplus amounts in abandonment funds left over following the completion of abandonment activities for particular pipelines) or it could be a legislated obligation on the part of government to cover the cost of pipeline abandonment where a pipeline company defaults on that obligation.

One way or another, the outcome of the LMCI Stream 3 process and any subsequent related process must be the fulfillment of the Board's fundamental principle that "landowners will not be liable for costs of pipeline abandonment." All landowners whose lands are affected by Board-regulated pipelines must be protected, regardless of the financial capacity of the pipeline companies who own the pipelines. CAPLA urges the Board to push forward immediately with the implementation of pipeline abandonment funding mechanisms based on the proposed removal/perpetual maintenance technical assumption to be adopted in this proceeding.

228. **MR. CROWTHER:** Thank you, Madam Chair.

229. As I indicated earlier, Enbridge Pipelines Inc. is presenting a panel of three witnesses.

230. Seated closest to you is Dr. Robert Mansell, professor of economics, Academic Director, School of Policy Studies and fellow of the Institute for Sustainable Energy, Environment and Economy, University of Calgary.

231. Next to Dr. Mansell is Mr. Michael Hrynchyshyn, Director, Special Projects and Research for Enbridge Pipelines Inc.

232. Madam Chair and Members, you may note that Mr. Hrynchyshyn has been so kind as to allow us to include a phonetic spelling on his name card, which it is hoped will assist parties with pronunciation.

233. Seated furthest from the Board is Mr. Peter Douvris, Manager, Special Projects for Enbridge Pipelines Inc.

234. May the witnesses be sworn, please?

PETER DOUVRIS: Sworn/Assermenté
MICHAEL HRYNCHYSHYN: Sworn/Assermenté
ROBERT MANSELL: Sworn/Assermenté

235. **MR. CROWTHER:** The curriculum vitae of the witnesses were filed under cover of my letter dated January 7, 2009 and have been pre-assigned Exhibit Numbers C-10-13B for Mr. Douvris; C-10-13C, Mr. Hrynchyshyn; and C-10-13D, Dr. Mansell.

--- EXAMINATION BY/INTERROGATOIRE PAR MR. CROWTHER:

236. **MR. CROWTHER:** Gentlemen, in each of your cases, was the curriculum vitae as I have just described and as identified by the relevant exhibit number either prepared by you or under your direction and control and is it accurate, to the best of your knowledge and belief, Mr. Douvris?

237. **MR. DOUVRIS:** Yes, it was.

238. **MR. CROWTHER:** Mr. Hrynchyshyn?

239. **MR. HRYNCHYSHYN:** Yes.

240. **MR. CROWTHER:** And Dr. Mansell?

241. **DR. MANSELL:** Yes.

242. **MR. CROWTHER:** Madam Chair, you will note from his CV that Dr. Mansell has provided evidence in several prior National Energy Board proceedings and has been accepted by the Board as an expert witness.

243. Unless you would prefer that I do so, I don't propose to engage Dr. Mansell in an examination of his qualifications today, but I would nevertheless request that the Board accept him as an expert witness in economics and matters of pipeline regulation.

244. **THE CHAIRPERSON:** Mr. Crowther, the Board accepts Dr. Mansell as an expert in economics and in matters of pipeline regulation.

245. **MR. CROWTHER:** Thank you, Madam Chair.

246. As explained in my January 7th, 2009 letter to the Board, which I believe is Exhibit C-10-13A, Mr. Hrynchyshyn and Mr. Douvris are appearing to address relevant issues arising from the Enbridge Pipelines Inc. pre-filed evidence, including

responses to information requests.

247. The relevant exhibits are as follows: C-10-3B being the document dated September 5, 2008 and entitled Written Evidence of Enbridge Pipeline Inc.; C-10-5B, the Enbridge responses to CAPP Information Request No. 1; C-10-6B, the Enbridge responses to CAPLA Information Request No. 1; C-10-7B, the Enbridge responses to Kinder Morgan Information Request No. 1; C-10-8B, the Enbridge responses to NEB Information Request No. 1; C-10-9B, the Enbridge responses to TCPL Information Request No. 1; C-10-10B, the Enbridge responses to NEB Information Request No. 2; C-10-12B, being the document dated December 17, 2008 and entitled "Reply Written Evidence of Enbridge Pipelines Inc."; C-10-14B, the Enbridge response to NEB Information Request No. 3 and; finally, the Opening Statement of Enbridge Pipelines Inc. dated January 16, 2009.

248. I appreciate an exhibit number has not been assigned to the Opening Statement and it will form part of the transcript of today's proceedings.

249. Mr. Douvris and Mr. Hrynchyshyn, were the documents that I have just listed and described prepared by you jointly or under your joint direction and control? Mr. Douvris?

250. **MR. DOUVRIS:** Yes.

251. **MR. CROWTHER:** And Mr. Hrynchyshyn?

252. **MR. HRYNCHYSHYN:** Yes.

253. **MR. CROWTHER:** Are there any corrections that you would care to make to any of those documents, Mr. Douvris?

254. **MR. DOUVRIS:** No.

255. **MR. CROWTHER:** Mr. Hrynchyshyn?

256. **MR. HRYNCHYSHYN:** Yes, Mr. Crowther. Although I have no corrections to make to the Enbridge pre-filed evidence or responses to information requests, in reviewing these documents in preparation for my appearance here today, it occurred to me that Enbridge may have unintentionally left room for some misunderstanding about the Enbridge proposal in this matter.

257. To clarify, Enbridge's proposal is that before any pipeline company should be required to commence collection of abandonment funds, certain key details need to be resolved; one example being income tax treatment.

258. We would be happy to elaborate on these details should the Board or any party have questions or require further information in this regard.

259. Once these key details have been resolved, then all NEB-regulated pipelines would be required to begin collecting abandonment funds unless the NEB were to approve deferral of collection. The Enbridge materials discuss the sort of considerations that should factor into a decision about deferral, but we would also be happy to elaborate on these points as well.

260. Thank you, Mr. Crowther.

261. **MR. CROWTHER:** Thank you for that, Mr. Hrynchyshyn.

262. Gentlemen, with Mr. Hrynchyshyn's clarification, are the documents that I have previously listed and that we have been discussing accurate to the best of your knowledge and belief? Mr. Hrynchyshyn?

263. **MR. HRYNCHYSHYN:** Yes, subject to that clarification.

264. **MR. CROWTHER:** And Mr. Douvris?

265. **MR. DOUVRIS:** Yes.

266. **MR. CROWTHER:** Do you adopt the documents as part of your evidence and the evidence of Enbridge Pipelines Inc. in this proceeding, Mr. Hrynchyshyn?

267. **MR. HRYNCHYSHYN:** Yes, I do.

268. **MR. CROWTHER:** And Mr. Douvris?

269. **MR. DOUVRIS:** Yes.

270. **MR. CROWTHER:** Madam Chair, as also explained in my January 7, 2009 letter to the Board, Dr. Mansell is appearing to address the Wright Mansell Research Ltd. report entitled "Evaluation of Alternative Funding Horizons for Facility Abandonment".

271. Dr. Mansell, you, sir, are the President of Wright Mansell Research Ltd.; correct?

272. **DR. MANSELL:** I am.

273. **MR. CROWTHER:** Was the document that is attached as Appendix A to the Reply Written Evidence of Enbridge Pipelines Inc, Exhibit C-10-12B, as I have just described entitled "Evaluation of Alternative Funding Horizons for Facility Abandonment" and dated December 17, 2008, prepared by you or under your direction and control?

274. **DR. MANSELL:** It was.

275. **MR. CROWTHER:** Are there any corrections that you would care to make to that document, sir?

276. **DR. MANSELL:** No.

277. **MR. CROWTHER:** And do you adopt it -- rather, is the document accurate to the best of your knowledge and belief?

278. **DR. MANSELL:** Yes.

279. **MR. CROWTHER:** And do you adopt it as part of your evidence in this proceeding?

280. **DR. MANSELL:** I do.

281. **MR. CROWTHER:** Madam Chair, that concludes my examination in-chief. The witnesses are now available to answer questions.

282. Thank you.

283. **THE CHAIRPERSON:** Thank you, Mr. Crowther.

284. I understand that the first party who wishes to cross-examine Enbridge's panel is Kinder Morgan. If I'm mistaken -- no. Then let's proceed.

285. **MR. FORRESTER:** Kinder Morgan does not intend to cross-examine Enbridge. Thank you.

286. **THE CHAIRPERSON:** Thank you very much.

287. Pouce Coupé Pipe Line Ltd?

--- (A short pause/Courte pause)

--- EXAMINATION BY/INTERROGATOIRE PAR MR. JEFFREY:

288. **MR. JEFFREY:** Thank you, Madam Chairman, and good morning.

289. I've passed to Dr. Mansell a complete text of one of his publications that I wanted to refer to. I was only able to speak to his counsel later yesterday and I learned this morning that he was only able to speak to Dr. Mansell about the purpose of my cross-examination this morning and I thought he may want to refer to something else in the entire publication.

290. What I would like to do is focus my questions to you, Dr. Mansell, and start by passing out an excerpt of the publication I've handed to you. That publication is entitled "Traditional and Incentive Regulation".

291. Am I correct that you are the Robert L. Mansell listed as one of the two authors?

292. **DR. MANSELL:** Good morning, sir. That is correct.

293. **MR. JEFFREY:** Thank you.

--- (A short pause/Courte pause)

294. **MR. JEFFREY:** Now, Dr. Mansell, I've handed to you a couple of excerpts that are stapled together; namely pages 54 through 56, and pages 171 and 172.

295. Can you confirm that that excerpt is from the publication?

296. **DR. MANSELL:** It is.

297. **MR. JEFFREY:** Okay, thank you.

298. And if you would let me know when you've had a chance to review that and are ready for questions I'd appreciate it.

--- (A short pause/Courte pause)

299. **DR. MANSELL:** Sir, it does look familiar.

300. **MR. JEFFREY:** Thank you. And I recognize that the document was published over a decade ago. Looking specifically at pages 54 to 56, is it your view that those principles or regulatory objectives and criteria are as valid today as they

were when you wrote the report?

301. **DR. MANSELL:** Yes, I believe they are.

302. **MR. JEFFREY:** All right. I'd like to take your attention specifically to the fifth of those, on page 55, the regulatory burden, and perhaps take a moment by way of context, if that would help yourself and listeners to understand the exchange I want to have with you.

303. Pouce Coupé has recommended that there be what might often be called a lighter handed regulatory approach to a pipeline company accessing any fund that's established for protecting landowners from having to bear any costs of abandonment. Most other parties have suggested that accessing the funds ought to follow regulatory approval or application of some kind.

304. I can take you to the specific parts of Pouce Coupé's evidence but it suggests that a pipeline company can access the funds as and when required but that would of course be subject to reporting obligations, audit, risk and intervention or enforcement by the regulator if necessary, as opposed to each and every occasion having to conduct a regulatory process, so that's the context.

305. And I'd like to ask you, sir, if you would agree that economic efficiency would be greater or, put another way, the regulatory burden would be lower under the scenario that Pouce Coupé has described.

306. **DR. MANSELL:** As you indicated, there are a number of criteria for considerations listed there. That is one.

307. Typically, there is a trade-off among those -- a decision involves a trade-off among those various criteria. The regulatory burden is one of those, as you've pointed out. Whether or not in the early stages it would be possible to define an efficient light-handed regime which would reduce regulatory burden is not something I've addressed directly.

308. In general, I would think that once the initial issues are dealt with the government -- the fund structure, the governance; all of those things, it would be easier to see what opportunities there are for streamlining or reduced regulatory burden in general.

309. I would agree that it would be sensible, as you're going forward, to look at ways in which one can minimize regulatory burden.

310. **MR. JEFFREY:** So if I understand that, sir, you are saying that it's a

reasonable objective over the long-term, and I take it, for economic purposes, but you don't sound enamoured by the concept to be applied immediately; is that fair?

311. **DR. MANSELL:** There are too many unknowns at this point for me to give you anything more definitive than I have. As you know, there are details that will have to be worked out on governance structure; how the funds would be accessed, the tax structure; possibly some accounting issues. I'm not sure the full range of things that have to be worked out but it is a significant list.

312. Until those are worked out it would be difficult for me to point to specific things where there is the potential for streamlining or other ways of reducing the regulatory burden.

313. **MR. JEFFREY:** Is it your view, sir, that the Board's practice thus far in requiring reporting; for example, of group one companies of auditing the activities of the utilities that it oversees of enforcing breaches has not satisfactorily achieved the objective of behaviour that it desires in an economically efficient manner?

314. **DR. MANSELL:** Could I get you to restate that question?

315. **MR. JEFFREY:** I'm asking if you have reason from the Board's practice so far, in the activities I've described; audits, enforcement, reporting requirements, if those have not been satisfactory in your view to accomplish the objective of a specific kind of behaviour coupled with minimizing the regulatory burden.

316. **DR. MANSELL:** I have not done an evaluation of that and therefore I can't give you an answer.

317. **MR. JEFFREY:** Nothing comes to mind off the top, sir?

318. **DR. MANSELL:** No, I think it's something that one would want to do a fairly complete and thorough study of before one would take a position.

319. **MR. JEFFREY:** All right. Thank you.

320. Madam Chair, those are all of our questions.

321. **THE CHAIRPERSON:** Thank you very much.

322. Spectra...?

--- (No response/Aucune réponse)

323. **THE CHAIRPERSON:** No questions?

324. CAPLA...?

--- (A short pause/Courte pause)

--- EXAMINATION BY/INTERROGATOIRE PAR MR. VOGEL:

325. **MR. VOGEL:** Thank you, Madam Chair.

326. Good morning, panel.

327. **DR. MANSELL:** Good morning, Mr. Vogel.

328. **MR. VOGEL:** Good morning.

329. Mr. Douvris, perhaps we could start with you.

330. Referring to Enbridge's pre-filed evidence, Exhibit C-10-3B. At page 6 in the pre-filed evidence Enbridge is responding to Question 2a at page 5:

> *"What are the technical and financial assumptions which should be used to create preliminary cost estimates?"*

331. And at page 6 in the middle of the page at the bullet points there, Enbridge identifies a number of assumptions that must be made in order to establish preliminary costs.

332. Do you have that there, Mr. Douvris?

333. **MR. DOUVRIS:** I do.

334. **MR. VOGEL:** And one of those assumptions is the second bullet there. I see it relates to the required method of abandonment and the cost of the required abandonment method. Is that correct?

335. **MR. DOUVRIS:** Yes.

336. **MR. VOGEL:** So would Enbridge agree then that in order to estimate abandonment cost you have to have a technical assumption with respect to the method of abandonment?

337. **MR. DOUVRIS:** That's correct.

338. **MR. VOGEL:** And Enbridge then goes on in the following paragraph there to express the view that abandonment in place should be assumed as the required method of abandonment for the purpose of establishing preliminary cost estimates.

339. That's Enbridge's position in this proceeding; is that correct?

340. **MR. DOUVRIS:** Yes.

341. **MR. VOGEL:** But from -- if we turn to page 13 in the pre-filed evidence at Question 6, I take it that Enbridge would agree -- there is discussion of the uncertainties down at the bottom of the page.

342. I take it that Enbridge would agree that uncertainties with respect to the costs that may result from that technical assumption of abandonment in place contribute to the potential risk that at the date of the abandonment, as it says here, the amount of the funds collected and set aside will differ from the abandonment costs that are incurred; correct?

343. **MR. DOUVRIS:** Yes, there is some risk, but we do view that as a temporary assumption which would not have long-term consequences.

344. **MR. VOGEL:** That's fair enough, Mr. Douvris.

345. But we can agree then that for any pipeline it's going to be difficult, if not impossible, to accurately predict the cost consequences of dealing with issues that might be created by this technical assumption of abandonment in place; correct?

346. **MR. DOUVRIS:** Yes.

347. **MR. VOGEL:** All right.

348. And, for example, if the assumption underlying the collection of abandonment cost is abandonment in place and at the time of the event, or subsequently, what is required is the removal of the pipeline, then I take it you would agree that creates a risk that the abandonment funds collected will be insufficient to deal with those actual costs of abandonment; correct?

349. **MR. DOUVRIS:** I mean, that risk would exist if you were to not change your assumption, your initial preliminary assumption, if you were to correct for it in the process leading up to the abandonment.

350. **MR. VOGEL:** Fair enough.

351. But if the assumption is abandonment in place and what ends up at the end of the day is removal, you have this risk that the funds collected are going to be insufficient for that purpose; correct?

352. **MR. HRYNCHYSHYN:** In the scenario that you're positing, that would be a risk, but Enbridge doesn't view that that's how the scenario would unfold.

353. In the key elements that I alluded to in my first comments this morning, one of those is NEB guidance or direction on the appropriate technical standard. We would expect that the appropriate technical standard for abandonment would be established well in advance of the actual abandonment date, Mr. Vogel.

354. The scenario, as I understand you describing it, would be a situation where you've collected for 40 years or some period of time and then you get to the end and you've assumed abandonment in place all these many years and then all of a sudden it's some other assumption as to the technical standard.

355. Enbridge doesn't expect that that's how the process would unfold, that the technical standard -- and we would expect -- as I said, one of our key elements is direction from the Board as to what the appropriate technical standard is that we should ultimately be funding to.

356. **MR. VOGEL:** That's fair enough, Mr. Hrynchyshyn.

357. But sitting here today in January of 2009, and the Board faced with the task of setting a technical assumption to underlie the collection of abandonment costs, if the Board, today, were, for example, to accept Enbridge's proposition that the assumption should be abandonment in place, and if at the end of the day what is required is removal of the pipeline, if there is no such change in assumption over the period of time, you'll agree there's a risk that the funds created will be deficient to deal with the actual abandonment costs; correct?

358. **MR. HRYNCHYSHYN:** I would agree that that's a theoretical risk but, again, I don't see that that's the way the process would ---

359. **MR. VOGEL:** All right.

360. Well, acknowledging that risk, I simply put it to you, Mr. Hrynchyshyn, if we go to page 3, Question 4 in the pre-filed evidence where it says,

"Enbridge sets out its position that landowners will not be responsible for abandonment of Enbridge pipelines nor for the associated costs."

361. Can I take it that Enbridge agrees that whatever that risk is, that the collected fees will be less than the actual cost is not a risk that should be borne by landowners?

362. **MR. HRYNCHYSHYN:** No, sir, I would agree that that's a risk borne by the company.

363. **MR. VOGEL:** Mr. Hrynchyshyn, your counsel suggests you might want to pull that mic closer to you so that you're more audible throughout the room.

364. **MR. HRYNCHYSHYN:** Is this better?

365. **MR. VOGEL:** I think so.

366. **MR. HRYNCHYSHYN:** Okay.

367. **MR. VOGEL:** Well, Mr. Douvris, coming back to you, with respect to the company's obligations to plan for abandonment to ensure that landowners do not bear this at least potential risk of under-funding of abandonment costs, in the Filing Manual Guide B, a copy of which you'll find in the CAPLA Reply Evidence, Exhibit C-1-13G -- that's Appendix E in that evidence, Mr. Douvris.

368. Do you have that?

369. **MR. DOUVRIS:** We'll work off the screen.

370. **MR. VOGEL:** At page 4 B3, at the time of abandonment then in conjunction with the filing of an abandonment obligation, if we look at number 6 on page 4 B3, the company then has an obligation to advise landowners firstly of the Board's loss of jurisdiction to deal with the issues that may arise after abandonment.

371. That's your understanding, correct?

372. **MR. HRYNCHYSHYN:** Sorry, I just couldn't find your reference, Mr. Vogel.

373. **MR. VOGEL:** It's number 6, the last bullet on that page.

374. **MR. HRYNCHYSHYN:** Okay, I see it.

375. **MR. VOGEL:** So the first obligation the company has is to advise the landowners of the termination of the Board's jurisdiction; correct?

376. **MR. HRYNCHYSHYN:** I'm sorry, I'm not intimately familiar with how exactly a Section 74 application would be executed through the Board in terms of the steps of consultation and Board approval. I just don't know the answer to that.

377. **MR. VOGEL:** Mr. Douvris, do you know that you're responsible -- did I see in your CV you are responsible for regulatory affairs or have some responsibility in that regard?

378. **MR. DOUVRIS:** More from a tolling perspective not a facilities application perspective. I did have some involvement in the tolling, commercial aspect.

379. **MR. VOGEL:** All right.

380. And can you agree with me that on -- well, at least with respect to abandonment regulatory obligations are you in a position to agree that there is an obligation as it appears to indicate in the Filing Manual to advise landowners with respect to termination of the Board's jurisdiction on an abandonment application?

381. **MR. DOUVRIS:** Yes, that is what Guide B says.

382. **MR. VOGEL:** And in the second bullet there, similarly, Mr. -- should I be asking these questions to Mr. Hrynchyshyn or Mr. Douvris?

383. **MR. HRYNCHYSHYN:** Either will answer them. Either one of us will answer to as best we can, sir.

384. **MR. VOGEL:** All right. Well, I'll continue with Mr. Hrynchyshyn and you can let me know if I should be talking to Mr. Douvris then.

385. **MR. HRYNCHYSHYN:** Very good.

386. **MR. VOGEL:** All right.

387. In the second bullet the obligation then is on the company to ensure that there is a contingency plan in place to deal with post-abandonment issues, that's part of the company's responsibilities in connection with proposed abandonment?

388. **MR. HRYNCHYSHYN:** I'd say that would be part of the abandonment

filing.

389. **MR. VOGEL:** All right.

390. And so with respect to what some of those issues may be related to, Enbridge's proposal regarding a technical assumption of abandonment in place, they'd need to be addressed by the company then.

391. If you look in the second filing, CAPLA's second filing, Exhibit C-1-9B in this proceeding, at pages 5 and 6 there, starting at the bottom of page 5 and then on to page 6, you have some excerpts taken from the Board's Stream 4 discussion paper as to the issues related to abandonment in place.

392. And you'll see as reviewed -- or as excerpted there, at pages 5 and 6 of this evidence, that includes then corrosion, collapse of the pipeline, the subsidence of the soils over the pipe, Enbridge would agree that that's a potential issue related to abandonment in place?

393. **MR. CROWTHER:** Mr. Vogel, these witnesses are here to speak to the financial aspects of abandonment. They are not here as experts on the process of abandonment; they're not here as engineers or corrosion engineers or corrosion specialists.

394. So I'm not sure they're going to be able to assist you if you begin to ask questions, as you just did, about issues that are associated with abandonment.

395. **MR. VOGEL:** Well, let me ask you this; in connection with this proceeding, Mr. Hrynchyshyn, have you and other Enbridge employees reviewed the background documents and discussion papers going back to the 1985 Board discussion paper and the 1996 and '97 Pipeline Advisory Steering Committee discussion papers which all deal with the nature of the problems that result from abandonment in place and the potential liabilities and costs associated with those issues?

396. Are you familiar with all that material?

397. **MR. HRYNCHYSHYN:** Yes, I've reviewed that -- reviewed the information.

398. **MR. VOGEL:** All right.

399. And can we perhaps then simply agree that there are significant environmental safety land use issues that may result from abandonment in place that

have -- that have costs and liabilities associated with them?

400. **MR. CROWTHER:** Mr. Vogel, I don't think that's a proper question or within the parameters of this proceeding. You asked the witnesses whether they had reviewed the material. Mr. Hrynchyshyn indicated that he had but then you went on to ask whether or not there are environmental consequences associated with abandoning pipelines.

401. I just don't think that's an appropriate question for these witnesses and I object to it.

402. **MR. VOGEL:** And Madam Chair, that's what those reports deal with and I'm simply requesting -- what we're dealing with here is what are the technical issues which may arise with respect to the assumption Enbridge is putting forward and the liability and cost that creates and the challenge I would suggest for the Board here is then to determine how to ensure that landowners don't bear the risk of the liabilities and costs associated with those issues.

403. **THE CHAIRPERSON:** Mr. Crowther?

404. **MR. CROWTHER:** Madam Chair, the issues list that the Board developed in respect of this proceeding includes, as paragraph 2(a) what technical and financial assumptions should be used to create preliminary cost estimates.

405. That is the issue that can be addressed with these witnesses. But what cannot be addressed with these witnesses who are not here to speak to technical matters, is the -- are the technical impacts, the environmental impacts, assumptions about what impacts the abandonment of a pipeline may have on a particular area of land et cetera, et cetera.

406. That's not why these witnesses are here; they're here to speak to financial issues of pipeline abandonment. And we can debate whether or not the assumption of abandonment in place or physical removal is the assumption that ought to be made for purposes of calculating or estimating abandonment costs.

407. But I suggest to you it's not going to be helpful to pursue these witnesses on the underlying technical issues. That's why I objected to the question ---

408. **THE CHAIRPERSON:** Thank you, Mr. Crowther. Please give us a minute.

--- (A short pause/Courte pause)

409. **THE CHAIRPERSON:** Thank you very much for your patience.

410. Mr. Vogel, from the composition and the CVs of this particular panel, we understand that they are not in a position, on an expert basis, to speak to the veracity of the technical aspects of any assumptions that were made.

411. However, we are very interested in having you pursue the line of questioning with respect to the financial assumptions without any cross on the veracity of the actual technical aspects that they have made.

412. **MR. VOGEL:** Thank you, Madam Chair.

413. **THE CHAIRPERSON:** Thank you very much.

414. I think with that, this might be a good time to take a break. Would that work for you, Mr. Vogel?

415. **MR. VOGEL:** It certainly would. Thank you.

416. **THE CHAIRPERSON:** Okay. So it's 10:35. Let's return at 10:50. Thank you, everyone.

--- Upon recessing at 10:34 a.m./L'audience est suspendue à 10h34
--- Upon resuming at 10:50 a.m./L'audience est reprise à 10h50

417. **THE CHAIRPERSON:** Mr. Jeffrey.

418. **MR. JEFFREY:** Thank you, Madam Chairman.

419. I neglected, in the course of my cross-examination, to ask for an exhibit number for the document I put to the witness, and since he did corroborate its accuracy, I would like an exhibit number for this for the record.

420. **THE CHAIRPERSON:** Could we have an exhibit number for that, please?

421. **THE REGULATORY OFFICER:** Thank you.

422. That will be Exhibit C-19-10. And the witnesses list that was filed by Pouce Coupé this morning would be C-19-9.

--- EXHIBIT NO./PIÈCE No. C-19-9:

Witness List filed by Pouce Coupé Pipe Line Ltd.

--- EXHIBIT NO./PIÈCE No. C-19-10:

Pouce Coupé Pipe Line Ltd. - Hearing Exhibit - Traditional and Incentive Regulation

423. **THE CHAIRPERSON:** Thank you, Mr. Jeffrey.

424. Mr. Vogel, please continue.

425. **MR. VOGEL:** Thank you, Madam Chair.

PETER DOUVRIS: Resumed
MICHAEL HRYNCHYSHYN: Resumed
ROBERT MANSELL: Resumed

--- EXAMINATION BY/INTERROGATOIRE PAR MR. VOGEL: (Continued/Suite)

426. **MR. VOGEL:** Mr. Hrynchyshyn and Mr. Douvris, recognizing that neither of you are engineers, can we simply agree that Enbridge's proposed technical assumption of abandonment in place has the potential to create a risk of liabilities and costs on abandonment.

427. Can we agree with that?

428. **MR. HRYNCHYSHYN:** Actually, Mr. Vogel, I would not agree with that, and I'll tell you why. Enbridge views that the interests of its shareholders and landowners are aligned on this issue.

429. That is to say that Enbridge views that abandonment costs in whatever form are ultimately part of the cost of service and ought to be recovered in full from its shippers during the time -- while the pipeline is providing service.

430. Enbridge shareholders would view that as that the company ought to and is entitled to make a full recovery of those costs, whatever form abandonment is ultimately required.

431. So it's also in the company's interest to ultimately collect the right amount for abandonment.

432. Now, it's our view that the necessary funds will be collected. The use or

our suggestion as to the abandoned in place assumption was -- in our view, that was sort of a temporary or short-term assumption. Enbridge's view is that the appropriate technical standard for abandonment that direction on that ought to come from the Board.

433. The Board has established the Stream 4 process to address the technical issues and Enbridge's view is that the Board ought to provide to its regulated company's direction on ultimately the appropriate form of abandonment is.

434. Now, there is a more practical reason why we advocated that assumption in the near term, Mr. Vogel, and that is that while we can't envision every outcome from this proceeding, one outcome that we did envision, potentially, was that the Board may require companies to be in collection before the elements that I referenced in my earlier comments this morning, before those elements were all in place.

435. Our view was that those five elements ought to be in place before collection commences for anybody, but in the outcome that collection was required, our view was that if -- and sorry, I mentioned the tax -- resolution of the tax issue but one of the other key elements we felt was guidance from the Board on the technical abandonment standard.

436. If we were required to be in collection before that guidance was provided, in our view it was unlikely that we would have resolution to the tax issue as well. And we felt it was a reasonable assumption to proceed with abandoned in place until such time as that technical assumption could be more properly directed by the Board.

437. **MR. VOGEL:** And thank you for that, Mr. Hrynchyshyn, but I think my question is actually much more simple than that.

438. Would you agree with me that if pipelines are abandoned in place there will be costs and liabilities at the time of abandonment and potentially post-abandonment, related to that abandonment in place; can you agree with that?

439. **MR. HRYNCHYSHYN:** I'm not sure what types of liabilities you would be referring to.

440. **MR. VOGEL:** Well, there are costs and liabilities with respect to the issues that may arise with respect to abandonment of costs -- of pipelines in place. Would you agree with that?

441. In other words, if a pipeline is abandoned in place there will be certain costs and liabilities incurred at the time of abandonment and potentially thereafter as issues may arise with respect to those pipelines abandoned in place.

442. Do you agree with that?

443. **MR. HRYNCHYSHYN:** Yes, I would think that -- yes, I would think that there may be some potential ongoing costs or liabilities associated.

444. **MR. VOGEL:** Thank you, and that's really my question.

445. And I think you've already told me this, Mr. Hrynchyshyn, but Enbridge then agrees that this risk for post-abandonment, liabilities and costs, Enbridge agrees that that's not a risk the landowners should have to bear; correct?

446. **MR. HRYNCHYSHYN:** Just a minute, Mr. Vogel.

--- (A short pause/Courte pause)

447. **MR. HRYNCHYSHYN:** Could you repeat your question, Mr. Vogel, please?

448. **MR. VOGEL:** With respect to this potential risk created with respect to the abandonment of facilities in place, Enbridge agrees that's not a risk that should be borne by landowners; is that correct?

449. **MR. HRYNCHYSHYN:** Yes, that's correct, but I would expect that the abandonment requirements, the technical requirements under abandon in place would work to minimize those risks.

450. **MR. VOGEL:** All right. If I can take you back to page 3, Question 4 of Enbridge's pre-filed evidence, Exhibit C-10-3B, am I correct as it appears from the answer that appears there that Enbridge's proposal is that the landowners' protection is afforded by Enbridge's confidence that it will have more than sufficient financial means to satisfy its pipeline abandonment obligations.

451. Is that what Enbridge is proposing to deal with this potential risk?

452. **MR. HRYNCHYSHYN:** Enbridge's confidence in that stems first and foremost from its ability to collect and set aside the appropriate funds for abandonment from its shippers, that that will be the primary and likely the only required source of -- we would expect it to be the only required source of funding to effect pipeline abandonment.

453. **MR. VOGEL:** But in the event there is a deficiency such as, I think, Mr. Douvris acknowledged might exist if -- and I think you yourself acknowledged might

exist -- at the end of the day Enbridge's proposal as it appears on page 3, Question 4, is that the risk for landowners is addressed by Enbridge's financial status.

454. Is that correct?

455. **MR. CROWTHER:** Mr. Vogel, I think you're going to have to be clearer on what deficiency at the end of the day you think the witnesses acknowledged.

456. **MR. VOGEL:** Well, I think it was clear when I put to Mr. Douvris, Madam Chair, this morning the scenario of an assumption being in place throughout the collection period of abandonment in place and, at the end of the day or thereafter, the pipelines having to be removed, that that has the potential of creating a deficiency in abandonment funding. So that's what I'm talking about, Mr. Hrynchyshyn.

457. And with respect to the existence of a deficiency at the end of the day, am I correct from this response to Question 4 that Enbridge is suggesting that landowners can be -- look to Enbridge's assets and have Enbridge's confidence that there will be sufficient financial means to satisfy its pipeline abandonment obligations? Is that correct?

458. **MR. HRYNCHYSHYN:** Yes, to reiterate, our expectation is that that funding will come from tolls charged over the next whatever period the pipeline remains in service and those funds will be set aside and will be collected and in a manner that will allow them to accumulate to the appropriate amount of funds required at the end of the day to effect abandonment.

459. **MR. VOGEL:** But Mr. Hrynchyshyn, to the extent that there may be a deficiency, is Enbridge suggesting that landowners should be looking to Enbridge's financial status at the time to satisfy that risk?

460. **MR. HRYNCHYSHYN:** My understanding is that the liability is on the company and so therefore it would follow that if there was additional funds required beyond what had set aside, that that obligation falls to the company.

461. **MR. VOGEL:** And we're talking about abandonment in this context theoretically. We don't know when any particular abandonment might occur at this point in time.

462. Is that correct?

463. **MR. HRYNCHYSHYN:** That is correct.

464. **MR. VOGEL:** All right. And so we don't know what point in time, really, we're talking about, do we? We don't have a date set?

465. **MR. HRYNCHYSHYN:** No, sir. Sorry.

466. **MR. VOGEL:** Go ahead.

467. **MR. HRYNCHYSHYN:** I was going to say that, no; we don't have a date for abandonment. Enbridge expects that it will be in business for a long time to come. We sit adjacent to one of the world's great deposits of natural resources and we expect that that will keep us in business for decades to come.

468. **MR. VOGEL:** But I'm concerned, Mr. Hrynchyshyn, with respect to what comfort the landowners can derive from Enbridge's financial status at that time. So we don't know when abandonment might occur and if I can take you to your response to NEB IR Number 2.3 which is Exhibit C-10-10B in this proceeding, at page 3.

469. Enbridge dealing with exactly that time of abandonment says in that response, at subparagraph (a) that it doesn't know what its assets might be. It says it cannot be known at present; correct?

470. **MR. CROWTHER:** Mr. Vogel, it says the precise mix of assets cannot be known.

471. **MR. VOGEL:** It does say the precise mix of assets cannot be known. Is it correct that not knowing the date of abandonment Enbridge is not in the position today to advise the Board as to what its mix of assets or even what those assets themselves might be at some unknown date in the future?

472. Is that correct, Mr. Hrynchyshyn?

473. **MR. HRYNCHYSHYN:** Yes, given our expectation of how long we expect to be in business I would not be able to specify what that -- what the company's balance sheet might look like decades into the future.

474. Although whatever the company expects to operate as a going concern so whatever assets would be there at the time would be there to provide or backstop any hypothetical deficiency that may come up.

475. **MR. VOGEL:** Fair enough but sitting here today we don't know what those assets may or may not be or the mix of them; correct?

476. **MR. HRYNCHYSHYN:** That's correct.

477. **MR. VOGEL:** All right.

478. And of course with respect to any post-abandonment liabilities that might occur and the costs that might be identified, 10 or 20 or 30 or 50 years after the abandonment, in the event of some of these issues arising with respect to these pipes abandoned in place, you'd agree with me that we don't have any better idea today as to what Enbridge's financial status might be at that point in time or in fact if there would be any assets available at that point in time in order to deal with these costs.

479. You'd agree with that?

480. **MR. HRYNCHYSHYN:** Yes, beyond abandonment I also don't know what the balance sheet might look like.

481. **MR. VOGEL:** Thank you.

482. And the problem, of course, Mr. Hrynchyshyn, is that -- it's identified by the Board in its Stream 3 Discussion Paper -- you'll find the excerpt in CAPLA's second filing at page 5. This is Exhibit C-1-9B.

483. **MR. HRYNCHYSHYN:** Sorry, did you say B or D?

484. **MR. VOGEL:** B as in Bob.

485. Do you have the excerpts there at page 5, Mr. Hrynchyshyn?

486. **MR. HRYNCHYSHYN:** Yes, I do.

487. **MR. VOGEL:** So these are excerpts from the Stream 3 Discussion Paper and it's -- what the Board poses there is that costs could be incurred when there may not be sufficient revenue to cover them.

488. And those costs, in the second bullet there, you'll see the Board has identified as the financial obligation of the company. Enbridge doesn't disagree with these observations, does it?

489. **MR. HRYNCHYSHYN:** The four bulleted points there?

490. **MR. VOGEL:** Well, let's just deal with the top two; the two that I pointed out to you; that costs may be incurred when there isn't sufficient revenue to cover them and those costs are the financial obligation of the company. You don't

disagree with those observations do you?

491. **MR. HRYNCHYSHYN:** No, I do not.

492. **MR. VOGEL:** All right.

493. And similarly, as expressed by the Pipeline Advisory Steering Committee you'll find those excerpts over on the reply evidence which is C-1-13B, at page 7.

494. These are from the legal issues, 1997 legal issues paper by PASC. You see the bullet points there, the second and third one? The legal obligation on the part of a pipeline operator may exceed the life in fact of the operator and leaving the landowner liable for loss or injuries suffered as a consequence of improper abandonment.

495. Enbridge doesn't disagree with that analysis does it?

496. **MR. CROWTHER:** Mr. Vogel, since you're asking the witness legal questions, why don't we wait for argument to address that?

497. **MR. VOGEL:** Well, let me ask you an accounting question if I dare be so bold. Is it fair to say that the obligation on a pipeline operator that its obligations -- financial obligations as an accounting matter may exceed the life of that entity?

498. **MR. HRYNCHYSHYN:** In the theoretical or hypothetical?

499. **MR. VOGEL:** Yes.

500. **MR. HRYNCHYSHYN:** Yes, that is -- that's possible.

501. **MR. VOGEL:** All right. Which may mean -- all right, that's fine.

502. So if we accept the Board's and PASC's premise in these excerpts that we just looked at, that there may be post-abandonment costs and liabilities for which Enbridge is no longer around to answer, does Enbridge agree and accept that its obligation in planning for abandonment to make provision for such abandonment costs and liabilities?

503. That's one of the contingencies for which Enbridge is responsible, is that not correct? Under the Filing Manual.

504. **MR. HRYNCHYSHYN:** Sorry, I was just looking at the Guide B requirements for costs associated with the banning of facilities.

505. Sorry, can you repeat your question?

506. **MR. VOGEL:** It's a simple question, Mr. Hrynchyshyn.

507. Would you accept that part of Enbridge's responsibility under that Filing Manual requirement is to address contingencies with respect to post-abandonment liabilities and costs that may arise so as to protect the landowner? That's Enbridge's responsibility isn't it?

508. **MR. CROWTHER:** Can you help me, Mr. Vogel, which filing requirement in the manual, please?

509. **MR. VOGEL:** In the reply evidence, again, C-1-13G, at page 4(b)(3) and the requirements are the requirement that I previously put to the witness panel which was expressly to develop a contingency plan to put in place, to protect the landowner should subsequent land issues arise following abandonment.

510. **MR. HRYNCHYSHYN:** Abandonment of the facility and surrender of the easement. Yes, I see that.

511. **MR. VOGEL:** All right.

512. Now, do you accept then that as part of Enbridge's responsibilities under this Filing Manual requirement, with respect to abandonment, to develop -- to address the potential for these post-abandonment costs and liabilities so as to protect the landowner?

513. **MR. HRYNCHYSHYN:** Well, again, I'm not a section 74 expert, but as I read that section and the section under abandonment costs, where if the facilities will be abandoned in place, an itemization of any associated cost. So I believe that would reflect those costs that you're referring to.

514. **MR. VOGEL:** All right.

515. So that's Enbridge's responsibility is to deal with those costs; correct, to protect the landowner?

516. **MR. HRYNCHYSHYN:** Right, where the easement is being surrendered.

517. **MR. VOGEL:** All right.

518. And would you agree, Mr. Hrynchyshyn, that whatever funding provision is made for abandonment liabilities and costs as a result of this Stream 3 proceeding, it must be sufficient so that landowners are not left bearing liability for those liabilities and costs?

519. **MR. HRYNCHYSHYN:** Landowners and shareholders. I would agree with that.

520. **MR. VOGEL:** Fair enough.

521. Now, if we look at the Board's answer to that problem, going back to this 1985 analysis, let's turn to the Reply Evidence. It's Exhibit C-1-13C. And if we look to the 1985 paper which is Exhibit A -- sorry, Appendix A in that document, at page 1, in the right-hand column, the second paragraph down, we read that the Board concluded:

> *"Not surprisingly, the analysis leads to the general conclusion that the best course of action is to either remove or maintain large and medium diameter abandoned pipelines."*

522. Do you see that there?

523. **MR. HRYNCHYSHYN:** I'm sorry; I do not.

524. **MR. VOGEL:** This is in the second paragraph on the right-hand side of page 1 of that document.

525. **MR. HRYNCHYSHYN:** Sorry, now I see the reference.

526. **MR. VOGEL:** And the reference is:

> *"Not surprisingly the analysis leads to the general conclusion that the best course of action is to either remove or maintain large and medium diameter abandoned pipelines."*

527. Do you see that?

528. **MR. HRYNCHYSHYN:** Yes, I do.

529. **MR. VOGEL:** And would you agree with me, Mr. Hrynchyshyn, that that is certainly one solution to ensure that landowners are not required to bear the risk of post-abandonment liabilities and costs associated with abandonment in place? That's one possibility. That's one way to deal with that issue, isn't it?

530. **MR. HRYNCHYSHYN:** Yes, that would be one alternative.

531. **MR. VOGEL:** Okay. And if we look at the Board's analysis as to how that conclusion might be applied to agricultural land, dealing with -- let's turn to CAPLA's initial pre-filed evidence, C-1-6C. And firstly, at Appendix 2 there you'll see excerpted from the 1985 discussion paper, Table 3.4.2.

532. Do you have that?

533. **MR. HRYNCHYSHYN:** Yes, I do.

534. **MR. VOGEL:** All right.

535. And you'll see there then that an agricultural crop land for pipe diameters in excess of 10 inches, the Board's table analysis would require removal of those pipelines.

536. Do you see that?

537. **MR. HRYNCHYSHYN:** Well, I see that in excess of 12 inches that they would -- that we require removal for agricultural for 12 inches dependent on the nature of the -- sorry, for 12 inches dependent on the nature of the land.

538. **MR. VOGEL:** Well, it says in Table 3.4.2 under "Agricultural Crop Lands" starting at diameter 10 inches, the requirement would be removal of all of those pipelines; correct?

539. **MR. HRYNCHYSHYN:** Yes, that's correct.

540. **MR. VOGEL:** All right.

541. And if we look at the more current evolution of that analysis at Tab 3, the next document at Appendix 3, which is Table 1 from the Stream 3 discussion paper, that continues to be the result then for all agricultural lands for pipes with a diameter in excess of 10 inches; correct? That would continue to be the requirement for removal?

542. **MR. HRYNCHYSHYN:** Yes, I see that.

543. **MR. VOGEL:** And similarly, at the Table 2 from Stream 4, which is at Appendix 4 in that document, that's the same requirement removal from agricultural land for pipes in excess of 10 inches in diameter, right?

544. **MR. HRYNCHYSHYN:** Yes, sir.

545. **MR. VOGEL:** So in all of this table analysis from 1985 to date, it appears that the removal of pipes more than 10 inches in diameter from agricultural land has been suggested by the Board as one solution to landowners not bearing the risk of post-abandonment liabilities and costs.

546. Is that correct?

547. **MR. HRYNCHYSHYN:** Yes.

548. **MR. VOGEL:** All right.

549. And then with respect to providing an abandonment fund sufficient to cover the cost of that option, if that were to be the result of this proceeding, or if required by the Board at the time of abandonment, if we can turn to -- Dr. Mansell, if we can turn to your report, which is C-10-12B in the Appendix A to the Reply Evidence?

550. And referring to page 15 in that report, can I take it, Dr. Mansell, that it's Enbridge's position that, as it says here, key variables such as the expected cost of abandonment cannot be reasonably estimated until decisions are taken regarding the required nature of abandonment.

551. Does that accurately reflect Enbridge's position as you understand it in this proceeding?

552. **DR. MANSELL:** Mr. Vogel, those were my words related to the task I was assigned. I wasn't putting them as reflecting necessarily Enbridge's view.

553. **MR. VOGEL:** All right.

554. Mr. Hrynchyshyn, do you accept that as Enbridge's position in this proceeding?

555. **MR. HRYNCHYSHYN:** Enbridge's view is that the required nature of abandonment may not be known until some -- the exact required nature of some of the abandonment may not be known for some time.

556. However, in order to facilitate collection we needed and asked and we're advocating for some guidance from the Board in that regard as to what the appropriate technical standards should be.

557. **MR. VOGEL:** Well, you're not disagreeing with Dr. Mansell, what he says here, that the expected cost of abandonment cannot be reasonably estimated until decisions are taken regarding the required nature of the abandonment? We need that technical assumption in order to come up with the costs, don't we, Mr. Hrynchyshyn?

558. **MR. HRYNCHYSHYN:** Yes, you need to know what you have to do in order to estimate the costs associated with that.

559. **MR. VOGEL:** Okay. And Dr. Mansell, would you agree that if, consistent with the table analysis that I just reviewed with Mr. Hrynchyshyn, the Board were to adopt a technical assumption that pipelines in excess of 10 inches in diameter in agricultural lands will be maintained until removal and not abandoned in place, those abandonment costs based on that technical assumption could be reasonably estimated; correct?

560. **DR. MANSELL:** Sorry, could I just get you to repeat the first part?

561. **MR. VOGEL:** Yes.

562. **DR. MANSELL:** You said less than 10 inches?

563. **MR. VOGEL:** No, pipelines more than 10 inches -- the table analysis is that pipelines more than 10 inches in agricultural lands should be removed. So if that was -- the Board's technical assumption is that pipelines will be maintained in place and then removed and not abandoned in place, the costs of that technical assumption could be reasonably estimated; correct?

564. If you made that assumption, then you could move to the next step which is estimating the cost?

565. **DR. MANSELL:** Yes, I believe that would be an important step in being able to reasonably estimate the cost.

566. **MR. VOGEL:** All right.

567. And that technical assumption, then, could be applied to determine the size of the funds required; correct?

568. **DR. MANSELL:** Yes. That's one of the elements that would be required.

569. **MR. VOGEL:** Okay. And if we look back here -- I'm sorry?

570. **DR. MANSELL:** I forgot to put my mic on. I'm sorry.

571. **MR. VOGEL:** Oh, you can answer the question again.

572. **DR. MANSELL:** Yes, it's one of the elements that would be required in order to ultimately determine the appropriate size of the fund.

573. **MR. VOGEL:** Thank you.

574. And if we turn back to page 6 in your report, I take it, Dr. Mansell, from the bullet that appears at the bottom of that page that it's then the size of the fund required which is going to be the main determinant of some of these other issues as discussed there, like the time horizon required to collect the funds and what's going to be required in terms of the toll surcharge; correct?

575. **DR. MANSELL:** The largest determinants are the ultimate size of the fund, in particular in relation to the revenue requirement; the deductibility of abandonment expenditures; the opportunity cost and, to a lesser extent, differences in returns on the fund.

--- (A short pause/Courte pause)

576. **MR. VOGEL:** Thank you, panel. Those are my questions.

577. Mr. Goudy will also have some questions for this panel.

--- EXAMINATION BY/INTERROGATOIRE PAR MR. GOUDY:

578. **MR. GOUDY:** Thank you. Good morning, panel.

579. **MR. HRYNCHYSHYN:** Good morning.

580. **DR. MANSELL:** Good morning.

581. **MR. DOUVRIS:** Good morning.

582. **MR. GOUDY:** I'd first like to turn you to Enbridge's response to CAPLA Information Request 1.1 which is Exhibit C-10-6B.

--- (A short pause/Courte pause)

583. **MR. GOUDY:** Do you have it there?

584. **MR. HRYNCHYSHYN:** Yes, sir.

585. **MR. GOUDY:** The question is very simple. You can see that what CAPLA asked of Enbridge was several questions regarding, I guess, technical aspects regarding abandonment given Enbridge's view that for the purposes of making preliminary estimates of abandonment costs, abandonment in place should be assumed to be the required method.

586. In response to parts B through F of that information request, Enbridge responded that these issues are not relevant to this proceeding and instead should be considered in the Stream 4 process.

587. Does that remain Enbridge's position today?

588. **MR. HRYNCHYSHYN:** Yes.

589. **MR. GOUDY:** Next, I'd like to turn you to Enbridge's Written Evidence, and it's answer 2(b) which is at pages 6 and 7 in Exhibit C-10-3B.

--- (A short pause/Courte pause)

590. **MR. GOUDY:** So starting at the bottom of page 6 of Enbridge's Written Evidence, Enbridge -- the question was posed:

> *"What process would be appropriate for the Board to consider preliminary estimates for individual pipelines?"*

591. Enbridge provides its response that each company could be required to file an application for approval of preliminary estimates and commencement of funds collection.

592. Do you think that Stream 3 -- given your review and appraisal of the evidence and information that's been filed in Stream 3, is it Enbridge's position that the Board will be in a position to require companies to make or to file applications for such approvals following the conclusion of this Stream 3 process?

593. **MR. HRYNCHYSHYN:** Sorry, it's a very complicated question you asked.

594. **MR. GOUDY:** Sorry. Basically, are we at that point yet? Enbridge has suggested that a next step to consider preliminary estimates would be to require

companies to file an application seeking approval of preliminary estimates.

595. Does Enbridge -- based on the information that Enbridge now has -- the parties have submitted their evidence in this proceeding or written evidence in this proceeding -- does Enbridge still believe that we're at that point following Stream 3 or does something else have to happen before we're going to be at that point?

596. **MR. HRYNCHYSHYN:** Enbridge's view would be that, as noted, we would advocate that some form of guidance in terms of the technical standard of abandonment come from the Board.

597. **MR. GOUDY:** And is that to take place in Stream 4?

598. **MR. HRYNCHYSHYN:** I think that Stream 4 as structured to address the technical assumptions and technical issues associated with abandonment would be of assistance in terms of the Board determining that guidance, but whether that is strictly from Stream 4, no, I would say that the Board would rely on that, utilize that, but it will -- ultimately the guidance would come from the Board.

599. **MR. GOUDY:** Okay. And further in the Written Evidence at the response to Question 3, which is on page 7, the question is:

> *"If companies are required to set aside funds, when should the collection of funds commence?"*

600. And the response provided there is that funds should be -- commencement should be when a reasonably accurate estimate of future abandonment costs can be made.

601. That's Enbridge's position; correct? Does that fairly summarize what the response is?

602. **MR. HRYNCHYSHYN:** Sorry. I think that might be a little oversimplified. We mentioned earlier this morning that we thought there were some key elements that had to be in place before any company would commence collection of abandonment costs and this is perhaps a good opportunity to iterate what those are.

603. And the first one was abandonment -- NEB guidance on the abandonment methodology, the appropriate form, technical assumption, a tax structure that is both efficient and equitable in the treatment of both abandonment costs and funds collected for abandonment.

604. The third element that Enbridge viewed as critical was a funds

management structure and whether that is a trust, most likely, a trust but other options might be available. But if it was a trust, then access to funds, trust governance and the creation of a trust indenture will be key issues in getting us to that point.

605. Enbridge would view the creation and establishment of investment policy and guidelines for those funds as being a critical component, a critical element before funds ought to be collected.

606. And finally, the establishment of an overall governance, update, monitoring and reporting process under the Board's direction and oversight would also be required.

607. Now, having those elements in place for all companies on an individual company basis, the company -- a pipeline company would then presumably be in a position to make an appropriate -- a reasonable estimate based on information we would have today as to what those abandonment costs might be.

608. Beyond that, as we outlined in our position that, you know, this is a very complex process. It's unlike a traditional cost-of-service hearing. We're trying to establish just and reasonable tolls to collect a cost-of-service item that's going to happen under -- with the technology, we can't necessarily know at a date, we can't necessarily know, and we need to somehow, out of that, create an art that would allow us to collect just and reasonable tolls in that regard.

609. What we had advocated, and our position was given that there is such complexity to that process, that there ought to be some level of flexibility in that, and that is our deferral concept, that if the abandonment was -- the time of abandonment was not reasonably foreseeable; that is, that it's beyond some Board-established threshold, that a company would have -- the pipeline company would have the opportunity to apply for and have the Board grant or reject, but on the balance of probabilities that the abandonment event was not within a reasonably foreseeable timeframe.

610. **MR. GOUDY:** Now, that's a lot of information; there's a lot of elements to be determined before you're going to be in a position to decide what amount needs to be collected, right?

611. **MR. HRYNCHYSHYN:** That is a lot of information, a lot of work, but this is a -- this is a complex -- clearly a complex issue with many factors and many considerations to be taken into account.

612. **MR. GOUDY:** Right.

613. And following that process then, Enbridge is also advocating that there may be a deferral of the commencement of collection. Even after you've determined what the cost might be, there'd be a further deferral to appoint where abandonment was reasonably foreseeable.

614. Is that correct?

615. **MR. HRYNCHYSHYN:** Right. That if the abandonment event was beyond some appropriate threshold established by the Board, the company could apply for a deferral.

616. **MR. GOUDY:** So there could be quite a significant delay before the commencement of the collection of funds to go into an abandonment fund; is that correct?

617. **MR. HRYNCHYSHYN:** If you could clarify for me your vision of significant, your view of what's a significant delay?

618. **MR. GOUDY:** Have you given any thought to how many years this might take before you're in a position to begin collecting abandonment funds?

619. Let's break it down into two steps because it's a two-stage process, right? So the first part, coming up with the estimate of how much you need to collect, have you given any thought to how many years that might take?

620. **MR. HRYNCHYSHYN:** It's a little difficult to answer your question because part of the five elements that I have -- that I went through was one of which at least was an item which was sort of beyond either the pipeline company's control or the Board's control, and that was the issue of sort of the appropriate tax structure. That is a Department of Finance -- ultimately a Department of Finance issue.

621. As to the other issues, I could foresee that it would be probably, well, something like 24 to 48 months probably we could have a lot of those items in place. We could have some guidance from the Board. We could, in that period, establish, again, assuming the trust structure is the way to go, the trust indenture and all of the myriad and complex details associated with a trust, but nevertheless we could work towards that.

622. Investment policy guidelines and governance and control monitoring process, you know, those are items, I think, that are achievable in a relatively short period of time.

623. **MR. GOUDY:** So 24 to 48 months, that's two to four years. It could be

more if the tax structure requires change and takes longer to achieve legislative change. Is that correct?

624. **MR. HRYNCHYSHYN:** Potentially, although it certainly would be within the Board's discretion to determine perhaps how long they're prepared to let that issue run.

625. **MR. GOUDY:** And then at least for some pipelines, Enbridge is advocating a further deferral of collection after that period is over. So it would be, you know, two years to four years or maybe more, and then in some cases at least, there would be a further deferral of the commencement of collection?

626. **MR. HRYNCHYSHYN:** Sorry, Mr. Goudy, I need to challenge that a little bit.

627. What Enbridge is advocating is not the deferral. What Enbridge is advocating is a flexibility that would allow a company to apply for a deferral but not necessarily that we're advocating a deferral. All we're seeking is some -- is flexibility in the process overall.

628. **MR. GOUDY:** Well, let's assume that a deferral is made part of the structure for collecting abandonment tolls, because that's what Enbridge has suggested in this evidence, right?

629. **MR. HRYNCHYSHYN:** That's correct, that deferral be an option.

630. **MR. GOUDY:** Doesn't a deferral simply shorten the amount of time in which to collect the necessary funds to cover the cost of abandonment?

631. **MR. HRYNCHYSHYN:** Yes, over the lifespan of an entire pipeline it would, but I don't know that -- I don't believe that's the issue. The issue is, is there still a sufficient period of time to collect the appropriate amount of abandonment funds? And that would be what the Board would be deciding when they are reviewing a deferral application.

632. **MR. GOUDY:** Would you agree that the shorter the time that you have in which to collect abandonment funds, the greater the risk that you will not, at the end of the day, collect the full cost of abandonment?

633. **MR. HRYNCHYSHYN:** Again, Mr. Goudy, my -- Enbridge's view would be that as long as there is a sufficient period of time that that risk is really -- is unchanged.

634. **MR. GOUDY:** So you wouldn't agree that extending the period during which you're collecting the costs would reduce the risk that, at the end of the day, there would be a shortfall?

635. **DR. MANSELL:** Mr. Goudy, I think the point that Mr. Hrynchyshyn is trying to make, if I could give a slightly different take, is that there is a fairly long period of time for the -- in terms of the life of most pipeline systems.

636. What we're asking is when you shorten or lengthen time periods what is the material impact on the risk and is that impact material; technically yes, if you shorten the time period by definition there is fewer years. Does it materially affect the risk relative to the other issues that are involved or other issues that determine risk?

637. So our answer is it depends. It depends on whether you're shortening it from 20 years down to five or whether you're shortening it from 50 years down to 35 years, for example.

638. **MR. GOUDY:** Right. It might also depend on the age of the pipeline and the life expectancy of the pipeline?

639. **DR. MANSELL:** I'll just say that it really depends on the individual circumstances to a great degree and I'll leave it at that.

640. **MR. HRYNCHYSHYN:** We wouldn't -- we wouldn't view the age of a pipeline as being a significant consideration. Pipelines, if properly maintained, would have a life span which is virtually indeterminate; that if proper maintenance is done on pipelines that there's no reason the asset can't last for, as far as I understand, but the asset can last for a considerably long period of time.

641. **MR. GOUDY:** How old is Enbridge's oldest pipeline?

642. **MR. HRYNCHYSHYN:** I'm going to say subject to check, I believe the pipeline was -- the initial pipeline was approximately 1948-1949, which would make it 60 years old, approximately.

643. **MR. GOUDY:** Not looking at the same sort of questions, not from a risk standpoint, a risk that you won't collect enough in the end, but isn't it correct that if you have a set number -- a set abandonment cost for which you need to collect the funds to cover, that the shorter the time period in which you're collecting those funds, the larger the incremental amounts you're contributing must be?

644. So if you were doing it on an annual basis and you were going to be

collecting for a shorter period of time rather than a longer period of time your annual contributions would have to be higher. Is that correct?

645. **MR. HRYNCHYSHYN:** Yes, that would be correct.

646. **MR. GOUDY:** So would Enbridge agree from the standpoint of the shippers who would be contributing to an abandonment fund through tolls that their payments would be lower on an annual basis or on a periodic basis if the period of collection was longer than if the period of collection was shorter due to a deferral?

647. **MR. HRYNCHYSHYN:** The annual amount would be lower but ultimately you would collect the same amount. You're funding towards the same ultimate requirement so you would ultimately collect from your toll-payers the same amount over one period or over another period of time.

648. **MR. GOUDY:** In a shorter period of time to collect, rather than a longer period, wouldn't the risk that there'd be, you know, a shock to the shippers be greater?

649. **DR. MANSELL:** Again, it goes back to what do you mean by shortening relative to the entire time horizon. Within the time horizons that we looked at, for example, in the Wright-Mansell evidence, the impact -- we used as a benchmark, the impact of a 5 percent increase in total. It could be less -- the threshold could be less than that.

650. As you devise the system such that the potential impact in any one year or over a period of time would be more than 5, 6, 7, 8 percent, then yes, that would be a more serious concern.

651. **MR. GOUDY:** So if circumstances changed in the future and the -- say, that the number you had originally thought was going to be the cost of abandonment increases, somewhere down the road, during the collection process, if you'd been collecting for a shorter period of time and you had further to go to complete the collection process, wouldn't -- wouldn't the fact that you'd shortened the period of time during collection and you hadn't moved as far ahead, wouldn't that increase the risk of a rate shock, if circumstances changed down the road?

652. **DR. MANSELL:** Well, in the absolute and the hypothetical situation where we don't have to talk about what the time horizons are, yes. The question again is would it materially increase the risk?

653. Given that there are also costs associated with extending the collection period, including things like the opportunity cost to those contributing to funding. I

mean -- and again, it goes back to one of the points we made; that it depends on how the fund is structured and particularly the investment policy.

654. If there's a big gap between the return on the fund, for example, because it's required to hold only fixed income assets, and the opportunity value funds for the shippers is 15 percent, then there's a huge cost so we're balancing off all of these things.

655. In the abstract and in the hypothetical, all of the things equal, what you're saying is correct.

656. **MR. GOUDY:** Could I turn you to Enbridge's response to NEB Information Request 1.3 which is Exhibit C-10-8B?

657. **MR. HRYNCHYSHYN:** I'm sorry, which was the particular IR in 1.3?

658. **MR. GOUDY:** One point three (1.3), it's at page 3 of 12.

659. In the response Enbridge states:

> *"Each pipeline would likely charge a different level of tolls for abandonment fund collection. Depending on its unique circumstances this could result in declining utilization of some pipelines but not others. Higher tolls could also place NEB-regulated pipelines and the producers that they serve at a competitive disadvantage globally. This could also result in reduced utilization of some pipelines."* (As read)

660. Would you agree that allowing deferrals of the commencement of collection of abandonment costs could also result in declining utilization of some pipelines and I guess inequities in terms of competitiveness as between pipelines that are required to begin commencement of collection of abandonment costs at a certain point and companies that are permitted to defer the collection of abandonment costs?

661. **MR. HRYNCHYSHYN:** Well, first of all, Mr. Goudy, I'm not sure I agree with your characterization in terms of -- as being "inequities".

662. What I think is important is that when we're talking about deferral or not deferring for between pipelines really what you're concerned about is the differential and that differential can also arise if all companies are required to collect and that differential stems from each pipeline company's unique situation with respect to what its particular abandonment will cost.

663. So that situation can arise even if all companies are -- even if all pipeline companies are required to collect. Deferral is not a unique circumstance in that regard.

664. Overall, in terms of competitiveness, Enbridge is of the view that toll -- the actual toll is one element, but it's certainly not the only element in how shippers and producers decide which barrels to ship to which markets and to utilize which pipelines.

665. Toll, like I said, is a component, but it's not the -- and oftentimes it's not usually the most significant component. A shipper or producer will pay 50 cents a barrel more to use a pipeline to get to a market where they get a dollar more per barrel for their product.

666. So what's really, I think, the overriding issue is, you know, what is the larger competitive issue that shippers do not make decisions about which pipelines to utilize or not utilize based on the tolls that they're facing? It's much more complex than that.

667. **MR. GOUDY:** Could I turn you to Enbridge's Reply Written Evidence which is Exhibit C-10-12B? I'm looking at page 5, which is a response to question 9.

668. Enbridge says that landowner participation and fund governance would be inappropriate and then provides a reason related to a qualifying environmental trust, saying that in fact there's some prohibition on landowners being trustees of a -- of such a trust.

669. What about an oversight board as opposed to the actual trustees of a pipeline fund? Would Enbridge see any problem with landowners being part of an oversight board for a pipeline abandonment fund?

670. **MR. HRYNCHYSHYN:** Mr. Goudy, I really find it quite difficult to respond to that question because I'm not exactly sure what you're referring to when you mean an oversight board, what exactly their roles and responsibilities would be.

671. It's fine to say that, I guess, or suggest that, but until Enbridge would be able to understand exactly what that meant, what the terms and conditions and rules and responsibilities were, I'm afraid I just can't respond to that question.

672. **MR. GOUDY:** Well, what's Enbridge's view on what the oversight structure would be for an abandonment fund?

673. **MR. HRYNCHYSHYN:** I think, again, we haven't necessarily fixed all

of the details, but as sort of a thumbnail of what that might look like, that we would expect a process along the lines of the board and the pipeline companies would, through an open process, establish a set of investment guidelines and policies that would then be communicated to the trustees.

674. I may -- I hope I'm not misunderstanding the legal and technical requirements associated with the trust account because I just don't know all the specifics, but you would have that investment policy guideline that the trustees would follow. They would engage investment managers, but the trustees would make all of the decisions for sort of the administration and ongoing investment of the trust fund.

675. **MR. GOUDY:** Would there be any additional oversight by the National Energy Board?

676. **MR. HRYNCHYSHYN:** Absolutely. That oversight would come in the form of what we would expect to be -- or advocate for an annual filing requirement, that we would update the status, the performance of the fund. We think that Enbridge views that as a critical component of the ongoing monitoring and governance of the trust funds.

677. **MR. GOUDY:** Do you see any role for landowners in that oversight process?

678. **MR. HRYNCHYSHYN:** I don't envision that as sort of a hearing process, but the information would certainly be, as all the Board information would be, subject to public scrutiny and review.

679. **MR. GOUDY:** So Enbridge's view on landowner participation in oversight of these abandonment funds is limited to a landowner's opportunity to view publicly available documents?

680. **MR. HRYNCHYSHYN:** I just don't see a process or a requirement that would require more participation or more extensive participation than that.

681. **MR. GOUDY:** Could I turn you to Enbridge's response to National Energy Board Information Request 1.6? It's Exhibit C-10-8B. I'm at page 6 of 12.

682. This is the Board's question to Enbridge regarding the pooling of funds, and you'll see at part (a) of the question it says:

"Who will be liable for costs related to orphan pipelines?"

683. And Enbridge suggests at the very bottom of the response that:

"No further risk mitigation should be necessary."

684. Does Enbridge agree that for -- it may not be for Enbridge's pipelines; it may be for the pipelines of another company -- there is a risk that at the end of the day, at the time of abandonment, there may be insufficient funds in an abandonment fund to cover the cost of abandonment and the company itself may have insufficient financial resources to cover the shortfall?

685. **MR. HRYNCHYSHYN:** Sorry, I missed what the question was there.

686. **MR. GOUDY:** Would you agree that there's a possibility that either for Enbridge's pipelines or for -- for any one of Enbridge's pipelines or for any one of another company's pipelines regulated by the National Energy Board, there is a possibility that at the time of abandonment, there would be insufficient funds in the abandonment fund to cover the cost of abandonment and, at the same time, the pipeline company itself may have insufficient assets to make up the shortfall.

687. Would you agree that's a possibility?

688. **MR. HRYNCHYSHYN:** I would agree that is a risk, but in Enbridge's view, what is critical is establishing a process under the Board guidance which manages that risk appropriately and prudently, and each pipeline under the Board's jurisdiction would be subject to the same standards and the same process.

689. So is there a risk that a pipeline company -- is there a theoretical risk that a pipeline company could run into that possibility? Yes, the theoretical risk exists.

690. What I'm saying is that an appropriately-established monitored, continuous process mitigates that risk.

691. **MR. GOUDY:** But it doesn't eliminate the risk, does it?

692. **MR. HRYNCHYSHYN:** Excuse me.

--- (A short pause/Courte pause)

693. **MR. HRYNCHYSHYN:** Yes, you're unable to eliminate any possibility of risk. You can't eliminate the entire risk but what you can do is -- as I mentioned, you can put the processes and governance in place that allow you to prudently and appropriately manage that risk to an acceptable level.

694. **MR. GOUDY:** But that's dealing with mitigation. If we're talking about

upholding or fulfilling the Board's principle that landowners not be liable for the costs of abandonment at the end of the day and landowners are -- when the Board says "landowners" it's not restricted to Enbridge's landowners, it's all landowners on federally-regulated pipelines.

695. You've acknowledged that there's a risk. There is a theoretical or a hypothetical risk. The proposal that Enbridge has put forward is designed to mitigate that risk but it won't eliminate that risk.

696. Does Enbridge have anything to put forward in terms of dealing with the hypothetical risk that may remain, even in spite of the mitigation measures that are put in place?

--- (A short pause/Courte pause)

697. **MR. HRYNCHYSHYN:** Mr. Goudy, it's not -- Enbridge's view is that it's not -- simply not practical to 100 percent eliminate that risk and, therefore, we don't have anything practical to put in -- to suggest as being put in place to "guarantee" that.

698. Again, Enbridge's view is that an adequately designed, appropriately-designed process with sufficient oversight in governance will reduce that risk and achieve the outcome that stakeholders want out of this process.

699. **MR. GOUDY:** Okay. My last questions deal with a response -- well, part of Enbridge's written evidence which is Exhibit C-10-3B -- it's at page 13 of that evidence, response to Question 5(k).

700. It's a question regarding surplus funds and Enbridge states:

> *"The pipeline companies should retain any surplus funds, as it is bearing both the risk and reward of trust account performance, as described further below."* (As read)

701. Based on that response is it Enbridge's position that Enbridge or a pipeline company generally bears the ultimate risk of under-funding of abandonment costs?

702. **MR. HRYNCHYSHYN:** Yes, and I believe that was our earlier testimony, was that the liability ultimately is upon the company, the pipeline company to effect the abandonment.

703. **MR. GOUDY:** What if the pipeline company is financially unable to make up a shortfall in the abandonment fund? Who bears the risk then?

704. **MR. DOUVRIS:** Excuse us.

--- (A short pause/Courte pause)

705. **MR. HRYNCHYSHYN:** Mr. Goudy, Enbridge's response is that through this process we will create the ability to collect and set aside those funds. That will be the first -- sort of the first element to providing the necessary funds for abandonment, and that will be a rigorous and monitored process over its timeframe.

706. Beyond that the company is there to fulfil any additional abandonment requirements. Beyond that I simply -- I don't know if it's knowable at this point in time who would be there beyond the pipeline company.

707. But Enbridge's view is that first and foremost that the process provides the funds and then; secondarily, the company is there in the unlikely event that there is any further funding required.

708. **MR. GOUDY:** But you would agree with me then that there is -- that the ultimate risk doesn't lie with Enbridge; it doesn't lie with the pipeline company? The ultimate risk, ever so unlikely as it may be, lies with some other party, if the company isn't there -- doesn't have the financial capacity to make up a shortfall?

709. **MR. HRYNCHYSHYN:** I'm not sure what you mean by ultimate risk.

710. **MR. GOUDY:** I asked you -- sorry to interrupt. I asked you previously who bears the ultimate risk for under-funding and you told me it was the pipeline company.

711. But isn't it the case that there's a chance -- there's a possibility -- we're looking many years down the road -- there's a possibility that the pipeline company won't have the financial wherewithal to make up a funding shortfall?

712. So if the pipeline company isn't there, maybe it's gone out of business -- if it isn't there, then it's not the pipeline company that bears the ultimate risk, is it? It's going to be someone else who's going to have to make up that shortfall; isn't that correct?

713. **MR. HRYNCHYSHYN:** Hypothetically, theoretically, that is correct.

714. Again, Enbridge's view is that the process first will provide the funds and then secondarily the company will be there to backstop. Beyond that, it's not -- certainly not noble to me, at this point in time, who -- who in a very remote or

theoretical case that that may fall to.

715. **MR. GOUDY:** Doesn't that affect the response that Enbridge has given here that it's the pipeline company that should retain any surplus funds because it's the pipeline company that bears the risk and reward of trust account performance?

716. **MR. HRYNCHYSHYN:** No, I'm not sure that it does change or affect our response, Mr. Goudy.

717. **MR. GOUDY:** But you've acknowledged that it may be someone else, some other party. Theoretically, it may be some other party that bears the ultimate risk to make up a funding shortfall?

718. **MR. HRYNCHYSHYN:** Right. But the two are mutually exclusive. I mean, if you have surplus funds, by definition you've fully affected the abandonment. So there's no -- there can't be a shortfall.

719. I mean, you only -- you can't have a shortfall and a surplus, to my understanding.

720. **MR. GOUDY:** That's correct, but if there's a surplus -- we're talking about who bears the risk. You've told me in this response or Enbridge has told me in this response that Enbridge or the pipeline company is bearing both the risk and reward.

721. You've acknowledged that the ultimate risk isn't borne by the pipeline company; it's up in the air who bears that ultimate risk if the pipeline company fails.

722. So how can you say that then the reward should go to the pipeline company or to Enbridge?

723. **MR. HRYNCHYSHYN:** Well, in my previous response, beyond the fund -- you know, if the fund were to be insufficient, hypothetically the fund were to be insufficient, then the pipeline company is the next in line and has -- bears that obligation to fund the abandonment requirements. So it does have that first obligation to step up and fill the abandonment requirement.

724. Our view was that from a symmetrical -- sort of a symmetry of risk and reward, that if the company has -- is taking on that responsibility, that obligation, then in the event where there was a surplus and that those -- any leftover funds ought to accrue to the company.

725. But I mean, Mr. Goudy, we're not suggesting in any way that

abandonment is a profit centre. What we're talking about, ultimately, first and foremost, is just making sure we have the right funds in place to effect the abandonment to the required standard.

726. **MR. GOUDY:** Would you agree that there's a risk? If you set up a system in which surplus left over after abandonment costs are covered goes to the pipeline company, the same party that's carrying out the abandonment, wouldn't you agree that there's a risk that the pipeline company will have the incentive to cut corners on abandonment spending because it knows at the end of the day it receives any surplus funds left over?

727. **MR. HRYNCHYSHYN:** No. No, sir, I wouldn't agree with that proposition. The pipeline company's requirement to abandon the pipeline to a technical standard, to my mind, whatever that technical standard happens to be, is the level that the work has to get done to.

728. I don't believe the incentive, if any, is for the pipeline company to manage the required abandonment as specified by the Board in as cost-efficient a method as possible, but I don't -- I disagree that you could -- that the company has an incentive to cut corners because it is required to abandon to a specified technical standard.

729. **MR. GOUDY:** Those are all my questions.

730. **THE CHAIRPERSON:** Thank you, Mr. Goudy.

731. This might be an appropriate time to take a quick five-minute break. So we'll stretch that five-minute break a little bit and come back at 12:30. Thank you.

--- Upon recessing at 12:19 p.m./L'audience est suspendue à 12h19
--- Upon resuming at 12:28 p.m./L'audience est reprise à 12h28

732. **THE CHAIRPERSON:** Thank you very much everyone.

733. Are there any parties here who did not register this morning who wish to register now?

734. **MS. WORTHY:** Good afternoon. Thank you very much. Cheryl Worthy on behalf of BP Canada Energy Company.

735. BP Canada Energy Company is very interested in the land consultation matters initiative and is actively participating in the associations, both CEPA and CAPP. As a result, we are not actively participating on a standalone basis.

736. However, in respect of this stream and this hearing we would like to reserve our right to file final argument, if we determine necessary to do so.

737. Thank you very much.

738. **THE CHAIRPERSON:** Thank you, Ms. Worthy.

739. Just to finish up on the other matter this morning about the definitions, the Board wishes to thank you for your input with respect to the definitions.

740. At this point the Board sees no need to provide further direction with respect to definitions. However, we encourage parties to clarify definitions with witnesses to ensure that all parties are clear on the meaning of the terms that are being discussed.

741. And with that, I'll call on the Alberta Department of Energy for their cross-examination.

742. **MR. KING:** Madam Chair, we have no questions for this panel.

743. **THE CHAIRPERSON:** Thank you.

744. I turn to Board counsel now then. Ms. Saunders, please.

PETER DOUVRIS: Resumed
MICHAEL HRYNCHYSHYN: Resumed
ROBERT MANSELL: Resumed

--- EXAMINATION BY/INTERROGATOIRE PAR MS. SAUNDERS:

745. **MS. SAUNDERS:** Thank you, Madam Chair.

746. Gentlemen, my name is Jody Saunders; I'm representing the Board.

747. I have a number of questions for you today and we'll probably end up spilling into tomorrow as well.

748. **MR. HRYNCHYSHYN:** Good afternoon.

749. **MS. SAUNDERS:** I'll try to not duplicate questions that were asked by other parties, but if you want to refer to a prior response that you've already made, please do so or if you want to supplement one of your responses you've already made.

--- (A short pause/Courte pause)

750. **MS. SAUNDERS:** I want to talk to you, first of all, about Enbridge's proposal regarding deferrals and actually response to Kinder Morgan, IR 1.2 which is Exhibit C-10-7B and it's Adobe page 2 and, as well, if you want to refer to your response to the NEB's IR 1.8D which is C-10-8B. I'll give you a minute to pull those up.

--- (A short pause/Courte pause)

751. **MS. SAUNDERS:** All right?

752. **MR. HRYNCHYSHYN:** Okay.

753. **MS. SAUNDERS:** Okay. Enbridge has stated that deferral of abandonment fund collection by the Board in appropriate circumstances can mitigate any risks from the collection of funds.

754. It also states that the deferral of fund collection is unlikely to impact competitiveness since the expected economic lives of competing pipelines can be expected to be of similar length.

755. You've also indicated that a company could rely on supply and market fundamentals -- supply and market demand fundamentals as support for a request for deferral.

756. A couple of clarifications with respect to your deferral proposal: Would you consider pipelines to be competing if they only had the same supply and not the same market?

757. **MR. DOUVRIS:** In a sense it would be if they were serving different markets. They also could be in competition. But I think Mr. Hrynchyshyn mentioned earlier that their supply market dynamics would probably be the biggest factor in driving where those barrels go.

758. **MS. SAUNDERS:** Okay. With respect to the impact of deferrals to -- on competitiveness, if deferral were considered to be an appropriate option, a flexibility provided by the Board, what sort of process do you see the Board determining who is competing with whom and whether deferral is appropriate in a particular pipeline circumstance?

--- (A short pause/Courte pause)

759. **MR. HRYNCHYSHYN:** Ms. Saunders, if I can maybe take a shot at answering your question there.

760. What -- Enbridge would view competitiveness as a small issue in terms of evaluating a potential deferral application. First and foremost, Enbridge would anticipate that they expect the Board to review that deferral application on the merits of what is appropriate for that individual pipeline in its circumstances, vis-à-vis making sure that the -- ultimately the appropriate level of abandonment funds are required.

761. **MS. SAUNDERS:** Would you anticipate that a deferral granted to one party could impact the competitive -- impact competitive dynamics between parties sourcing from the same supply or sending to the same market?

762. **MR. HRYNCHYSHYN:** Right. And as we said earlier this morning, that the -- what was important is that the -- is the differential toll effect that would be created.

763. But that, as again, as previously indicated, that effect could be -- also could be a result from both -- from each pipeline company all having to collect at the same time because ultimately their abandonment costs and what gets included into tolls is unique and specific to each particular pipeline company. So there may be competitive effects on that basis as well.

764. And again, the other -- Enbridge's other perspective is that we view -- it's certainly our experience that toll is just one -- is one consideration in determining -- or in shippers determining rather, which pipelines into which markets they ultimately send their barrels.

765. **MS. SAUNDERS:** So let me see if I can understand.

766. So your reference to deferral of fund collection being unlikely to impact competitiveness since the expected economical side of competing pipelines can expect to be of similar length doesn't relate necessarily only to the supplier market, it relates, if I understand your evidence that you gave to CAPLA, more to the time horizon of expected abandonment?

767. I'm not sure why supply and market fundamentals were brought up in the context of competitiveness and when you're discussing deferrals.

768. **MR. HRYNCHYSHYN:** Maybe I can explain it this way. Our view of the -- certainly the opportunity, if we -- if that's the outcome of this process, that

deferral -- an application for deferral were to be an opportunity, our view is that all pipeline companies would be able to argue the merits of their particular circumstances and how that might be appropriate for deferral.

769. But our view was that competitive -- the issue of competitiveness, we felt that individual -- or that, sorry, pipeline companies that were similarly situated, in terms of their supply and demand markets, would -- we would expect or anticipate that those pipelines would have similar economic service lives.

770. And that that being one -- a significant consideration in determining whether a deferral was appropriate, i.e. the length of time that a pipeline expects to operate, our view was that, you know, if pipelines that were competitors had those similar fundamentals that they presumably would be similarly situated in terms of their ability to apply for a deferral.

771. **MS. SAUNDERS:** But the granting or the not granting of a deferral is not key to whether there is a differential impact or key to the competitive dynamics between two potentially competing companies? You said the deferral is one aspect that there be -- it's the differentials that's the key.

772. **MR. HRYNCHYSHYN:** Right. Another way to -- like I said, another way to think of it is that even if pipelines were all required to start collecting at -- you know, at the same time, that based on their particular circumstances of geography and where they go and the terrain in which their pipelines are situated, they may well have dramatically different abandonment costs they're ultimately trying to collect for, and that will manifest itself in terms of different tolls for those respective pipelines.

773. So there would be, presumably, some competitive dislocation or disruption even in the event that all pipeline companies were collecting at the same time, because they will not have the same abandonment costs at the end of the day.

774. **MS. SAUNDERS:** Now, with respect to the differentials, whether or not a deferral is granted or appropriate, you had mentioned previously that toll is one element but not the only element and often not the most significant and you gave an example of market prices.

775. What other elements could there be?

776. **MR. DOUVRIS:** Some of the other -- excuse me -- some of the other factors that impact competitiveness or the vintage in cost structure of the pipeline itself. And as well as that it's toll structure and resulting tolls.

777. So the abandonment surcharge alone doesn't determine the competitive

impacts. Those factors all need to be considered.

778. The other thing I'd like to add with respect to the differentials is that the collection periods should be sufficiently long as to minimize rate shock which is an area that Dr. Mansell touches on in his evidence. And I believe that to mean that, you know, it would also minimize those types of impacts.

779. **MS. SAUNDERS:** Can you discuss Enbridge's deferral proposal and how it relates to concepts of intergenerational equity between shippers, present and future?

780. **DR. MANSELL:** Ms. Saunders, I'll try to answer that question but before doing so, so that I don't get off on the wrong track, could you be more specific? You said talk about Enbridge's proposal in the context of intergenerational equity.

781. **MS. SAUNDERS:** Inter ---

782. **DR. MANSELL:** What specific part of Enbridge's proposal?

783. **MS. SAUNDERS:** The proposal to allow flexibility for deferrals. So if a deferral was determined to be appropriate or the flexibility was appropriate and the Board were to determine whether deferrals should be granted, presumably the commencement of collection would be postponed for a period of time, meaning the current shippers aren't contributing to that fund, whereas later shippers will be.

784. So it's the intergenerational equity between the shippers.

785. **DR. MANSELL:** I'll go back to one of the earlier answers I gave and that it really depends on what specific time horizons we're talking about, because it makes a big difference whether it's 20 years or it's from zero to 20 years, 20 to 40 years, 40 to 60 years.

786. If, in the context of 60 years it's a deferral of five years the implications in terms of many things; toll impact and any intergenerational equity issues is much smaller. It's almost insignificant in most cases. So we really have to be clear about the time horizon that we're talking about.

787. But intergenerational equity is one of those criteria -- one of, I'm thinking, 10 to 15 individual principles and criteria the Board and other boards use in setting just and reasonable tolls. So it's just one of many but it's also a very attractive criterion at a high level. It's when you bring it down to an operational level that it's not quite so clear and neat.

788. First of all, one has to look at the existing toll structure. If it's a front-end

loaded toll one could argue that intergenerational equity suggests that the toll should be back-end loaded somewhat, right, that in other words disproportionate share of the total costs should be delay of -- the costs associated with abandonment should be on the later shippers and not the earlier shippers who are already carrying the front-end load. So it really depends on that.

789. And when you look at toll structures for most systems over time there are lots of little bumps in there where there were expansions and then when the front-end loading typically comes into effect.

790. So actually, going from the high level down to actually saying something quantitative about intergenerational equity is not the easiest thing to do and it really depends, again, on the individual circumstances.

791. To some extent -- now, our very definition of intergenerational equity is circular. If you look at, for example, the Board's background paper which I believe is Exhibit A-2C, and I'll just read from it. It says:

> *"Intergenerational equity is a principle that users in any period are generally required only to pay for the costs of providing them with services in that period."*

792. But in determining what the costs are in any one period we've already made assumptions about how we're going to distribute the appreciation for the recovery of capital over time. So it's not as determinant as it sounds at a very high level.

793. In addition, we always run into these issues of how much change there's been on a system over time in terms of the shippers and, also, the incidence of the tolls. Who actually paid them? And you get into these discussions about was it the producer that paid them because they got a lower netback or was it the market that paid them because they paid a higher price?

794. And so, in general, there are many elements that have to be looked at. My view, as I've expressed in this study, is that for the type of surcharge we're envisioning, and I just used 5 percent as surcharge, which is 5 percent of the base toll -- as an example, but it could be 4 percent; could be 6 percent; could be 3 percent; whatever -- a surcharge in that range is unlikely to significantly impact any intergenerational equity or inequity that already exists. In other words, it's unlikely to be the determining factor.

795. So one should not simply just look at this notion of how the toll is distributed or how many years it's distributed over as the only consideration.

796. Again, deferring if you're talking about what the impact of the proposed list to defer it, really until you determine what number of years and in what context; is it five years deferral in the context of 50 years or is it five years in the context of 10 years? It makes a big difference.

797. In the latter case I would say it's probably easy to make an argument that there is an intergenerational equity issue. In the former case where it's a deferral of five years in the context of 60 years, if you look at the total impact and the differential relative to all of those other things that affect the temporal distribution of cost where -- the inner temporal structure of the toll -- relative to those many other factors it's just not a big thing.

798. **MS. SAUNDERS:** Mr. Hrynchyshyn -- sorry -- thank you for the phonetics.

799. In your discussion, I believe, with CAPLA's counsel, you mentioned that deferral won't change -- whether or not there is a deferral that it won't change the amount that has to be collected at the end of the day, something along those lines. It's still the same amount.

800. **MR. HRYNCHYSHYN:** That's correct. Ultimately, the amount that's required is based upon the technical abandonment standard and the timing of the abandonment itself. So that's not affected by whether there is a deferral or not a deferral.

801. **MS. SAUNDERS:** Although the amount that may be required could remain stable, is the amount that needs to be collected very variable? For example, could it be impacted by the amount of interest that you earn so you have a longer period of time over which to compound interest so you need to collect less?

802. **MR. HRYNCHYSHYN:** Yes, that's true but you would also balance -- I believe in a previous answer Dr. Mansell gave you need to balance that against the shippers who are paying the tolls ultimately what their alternatives are for that cash.

803. And I think the example that he said was if, you know, if that difference was 15 percent it would seem to be imposing a much -- a truly high opportunity cost on the ratepayers of the system.

804. **MS. SAUNDERS:** I'd ask you to take a look at the reply evidence of Kinder Morgan, and it's Exhibit C-15-9B and it's on page 3.

805. And as you're looking for it, I'll summarize what it says.

806. Kinder Morgan provides an example of the implications of timing on collection of abandonment funds and concludes that any proposal that allowed parties to defer the collection of abandonment funds could lead to three consequences: deferral of collection of abandonment costs in order to remain competitive; back-end collection of abandonment costs and a greater risk that abandonment costs could not be recovered from shippers because collection may occur in periods of shipper distress.

807. Does Enbridge agree with these collections, and why or why not?

--- (A short pause/Courte pause)

808. **MR. HRYNCHYSHYN:** Ms. Saunders, Enbridge's view is that we would not agree with the comment that any proposal that allowed parties to defer the collection of abandonment costs would lead to those issues.

809. I think we've addressed the issue of competitiveness, toll competitiveness and how that's simply one factor, often one small factor in the determination of how pipelines -- how barrels move on different pipelines, and our view is that a deferral process which had adequate checks and balances was conducted under Board oversight would not lead to a greater risk that abandonment costs could not be recovered from shippers.

810. **MS. SAUNDERS:** If you could turn to Exhibit C-10-8B, and that's your response to NEB IR 1.8(d). And in the response, Enbridge states that:

> *"Longer term collection exposes early payers to the potential for overpayment as estimates for abandonment costs may not be accurate."*

811. Is it possible as well that inaccurate estimates could also result in underpayment?

812. **MR. HRYNCHYSHYN:** Yes, that would be an outcome. We would point out that those determinations of under or over-collecting are only sort of available with the benefit of hindsight.

813. I think that if you make your best estimate at the time with the best available information you have, that that is an appropriate collection of funds, and the comment that this is an over-collection, like I said, is only available through the benefit of hindsight, when you've had those future events unfold different from what your expectations were when you made the original collection estimate.

814. **MS. SAUNDERS:** And I believe in your previous discussions you had mentioned periodic reviews of the estimates as mitigating the risk of over or under-collecting; correct?

815. **MR. HRYNCHYSHYN:** Right. We would view the periodic estimate as an opportunity to revisit a pipeline company's previous expectations and assumptions, to validate those assumptions, to take into account any developments in terms of fund performance or cost estimates, and at some time -- at points in time, maybe to recognize the differences in markets, in technology that will also occur.

816. You know, as I said at the outset, we expect to be in business for a very long time and there will undoubtedly be technological developments which will affect our industry, our shippers and, you know, the benefit, the periodic correction or periodic review would allow then those types of developments to be reflected in toll collection for abandonment costs on a prospective basis going forward.

817. **MS. SAUNDERS:** Beyond a periodic review, are there any other actions that could be taken to mitigate this risk?

818. **MR. HRYNCHYSHYN:** Sorry, which risk?

819. **MS. SAUNDERS:** The risk of either over-collection or under-collection, contingency funds or something along those lines.

820. **MR. HRYNCHYSHYN:** I think Enbridge's view would be that the sort of -- the two responses would be the periodic review process and then an adjustment to tolls were that warranted based on the review process.

821. **MS. SAUNDERS:** So no other steps necessary?

822. **MR. HRYNCHYSHYN:** Enbridge does not advocate any at this time.

823. **MS. SAUNDERS:** That sort of leads me into a line of questions I was going to do a little bit later; so excuse the shuffling of papers.

824. In your response to NEB IR 1.6, which is C-10-8B, and we're looking at page 6 -- in response to a question regarding pooling or financial assurances, Enbridge has stated that an order from the Board requiring companies to collect for abandonment with ongoing regulatory oversight is all the risk mitigation that is necessary. And you further state that it's unclear why there should be any so-called orphan pipelines.

825. And I just want to clarify a term with you. When you use the term "orphan pipeline" do I understand that you mean a pipeline or associated facility which does not have any legally responsible or financially able party to deal with its abandonment and reclamation? Can we use that as the shorthand for orphan pipeline?

826. **MR. HRYNCHYSHYN:** Enbridge can accept that definition.

827. **MS. SAUNDERS:** And I believe in your cross-examination with CAPLA you had indicated that there is a possibility that a risk will exist that there is unfunded or residual risk of unfunded abandonment obligations. Is that correct, a possibility, but ---

828. **MR. HRYNCHYSHYN:** Our view was that there is a theoretical risk, but that, again, a rigorous process with continuous oversight should mitigate that risk.

829. **MS. SAUNDERS:** Are there implications to funding of abandonment if a pipeline is sold in its final years of economic life?

830. **MR. HRYNCHYSHYN:** No, Ms. Saunders, I don't believe that there are any, and I say that for a couple reasons. My understanding is that pipeline were to be sold doesn't mean it has left NEB jurisdiction. In fact, I -- my recollection is that the sale would actually have to go through a Board-approval process, but I may be mistaken.

831. In any event, the mere transfer of ownership wouldn't necessarily -- would not mean that the pipeline has left the Board's jurisdiction and therefore it would continue to fall under its oversight with respect to its abandonment costs.

832. The other comment I would like to make is that -- in Enbridge's view is that the funds should follow the pipeline; that that would be a condition of the sale of the transfer that the trust fund or whatever form of financial asset security has been established to fund future abandonment costs ought to move with the pipeline.

833. **MS. SAUNDERS:** If the funds follow the pipeline and the purchaser of a pipeline is a provincially regulated, falls out of NEB jurisdiction, are there any safeguards now that could be established to deal with the possibility that that provincially regulated pipeline won't have sufficient assets or won't continue to collect sufficient assets to cover the full cost of abandoning that pipeline?

--- (A short pause/Courte pause)

834. **MR. HRYNCHYSHYN:** Ms. Saunders, it would be Enbridge's expectation that in a scenario that you're outlining that the transfer of a pipe would be

subject to -- I'm not sure that -- negotiation is not the right word -- review by the respective regulators and approval by the respective regulators, and I would expect that in that process the review transfer and ultimately the disposition of those abandonment funds is something that would be dealt with in that process.

835. **MS. SAUNDERS:** In CAPP's response to NEB IR 1.8D it indicated that CAPP -- or that at risk companies could be made to provide financial assurances. Did you -- would you agree with that comment?

836. Sorry, it's ---

837. **MR. HRYNCHYSHYN:** I'm sorry; I'm trying to catch up on the reference.

838. **MS. SAUNDERS:** It's Exhibit C-2-7B, and it's their response to NEB 1.8.

839. **MR. HRYNCHYSHYN:** Would you have the reference?

840. **MS. SAUNDERS:** Sorry, the page reference or the ---

841. **MR. HRYNCHYSHYN:** No, I have the ---

842. **MS. SAUNDERS:** Oh, certainly. It's just ---

843. **MR. HRYNCHYSHYN:** I believe I have the reference that you made but I can't remember what your question was.

844. **MS. SAUNDERS:** Do you agree with their evidence that at risk companies could be made to provide financial assurances? And it's in their evidence, 1.8D.

845. **MR. HRYNCHYSHYN:** Ms. Saunders, is the question could the Board require that or are you asking me if that is something that ought to be done, ought to be put in place?

846. **MS. SAUNDERS:** Whether it ought to be put in place.

847. **MR. HRYNCHYSHYN:** Ought to.

848. Enbridge would view that as essentially as a last resort, I would expect. We've outlined what we feel would be a solid process which would provide for the funds, but it may be in the Board's view that sufficient -- that may not be sufficient to

provide a reasonable level of assurance.

849. **MS. SAUNDERS:** In your view, would the risk of abandonment before sufficient funds are collected vary depending on the credit rating of the individual pipeline company?

850. **MR. HRYNCHYSHYN:** Sorry, what was the first part of that question?

851. **MS. SAUNDERS:** Would the risk of abandonment before sufficient funds are collected vary depending on the credit rating of the individual pipeline company?

--- (A short pause/Courte pause)

852. **MR. HRYNCHYSHYN:** Enbridge's view is that we're not sure that that would be the outcome. The idea behind the process -- and one aspect of the process is that the funds are segregated.

853. I can envision a situation where the collection of funds continues, the funds are set aside, put in a trust account, and one of the whole -- one of the reasons for a trust account approach was it provides the security in the event of an insolvency or other disruption in the pipeline company's financial position.

854. So I can see that -- my view would be that the collection of abandonment can cost -- can continue as pipeline has prospects of continuing in business; shippers value the service and continue to pay for transportation service; that the abandonment funds can be collected, set aside in a trust fund and be -- and is independent of the actual company's credit rating.

855. **MS. SAUNDERS:** At page 9 of your initial evidence, it's C-10-3B, Enbridge has indicated that it's opposed to pooling a portion of abandonment funds.

856. Can you explain the rationale for opposing both pooling and the provision of financial assurances?

857. **MR. HRYNCHYSHYN:** If you don't mind, Ms. Saunders, maybe I'll take those into two pieces; the first of which was around Enbridge's rationale for not being in favour of a pooling or a pooled approach.

858. Quite simply that Enbridge would be concerned that pooling would result in cross-subsidization of funds between pipeline companies and by shippers, and that our view was that that wasn't consistent with a view of cost causality; that -- and Enbridge is accountable.

859. Our view is that we are accountable and responsible for our pipelines but that we shouldn't be in a position of having portion or partial responsibility or accountability for anyone else's assets. And I'm sure our peers would probably feel the same way.

860. I'm sorry, I forgot the second issue that you were ---

861. **MS. SAUNDERS:** I think you've already answered with respect to financial assurance which we talked about earlier.

862. The questions on financial assurances and pooling deal with risk of unfunded abandonment costs. You've mentioned cross-subsidization as a reason why you wouldn't want pooling.

863. Are there any considerations that the Board should take into account that would balance cross-subsidization?

864. I think Dr Mansell had mentioned that there is a number of considerations that balance and sometimes they don't all go in one direction. What are the opposing considerations that the Board might take into account to determine whether pooling is ---

865. **MR. HRYNCHYSHYN:** Sorry, in terms of specifically a pooling method?

866. **MS. SAUNDERS:** Or whether pooling is appropriate.

867. **MR. HRYNCHYSHYN:** Well, as I mentioned in my previous response, we didn't feel pooling was consistent with sort of cost causality, that shippers should pay the costs associated with the facilities that they use and given that we're talking about collecting these abandonment costs from shippers, that would seem to be inconsistent with the principle -- or is inconsistent with the principle of cost causality.

868. Other concerns that Enbridge has with respect to pooling -- a pooling approach here is that -- one of which we can see is that whoever is first to access the funds draws on the funds and then those that are -- remain in operation may be faced with the situation of having to replenish the abandonment pool, if you will, to ultimately fund their own abandonment and in effect end up sort of -- they and their shippers end up paying twice for the same abandonment. That would be another concern with pooling.

869. **MS. SAUNDERS:** Are there broader public interest considerations in

terms of deficient and proper reclamation of energy infrastructure that the Board should be taking into account?

870. You've mentioned some shipper-specific and some company-specific things but are there other considerations the Board should take into account?

--- (A short pause/Court pause)

871. **MR. HRYNCHYSHYN:** Ms. Saunders, Enbridge's view would be that ultimately the effecting of abandonment in the appropriate and required fashion, that that abandonment is fully paid for and conducted in the appropriate manner, to the appropriate standards, ultimately is -- it is clearly in the public interest overall.

872. And so providing for funds to do that would be -- as I see it anyway -- really the significant public interest issues in this matter.

873. **MS. SAUNDERS:** Besides cross-subsidization and sort of the first to access the pool issues, are there any other advantages or disadvantages of pooling for Group 1 companies, Group 2 companies, landowners, governments or other stakeholders?

--- (A short pause/Court pause)

874. **MR. HRYNCHYSHYN:** Ms. Saunders, if I could please ask you to repeat your question for me.

875. **MS. SAUNDERS:** Sure. You've mentioned disadvantages in terms of cross-subsidization, cost causality. We've talked a little bit about public interest considerations and the first parties accessing the pool, depleting the amount of pooled funds.

876. But are there advantages or disadvantages, any other advantages or disadvantages to pooling that you see?

877. And it would be for pipeline companies, for landowners, for governments or any other stakeholders.

878. **MR. HRYNCHYSHYN:** I think in a pooling approach it may be -- it may well be more difficult to appropriate identify and quantify sort of the risk, whereas on an individual pipeline basis you would deal with each specific set of circumstances to come up to quantify that; to quantify the risk and then ultimately to quantify the amount that needs to be collected for each pipeline.

879. **MS. SAUNDERS:** Sorry, I'm ---

880. **DR. MANSELL:** Ms. Saunders, if I could just add to that?

881. This falls under the category that economists referred to as "moral hazard" which we've seen operating recently in financial markets.

882. It's not to say that if you have a pooled approach and you spend enough money you couldn't actually properly allocate the risks and set premiums or set contributions from individual companies to properly reflect that, but it is a lot more difficult.

883. The question then is: What is the cost if you're to do it, to preserve a similar level of risk where you have the individual pipelines with individual trusts as opposed to one large trust? Assuming the same level of risk, what is the cost of one versus the other?

884. It's not clear the pooled approach would be cheaper because in most cases you're talking about substantial amounts of money, for example, held in trust, and those may be enough to exploit a lot of the economies of scale and so on that would typically be important.

885. The other factor, I think, that's relevant, and this comes up perhaps more in the context of abandoning nuclear facilities, is that you collectivize that risk or you pool that risk across all of society because it's much larger, potentially much larger, and we don't have instruments and institutions capable of managing that level of risk.

886. And so in those cases you really have no choice but to collectivize that risk or have a single fund.

887. The other example I can think of is in -- it comes up now in the context of, say, carbon capture and storage where, you know, who actually ultimately carries the liability of the CO_2 leaking out? Well, again, we have no institutions, no instruments available to manage that, and so the only alternative is the government has to do it.

888. In this case where you've got a choice, it's not clear that -- it's not clear from any of the evidence presented, at least to this point, that it would be cheaper, necessarily more effective or more efficient to pool those risks than to have them managed on a pipeline-by-pipeline basis.

889. **MS. SAUNDERS:** Do you see any benefits, rather than pooling all of the funds that are collected, to pooling just a portion of the funds to deal with orphan pipelines, for example, to deal with the contingency of an orphan pipeline?

890. And if there is a benefit for doing that, do the same drawbacks apply as apply to pooling all of the funds in terms of being able to identify and quantify the risk and the amount?

891. **MR. HRYNCHYSHYN:** Well, again, Ms. Saunders, Enbridge's view would be that the individual collection or the collection by individual pipelines of their required abandonment costs would essentially eliminate the need for -- or eliminate the risk that there would be any orphan pipeline and eliminate the need for any pooling of funds in that regard.

892. **DR. MANSELL:** Ms. Saunders, if I could just add to that? I mean, one of the issues that we didn't address is the incentives that are put in place when you create a fund such as that, or indeed it's applicable if you have a combined fund as well.

893. It can create a situation where the incentives for the individual pipelines to perhaps worry less about abandonment issues than they might otherwise if they think that it will all be looked after in this collective fund.

894. In the case of an orphan fund, one might argue the same thing, that as soon as you put an orphan fund in place, it lets the companies off the hook to some degree, or at least some companies might feel they're off the hook.

895. Whether or not you would go to an orphan fund may depend on how the system, as proposed, for example, by Enbridge but also by others, works over some period of time.

896. You might review it, and if it appears that that risk of orphan pipelines is greater than we've discussed today, then that might be the time to look at some alternative mechanisms as opposed to designing a system up front with that as a given, which may result in quite a different system and quite different behaviour.

897. **MS. SAUNDERS:** Madam Chair, I realize it's 1:30 and I have a substantial number of questions left. Should we wait until tomorrow to conclude?

898. **THE CHAIRPERSON:** Let's do that. We said we were going to sit until 1:30, so let's conclude for today and we'll start again at 8:30 tomorrow morning.

899. Thank you, everyone.

--- Upon adjourning at 1:26 p.m./L'audience est ajournée à 13h26

NATIONAL ENERGY BOARD
OFFICE NATIONAL DE L'ÉNERGIE

Hearing RH-2-2008
Audience RH-2-2008

Land Matters Consultative Initiative (LMCI) Stream 3
Pipeline Abandonment - Financial Issues

Troisième volet de l'Initiative de consultation relative aux questions financières (ICQF)
Cessation d'exploitation de pipelines - Questions financières

VOLUME 4

Hearing held at
L'audience tenue à

National Energy Board
444 Seventh Avenue West
Calgary, Alberta

January 23, 2009
le 23 janvier, 2009

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HEARING /AUDIENCE
RH-2-2008

IN THE MATTER of the Land Matters Consultative Initiative (LMCI)
Stream 3 - Pipeline Abandonment - Financial Issues

HEARING LOCATION/LIEU DE L'AUDIENCE

Hearing held at Calgary (Alberta), Friday, January 23, 2009
Audience tenue à Calgary (Alberta), Vendredi, le 23 janvier 2009

BOARD PANEL/COMITÉ D'AUDIENCE DE L'OFFICE

S. Leggett	Chairperson/Présidente
K. Bateman	Member/Membre
L. Mercier	Member/Membre

APPEARANCES/COMPARUTIONS

Companies/Compagnies

Alliance Pipeline Ltd.
- Mr. D. Crowther
- Mr. R. Power

BP Canada Energy Company
- Ms. C. Worthy

Enbridge Pipelines Inc.
- Mr. D. Crowther
- Ms. M. Yohemas

Foothills Pipe Lines Ltd.
- Mr. S. Denstedt
- Ms. N. Berge
- Mr. M. Keen

Imperial Oil Resources
- Ms. L.R. Aufricht

Kinder Morgan Canada Inc.
- Mr. P. Forrester
- Ms. M. Novak

NOVA Gas Transmission Ltd.
- Mr. S. Denstedt
- Ms. N. Berge
- Mr. M. Keen

Pouce Coupé Pipe Line Ltd.
- Mr. P. Jeffrey
- Mr. P. Khan

Spectra Energy Transmission (Westcoast Energy Inc.)
- Mr. D. Davies
- Ms. R. Sirett

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Suncor Energy Marketing Inc. (SEMI)
- Mr. D. Armstrong

TransCanada Keystone Pipeline GP Ltd.
- Mr. S. Denstedt
- Ms. N. Berge
- Mr. M. Keen

TransCanada PipeLines Limited
- Mr. S. Denstedt
- Ms. N. Berge
- Mr. M. Keen

Trans Québec & Maritimes Pipeline Inc.
- Mr. S. Denstedt
- Ms. N. Berge
- Mr. M. Keen

Associations

Canadian Allliance of Pipeline Landowners' Association (CAPLA)
- Mr. P.G. Vogel
- Mr. J. Goudy

Canadian Association of Petroleum Producers (CAPP)
- Mr. N.J. Schultz

Governments/Gouvernements

Alberta Department of Energy
- Mr. C. King

National Energy Board/Office national de l'énergie
- Mr. P. Johnston
- Ms. J. Saunders

ERRATA

Tuesday, January 20, 2009 - Volume 1

Paragraph No.:	Should read:
146: "It also indicted that direction..."	"It also indicated that direction..."
"…parties could or could be required…"	"...parties could, or could be required..."
147: "…that for instance definitions..."	"...that, for instance, definitions..."
149: "...or expressions but, with respect,..."	"...or expressions. But, with respect,..."
230: "...professor of economics,..."	"...Professor of Economics,..."
"...and fellow of the Institute..."	"...and Fellow of the Institute..."
235: "The curriculum vitae of the witnesses..."	"The curricula vitae of the witnesses..."
308: "...the government -- the fund..."	"...the governance -- the fund..."
349: "...assumption, if you..."	"...assumption, unless you..."
370: "...abandonment obligation..."	"...abandonment application..."
381: "**MR. DOUVRIS:** Yes, that is..."	"**MR. HRYNCHYSHYN:** Yes, that is..."
383: "...answer to as best we can..."	"...answer as best we can..."
433: "...company's direction on ultimately the..."	"...companies direction on ultimately what the..."
436: "...with abandoned in..."	"...with abandonment in..."

ERRATA

Tuesday, January 20, 2009 - Volume 1

Paragraph No.:	Should read:
460: "...what had set aside,..."	"...what had been set aside,..."
474: "Although whatever the company..."	"Although whatever -- the company..."
504: "...with the banning of..."	"...with abandoning of..."
535: "...then that an agricultural..."	"...then that in agricultural..."
588: "**MR. HRYNCHYSHYN:** Yes."	"**MR. CROWTHER:** Yes."
598: "...Stream 4 as structured..."	"...Stream 4 is structured..."
603: "...assumption a tax..."	"...assumption. A tax..."
604: "...likely, a trust but..."	"...likely a trust, but..."
608: "...technology, we can't necessarily know at a date, we..."	"...technology we can't necessarily know, at a date we..."
609: "...our position was given that there is..."	"...our position was, given that there is..."
"...balance of probabilities that the…"	"...balance of probabilities, that the..."
613: "...further deferral to appoint where..."	"...further deferral to a point where..."
620: "...that I went through was one of which at least was an item..."	"...that I went through was, one of which at least, was an item..."

ERRATA

Tuesday, January 20, 2009 - Volume 1

Paragraph No.:	Should read:
621: "…well, something like 24 to 48 ..."	"...well, in something like 24 to 48..."
655: "...all of the things equal,...	"...all other things equal,..."
662: "...or not deferring for between pipelines really what you're concerned..."	"...or not deferring between pipelines, really what you're concerned..."
665: "Toll, like I said, …"	"Tolls, like I said, ..."
666: "...competitive issue that shippers do not make..."	"...competitive issue? That shippers do not make..."
698: "...sufficient oversight in governance..."	"...sufficient oversight and governance..."
714: "...certainly not noble to me,..."	"...certainly not knowable to me,..."
723: "...to step up and fill the abandonment requirement."	"...to step up and fulfill the abandonment requirement."
764: "...that toll is just one..."	"...that tolls is just one..."
766: "...since the expected economical side of competing pipelines..."	"...since the expected economic life of competing pipelines…"
776: "...that impact competitiveness or the vintage in cost structure..."	"…that impact competitiveness are the vintage and cost structure..."
792: "...we're going to distribute the appreciation for the recovery of capital…"	"...we're going to distribute the depreciation or the recovery of capital…"

ERRATA

Tuesday, January 20, 2009 - Volume 1

Paragraph No.:	Should read:
796: "...the proposed list to defer it, really..."	"...the proposal to defer is really..."
797: "...that affect the temporal distribution of..."	"...that affect the intertemporal distribution of..."
802: "...answer Dr. Mansell gave you need to..."	"...answer Dr. Mansell gave, you need to..."
807: "Does Enbridge agree with these collections, and why or why not?"	"Does Enbridge agree with these conclusions, and why or why not?"
809: "...checks and balances was conducted under Board oversight would not lead to..."	"..checks and balances, was conducted under Board oversight, would not lead to..."
854: "...of the actual company's credit rating."	"...of the company's actual credit rating."
859: "...of having portion or partial…"	"...of having a portion or partial…"
878: "...difficult to appropriate identify and…"	"...difficult to appropriately identify and..."
881: "...the category that economists referred to..."	"…the category that economists refer to..."

ERRATA

Wednesday, January 21, 2009 - Volume 2

Paragraph No.:	Should read:
938: "...I did make a -- provide the court..."	"...I did make a -- provided the court..."
940: "...explain a little but further how..."	"...explain a little bit further..."
951: "...designing their pipelines to ignore the abandonment costs."	"...designing their pipelines, to ignore the abandonment costs."
952: "...because the cost in the present are..."	"...because the costs in the present are..."
985: "...both are reasonably accurate estimate..."	"...both a reasonably accurate estimate..."
1011: "...companies to -- not there may be..."	"...companies to -- not that there may be..."
1026: "**MR. HRYNCHSHYN:** ..."	"**MR. HRYNCHYSHYN:** ..."
1028: "**MR. HRYNCHSHYN:** No, we..."	"**MR. HRYNCHYSHYN:** No, what we..."
1031: "**MR. HRYNCHSHYN:** ..."	"**MR. HRYNCHYSHYN:** ..."
"...need to be resolved that a trust structure..."	"...need to be resolved to determine that a trust structure..."
1034, 1036, 1038, 1040, 1048 and 1050: "**MR. HRYNCHSHYN:** ..."	"**MR. HRYNCHYSHYN:** ..."
1092: "...if the Board were to establish an analogous practices..."	"...if the Board were to establish analogous practices..."
1103: "...definition of planned sponsor, if it were…"	"…definition of plan sponsor, if it were..."

ERRATA

Wednesday, January 21, 2009 - Volume 2

Paragraph No.:	Should read:
1104: "They're the planned sponsor..."	"They're the plan sponsor…"
1125: "...which would be produce a lower yield,..."	"…which would produce a lower yield..."
1129 and 1131: "**MR. HRYNCHSHYN:** ..."	"**MR. HRYNCHYSHYN:** ..."
1138: "...difference between appliance bearing the..."	"…difference between a pipe bearing the..."
1144: "**MR. HRYNCHSHYN:** ..."	"**MR. HRYNCHYSHYN:** ..."
1225: "...example, your portfolio is a much higher…"	"…example, if your portfolio has a much higher..."
1236: "None of this is as certain, and…"	"None of this is certain, and..."
1252: "Yes, and we would."	"Yes, we would."
1278, 1280, 1283, 1285, 1287, 1289 and 1292: "**MR. HRYNCHSHYN:** ..."	"**MR. HRYNCHYSHYN:** ..."
1323: "...four or five factors that identified..."	"...four or five factors that are identified…"
1330: "...that would give you nominal inflation rates of 5 percent,..."	"...that would give you nominal interest rates of 5 percent,..."
1344: "...something about 2 percent is not price stability below..."	"...something above 2 percent is not price stability but below..."
1358: "...the time patters of tolls..."	"...the time patterns of tolls..."

ERRATA

Wednesday, January 21, 2009 - Volume 2

Paragraph No.:	Should read:
1376:	
"...and it's indicated there are some..."	"...and as indicated there are some …"
"I can't think of any in the regulatory..."	"I can't think of anything in the regulatory..."
1387:	
"...any precise propositions in mind,…"	"…any precise proportions in mind,..."
"...would account for 95-98 per cent of the situations."	"...would account for 95, 98 per cent of the situations."
1390:	
"...and so to the text that there is moral..."	"...and so to the extent that there is moral..."

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LIST OF EXHIBITS/LISTE DES PIÈCES

No.	Description	Paragraph No./No. de paragraphe

UNDERTAKINGS/ENGAGEMENTS

No.	Description	Paragraph No./No. de paragraphe
U-4	By Mr. Van der Put to seek permission, through counsel, in terms of the Oil and Gas Journal information	3399

--- Upon commencing at 8:27 a.m./L'audience débute à 8h27

3137. **THE CHAIRPERSON:** Good morning, everyone.

3138. Are there any preliminary matters before we proceed?

--- (No response/Aucune réponse)

3139. **THE CHAIRPERSON:** Seeing none, Mr. Denstedt, are you ready to proceed with your panel?

3140. **MR. DENSTEDT:** We are, Madam Chair, and my friend, Mr. Keen, will introduce the witnesses.

3141. **MR. KEEN:** Good morning, Madam Chair, and Members.

3142. It's my pleasure here to introduce TransCanada's witness panel. Seated closest to me is Mr. John Van der Put and he is the Vice-President of Market Development, Canadian and U.S. Eastern PipeLines for TransCanada PipeLines Limited.

3143. Seated beside Mr. Van der Put is Ms. Amy Leong. She is the Director of Pipeline Accounting for TransCanada PipeLines Limited.

3144. And working the scenes -- working behind the scenes, I should say, is Mr. Ben Leong.

3145. Might the witnesses please be sworn?

JOHN VAN DER PUT: Sworn
AMY LEONG: Sworn

3146. **MR. KEEN:** Thank you.

--- EXAMINATION BY/INTERROGATOIRE PAR MR. KEEN:

3147. **MR. KEEN:** Mr. Van der Put, your direct evidence is found at Exhibit C-26-11C. Do you have it before you?

3148. **MR. VAN DER PUT:** I do.

3149. **MR. KEEN:** Ms. Leong, your direct evidence is found at Exhibit C-26-11B. Do you have it before you?

3150. **MS. LEONG:** Yes, I do.

3151. **MR. KEEN:** Mr. Van der Put and Ms. Leong, were those exhibits prepared by you or under your direction and control?

3152. **MR. VAN DER PUT:** Yes, they were.

3153. **MS. LEONG:** Yes.

3154. **MR. KEEN:** Are those exhibits accurate to the best of your knowledge and belief?

3155. **MR. VAN DER PUT:** Yes, they are.

3156. **MS. LEONG:** Yes, they are.

3157. **MR. VAN DER PUT:** With the exception of one correction that I'd like to make.

3158. **MR. KEEN:** Okay. We'll come to that in a moment.

3159. Mr. Van der Put and Ms. Leong, are you aware of the exhibits filed by TransCanada in this proceeding comprising the C-26 series and extending from C-26-1 to C-26-11C?

3160. **MR. VAN DER PUT:** Yes.

3161. **MS. LEONG:** Yes.

3162. **MR. KEEN:** And were you involved in the preparation of those exhibits?

3163. **MS. LEONG:** Yes, I was.

3164. **MR. VAN DER PUT:** Yes.

3165. **MR. KEEN:** And do either of you have any corrections to make to those exhibits?

3166. **MR. VAN DER PUT:** I do have one correction.

3167. **MR. KEEN:** Please go ahead.

3168. **MR. VAN DER PUT:** TransCanada would like to clarify its position regarding the commencement of collection of abandonment funds.

3169. In its response to NEB IR 1.2(a) which is in Exhibit C-26-08 at page 1 of 2, TransCanada stated the following -- and I quote:

> *"Pipeline companies will require a reasonable amount of time to prepare terminal abandonment cost estimates and an outlook of when those costs would be incurred through a retirement study. Accordingly, collection should not begin until a company is given sufficient time to complete these estimates. Since this part of its evidence was developed, TransCanada has given further consideration both to the appropriate time to undertake the preparation of abandonment cost estimates and also to whether there would be an alternative mechanism which could allow for collection of abandonment funds to commence prior to the completion of abandonment cost estimates."* (As read)

3170. And beginning at page 2, line 16 of its opening statement, TransCanada sets out its position in regard to these two issues as follows, and I quote:

> *"Stream 4 of the LMCI process will consider abandonment requirements in technical detail. Estimates of abandonment costs therefore require that the outcomes of the LMCI Stream 4 process be known before abandonment cost estimates can be properly prepared. Once the technical guidelines on abandonment contemplated by Stream 4 are determined, pipeline companies can proceed with an estimate of abandonment costs. TransCanada also recognizes that it may take some time for each pipeline company to develop an abandonment study because TransCanada proposes collecting as soon as practical. TransCanada proposes that in the interim, a nominal amount be collected based on, for example, an agreed-to percentage of each pipeline's annual revenue requirement. This nominal charge would not be based on any specific assumptions regarding the scope of pipeline abandonment and would be intended to get the process of collecting abandonment funds started in order to take a meaningful step towards addressing the issue of pipeline abandonment funding. TransCanada believes that its proposal regarding a nominal charge is responsive to one of the potential outcomes for LMCI Stream 3 articulated by the Board; namely, a preliminary mechanism to begin setting aside funds for abandonment costs is identified. T his was set out in its January*

17th, 2008 letter and cited at page 3 of the Board's ruling Number 1, which is Exhibit A-08A. Page 3 of Ruling Number 1 also states that the Board is not foreclosing the possibility that Stream 3 may result in the collection of some funds for abandonment; for example, a nominal amount as a placeholder or starting point from which future collection may proceed." (As read)

3171. That concludes the correction that I wanted to make.

3172. **MR. KEEN:** Thank you, Mr. Van der Put.

3173. And with that correction, Mr. Van der Put and Ms. Leong, are those exhibits now accurate to the best of your knowledge and belief?

3174. **MR. VAN DER PUT:** They are.

3175. **MS. LEONG:** Yes, they are.

3176. **MR. KEEN:** Do you therefore adopt these exhibits as your evidence in this proceeding and as the evidence of TransCanada?

3177. **MR. VAN DER PUT:** I do.

3178. **MS. LEONG:** I do.

3179. **MR. KEEN:** Thank you.

3180. Madam Chair, the witnesses are now available for cross-examination.

3181. **THE CHAIRPERSON:** Thank you, Mr. Keen.

3182. From my notes the first company on the Order of Appearances who might wish to cross-examine this panel is Enbridge Pipelines Inc.

3183. Is there anyone in front of Enbridge who has cross-examination questions?

--- (No response/Aucune réponse)

3184. **THE CHAIRPERSON:** Then I call on Enbridge Pipeline Inc.

3185. **MR. CROWTHER:** I have no questions for this panel.

3186. **THE CHAIRPERSON:** Thank you very much.

3187. Proceeding along, is there anyone listed in the Order of Appearances in the advance of Spectra Energy Transmission who wishes to cross-examine this panel?

--- (No response/Aucune réponse)

3188. **THE CHAIRPERSON:** Then I call on Spectra Energy Transmission, please.

--- (A short pause/Courte pause)

--- EXAMINATION BY/INTERROGATOIRE PAR MR. DAVIES:

3189. **MR. DAVIES:** Good morning, panel.

3190. **MR. VAN DER PUT:** Good morning.

3191. **MR. DAVIES:** In its initial evidence, TransCanada advocated that the collection of abandonment costs should begin *"as soon as practical"*, right?

3192. **MR. VAN DER PUT:** That's correct.

3193. **MR. DAVIES:** And if I could have you turn, please, to your response to National Energy Board Information Request 1.2, which is part of Exhibit C-26-C(b) (sic)?

3194. **MR. VAN DER PUT:** I have that.

3195. **THE CHAIRPERSON:** Mr. Davies, did I hear you say C-26C(b)?

3196. **MR. DAVIES:** C-26-6B.

3197. **THE CHAIRPERSON:** Thank you very much.

3198. **MR. DAVIES:** I'm sorry.

--- (A short pause/Courte pause)

3199. **MR. DAVIES:** That's probably what President Obama should have said to the Chief Justice, Madam Chair.

3200. Now, in that response you're asked about the criteria that would determine

when it is practical to begin collection and in the last bullet on that page you say:

> *"Pipeline companies will require a reasonable amount of time to prepare terminal abandonment cost estimates and an outlook of when those costs would be incurred through a retirement study."*

3201. So, as I understand it, your proposal is to do a retirement study to determine when each of the various TransCanada-owned pipelines would be abandoned.

3202. Is that right?

3203. **MR. VAN DER PUT:** That's correct. And bearing in mind that that retirement study would be completed once the results from Stream 4 are available to allow for the completion of abandonment cost estimates as well.

3204. **MR. DAVIES:** So TransCanada is of the view that the timing of abandonment of each of its pipelines is now determinable.

3205. Is that right?

3206. **MR. VAN DER PUT:** TransCanada is of the view that estimates can be made with regards to ranges of possibilities in terms of the point of abandonment for its various assets, and that that can be used to determine preliminarily what the abandonment costs would be when facilities would be abandoned and therefore what the collection amounts should be, bearing in mind that we would propose, as other panels have, that there be periodic reviews of those estimates during the economic -- the remaining economic life of a pipeline and that those reviews should become more frequent as we near the point of actual abandonment of facilities.

3207. And, obviously, better information will be available as those -- each of those subsequent reviews are done and the point of abandonment will be refined at each review point.

3208. **MR. DAVIES:** So what's the answer to the question that I asked you?

3209. **MR. VAN DER PUT:** The answer to the question is that there is sufficient information to make an estimate initially in order to determine abandonment costs, in order to complete a retirement study, and also to determine what the collection amounts should be emanating from that study, with the understanding that that will be revised each time more information is available to facilitate that.

3210. **MR. DAVIES:** So just so that I'm clear, is TransCanada's view that the timing of abandonment of each of its pipelines is now determinable, yes?

3211. **MR. VAN DER PUT:** Assumptions can be made with regards to facilitating an initial estimate in order to ultimately determine what the collection amounts should be, again recognizing that that can only be done once the results from Stream 4 with regards to the scope of abandonment activities has been completed.

3212. **MR. DAVIES:** Well, you can make assumptions or guess about whatever you want, but my question is, is TransCanada of the view that the timing of abandonment of each of its pipelines is now determinable, yes or no?

3213. **MR. VAN DER PUT:** One can make a determination based on information that is available today with regards to expected reserve life, with regards to market demand, that will allow one to make a determination of abandonment costs, timing of abandonment, as well as determine the collection amounts and to make that initial determination to allow a pipeline company to begin to collect abandonment costs, recognizing that those estimates are going to be refined and revised during the economic life of the pipeline.

3214. **MR. DAVIES:** So the answer to my question is yes.

3215. **MR. DENSTEDT:** Madam Chair, my friend has asked the same question a number of times here.

3216. The witness has proposed to answer it in a manner that is appropriate, responsive to an inquiry of this nature, that given the right circumstances and the right assumptions that the amounts can be determined for the purposes of collecting abandonment funds.

3217. My friend wants my witness to say one specific word; he doesn't have to do that.

3218. **MR. DAVIES:** Well ---

3219. **THE CHAIRPERSON:** Mr. Davies, the panel believes it has the information from your questions. If you want to move along to your next line of questioning, please?

3220. **MR. DAVIES:** Does TransCanada currently recognize a liability for asset retirement obligation for any of its pipelines?

3221. **MS. LEONG:** No, we do not.

3222. **MR. DAVIES:** And can you tell us why not?

3223. **MS. LEONG:** Based on our accounting assessment and under the Handbook, Section 3110, which stipulates the definition of asset retirement obligation, and as well setting out the criteria on how the accountants determine whether or not at this point in time we have an obligation, the criteria that we've looked at is whether or not we can determine with sufficient information as well as reliable estimates whether or not we have a determinant scope as well as determinant life.

3224. And at this point in time, from an accounting standpoint, we do not believe that we have an asset retirement obligation.

3225. **THE CHAIRPERSON:** Ms. Leong, can we just ask you to move your mic a little closer to you when you're speaking? Thank you.

3226. **MS. LEONG:** Absolutely.

3227. **THE CHAIRPERSON:** Thank you.

3228. **MR. DAVIES:** So did I hear in that then, Ms. Leong, that for accounting purposes you've determined that your pipelines have an indeterminate life?

3229. **MS. LEONG:** We have determined in assessment of the asset retirement obligation that we have insufficient information and reliable estimates in coming up with a reasonable fair value.

3230. **MR. DAVIES:** Thank you.

3231. Can you tell us how the study that you're proposing to do would differ from the studies that you do to determine the economic planning horizon of your pipelines for depreciation purposes?

3232. **MS. LEONG:** So maybe if I can back up, just the terminology of "economic planning horizon," that is something that TransCanada has adopted in its depreciation study, and it really refers to applying a concept of a life, a finite life, to allocating depreciation over a period of time.

3233. And part of our economic planning horizon is looking at a future forecast, a throughput forecast. But what is more important is looking at the mid-term or a mid-term of range of dates over which we will retire our assets.

3234. **MR. DAVIES:** Thank you.

3235. In your opening statement, and you alluded to this in your clarifying or correcting comments, you say that -- and I'm looking at the second page, line 22.

3236. **MR. VAN DER PUT:** I have that.

3237. **MR. DAVIES:** You say:

> "*Because TransCanada proposed collecting as soon as practical, TransCanada proposes that in the interim a nominal amount be collected based on, for example, an agreed-to percentage of each pipeline's annual revenue requirement*."

3238. Now, we can agree that the first time that TransCanada makes this proposal to collect a nominal amount is in its opening statement, right?

3239. **MR. VAN DER PUT:** It is the first time that TransCanada has specifically mentioned the concept of collection of a nominal amount, but I would submit that it's a proposal that flows from TransCanada's position within its pre-filed evidence that commencement of collection of abandonment funds should begin as soon as practical.

3240. **MR. DAVIES:** Well, in fact, in your opening statement you say it's because you're proposing to collect as soon as practical that you're now proposing this nominal amount collection, right?

3241. **MR. VAN DER PUT:** We're proposing that if there were a desire to pursue a means of collecting abandonment funds -- beginning to collect abandonment funds prior to the conclusion of Stream 4, this is a potential option that could facilitate that.

3242. **MR. DAVIES:** And why is it that we first see this proposal in your opening statement?

3243. **MR. VAN DER PUT:** This is a proposal that has flowed and evolved from our position throughout this proceeding that collection of abandonment funds should begin as soon as practical, for the reasons that we've outlined in our evidence.

3244. **MR. DAVIES:** You should consider yourself fortunate that you're not being cross-examined by Mr. Yates, because he would chastise you about the impropriety of introducing new proposals in an opening statement. But I'm friendlier than Mr. Yates is.

3245. **MR. VAN DER PUT:** I appreciate that.

3246. **MR. DAVIES:** Now, by "appreciate that," you mean you agree?

--- (Laughter/Rires)

3247. **MR. VAN DER PUT:** Thank you for being nice.

3248. **MR. DAVIES:** Now, this panel, Mr. Van der Put, is going to be issuing a report following this Stream 3 hearing, and I take it that you would like the report to say that pipelines should begin collecting a nominal amount, right?

3249. **MR. VAN DER PUT:** There are some clarifications or there are some things that I would like to say certainly with regards to TransCanada's position regarding the collection of a nominal amount.

3250. In responses to IRs, TransCanada has clarified what it means by collection as soon as practical, has identified a number of factors that the Board may want to consider in terms of determining when that might be.

3251. We did mention the time required to prepare abandonment costs, retirement studies, but as I've mentioned, we're proposing the option of collection of a nominal amount as a means of facilitating -- beginning collection prior to the conclusion of Stream 4, which is again when we're saying that determination of abandonment costs and retirement studies should be done.

3252. There's three other factors that we had indicated the Board should consider in terms of determining when it would be practical. One of those is the issue of settlements.

3253. Some pipelines are under settlement with their shippers with regards to the tolls being charged. That is an issue that would need to be addressed prior to the commencement of any collection of abandonment funds, again, certainly for those pipelines that are under settlement.

3254. Another issue that would have to be addressed is the establishment of the mechanism to set aside the funds.

3255. We've talked within this proceeding with regards to a trust mechanism, some kind of a fund managed by an independent third party as perhaps being the most appropriate means of doing that.

3256. We would submit that that would have to be addressed and established prior to commencing collection of abandonment funds.

3257. The other factor that we've mentioned as well is the issue of the tax efficiency of collections.

3258. That's a very important issue and certainly one that will affect the quantum of the collection amount, one that I would submit all of the parties to this proceeding feel needs to be addressed and certainly all other parties appear to be committed to pursuing the expeditious resolution of that issue.

3259. We suggest that that would be another factor that would be important to address prior to beginning collection of any amount.

3260. **MR. DAVIES:** Thank you.

3261. So do I understand that your position is that these three factors that you've mentioned have to be addressed and resolved before it would be appropriate to begin commencement or begin collection of a nominal amount?

3262. **MR. VAN DER PUT:** Our position is that although those three factors are quite important and are, I would say -- are very important in terms of ensuring that the collection of any amounts will be done effectively.

3263. **MR. DAVIES:** Okay. And when you say "any amounts" you're including in that even a nominal amount?

3264. **MR. VAN DER PUT:** That's correct.

3265. **MR. DAVIES:** So your position is that these three factors have to be addressed before we even start collecting a nominal amount?

3266. **MR. VAN DER PUT:** They do have to be addressed, yes.

3267. **MR. DAVIES:** Now, at what point do you envisage that we would determine what this nominal amount would be?

3268. **MR. VAN DER PUT:** What we've suggested is that -- and there's various means that presumably nominal amounts could be determined.

3269. What we've suggested in our opening statement; that one mechanism could be to determine a percentage of revenue requirement, and there presumably would be various means of coming to agreement or coming to a conclusion with

regards to what those might be.

3270. But just in terms of the mechanics of coming up with a proposal or number, I would not expect that that would be very time consuming.

3271. **MR. DAVIES:** So, sorry, when is it that you are proposing then that this nominal amount be derived?

3272. Let me ask you this question first. The Board is going to be coming out with a report. Do you envisage that the Board would, in its report, specify the nominal amount?

3273. **MR. VAN DER PUT:** I would propose that the Board would specify in its report the mechanism or the process that would be undertaken to determine the nominal amounts.

3274. **MR. DAVIES:** Okay. So I take it from that that you're not proposing that the Board would, in a report, specify the nominal amount?

3275. **MR. VAN DER PUT:** The Board will choose to do what it will, but I would envision that there would be some kind of a process that would be undertaken in order to determine what those nominal amounts would be.

3276. I suppose that that process could be undertaken prior to the Board's issuance of its report on LMCI Stream 3 or presumably it could be one of the recommendations in the report. It could be then completed after.

3277. **MR. DAVIES:** Okay. Thank you.

3278. And when you say that in your view the nominal amount to be collected could be based on an agreed-to percentage of each pipeline's annual revenue requirement; first of all, agreed-to among whom?

3279. **MR. VAN DER PUT:** Certainly the Board would be a significant player in terms of determining what that would be, as well as all industry participants, the pipelines, the shippers.

3280. Certainly all the stakeholders to the pipeline's business would have an interest in being a part of the process to determine what those nominal amounts should be.

3281. **MR. DAVIES:** So what you have in mind is that all stakeholders then would come to an agreement on the nominal amount?

3282. **MR. VAN DER PUT:** Yes.

3283. **MR. DAVIES:** Okay. And you then discuss a percentage of each pipeline's annual revenue requirement, and what sort of percentage did you have in mind?

3284. **MR. VAN DER PUT:** It would be a percentage that the parties involved in the kind of process that I was suggesting would agree would have a nominal impact on, ultimately, the tolls that shippers would be paying.

3285. **MR. DAVIES:** Okay. But can you give us any estimate or ballpark as to what sort of percentage TransCanada has in mind?

3286. **MR. VAN DER PUT:** If I were to venture a suggestion, I would suggest that in my opinion, something in the order of a half a percent to one percent of revenue requirement, likely most parties would agree would probably have a nominal effect.

3287. **MR. DAVIES:** And can you tell me how would this proposal to collect a nominal amount be consistent with cost-based tolls?

3288. **MR. VAN DER PUT:** This would be -- the intent of proposing the collection of a nominal amount is to get the process started.

3289. It's to -- it's recognizing that it's important for us to take a concrete step collectively towards addressing the issue of pipeline abandonment and, you know, clearly send a signal to the public at large, to landowners in particular, that they're not going to be held liable for the cost of abandonment, that steps are being taken to begin to collect those funds.

3290. There's no intent, by its very nature, to tie a nominal amount to specific costs. There would be the intention then to ultimately replace that nominal amount with a cost-based collection amount that, as I suggested, would be based on the conclusion of Stream 4 in terms of the scope of the abandonment effort, which would then facilitate calculation of abandonment costs, supported with a full retirement study to identify when the abandonment of facilities would take place.

3291. **MR. DAVIES:** So am I correct in saying that the primary purpose of your proposal to collect a nominal amount then is, as you've said, to send a signal to landowners?

3292. **MR. VAN DER PUT:** I would say there's other factors.

3293. It's also important to minimize, I would suggest, intergenerational inequity, ensure that all shippers who are contracting for service throughout the remaining life of a pipeline contribute towards the cost of abandonment.

3294. And I would also say that it's practical to maximize the opportunity for growth of the abandonment fund through compound interest earnings on those funds.

3295. So those are other factors as well which argue for beginning collection of abandonment funds as soon as it can practically be done.

3296. **MR. DAVIES:** Thank you very much, panel.

3297. Thank you, Madam Chair.

3298. **THE CHAIRPERSON:** Thank you, Mr. Davies.

3299. Are there any other companies who wish to cross-examine this panel?

--- (No response/Aucune réponse)

3300. **THE CHAIRPERSON:** Thank you. Then I call on CAPLA.

--- EXAMINATION BY/INTERROGATOIRE PAR MR. VOGEL:

3301. **MR. VOGEL:** Thank you, Madam Chair. Good morning, panel.

3302. **MR. VAN DER PUT:** 'Morning.

3303. **MR. VOGEL:** Mr. Van der Put, if I can take you to TransCanada's Pre-filed Evidence, Exhibit C-26-4, at page 11, and TransCanada's response in A-12 there. The last paragraph on that page deals with the absence of any conclusion from Stream 4.

3304. Now, I've heard this morning your correction with respect to TransCanada's current position, that a Stream 4 result is necessary in order to estimate abandonment costs in Stream 3.

3305. But if the Board nevertheless proceeded in Stream 3 and did not accept your proposal with respect to a nominal amount, can I take it from the original Pre-filed Evidence that TransCanada would acknowledge that in order to develop preliminary cost estimates, the companies will have to make a technical assumption

with respect to the scope of abandonment?

3306. **MR. VAN DER PUT:** That certainly reinforces our position that estimation of abandonment costs should not be done until the conclusion from Stream 4 are completed.

3307. But based on your scenario that you've described, where pipeline companies are ordered to make those determinations prior to the conclusion of Stream 4, I would agree with you.

3308. **MR. VOGEL:** And turning to page 8 in that Pre-filed Evidence and your response A-8, that preliminary assumption that companies would then have to make, I take it, would include the extent to which the pipelines may be required to be removed on abandonment or allowed to remain in place with or without continuing maintenance.

3309. **MR. VAN DER PUT:** That's correct. In terms of the pipelines' facilities specifically, assumptions would have to be made with regards to the specific scope of abandonment and the couple of options that you've had it described are some of the options.

3310. **MR. VOGEL:** And referring, with respect to this reference on page 8, if the technical assumption is incorrect and, for example, more pipeline removal is required than allowed for by the company in its technical assumption, would you agree to the extent that insufficient funds are collected to pay for removal that would constitute what's called there an unfunded liability?

3311. **MR. VAN DER PUT:** I would suggest to you, Mr. Vogel, that we're -- we've been talking within this proceeding with regards to many mechanisms that would avoid the kind of scenario that you've described.

3312. First off, we're talking about setting up a mechanism whereby each pipeline company would determine its abandonment costs and all of the panels have talked about frequent -- or, periodical reviews of those assumptions to take, you know, changes in circumstances into consideration during the economic life of the pipeline.

3313. I would suggest that as the -- as we near the actual point of abandonment of facilities, that those periodical reviews should become more frequent.

3314. As well, we have a situation where we're talking about a heavily regulated industry with oversight from the Board. The Board will ensure that the appropriate steps are being taken to ensure that the -- that adequate funds are available.

3315. And as well, the other factor I would point out is the mechanism that we've discussed with regards to setting aside the funds in a fund separate from the company's general revenues, managed by an independent third party, provides assurance -- greater assurance that the funds will be available when needed to cover the abandonment costs.

3316. **MR. VOGEL:** That's all fair enough, Mr. Van der Put, but if the company makes an assumption with respect to abandoning a pipeline in place and that assumption isn't changed or isn't changed sufficiently overtime and at the end of the day more pipeline removal is required than what the company had provided for, there is a risk there that there will be under-funding, which will constitute an unfunded liability.

3317. Is that not correct?

3318. **MR. VAN DER PUT:** I would suggest that that is a very small risk, I would almost submit negligible. Recognizing that abandonment is not a one-time event, abandonment is a proceeding that's going to take place over quite a few years.

3319. As we start abandoning facilities, clearly we will have much better information with regards to both what the appropriate scope of abandoning those facilities should be, as well as what the cost of that physical abandonment activity is.

3320. We will have the opportunity then to make adjustments, any required adjustments to the collection amounts, to ensure that at the end of the day sufficient funds are available to cover the cost of abandonment.

3321. **MR. VOGEL:** But in this scenario I've put to you, Mr. Van der Put, you acknowledge that there is a risk -- however small, there is a risk of an unfunded liability at the end of the day.

3322. **MR. VAN DER PUT:** I would suggest that -- again, that that risk, given all of the mechanisms, belts and suspenders, you know, that I've described, there are much more critical things that, you know, should be focused on within this proceeding than that specific issue.

3323. **MR. VOGEL:** Well, that's certainly your judgment, Mr. Van der Put, but from other perspectives, perhaps the risk is the important element to focus on. So I put it to you, you will acknowledge, at the end of the day, there is some risk.

3324. We may not be in a position to pressure that risk today, but there is some risk of an unfunded liability at the end of the day in the scenario I put to you.

3325. **MR. VAN DER PUT:** I would suggest to you that there's a risk that, you know, that yeah, there could be underfunding. There's also a risk that there would be overfunding. I mean, both those situations could occur.

3326. **MR. VOGEL:** Fair enough. Thank you.

3327. And turning to page 9 in your Pre-filed Evidence, again in your response to -- your response A-8, should there be this insufficiency, this underfunding -- this unfunded liability that you've talked about there, and in the event that there was no pipeline then in existence, landowners could then be at risk to the extent of that unfunded liability, what it might be.

3328. Is that not correct?

3329. **MR. VAN DER PUT:** Mr. Vogel, do I presume that you're referring to lines 178 and 179 ---

3330. **MR. VOGEL:** That's right.

3331. **MR. VAN DER PUT:** --- in our evidence? I would submit to you the context for that statement, which is if there were no funds set aside for abandonment costs -- and that was really the context of the question that we included in our Pre-filed Evidence; what are the implications of requiring or not requiring pipeline companies to set aside funds?

3332. So it really was in the context of a scenario where we didn't take the step that we're currently taking with this proceeding to deal with the whole issue of abandonment.

3333. **MR. VOGEL:** But the question I'm now putting to you is that in the event that this risk materializes, that there is this insufficiency, this underfunding that we've agreed might be created, and as it says there, and there is no pipeline company left after abandonment, would you agree, as it says there, that landowners or government could be at risk?

3334. **MR. VAN DER PUT:** Again, understanding the circumstances that approach reality in terms of this industry, again, a heavily regulated industry with relatively few well-capitalized players, the kinds of processes that I described earlier would suggest that that kind of result would likely not be realistic.

3335. **MR. VOGEL:** I understand that's your assessment, Mr. Van der Put, but I'm positing to you now the very scenario that you've painted, TransCanada's painted

in its Pre-Filed Evidence. So if there is this acknowledged underfunding, insufficiency that risk materializes and there is no pipeline company left after abandonment, which is the situation you posited in your evidence, landowners or government could be at risk to the extent of that insufficiency.

3336. Is that not correct?

3337. **MR. VAN DER PUT:** What I would say, Mr. Vogel, is that ultimately it's the responsibility of the pipeline to ensure that abandonment costs are funded and it's up to the pipeline company to collect the appropriate funds from the users of -- it's the transportation services on its pipeline to cover those costs.

3338. Ultimately, it's up to the pipeline and its regulator to ensure that at the end of the day the abandonment costs are covered.

3339. I would also bring you back to one of the positions, one of the central positions that we put forward in our evidence. It would just be consistent with the other panels; that landowners would not be liable for the cost of abandoning pipelines.

3340. **MR. VOGEL:** And I understand that position, Mr. Van der Put and I am simply putting to you what is in your own Pre-Filed Evidence.

3341. If the risk of the insufficiency which you acknowledge materializes and there is no pipeline company left after the abandonment, will you agree, as it says here, that in those circumstances landowners or government could be at risk to the extent of that funding deficiency?

3342. **MR. VAN DER PUT:** Again, the context of our evidence was in the scenario where there was no pipeline abandonment fund established.

3343. **MR. VOGEL:** I understand that, Mr. Van der Put. Answer the question, please.

3344. **MR. DENSTEDT:** Madam Chairman, I believe the witness has answered the question. He said in the event that no fund is put in place there is a risk. That's in TransCanada's evidence.

3345. If a fund is put in place, that eliminates that risk and that with the belts and suspenders that Mr. Van der Put has already spoken about, he's addressed the question. So I think we should move on.

3346. **THE CHAIRPERSON:** Thank you very much, Mr. Vogel. The Panel has what it needs from the evidence that's been presented; if you could move along

with your next line of questioning please.

3347. **MR. VOGEL:** In any event, we agree, Mr. Van der Put, that whatever that risk of insufficiency -- insufficient funding is, it's not a risk that should be born by landowners; correct?

3348. **MR. VAN DER PUT:** We wholeheartedly agree on that point.

3349. **MR. VOGEL:** And if I take you now to CAPLA's reply evidence, Exhibit C-1-13C in this proceeding. This is Appendix A in the reply evidence at page 1.

3350. **MR. VAN DER PUT:** I have that.

3351. **MR. VOGEL:** If we look at the Board's answer to this problem, going back to 1985, you'll see in the right-hand column on that page, second paragraph, a comment that:

> *"Not surprisingly the analysis leads to the general conclusion that the best course of action is to either remove or maintain large and medium diameter abandoned pipelines."*

3352. Do you see the Board's conclusion there?

3353. **MR. VAN DER PUT:** I do see it.

3354. **MR. VOGEL:** Would you agree that that's certainly one solution to ensure that landowners are not required to bear a risk of post-abandonment, liabilities and cost?

3355. **MR. VAN DER PUT:** I would agree that there are a number of different ways of abandoning facilities.

3356. The other thing I would point out is the context again of this report. This is a background report, background paper that was completed over 20 years ago.

3357. It was, as I best understand it, an attempt to provide some information, some guidelines, some thoughts based on the Board's work with regards to the body of work, the body of knowledge surrounding the abandonment of pipeline facilities at the time.

3358. I would suggest that, just like any other body of knowledge, there's evolution in that. If we look at the 1996 paper from the Pipeline Abandonment

Steering Committee we can see that the thought processes with regards to physical abandonment of facilities has evolved somewhat. And if we take it to today, you know, there's been further evolution.

3359. So I would suggest that this is information that is useful but there's many factors that need to be taken into consideration in ultimately arriving at what is the appropriate means of abandoning facilities.

3360. **MR. VOGEL:** With respect to any of that more recent analysis that's been conducted, would you agree with me that none of that would change the conclusion there that removal of pipeline or perpetual maintenance is at least one solution to ensure that landowners are not required to bear the risk of post-abandonment, liabilities and cost?

3361. **MR. VAN DER PUT:** I would agree that it is a potential solution but not necessarily the best solution.

3362. One other thing that I'd like to point out is that whenever you look at determining the best way to abandon a facility you really have to take site-specific circumstances into consideration.

3363. There's many factors that need to be looked at. Certainly pipe diameter is one of them, but soil characteristics would be another, moisture content of soil would be another ---

3364. **MR. VOGEL:** Land use would be another?

3365. **MR. VAN DER PUT:** Land use would certainly be another. I agree with you, Mr. Vogel.

3366. The pipe coating -- you know, there's different types of pipe coating. That would be another factor that would be taken into consideration.

3367. **MR. VOGEL:** And the potential environmental effects and the safety issues and the land use issues, all of that would impact a decision on a site-specific basis as to whether or not abandonment in place was appropriate?

3368. **MR. VAN DER PUT:** That's right. Consideration of those factors on a site-specific basis could very well lead to the conclusion that the appropriate means of abandonment is abandonment in place.

3369. **MR. VOGEL:** Okay. Thank you, Mr. Van der Put. Those are my

questions.

3370. Mr. Goudy will have no questions for this panel.

3371. **THE CHAIRPERSON:** Thank you very much, Mr. Vogel.

3372. Does CAPP wish to cross-examine this panel?

3373. **MR. JARDINE:** No, thank you.

3374. **THE CHAIRPERSON:** Alberta Department of Energy...?

3375. **MR. KING:** No, thank you.

3376. **THE CHAIRPERSON:** Does Board counsel have any questions of this panel?

3377. **MR. JOHNSTON:** Yes, I do, Madam Chair.

--- EXAMINATION BY/INTERROGATOIRE PAR MR. JOHNSTON:

3378. **MR. JOHNSTON:** Good morning, Mr. Van der Put and Ms. Leong.

3379. **MR. VAN DER PUT:** Good morning.

3380. **MR. JOHNSTON:** Paul Johnston. I'm counsel for the Board.

3381. I have a few questions to go through with you this morning. The first one -- if I can refer you to your Information Response to NEB 1.10, which is Exhibit C-26-6B? I'll give you an opportunity to locate that information.

3382. **MR. VAN DER PUT:** I do have that now.

3383. **MR. JOHNSTON:** Is this essentially the same information that was provided by Kinder Morgan at Attachment A to its response to NEB IR 1.13? And that's Exhibit C-15-6D.

3384. **MR. VAN DER PUT:** I would have to refer to that response, if you would give me a moment to do that, please.

3385. **MR. JOHNSTON:** Certainly.

3386. **MR. VAN DER PUT:** Could you -- could you repeat the exhibit number,

please?

3387. **MR. JOHNSTON:** The exhibit number is C-15-6D and it's an appendix. It's attachment A to the exhibit.

3388. **MR. VAN DER PUT:** I just wanted to make sure that I had the full IR response, so ---

3389. **MR. JOHNSTON:** Certainly.

3390. **MR. VAN DER PUT:** --- I do have that in front of me now.

3391. **MR. JOHNSTON:** And is this essentially the same information that TransCanada was referencing in the information request?

3392. **MR. VAN DER PUT:** Because I know we -- we were referencing Oil and Gas Journal and that's what I'm trying to establish. The information is from PennWell Petroleum Group. So I think it's a -- I mean, it's similar information, but not exactly the same.

3393. **MR. JOHNSTON:** Would you be willing to undertake through counsel to seek permission, in terms of the Oil and Gas Journal information?

3394. **MR. VAN DER PUT:** Give me a moment, please.

--- (A short pause/Courte pause)

3395. **MR. VAN DER PUT:** As we stated in the IR response 1.10(b), we are actually currently in the process of obtaining that permission. I was just conferring with my colleague regards to how long he thought it would take us to do that.

3396. Could we have a week to do that?

3397. **MR. JOHNSTON:** Certainly. Thank you.

3398. **MR. VAN DER PUT:** Thank you.

3399. **THE REGULATORY OFFICER:** Thank you. That will be undertaking U-4.

--- UNDERTAKING NO./ENGAGEMENT No. U-4:

By Mr. Van der Put to seek permission, through counsel, in terms

of the Oil and Gas Journal information

3400. **MR. JOHNSTON:** Madam Chairman, subject always, of course, to being turned down on getting that permission, right?

3401. **THE CHAIRPERSON:** Thank you, Mr. Johnston.

3402. **MR. VAN DER PUT:** And I understand that, yes. Thank you, Mr. Johnston.

3403. **MR. JOHNSTON:** Concerning the timing of potential collection, you did state to Mr. Davies this morning that one of the issues to address was existing settlements?

3404. **MR. VAN DER PUT:** That's correct.

3405. **MR. JOHNSTON:** What are the ways companies could deal with existing agreements if the Board were to require collection of funds for abandonment prior to the expiry of some of these agreements?

3406. **MR. VAN DER PUT:** In part of our evidence we had talked about, there's really only two ways to deal with the issue of settlements where abandonment -- where the collection of abandonment funds is not specifically provided for.

3407. One way would be for the pipeline under settlement to defer, simply to defer the commencement of collection of abandonment funds.

3408. The other way would be for the Board to order that collection of abandonment funds commence and, essentially, in that fashion, supersede the terms of the settlement, if that were possible.

3409. **MR. JOHNSTON:** And with respect to that information, as well as your response to NEB Information Request 1.6, which I believe you were referring to when you provided that response, which is Exhibit C-26-6B, what are the implications of those two suggestions to pipelines, shippers, or other stakeholders?

3410. **MR. VAN DER PUT:** The implications of the first one, in terms of deferring the collection of abandonment funds, would be that there would be presumably a short period of time -- most settlements are for somewhere between one to perhaps five years, but there would be a period of time where there would be a difference between the pipeline under settlement and competing pipelines in terms of collection of abandonment costs, and, obviously, that would have an effect on the competitive dynamics between those pipelines.

3411. With regards to the other issue or the other option, where the Board mandates the collection of funds during the settlement in the form of an order as stated in our IR response, the effect there would be that the shippers who are under settlement on that pipeline would have to pay more than what was contemplated under that settlement.

3412. **MR. JOHNSTON:** And does TransCanada have a general clause in some or all settlement agreements dealing with the implications of changes to regulatory requirements?

3413. **MR. VAN DER PUT:** The settlements vary in that regard. Some settlements do have such a clause, others do not.

3414. **MR. JOHNSTON:** And in your experience, is there an obstacle to a commercial party including that type of clause?

3415. **MR. VAN DER PUT:** The thing to be recognized is that the negotiation that surrounds a settlement looks at many different factors.

3416. Ultimately, the conclusion of the settlement is agreement on a package, if you will, of the costs that the shippers are going to bear during a certain period of time, and consideration with regards to changes in regulation would be one of those factors that would be considered as part of that negotiated package, typically.

3417. **MR. JOHNSTON:** And is there a risk that early shippers will underpay if the timing for collection is deferred because of existing settlements?

3418. **MR. VAN DER PUT:** We, certainly in our evidence, have indicated that from a principle perspective the cost of abandoning a pipeline is a legitimate appropriate cost of providing service and should be borne by the users of that service and that one can make the -- one can go from there to say that those costs should be borne by all the shippers who contract for service on that pipeline throughout the duration of its economic life.

3419. So, certainly, if there is a period of time at the beginning of that pipeline's economic life where shippers are not contributing to the cost of ultimately abandoning the pipeline, then clearly there's a difference between shippers who are contracting for service in the initial periods of a pipeline's economic life and the latter periods.

3420. **MR. JOHNSTON:** I'd like to ask you some questions about the interaction of Stream 4 and potential preliminary estimates coming out of Stream 3. You had mentioned to Mr. Davies that you have sufficient information to make initial

estimates, and with Mr. Vogel you had said that you would like to wait until Stream 4 was completed, although, as I understood it, it may be possible to make preliminary estimates without it.

3421. Is that -- am I understanding that correct?

3422. **MR. VAN DER PUT:** It's our position that the determination of abandonment costs should not begin until Stream 4 is concluded so that we can have the benefit of the collective wisdom, if you will, of the participants in that stream to use the appropriate body of knowledge, use the appropriate assumptions to determine what those abandonment costs should be.

3423. **MR. JOHNSTON:** And if I can ask you, the draft Stream 4 report was released, and I believe the date was December 18th, 2008.

3424. Have you had an opportunity to review this report?

3425. **MR. VAN DER PUT:** I can only say that I've skimmed it.

3426. **MR. JOHNSTON:** All right. If you've only skimmed it, I have no further questions on that issue.

3427. If I can refer you to a citation from Kinder Morgan and ask for your perspective on some of the conclusions, it's Exhibit C-15-9B, and it's found at page 3.

3428. **MR. VAN DER PUT:** If you could give us a moment to turn that up?

3429. **MR. JOHNSTON:** Sure.

3430. **MR. VAN DER PUT:** Is that initial evidence; is it an IR response?

3431. **MR. JOHNSTON:** It's in the Reply Evidence.

3432. **MR. VAN DER PUT:** Oh, Reply Evidence?

3433. **MR. JOHNSTON:** Yes.

3434. **MR. VAN DER PUT:** Thank you.

3435. **MR. JOHNSTON:** And it's number 8 in the Reply Evidence, A, B and C.

3436. **MR. VAN DER PUT:** I do have that now.

3437. **MR. JOHNSTON:** Great. And I won't read it again for the record because that's been done several times, but what I wanted to ask you was whether TransCanada is in agreement with all or some of Kinder Morgan's conclusions?

3438. **MR. VAN DER PUT:** As I understand the context of the reference, it has to do with the possibility that pipelines would be allowed to defer the collection of abandonment costs.

3439. With regards to the -- so I would understand the first point to suggest that pipelines might petition or apply to the Board for the authority to defer collection of abandonment costs for competitive reasons. I suppose that that could be a motivation.

3440. I would suggest, though that, certainly in our evidence, one of the factors that we have pointed to is the issue of the risk of changes to the competitive dynamics between pipelines.

3441. If pipelines are treated differently, and particularly pipelines that transport similar products under similar circumstances, then one can take similar circumstances to mean, in part, perhaps serving the same supply basin or the same market area.

3442. I would suggest that one of the issues that the Board should be mindful of with regards to competitive factors is to certainly be vigilant with regards to that issue and set up a mechanism whereby there would not be differences between pipelines transporting similar products under similar circumstances in terms of the timing for commencing collection of abandonment costs, so that we certainly avoid the kind of scenario that's suggested in Part A there.

3443. **MR. JOHNSTON:** And how about Part B and C?

3444. **MR. VAN DER PUT:** I think Part B is simply a mathematical result or a result of the mathematics, I guess. If you don't -- if a pipeline does not collect from its shippers abandonment funds during the initial portion of its economic life, then, you know, the way the math works out, those collections then are back-ended. So yeah, I would agree with that statement.

3445. With regards to the last one -- did you ask for my opinion with regards to all three?

3446. **MR. JOHNSTON:** Yes, certainly.

3447. **MR. VAN DER PUT:** Okay. So this posits a scenario where if you reduce the amount of time over which abandonment funds are collected, you might

run a greater risk that the period that you've chosen to collect abandonment funds over actually coincides with the period when shippers are in distress; shippers -- and I would take it to mean are in an inferior position to be able to, for example, to come up with the cash to pay higher amounts than what would have been charged to them had those abandonment funds been collected over a longer period of time.

3448. And you know, one can look at the current situation today, and I think certainly shippers, producers, for example, face a situation of very low commodity costs combined with a situation where, because of the global financial crisis, access to capital is constrained compared to what it might have been in other circumstances.

3449. So I would suppose that, yeah, I mean, the more you shorten the period of time over which abandonment funds are collected, the more chance there is that that period of time happens to coincide with a period of time when shippers, whether they be producers or end users, are less able to fund the abandonment costs.

3450. **MR. JOHNSTON:** Next, if I can turn to factors in TransCanada's evidence that you've submitted the Board may wish to consider before making its determination on whether it's practical to begin collection, and the one factor I will focus on is the tax issue.

3451. You said to Mr. Davies that tax efficiency needs to be addressed first. And I wonder if you could just elaborate on what you're referring to when you say "addressed". Does that -- are you looking for resolution or does address mean something different?

3452.

3453. **MR. VAN DER PUT:** It would suggest that all parties in this proceeding would be of the view that tax efficient collection of abandonment funds is something that should be pursued aggressively, expeditiously by setting up the kind of mechanism that we're talking about setting up for collection of the -- for putting aside the abandonment funds.

3454. An independently managed or a trust fund managed by an independent third party certainly facilitates the opportunity for tax efficient treatment.

3455. I would suggest as well that whether it's a nominal amount that's being collected or whether it's an amount that is cost-based, which would be facilitated after the conclusion of Stream 4, certainly the pipeline is not indifferent to the quantum of those collection amounts.

3456. Obviously, if collection is not tax efficient, the quantum is going to be greater and, certainly, we're well aware and very sensitive to the fact that shippers obviously are directly affected by the quantum of the collection amount.

3457. And again, I would point back to, you know, the current times. You know, like I mentioned, producers facing a situation of very low commodity costs; difficulty in terms of accessing the capital markets, liquidity crisis.

3458. At the other end of the pipeline, if we look at particularly the industrial users, for example, in Eastern Canada, those served by TransCanada's Mainline, many sectors of industry whether it's pulp and paper, whether it's auto manufacturing, metals, are going through very difficult times.

3459. So clearly, we're very sensitive as a pipeline company to that issue, very sensitive with regards to the competitiveness of the service that we provide and, as a result, this issue is one, as it is for the shippers, that is extremely important to us and, from our perspective, merits being dealt with aggressively, expeditiously.

3460. And I would further submit, as was discussed at the technical conference with regards to trusts, that the Board has a role that it can play in terms of expeditiously and aggressively working with the pipelines that it regulates and the shippers that those pipelines serve, all of the stakeholders, to, like I say, aggressively, expeditiously deal with this issue.

3461. **MR. JOHNSTON:** And would ---

3462. **MS. LEONG:** And if -- sorry, if I may add just to Mr. Van der Put's comments on the tax efficiency, if I could just throw a basic illustration just to demonstrate why we believe that this -- the tax efficiency is very fundamental and it does have a financial impact.

3463. For every 70 cents, for example, that we have to collect from the shippers, we would, under today's current tax regime, we would have to collect an extra 30 cents, assuming 40 percent tax rate. And so that would mean for every 70 cents, an extra 30 cents could have gone into the trust or a mechanism whereby the compounding interest will actually add to the growth and the funds.

3464. And because of that magnitude, we do believe, as Mr. Van der Put has put it, that it is a very significant impact or a critical element in the structure.

3465. **MR. JOHNSTON:** Thank you, Ms. Leong. Sorry for cutting you off on your answer there.

3466. What if changes, though, are not forthcoming or take significant time; should collection be delayed indefinitely?

3467. **MR. VAN DER PUT:** The way you posited your question, you said, "Should collection be delayed indefinitely?"

3468. We have to recognize, and I think all of us would, that at some point, however far out that may be, the pipeline will have to be abandoned and it behoves us to begin that process of collecting the necessary funds to cover those costs as early as we can for the various reasons that we mentioned.

3469. Certainly the reasons that Ms. Leong alluded to gives more time for the accumulation of earnings on those funds, but it goes back as well to the user-pay principle that I alluded to earlier, that the cost of abandoning a pipeline is a legitimate cost of providing service to all shippers throughout the economic life of a pipeline.

3470. So those costs should be collected throughout that period of time. That's certainly what the goal should be.

3471. **MR. JOHNSTON:** So tax issues are balanced with other principles. Is that what you're saying?

3472. **MR. VAN DER PUT:** There's always a balancing of factors and principles. It's very difficult, as has been discussed earlier in this proceeding, to assign more weight to one or the other, but I would suggest to you, for the reasons that I described and with Ms. Leong's amplification, the issue of tax efficient collection of abandonment funds is a critical one that needs to be dealt with.

3473. **MR. JOHNSTON:** And do you see any alternatives that could be instituted by companies other than income tax changes to create efficiencies? And the answer is not necessarily limited to trust, but I'll -- certainly answer it as you will.

3474. **MS. LEONG:** At this point, we can't think of any other options out there related to the efficiency of the trust fund or aiding the increase in fund growth. The tax efficiency is the one that is at the top of our minds just because it does provide the goal of accumulating as much money as we can in the most efficient manner.

3475. **MR. JOHNSTON:** And if I can ask you a question regarding your evidence concerning the phrase, "sufficiently in advance"? And I can refer you to Exhibit C-26-6B which is response to NEB 1.2, the (b) section of the response.

3476. **MR. VAN DER PUT:** I have that.

3477. **MR. JOHNSTON:** TransCanada stated that "sufficiently in advance" should be a principle for all pipelines whereby the collection of abandonment costs will minimize intergenerational inequity among ratepayers and there can be a material

accumulation of compounded interest.

3478. My question is how can the point where intergenerational inequity is minimized and when there will be a material accumulation of compound interest be determined or optimized on a general level or on a high level?

3479. **MR. VAN DER PUT:** I'm going to ask you to repeat your question. I'm not entirely sure that I caught the sense of it.

3480. **MR. JOHNSTON:** Sure. And the question relates to -- here I'm asking about balancing as well, and the question is how can the point where intergenerational inequity is minimized and when there will be a material accumulation of compound interest be determined or optimized?

3481. **MR. VAN DER PUT:** I think all we can do, from my perspective, at a very high level is go back to the principle that abandonment costs are a legitimate cost of providing service to shippers on a pipeline and, as such, then should be borne by shippers who contract for service on that pipeline throughout its economic life.

3482. And to the extent that there is departure from that, to the extent that there are periods of time, for example, at the front end of a pipeline's economic life, where shippers are not contributing to covering the abandonment costs, then necessarily there is, in some degree, intergenerational inequity which is being created, and the longer the period of time when no abandonment funds are being collected, then arguably the greater the intergenerational inequity.

3483. Did you want me to address in a similar fashion the issue of compounded interest on funds?

3484. **MR. JOHNSTON:** If you like. I was asking in terms of balancing the two, so certainly.

3485. **MR. VAN DER PUT:** If you've got enough, I'm happy to stop there, but it's up to you.

3486. **MR. JOHNSTON:** Sure, if you could elaborate briefly on the issue of compound interest?

3487. **MR. VAN DER PUT:** Yes. I mean, again, I would suggest to you that if we take, for example, accumulating compounded interest on funds -- on invested funds over a 15-year period as compared to over a 30-year period, there's a significant difference, certainly, in terms of the compound interest that will accumulate over that period.

3488. Obviously it's not just double. You know, that's the nature of compounding. It's quite a bit better to collect those funds and have the benefit of compounded interest over 30 years than it would be over 15 years, for example.

3489. **MR. JOHNSTON:** Ms. Leong, did you want to elaborate?

3490. **MS. LEONG:** If I could elaborate on Mr. Van der Put's comments, I think the approach to our response is that assuming that the right thing to do is to collect as soon as possible, from a compounding interest and from an intergenerational inequity perspective, that is -- the two aren't congruent. So it's not balancing the two principles.

3491. But if we assume that there's a risk of too early a collection or over-collection, when it comes to comparing that to the impact of early compounding interest, then there is a balancing. So the balancing is how soon, and from a compounding interest, I think our fundamental investment principles tell us that the earlier the better.

3492. So contrasting that to, let's say, a scenario that we don't believe we should collect sooner, then there is a balancing.

3493. **MR. JOHNSTON:** Thank you.

3494. The next area of questioning concerns risk and some of the potential safeguards.

3495. In your evidence earlier this morning, Mr. Van der Put, you had indicated that there's a very small risk of an unfunded liability at the end of the day when the abandonment actually takes place and it's almost negligible. And if I can also refer you to your response to NEB 1.7, which is Exhibit C-26-6B?

3496. **MR. VAN DER PUT:** I have that.

3497. **MR. JOHNSTON:** You're ahead of me.

3498. Your evidence is:

> "*There will always be some element of risk that insufficient funds will be collected before a pipeline is abandoned*."

3499. And then you go on to discuss the issues of the tight regulation and the need for a properly designed framework. Later -- later, in the last paragraph, you go

on to state that:

> "*Any risk to landowners, government and other stakeholders must be balanced with the appropriateness of collecting funds from shippers and users of other systems, who have received no benefit associated with the orphaned pipeline. Further, this would be a departure from cost causality that is fundamental to rate-making principles*."

3500. Other than the -- other than collection for abandonment, are there any other safeguards that could be put in place to handle the risk of insufficient funds being collected?

3501. **MS. LEONG:** I think, consistent with some of the comments we have heard from other panels, we would go back to the rigor behind the periodic review, but perhaps we can add to that by suggesting that the periodic review is not just -- it's robust and this is why we need to ensure that the framework does respond to changes in circumstances or changes in legislation.

3502. The robustness will have to come from, for example, the frequency and how periodic the review is. In earlier years perhaps a five-year period, but as we move through time, perhaps we can tighten that up to annual review.

3503. The other area where I think the robustness has to come in is also, if we adopt some sort of a trust or a pension mechanism, the investment policy is also very important and, again, robust enough so that the investment policy can respond to the time as well.

3504. Our personal investment guidelines is such that in earlier years, perhaps there is an opportunity for us to widen the risk level that one is able to tolerate and, again, as we move through time, we should probably tighten up the investment criteria to ensure that the risk is manageable.

3505. **MR. JOHNSTON:** My question, though, was about other safeguards or other alternatives. So I'd be interested in knowing -- I take it that trusts are the only viable alternative that you've found to put forward, but what were -- were there any alternatives that TransCanada considered, prior to submitting evidence, that it determined were not viable mechanics? And if there were, if you could explain why that is.

3506. **MS. LEONG:** We had at the very preliminary outset, we had throughout a few ideas, but we quickly, actually, determined that they were either not efficient or economic or not practical ideas, such as a letter of credit from a company or

insurance, taking an insurance placement on the abandonment fund. But again, for the reasons that I've stated, we quickly determined that those are just not practical.

3507. **MR. JOHNSTON:** And just if you can elaborate just a bit more on why insurance or a letter of credit weren't practical in your view.

3508. **MS. LEONG:** On the insurance, I think the quantum of what we would need to place in terms of an insurance policy is so significant -- at this point, I don't have a lot of insight into actually the insurance industry, but our initial thinking is to place an insurance policy on magnitudes of, and examples that we've heard during the proceeding is upwards of billions of dollars, might not be something that would be achievable.

3509. **MR. JOHNSTON:** And letters of credit, if you could quickly ---

3510. **MS. LEONG:** I think, similarly, on the letters of credit, again we'll need to take a look at what party, and assuming it's the pipeline company, the cost of putting a letter of credit of that quantum would be very costly from a company standpoint, and that would be just one of the many reasons.

3511. **MR. JOHNSTON:** What are the advantages and disadvantages of some form of pooling for Group 1 and Group 2 companies? And this could be from the standpoint of you as pipeline companies or shippers, landowners, governments, any other stakeholders.

3512. If you could comment on whether pooling may have any application and also the advantages and disadvantages.

3513. **MR. VAN DER PUT:** Our view fundamentally would be that abandonment funds should be set up for individual pipelines, that the model whereby there would be a pooling of funds should not be a model that we would pursue.

3514. A number of practical factors -- the funds need to be able to follow the pipeline -- if there is a sale, if there is a change in jurisdiction, whatever the -- whatever might trigger a change -- and with individual accounts the, you know, the funds are better able, it's more straightforward to follow the pipeline.

3515. It's also greater assurance with individual abandonment funds that -- or abandonment funds on an individual pipeline basis that the funds will be there when they're needed in order to cover the abandonment cost, that each pipeline is going to exercise the diligence that it needs to ensure that the funds are there, rather than falling into the, you know, the moral hazard trap that was discussed by some other panels, where, you know, some pipelines might lean on others, if you will, to collect

the funds and be able to then rely on those funds while they themselves aren't as diligent.

3516. I think, as you alluded to in some of our IR responses, it's not in keeping with the principle of cost causation where -- a pooling of funds would not be in keeping with cost causation.

3517. As well, individual funds would be more transparent from our perspective, less administratively complex in terms of trying to keep track of all of the funds, you know, which entities do they relate to, that sort of thing.

3518. So, for all those reasons, we've indicated in our evidence pooling of funds is not a model that, you know, that certainly we would propose be pursued.

3519. **MR. JOHNSTON:** And is your concern about pooling less significant if it were only the residual risk that was subject to pooling? And you said -- you said earlier in your evidence today that given all the mechanisms that are being proposed, there's a very small risk, almost a negligible risk of there being any liability at the end.

3520. So if pooling were based only on dealing with that portion of the risk that you've said you consider negligible, would you have the same concerns about pooling as you would if there was full pooling?

3521. **MR. VAN DER PUT:** I would say the principles are no different, so I wouldn't have any -- the concerns would remain whether we're talking about residual or otherwise.

3522. **MR. JOHNSTON:** And would pooling at all -- would pooling be of assistance with regard to the objective that landowners will not be liable for the costs of pipeline abandonment? From that -- from the perspective of that principle, do you see any benefits of pooling?

3523. **MR. VAN DER PUT:** We don't.

3524. **MR. JOHNSTON:** And why is that?

3525. **MR. VAN DER PUT:** Again, for all of the reasons that I cited that lead us to the conclusion that individual pipeline abandonment funds are the appropriate model, rather than a pooling of abandonment funds.

3526. **MR. JOHNSTON:** On the issue of governance, should the Board determine that landowners are required to some opportunity to participate in fund governance, whatever that might be, from the standpoint of administrative

efficiencies, would there be any benefits in having one fund that had been accumulated versus having funds separated by pipelines, from a governance standpoint?

3527. **MR. VAN DER PUT:** We don't think there would be.

3528. **MR. JOHNSTON:** And if you can just elaborate briefly on that answer as to why.

3529. **MR. VAN DER PUT:** Each particular or pipeline-specific abandonment fund needs to address the issues that are specific to that pipeline, including in -- as regards governance of the trust or the fund. So we wouldn't see it any more efficient to look at a pooled model in terms of the aspects of governance.

3530. **MR. JOHNSTON:** And just to follow-up on the issue of -- you've already said you're not in favour of letters of credit.

3531. Would there be any role for any type of financial assurances in a situation where a company were to be determined to be in some way at risk?

3532. **MS. LEONG:** I think TransCanada's position on the concept of placing financial assurance is that it is very inconsistent with the regulatory principle of user pay. There are both tangible and intangible costs associated with financial assurances.

3533. So at the end of the day, if one of the regulatory principles is user pay, our position is that any party outside of the users really shouldn't be burdened with any costs.

3534. And with respect to intangible costs -- and I'm definitely not an expert in the finance area, but off the top of my head there are probably impacts on the company's balance sheet to the extent that the company needs to place any kind of financial assurances.

3535. And so rating agencies may actually look at the balance sheet in a different light, and it may or may not result in limiting the company's ability to raise funds in the market. Liquidity is very key from a company standpoint.

3536. So our position is that financial assurances from a party that's outside of the user or even the use of the financial assurance has to be taken into consideration very carefully.

3537. **MR. JOHNSTON:** And has TransCanada ever required financial

assurances from shippers as security for a transportation contract?

3538. **MS. LEONG:** I believe we have.

3539. **MR. JOHNSTON:** And if you could elaborate on those circumstances and perhaps explain how they might be the same or how they would be differentiated from financial assurances in the context of abandonment.

3540. **MS. LEONG:** Just taking coaching from my colleague here, as I'm an accountant.

3541. So again ---

3542. **MR. JOHNSTON:** You're certainly welcome to let your colleague answer. I'll leave it to you.

3543. **MS. LEONG:** I will offer my perspective from an accountant's perspective.

3544. When it comes to financial assurances related to transportation contracts, I think that relates to the credit rating of our shippers, and so the shippers are paying for a transportation cost and they're benefiting from it.

3545. To the extent that they have either high or low credit rating, there is assurance that they do need to place and that's for the protection of both the pipeline and the company.

3546. I see the financial assurances that we are considering today to reduce the risk of future abandonment cost is very different. The company is not really the user of the transportation contract. So we're really looking at a completely different party to ensure that the burden of the cost or the risk of the landowner is mitigated.

3547. Does that help?

3548. **MR. JOHNSTON:** Anything to add, Mr. Van der Put?

--- (No response/Aucune réponse)

3549. **MR. JOHNSTON:** Continuing on with the issue of risk, you've indicated that the appropriate method of fund accumulation is pipeline by pipeline. You've reiterated that you're not in favour of pooling and you've said that regular revisions will help ensure that the expected cost is fully funded by the time of abandonment.

3550. Is that a correct summary?

3551. **MR. VAN DER PUT:** We also in my earlier statements mentioned a couple of other factors that are part of the belts and suspenders which I would reiterate.

3552. **MR. JOHNSTON:** Certainly.

3553. **MR. VAN DER PUT:** The other factor being that pipelines are heavily regulated entities. And certainly with regards to the mechanisms that would be established for the collection and the setting aside of abandonment funds, this is something that the regulator would play a significant part in.

3554. So, therefore, I would see that as another safety valve, if you will, with regards to the whole process.

3555. The other factor that I mentioned was just the fact that what we're talking about here is segregating the funds from the pipeline's general revenues into a special purpose or a fund that is intended for a specific purpose; that is to cover the cost of abandonment.

3556. Managed by an independent third party certainly provides as well an additional safeguard that the funds will be available when they're needed to cover the cost.

3557. **MR. JOHNSTON:** And suppose the fund accumulates, there's an eventual abandonment, and then at the end of the day after full reclamation there's money left over, I understand from your evidence that you've indicated that that should account to the shippers.

3558. Is that correct?

3559. **MR. VAN DER PUT:** That's correct. But to further elaborate, again going back to the point I made earlier, that abandonment isn't a one-time event. It's a process that's going to take place over a period of years.

3560. And whereas early on in the process of abandonment we may find more instances perhaps of situations where we've found ourselves to be a little bit under-funded or over-funded, we will -- as we gain experience with carrying out the abandonment activities, we'll get better and better certainly at determining what the required funds are and be able to make adjustments in terms of those collection amounts so that once we do get to the end, if you will, the likelihood that there would be either a surplus or a deficit should be pretty darn small.

3561. **MR. JOHNSTON:** And supposing there is a surplus, I'm interested in further elaboration on why the difference should account to shippers. Other pipeline companies have said the surplus should account to pipeline companies and I wanted your perspective on that.

3562. **MR. VAN DER PUT:** We latch onto the fundamental principle that abandonment costs are a legitimate cost of providing service on a pipeline and as such then should be collected from the shippers just like any other cost.

3563. Therefore, any surplus or funds that might exist, given that it's the shippers that contributed to the monies necessary to cover those costs, it should be to the shippers' account.

3564. And similarly, if we have a deficit situation, then we should take the appropriate measures to obtain the necessary additional funds from the shippers.

3565. **MR. JOHNSTON:** And in a deficit situation, supposing the deficit is at the end of -- and I recognize abandonment in your evidence is it will take place over a period of time and it won't all be in one event.

3566. But at the end of the day, if there's a deficit after a full cleanup to the necessary extent, how do you expect that deficit would be handled at that point?

3567. **MR. VAN DER PUT:** To tell you the truth, given that we're talking about something that is going to take place out -- considerably out into the future, and again, given that the risk that we would be in that kind of situation at the end would be quite small, we haven't spent any time thinking about what might be some means of doing that.

3568. I suppose Ms. Leong might want to elaborate. If we did do that, if we did give it some thought, we might perhaps come up with some mechanisms that might work. But at this point, I wouldn't have anything to offer, nor does Ms. Leong it appears.

3569. **MR. JOHNSTON:** And if I can move to the topic of pensioning or potential similarities between a trust fund for abandonment and pension funds. And if I can refer you to Exhibit A-42A, which is a January 14th, 2009 letter from the Board referencing definitions and principles from the pension context.

3570. I guess my first question is, do either of you have a background in the pension area?

3571. **MS. LEONG:** No, we do not.

3572. **MR. JOHNSTON:** I'll limit my questions, then, just on a very overview-type nature.

3573. Does the framing typical in the pension model resonate in the abandonment context? And I believe you've already said that it does.

3574. But if you could let us know the key reasons why there's similarities or if there's any -- if there's any differences of concern, if you could also provide that information.

3575. **MS. LEONG:** Just to comment on the similarities between pension and abandonment funds, I think there are some key similarities. Abandonment cost, very similar to pension, is about future and it's about a cost that we really cannot determine to a high degree of certainty today, and that's very similar to pension.

3576. The elements that actually -- that emulates from that are things like discount rates to determine how much we need to collect, other elements such as the time period, estimates of the technical assumptions; all that is very similar.

3577. If we're dealing with funds, the return investment policies, how the fund grows, those are all very, I think, similar technical aspects of the pension that we can actually apply to the workings of an abandonment fund.

3578. Commenting perhaps on the governance principles, I think these are very, very fundamental, very basic governance principles, and I really don't see -- I don't think there's anything that jumps out at me that says, to the extent that it applies to a pension fund cannot be applied to something similar on the abandonment fund.

3579. Having said that, I think there are a lot of complexities in the pension fund -- in the pension plan -- and the workings of the pension plan, including the oversight and the investment policies and the governance structure, and I don't think we need to overcomplicate what we need to do here.

3580. I think -- and perhaps I'm oversimplifying, but the way I see it is we would do need to collect some money, whether or not it's today or tomorrow, and that money needs to grow over time to ensure that we can discharge that liability when the time comes.

3581. So the workings is really something similar to pension, but can be very well simplified.

3582. **MR. JOHNSTON:** And Ms. Leong, you made reference earlier in your answer to returns and investment policy. So I want to ask you, there's been a lot of media discussion lately about the drop in the value of pension plans.

3583. Do you have any suggestions of how impacts of declines in equity markets or other types of investments could be mitigated against should the Board determine that funds collected for abandonment costs should be treated in a manner analogous to pensions?

3584. **MS. LEONG:** I think my -- the only suggestion I would offer is, going back to my comment of the rigor around the investment criteria. I think the recent volatile times is something that none of us really expected.

3585. So again, if we can put rigor around and the frequency around the periodic assessment, and assessing with a prudent and efficient manner the investment criteria, depending on the time period that we're in as well, whether or not we are in the early stages or closer to abandonment, I think those are some fundamental principles that are very important when we're looking at setting up an abandonment fund.

3586. **MR. JOHNSTON:** And I just have one further short line of questioning.

3587. If, as a result of this hearing, the Board ultimately directs that companies should prepare estimates and the Board provides a set of some or all assumptions which company needs to address and justify, how would TransCanada account under GAAP principles for this required estimate?

3588. **MS. LEONG:** I would have to clarify. So what you're proposing is, to the extent that the Board determines that there is an amount that we should recover, if that is the question, I would say from an accounting standpoint ---

3589. **MR. JOHNSTON:** I'm sorry, if I may just interrupt, I don't ---

3590. **MS. LEONG:** Absolutely.

3591. **MR. JOHNSTON:** --- think it was clear. Just at the standpoint where the Board asks you to provide a set of assumptions and justify, and once you -- once you go and study that, prepare -- prepare those assumptions, does that have any implications for GAAP or accounting requirements?

3592. **MS. LEONG:** So I think I know where you're headed, because I have heard similar questions, and the -- I think the question is really getting to the extent that the Board actually puts some framework or some technical assumptions to narrow what we need to do; in other words, providing the accountant with better

visibility or more information around the scope of the abandonment, which is one of the criteria under GAAP, or generally accepted accounting principles -- whether or not that would actually lead to any accounting consequences. And if that is the question, my preliminary assessment is I do not think so.

3593. Whether or not we have a collection amount -- and from an accounting standpoint, that should be recorded as revenue on the balance sheet side. The cash should be recorded as a restricted fund or a fund. Whether or not that triggers further accounting transactions is really an independent exercise.

3594. So whether or not that actually creates the possibility that we will have to record an asset retirement obligation, I think from an accounting standpoint, has to be assessed independently. We will actually have to go through the handbook section 3110 and apply those determinations or criteria in determining whether or not we should record that asset retirement obligation.

3595. **MR. JOHNSTON:** Thank you. I'll check with my colleagues and see if there are further questions.

--- (A short pause/Courte pause)

3596. **MR. JOHNSTON:** In the event -- if you do your review of section 3110 of the CICA handbook and you come to the conclusion that it does trigger any accounting changes, could you provide any -- could you provide any feedback in terms of the impact of such a change?

3597. **MS. LEONG:** Could you elaborate on the impact? Are you referring to ---

3598. **MR. JOHNSTON:** Well, the impact on TransCanada if such a -- if there was a required change as a result of accounting requirements.

3599. **MS. LEONG:** And the assumption is that we have determined that we have to record an asset retirement obligation?

3600. **MR. JOHNSTON:** Yes, we can -- we can deal with that as an assumption.

3601. **MS. LEONG:** So, on the assumption that we -- at the -- when we have determined that there will be an asset retirement obligation, based on handbook section 3110, the impact -- the accounting impact is that we will have to set up an asset retirement obligation, or a liability, on TransCanada's books.

3602. Equally, we will also have to set up an asset retirement cost, which is the asset, an equal and offsetting asset, on TransCanada's balance sheet. Annually, we will actually have to accrete that liability through time and as well amortize that asset retirement cost over time.

3603. So there will be an expense, both in the nature of an interest expense and as well an asset retirement cost amortization expense, coming through TransCanada's financial statements.

3604. If I can take that one step further, perhaps -- I suspect you will have follow-up question with respect to my response; so I'll take that one step further.

3605. To the extent that there is a difference between the asset retirement expense that is going through the annual financial statements and the revenue in the form of what the Board determines is the appropriate collection, that amount, under current GAAP, is set up or may be set up as a regulatory asset or a liability, depending on whether or not it's a positive or a negative difference.

3606. The one thing I do want to comment is that in my mind the key accounting -- the key objective of accounting is to fairly present financial transactions on the financial statement of a company, and it really in no way should drive regulatory policies or framework.

3607. So I actually see the determination of future abandonment cost, the recovery of that, very independent from the accounting of that action.

3608. **MR. JOHNSTON:** Thank you, panel.

3609. I have no further questions, Madam Chair.

3610. **THE CHAIRPERSON:** Madame Mercier, do you have any questions of this panel?

--- EXAMINATION BY/INTERROGATOIRE PAR MEMBER MERCIER:

3611. **MEMBER MERCIER:** Hello. Any of you could answer my question. I'll try to be clear.

3612. You've stated that you feel that if there should be any shortfall following abandonment, it should be the shippers who should pay for it. So if I follow your reasoning, it means -- and you stated that it's going to be a process and you should have time to readjust whatever has to be collected.

3613. Hearing this, I'm wondering whether this burden on shippers would not, at one point in time, precipitate the death spiral. You see, if there's abandonment, there's going to be less people on the pipeline, so less volume flowing, and if there is more money to collect than expected, it's going to be increasing the collection cost.

3614. So if it is the shipper, he could precipitate maybe the death spiral and, if so, what other suggestion would you have if that could happen?

3615. **MR. VAN DER PUT:** I think, Madame Mercier, the scenario that you described, I suppose, could be a possibility and in my mind, one of the things that it argues for is again commencement of collection of abandonment funds dealing with the whole issue of pipeline abandonment as early as possible in the economic life of a pipeline so that the costs of abandonment are borne by, in the ideal situation, all shippers throughout the economic life of a pipeline, reducing the risk of the kind of scenario that you've described, because in doing that, the collection amounts that are being charged to the various shippers are reduced from the alternative scenario where beginning of collection of abandonment funds is deferred for some period of time.

3616. So I certainly would agree that, in the kind of scenario that you've described, it would be a possibility. And like I say, that certainly argues for commencing collection of abandonment funds as soon as practical.

3617. **MEMBER MERCIER:** Thank you.

3618. **THE CHAIRPERSON:** Mr. Bateman…?

--- (No response/Aucune réponse)

--- EXAMINATION BY/INTERROGATOIRE PAR THE CHAIRPERSON:

3619. **THE CHAIRPERSON:** I just had a couple of clarifications, I think, from my perspective to make sure I've understood things correctly.

3620. I had thought I heard that you said that there was a role for financial assurances for companies that are considered at financial risk, but then I also thought I heard that asking for financial assurance from a pipeline company would be targeting the wrong company.

3621. If I've heard those two sentences correctly, could you clarify for me what the intention of those statements is?

3622. **MS. LEONG:** For sure. So the intention of those statements -- and if I

can clarify, I think I was falling back on the principle of user-pay, and to the extent that we're looking for a party who did not benefit from that service to be burdened with additional costs of the risk of under-recovery is inappropriate.

3623. **THE CHAIRPERSON:** And so what would you see the role of financial assurance is in this particular case?

3624. **MS. LEONG:** I think the comments that I was making was really alluding to the party which will actually have to place the financial assurance.

3625. So again, in alignment with user-pay, perhaps very similar to the example that was brought up, the financial assurances that the pipeline requires from their shippers to actually backstop their credit risk around transportation contracts, perhaps that's something that we could consider, imposing financial assurances on shippers, and again aligning that with the concept of a user being burdened with all the cost of the abandonment cost.

3626. **THE CHAIRPERSON:** So you're raising the concept of requiring specific shippers to provide financial assurances for collection of abandonment funds. Am I correct in that?

3627. **MS. LEONG:** I think in the context of -- and I believe we were talking about the risk of under-recovery at the end of the day and who that risk should be borne by, and financial assurances came up as an example.

3628. So I don't think we're suggesting that we apply financial assurances today to cover off the totality of future abandonment costs. It's really in the narrow scope of if the Board determines that it's necessary to put something in place today to ensure that, however minimal, that risk is 100 percent covered and that might be something that we can consider.

3629. On the flip side, there is the economic use of capital. So there are actually other conflicting factors that I would suggest that we would have to consider before we actually look at various other financial measures to ensure protection.

3630. **THE CHAIRPERSON:** And just to clarify one more time from my perspective, when you're talking about financial assurances, are you talking about those in lieu of a toll?

3631. **MS. LEONG:** No, I'm not.

3632. **THE CHAIRPERSON:** Just excuse us for a minute, please.

--- (A short pause/Courte pause)

3633. **THE CHAIRPERSON:** Thanks for your patience. One thing about being on the Board is that we're always told that we're masters of our own procedure, and as a result of the discussion that you and I have had, Ms. Leong, Mr. Bateman now has a further follow-up question for you.

--- EXAMINATION BY/INTERROGATOIRE PAR MEMBER BATEMAN:

3634. **MEMBER BATEMAN:** Ms. Leong, you had indicated that the user-pay principle would, in your view, require ultimately a shipper to be responsible for any shortfall that might occur with respect to abandonment costs, and one possibility is that financial assurance from shippers could be a method by which that shortfall could be recovered.

3635. The question that comes to my mind is the pipeline company ultimately would present and, in some ways, determine the toll methodology and have the responsibility to ensure then that there are sufficient funds for abandonment.

3636. Would you give me your view as to why it is that the pipeline company then might not be expected to provide the financial assurance should the analysis prove to be inadequate at the time of abandonment?

3637. **MS. LEONG:** I would first have to say that I am definitely not an expert in this area, but in my view, though, going back to just the principle of user-pay, I think the totality of the abandonment cost has to be borne by the shippers and there has to be symmetry to the extent that there is a risk at the end of under-recovery or over-recovery.

3638. I know, practically speaking, if this is the last day of the pipeline in service or being in operation, perhaps having no shippers around, it may or may not be a practical solution. But when we're talking about financial assurances, this is really an additional protection to ensure that those who are benefiting from the service are able to cover all the costs.

3639. So from a pipeline company perspective, our obligation is to ensure that, assuming these are prudently incurred costs, so that if they were imprudent I think the pipeline company would be actually obligated to ensure that there is coverage.

3640. But assuming that these are prudently incurred costs and Board-authorized costs, at the end of the day if we need an additional mechanism to ensure protection, protection that the ultimate risk of under-recovery is assured, then a financial assurance imposed on our shippers would be one element that could actually achieve

that goal.

3641. **MEMBER BATEMAN:** Thank you.

3642. **THE CHAIRPERSON:** Ms. Leong, I just had one other area that I wanted to follow-up with you on and it relates to a conversation that you had with Mr. Johnston towards the end of his questions of you.

3643. We've heard evidence during this procedure about using the accounting standards as the framework for collecting abandonment funds and I was just interested, if you would elaborate further, on your professional opinion of that type of approach?

3644. **MS. LEONG:** Thank you.

3645. I'd certainly have to agree with Spectra's panel, the -- suggesting that there is a lot of rigour around the accounting standards. The accounting standards actually provide some fairly prescriptive guidelines on how to come up with probabilities of what criteria that is needed to determine that asset retirement obligation.

3646. So we've talked about indeterminate life and indeterminate scope. To the extent that we have visibility on what that scope or vis-à-vis the technical assumptions are, that will actually facilitate the accountants to be able to calculate what that future obligation or the asset retirement obligation would be.

3647. So I think those principles are very sound from a regulatory perspective. My perspective is -- and maybe one additional comment. The fact that ensuring that the regulatory amount is consistent with the accounting amount will certainly make the accountant's life a lot easier, but I suspect that would be not on the top of the key list of regulatory principles.

3648. So the extent that I don't disagree that the accounting has a lot of rigour I just wanted to point out that it really shouldn't drive what the Board determines. So if at this point in time the Board determines that it's appropriate to collect an amount, given all the regulatory principles that are in place, then it really shouldn't delay just because there is no asset retirement obligation being recorded on the company's balance sheet.

3649. **THE CHAIRPERSON:** Thank you, Ms. Leong.

3650. Those are the Panel's questions.

3651. Mr. Denstedt, do you have any redirect?

3652. **MR. DENSTEDT:** Madam Chairman, nothing arising.

3653. If the witnesses could be excused, that would be great.

3654. **THE CHAIRPERSON:** Thank you very much to both of you for the evidence that you've provided in this proceeding. You can now be excused.

--- (The witnesses are excused/Les témoins sont libérés)

3655. **THE CHAIRPERSON:** We will take a break and return at 10:55.

3656. CAPLA, will you be ready to put your panel up at that point?

--- (No response/Aucune réponse)

3657. **THE CHAIRPERSON:** Thank you very much.

--- Upon recessing at 10:31 a.m./L'audience est suspendue à 10h31
--- Upon resuming at 10:51 a.m./L'audience est reprise à 10h51

3658. **THE CHAIRPERSON:** Thank you very much. Welcome back everyone.

3659. Mr. Vogel, when you're ready to proceed.

3660. **MR. VOGEL:** Thank you, Madam Chair.

3661. Madam Chair, I'm pleased to present to you CAPLA's witness panel.

3662. By way of introduction, in the centre of the panel we have Dave Core, who is the President of CAPLA. On either side of Mr. Core, we have landowner representatives from various CAPLA member associations.

3663. At the -- closest to me is Ken Habermehl. He's a member of the Saskatchewan Association of Pipeline Landowners. Dr. Habermehl is an Enbridge, Kinder Morgan by way of rental, and Alliance landowner.

3664. Seated next to Dr. Habermehl is Craig Storey. He's a representative of the Manitoba Pipeline Landowner Association and he is an Enbridge landowner.

3665. To Mr. Core's left we have Jim Ness who is here representing the Alberta

Association of Pipeline Landowners and he is a TransCanada landowner.

3666. Seated next to him is Mr. Kraayenbrink from the Gas Pipeline Landowners of Ontario and also GAPLO-TransCanada. He is a TCPL landowner, Vector landowner and also has Union or Westcoast lines.

3667. Seated next to him is Aggie Cheung and at the far end of the panel is Pat Teevens. Their respective CV's have both been filed previously with the Board.

3668. At the second table, providing assistance, are two landowners, Ian Goudy and Ryan Andrews, and seated behind Mr. Teevens is his associate Don Robertson.

3669. Mr. Core, were you responsible in conjunction with the other CAPLA representatives on the panel for the preparation of CAPLA's pre-filed evidence in this proceeding.

3670. **MR. CORE:** Yes, I was.

3671. **MR. VOGEL:** And that includes then Exhibit C-1-6A, CAPLA's original submission of May 20th, 2008; Exhibit C-1-9B, the second evidence filing of CAPLA November 5th, 2008; Exhibit C-1-13B, CAPLA's reply evidence of December 17th, 2008; CAPLA's IR Responses, C-1-8B, C-1-11B and C-1-14B; as well as CAPLA's opening statement.

3672. Is that correct, Mr. Core?

3673. **MR. CORE:** Yes, CAPLA was.

3674. **MR. VOGEL:** I'm sorry; I neglected to have these witnesses sworn. Perhaps we should do that first.

DAVE CORE: Sworn
PATRICK TEEVENS: Sworn
AGGIE CHEUNG: Sworn
JIM NESS: Sworn
KEN HABERMEHL: Sworn
CRAIG STOREY: Sworn
RICK KRAAYENBRINK: Sworn

--- EXAMINATION BY/INTERROGATOIRE PAR MR. VOGEL:

3675. **MR. VOGEL:** Mr. Core, then, you were responsible for the preparation of the Pre-filed Evidence, IR responses and opening statement I referred to

previously?

3676. **MR. CORE:** Yes, I was.

3677. **MR. VOGEL:** And was that evidence accurate to the best of your knowledge and belief at the time it was prepared?

3678. **MR. CORE:** Yes, it was.

3679. **MR. VOGEL:** And do you have any changes or additions to that evidence?

3680. **MR. CORE:** No, I don't.

3681. **MR. VOGEL:** And on behalf of CAPLA and the other panel landowner representatives, do you adopt that evidence as CAPLA's evidence in-chief in this proceeding?

3682. **MR. CORE:** Yes, I do.

3683. **MR. VOGEL:** Mr. Teevens, in CAPLA's initial Pre-filed Evidence, Exhibit C-1-6G, Appendix 6 in that document is a report entitled "Pipeline Abandonment, Pipeline Corrosion, Related Technical Issues and Long-term Landowner Impacts," dated May 14th, 2008.

3684. Is that a paper that was prepared by you or under your direction?

3685. **MR. TEEVENS:** Yes, it was.

3686. **MR. VOGEL:** And at Tab 6A is your curriculum vitae.

3687. Madam Chair, Mr. Teevens is a professional engineer and I propose to qualify him as an expert in pipeline corrosion and the implications of pipeline corrosion for pipeline abandonment technical options.

3688. Referring to your curriculum vitae, Exhibit C-1-6H in this proceeding, Mr. Teevens ---

3689. **MR. KHAN:** Madam Chair, if I may, I just ask my friend to clarify Mr. Teevens' technical knowledge. I understood him to be a corrosion engineer. That's what I had anticipated him being.

3690. **MR. VOGEL:** Yes, he is, he's a corrosion engineer.

3691. **MR. KHAN:** And that's his field of expertise?

3692. **MR. VOGEL:** Yes, it is.

3693. **MR. KHAN:** And that's what you're qualifying him in?

3694. **MR. VOGEL:** Yes, it is.

3695. **MR. KHAN:** Okay. Thank you.

3696. **MR. VOGEL:** Mr. Teevens, your -- looking at your CV at the first page there, you are a professional engineer and you've been certified as both a corrosion specialist and a cathodic protection specialist by NACE International.

3697. Is that correct?

3698. **MR. TEEVENS:** Yes, sir.

3699. **MR. VOGEL:** And what is NACE International?

3700. **MR. TEEVENS:** NACE International stands for the National Association of Corrosion Engineers. It's the world's leading organization of engineers and scientists whose sole purpose and function is the dissemination of corrosion science and engineering information related to infrastructure deterioration in a variety of industries.

3701. **MR. VOGEL:** And I see at the bottom of that first page that you are the lead instructor in the Internal Corrosion for Pipelines course.

3702. What is that?

3703. **MR. TEEVENS:** It is a course that was developed by NACE International in response to a couple of pipeline failures that happened in the United States with some serious consequences associated with it.

3704. NACE International developed a training program for pipeline operators and practitioners to have a fundamental understanding of internal corrosion principles. I have been appointed as one of a handful of -- approximately four or five lead instructors to conduct that course to trainees worldwide.

3705. **MR. VOGEL:** And turning in to the second page of your CV, I see you

were also a science coordinator at NACE in 2005.

3706. What was the nature of that position?

3707. **MR. TEEVENS:** I served in that position as Chair of the Science Technical Group. There's five main groups within NACE International. The purpose for -- is for the development of international standards related to specific industries.

3708. There's two groups that run industry-specific task groups for developing standards, and there's two that have a cross-industry sort of perspective, and I headed up the science, which was in charge of fundamental research and development of cutting-edge technologies associated with corrosion science and engineering.

3709. **MR. VOGEL:** And you are also, I see, the international representative to the Pipeline Standard Developing Organization.

3710. What is that?

3711. **MR. TEEVENS:** PSDOCC, Pipeline Standards Developing Organization Coordinating Council, is a voluntary organization of standards-writing bodies in the United States, for example, ASME, API, MPFA, NACE International.

3712. What we do is we come together two to three times per year, depending upon the urgency and need, to look at and review changes to existing pipeline safety standards, adoption of new standards in whole or in part, and, really, the last technical vet on pipeline safety issues before those go to Congress in the United States for adoption into the rule-making and then subsequent adoption by the DOT.

3713. **MR. VOGEL:** And at the same page I see that you are also on the advisory panel at the University of Calgary, Schulich School of Engineering.

3714. What are your responsibilities there?

3715. **MR. TEEVENS:** It's in its infancy. It's again a voluntary organization of corrosion experts -- engineers, scientists -- that can provide direction for industry funding or engineering studies within the department of the mechanical engineering, where it's headed by Dr. Bill Shaw, to look at issues surrounding pipeline degradation.

3716. **MR. VOGEL:** And with respect to your employment from your CV, it appears you've been involved in various aspects of pipeline corrosion engineering for the last 20 or 30 years.

3717. Is that correct?

3718. **MR. TEEVENS:** Thirty-one years, sir.

3719. **MR. VOGEL:** And most recently, the last eight years, you are president of Broadsword Corrosion Engineering.

3720. Is that right?

3721. **MR. TEEVENS:** That's correct, sir.

3722. **MR. VOGEL:** And what is the nature of your business?

3723. **MR. TEEVENS:** We're a corrosion engineering company that provides technical assistance to clients that require direction on understanding reasons for equipment failure, presentation of failures; integrity of their equipment, management and administration of their integrity programs. It covers a wide gamut.

3724. **MR. VOGEL:** Madam Chair, I'm requesting that the Board accept Mr. Teevens' qualifications as an expert in pipeline corrosion and the implications of pipeline corrosion for pipeline abandonment technical options.

3725. **THE CHAIRPERSON:** Are there any parties who wish to question Mr. Teevens with respect to his qualifications?

3726. **MR. KHAN:** I would, unless my friend just wants to limit his expertise to the area of corrosion, corrosion engineer, and not the implications with respect to that on the environment.

3727. **MR. VOGEL:** I think I'm satisfied to do -- Mr. Teevens' evidence, as indicated in his report, goes to corrosion of pipelines and the issues related to corroding pipelines. So that would be the nature of the evidence that this witness will be providing, Madam Chair.

3728. **MR. KHAN:** And I appreciate that that's the nature of his report. However, some of that evidence, in my respectful submission, goes outside both his expertise and in fact what the report has been commissioned for.

3729. Quite clearly, Mr. Teevens has extensive experience, as my friend pointed out, with respect to engineering corrosion, but there is nothing with respect to the implication of that corrosion on the environment.

3730. **MR. VOGEL:** Well, at page 4 in the report, Madam Chair, Mr. Teevens

does address certain issues related to abandonment in place and essentially adopts conclusions in that regard from the Stream 4 discussion paper.

3731. So he has addressed that in his report and we can certainly pursue a further line of questioning with him with respect to his experience in relating corrosion to the impact, if you would like me to do that.

3732. **MR. KHAN:** What I would like for Mr. Vogel to do is to present some qualifications from Mr. Teevens that indicate he has the technical knowledge with respect to the implications listed on page 4 of his report.

3733. And in fact, when you look at page 4 of his report he adopts the Stream 4 discussion paper but that doesn't mean that Mr. Teevens in fact has that knowledge.

3734. And, secondly, when you actually go down on page 4 of that report, it specifically states in the second sentence that Broadsword Corrosion Engineering has addressed specifically corrosion issues created by abandonment.

3735. With respect, corrosion issues created by abandonment and with Mr. Teevens' expertise do not include the consequences which are listed above. And if my friend would like to attempt to qualify Mr. Teevens with respect to the environmental consequences of abandonment, I would be pleased that he make that attempt. He has not done so.

3736. **MR. VOGEL:** Thank you, Madam Chair.

3737. Mr. Teevens ---

3738. **MR. FORRESTER;** Perhaps if I could just interrupt? At this point, Madam Chair -- it's Peter Forrester for the record -- I make an objection on a different ground, and the ground is this; that the technical aspects of corrosion do not have a proper place in front of this hearing. And by that I mean this; they are a Stream 4 issue.

3739. If this witness wants to give evidence in relation to the financial impacts which he's not an expert on, in that very specific dynamic, or if it can comment on the Board on the very small technical issues surrounding abandonment in place and how they might have a financial impact, we have no objection to that. But to the extent that there is going to be testimony on the main part of his expertise being corrosion, we do object to that.

3740. So it's not that he's not an expert. He's obviously well qualified in relation to corrosion. It is what is their place other than the financial aspect in front of

this Board.

3741. **MR. KHAN:** And just to be clear, I would adopt that second aspect of Mr. Forrester's commentary, and I reserve the right to make those arguments in final argument.

3742. **THE CHAIRPERSON:** Let's deal with Mr. Forrester's objection in terms of the content, and we'll hear from you, Mr. Vogel, on that please.

3743. **MR. VOGEL:** Yes, Madam Chair.

3744. My response to Mr. Forrester's objection is twofold. Firstly, what the Board is trying to decide here is a technical assumption for funding abandonment costs which will protect landowners from the impacts and related liabilities and costs and before the Board there appear to be essentially two technical options, one being the abandonment in place and the second being the removal of perpetual maintenance option put forward by CAPLA.

3745. What Mr. Teeven's evidence goes to, then, is the inevitable corrosion of the pipeline, the impacts which result from corrosion, and those are the impacts which create the risk of liabilities and cost for landowners.

3746. So in my submission his evidence is directly relevant and admissible to the very issue the Board must decide in this proceeding.

3747. The second response that I have to that objection is that that report is included in CAPLA's Pre-Filed Evidence which was delivered September 5th. It's been referred to repeatedly throughout CAPLA's second filing and reply evidence.

3748. My friends, if they intended to pursue an objection, the effect of which is to attempt to strike that evidence or a good portion of it, in my submission are simply out of time. They've had their opportunity to do that and my submission is that even on that basis alone it should be refused. But my primary position is that it's clearly relevant to the very issue that the Board must decide.

3749. We'll hear from Mr. Forrester first.

3750. **MR. FORRESTER:** Madam Chair, my learned friend says that there are two options in front of the Board. There has been a general discussion in this hearing as to whether or not there are sufficient assumptions to start collection at this point or whether or not there should be assumptions that start after Stream 4. That discussion is something that clearly Mr. Teevens is able to give evidence on.

3751. The point is this, that this Board is not, as my friend suggests, in a position at this point to be discussing the different aspects of removing pipe, not removing pipe, the technical aspects, the engineering aspects, the corrosion aspects, the impacts on the environment.

3752. From an administrative perspective we are not here today prepared to deal with those very significant and substantial issues which fall outside of the financial stream aspect with the exception that they deal with preliminary estimates.

3753. So the point I'm making at this point is not a complete objection to Mr. Teevens giving evidence and it's not a complete objection to the evidence that's been filed. That's fine. But it should not be getting into the details of corrosion versus non-corrosion versus abandonment in place versus taking out -- which we will have a very fulsome discussion about in Stream 4, no doubt.

3754. **THE CHAIRPERSON:** Mr. Khan…?

3755. **MR. KHAN:** I would note, as a starting matter, my friend did not address Mr. Teevens' expertise with respect to impacts of abandonment on the environment.

3756. However, more to the point, he would not be having an objection right now had he described what -- had he qualified Mr. Teevens only as a corrosion engineer. If he had done so I would not have objected. I could not object until he in fact delineated the expertise he seeks from Mr. Teevens.

3757. **THE CHAIRPERSON:** Are there any other parties who wish to speak to this?

3758. Mr. Vogel…?

3759. Oh, Mr. Denstedt…?

3760. **MR. DENSTEDT:** Thank you, Madam Chairman.

3761. Just briefly, the TransCanada group of companies expressed its concern and doubt about some of the information and the evidence that CAPLA proposed to introduce on November 13th, 2008 in Exhibit C-26-6A so we're on the record already casting doubt on some of the assertions that Mr. Vogel's clients make.

3762. But more importantly, in respect of the discussion around technical and physical aspects of abandonment, clearly a Stream 4 consideration and in the papers and the Board's public document dated February 28, 2008, "Stream 4 Physical Issues and Retirement and Reclamation Discussion Paper" it clearly identifies on page 11 of

that document that retirement options, engineering issues, land use considerations, environmental issues, post-abandonment, and principles for pipeline abandonment are all part of Stream 4. And that's where we would expect to discuss those; not here.

3763. That's all my comments.

3764. **THE CHAIRPERSON:** Thank you, Mr. Denstedt.

3765. Any other parties? Mr. Crowther…?

3766. **MR. CROWTHER:** Again, briefly, Madam Chair, the Enbridge position on the relevance of the technical discussion was set out, I thought -- I hope clearly when I objected to certain of Mr. Vogel's cross-examination questions the other day.

3767. Certainly, the issue of what technical and financial assumptions should be used to create preliminary cost estimates is on the issues list, in Enbridge's submission. That, however, does not imply that the matters of effects of corrosion on the environment, et cetera, ought to be addressed in this proceeding.

3768. The Enbridge position has been made quite clear, I would hope, that that is a Stream 4 issue and Enbridge is participating actively and in good faith in that process for that purpose.

3769. Thank you, Madam Chair.

3770. **THE CHAIRPERSON:** Thank you, Mr. Crowther.

3771. Any other parties who wish to speak to this? Mr. Vogel, please.

3772. **MR. VOGEL:** Madam Chair, Issue 2A in this proceeding is what technical option should provide the basis for preliminary estimate of abandonment costs for the purpose of achieving the principle the Board has said underlies this whole process, which is relieving landowners of risks and liabilities.

3773. It begs the question, Madam Chair, what is that risk? What is that risk of liabilities and costs that we've heard landowners bear, ultimately? And that's what Mr. Teevens' evidence goes to.

3774. It goes to what are the impacts of the technical assumption proposed by some parties, Enbridge in particular, of abandonment in place. What are the impacts and therefore what liabilities and costs are created by the impacts that may result?

3775. So Mr. Teevens' evidence goes to what are those impacts, and I'm happy,

if my friend would like me to, to pursue with Mr. Teevens his expertise and qualifications to discuss what are the impacts which result from corroding pipelines.

3776. **THE CHAIRPERSON:** Mr. Khan…?

3777. **MR. KHAN:** Perhaps it would be of assistance for the Board to review Exhibit C-13-E (sic). And this is the ---

3778. **THE CHAIRPERSON:** Mr. Khan, could we get clarification on the exhibit that you're referring to?

3779. **MR. KHAN:** Oh, sure. Sorry, it's C-1-13E. My apologies. And if you turn to page 15 of that exhibit -- and just to be clear, this is a discussion paper on technical and environmental issues, which I would agree is quite a Stream 4 issue regarding pipeline abandonment.

3780. And about halfway down page 15 there's a series of bullets which are issues to be addressed. And you'll see at Section 3, technical and environmental issues, land use management, ground subsistence, soil and groundwater contamination, pipe cleanliness, water crossings, erosion, utility and pipeline crossings, creation of water conduits, associated apparatus and cost of abandonment.

3781. Mr. Teevens does not have any expertise on any of these issues.

3782. **THE CHAIRPERSON:** Thank you, Mr. Khan.

3783. Mr. Vogel…?

3784. **MR. VOGEL:** Madam Chair, my submission is that the line of attack that you're hearing may be appropriate in cross-examination, may be appropriate in argument, but it's not appropriate at the stage of qualifying the witness.

3785. But as I've indicated to my friend, I'm quite happy to pursue with Mr. Teevens, his qualifications and experience, to address not only corrosion issues but the impacts of corrosion. And if you would like me to do that, I'll go ahead and do that.

3786. **THE CHAIRPERSON:** Would you give us a minute, please?

--- (A short pause/Courte pause)

3787. **THE CHAIRPERSON:** Mr. Vogel, we are interested in hearing any additional qualification that you want to make of this witness in light of the objections

raised.

3788. However, just to be clear, to frame what we're here to do, Stream 3, as everybody is aware, is to consider the financial aspects, and that's what this hearing was set up for.

3789. We recognize that there could be some small discussion about technical aspects in the context of the financial aspects, but also recognize completely that the technical aspects in the fulsome discussion is a very detailed and technical discussion that has been set up for Stream 4 and that it's most appropriate to have those discussions in Stream 4.

3790. So what we're interested in hearing about is the financial aspects of it and the extent to which Mr. Teevens can speak to that aspect of it as a corrosion engineer is what we'd like to hear, but if you want to continue on and seek to qualify your witness with respect to speaking on the environmental aspects, as you've mentioned, please proceed and we'll go from there on that aspect, but within the context of Stream 3, please.

3791. **MR. VOGEL:** Well, given that direction, Madam Chair, and in light of Issue 2A which does say that this hearing is to determine the technical assumption for preparing those preliminary estimates, and the purpose of the proceeding is to protect landowners from costs, therefore the technical assumption must be that technical assumption which protects landowners from that risk. So that's really the narrow, I think, focus of Mr. Teevens' evidence in Stream 3.

3792. I hadn't intended, in fact, to go beyond the four corners of his report with him, which is what his report deals with.

3793. So I'm content to have him accepted as an expert with respect to the limited -- with respect to the four corners of his report.

3794. **THE CHAIRPERSON:** Mr. Khan…?

3795. **MR. KHAN:** And that is the issue, is that the report, one, goes outside the financial aspects of pipeline abandonment, goes outside corrosion, Mr. Teevens' corrosion experience and starts to opine on environmental aspects of pipeline abandonment.

3796. **MR. VOGEL:** Well, perhaps I'll try and do this briefly, Madam Chair.

3797. Mr. Teevens, you've heard the discussion. There is no dispute about your expertise as a corrosion expert. Are you -- do you, by way of qualifications and

experience, are you in a position to provide opinion evidence with respect to the impacts of corroding pipelines?

3798. **MR. TEEVENS:** Yes, I am.

3799. **MR. VOGEL:** All right.

3800. And perhaps you could then tell us what qualifications and experience you have which would enable you to provide that opinion evidence?

3801. **MR. TEEVENS:** There's a duty to the profession as a professional engineer to safeguard the public, and the impacts that we do on corrosion is preservation of resources and protection of the environment, first and foremost.

3802. That's both in OPEGA's directives, in the Act and it's also a requirement, as a responsible corrosion engineer, to have an appreciation for the impact associated with corrosion and the environmental impacts associated with that.

3803. Notwithstanding, when I did my professional engineering training at the University of Calgary the hard way, through the exam route, I was required to take two graduate level courses in environmental engineering on both environmental aspects of soil and water and then air pollution by Dr. Badishkan and Dr. Tolefson at the University of Calgary.

3804. So I'm fairly well versed in it. I am not an environmental scientist, but I can certainly address the impacts associated with it and the cost impacts associated with it. That's my responsibility as a professional engineer.

3805. **THE CHAIRPERSON:** Mr. Khan…?

3806. I'm sorry, Mr. Vogel, were you finished?

3807. **MR. VOGEL:** Yes, Madam Chair.

3808. **THE CHAIRPERSON:** Thank you, Mr. Vogel.

3809. Mr. Khan…?

3810. **MR. KHAN:** You mentioned that the two sources of -- first of all, you mentioned that you're not an environmental scientist; correct?

3811. **MR. TEEVENS:** I have degrees in chemistry and my training is in chemical engineering and in advanced training in corrosion engineering. I am not an

environmental scientist. I am a scientist and I am an engineer.

3812. **MR. KHAN:** And you took two courses and that is the extent of your environmental training when you were in graduate studies ---

3813. **MR. TEEVENS:** I've taken two graduate level courses in environmental engineering, the environmental engineering aspects and impacts associated with pollution control and prevention, and I use those -- that knowledge, and I've used it throughout my career, in assessing the impact of the work that we're doing for our clients. I must; otherwise, I'd be totally irresponsible.

3814. **THE CHAIRPERSON:** Mr. Khan, could you please use your microphone. And would you mind just coming a little closer to your microphone when you speak? Thank you.

3815. **MR. KHAN:** I'd ask, Mr. Teevens, that you turn to Exhibit C-1-6H. And that's a copy of your CV; correct?

3816. **MR. TEEVENS:** Correct.

3817. **MR. KHAN:** Can you point out to me where at all in this CV you have gained any environmental experience?

3818. **MR. TEEVENS:** I don't have my CV in front of me. Is there a way I can scroll this?

3819. **THE CHAIRPERSON:** I'm sure your counsel can provide it to you.

3820. **MR. TEEVENS:** Yes, I'd say in terms of becoming certified as a corrosion specialist P through NACE International and taking the series of exams, which for all intents and purposes is the equivalent of obtaining a masters degree, there is the requirement to be environmentally sensitive to the work that we're doing.

3821. So in that light, I guess that's where I'd say that that's where it comes from. So you'd have to research the qualification requirements.

3822. **MR. KHAN:** Can you turn to page 3 of that exhibit, Mr. Teevens? And you'll see at the third bullet on that page it starts "Corrosion-Engineering", the sentence.

3823. **MR. TEEVENS:** I'm sorry; I'm not following where you're at.

3824. **MR. KHAN:** The bullet where the hand is at.

3825. **MR. TEEVENS:** Okay, yeah.

3826. **MR. KHAN:** And then you see the last sentence in that bullet, Mr. Teevens. Do you see that?

3827. **MR. TEEVENS:** Yes, sir.

3828. **MR. KHAN:** And it says:

> *"The success of the company has been based upon providing a very high level of responsible and timely expert engineering knowledge in the assessment, detection, prevention and management of corrosion problems."*

3829. Correct?

3830. **MR. TEEVENS:** Correct.

3831. **MR. KHAN:** And that's a pretty good summary of what Broadsword does; is that fair to say?

3832. **MR. TEEVENS:** It's one narrow scope of it, but yeah, it's a good assumption.

3833. **MR. KHAN:** So that is a fair description of Broadsword's expertise and what Broadsword does on a weekly basis?

3834. **MR. TEEVENS:** Correct, yeah.

3835. **MR. KHAN:** And just working backwards, you'd say that's a good description of what in fact you did at I believe it was AEC, your prior employer to Broadsword?

3836. **MR. TEEVENS:** Correct.

3837. **MR. KHAN:** And that's a fairly good description, in fact, of your duties and what you did at AEC as well?

3838. **MR. TEEVENS:** Correct, yes.

3839. **MR. KHAN:** And the same thing as well, I believe it was at Cantera, sir?

3840. **MR. TEEVENS:** Cantera Energy, yes.

3841. **MR. KHAN:** So more or less that's what you've done since, in fact, graduating from a chemistry degree and working towards that designation?

3842. **MR. TEEVENS:** No, no. No, at the same time while I was working, as I said earlier, I was doing my chemical engineering training, and so I was involved in engineering teams and pipeline design, pipeline -- virtually every aspect of putting in pipelines in the ground.

3843. **MR. KHAN:** Sorry, sir, I was going to move forward to that. And while you were working at Cantera, I believe, you took your engineering courses, as you say, the hard way ---

3844. **MR. TEEVENS:** That's right.

3845. **MR. KHAN:** --- through the University of Calgary. But your work experience during this time was centred, as you say here, on providing a very high level of responsible and timely expert engineering knowledge in the assessment, detection, prevention and management of corrosion.

3846. That's fair to say?

3847. **MR. TEEVENS:** That's right.

3848. **MR. KHAN:** And then if I could draw your attention to the LMCI Stream 4 discussion paper, which is at Exhibit C-1-13D, and in particular on page 13 of that discussion paper.

3849. It will come up for you on the screen, sir.

3850. **MR. TEEVENS:** Okay.

3851. **MR. KHAN:** If you go to footnote 9 there's a definition of corrosion. You'd agree with me there's a definition on the page, sir?

3852. **MR. TEEVENS:** That's a definition. If you're looking at metallic corrosion, that's correct, but there's also corrosion of non-metallics, plastics, wood and that sort of thing. But that's a good definition.

3853. **MR. KHAN:** Yeah, I understand that. And that's a good definition for sort of, I guess, with respect to pipelines; you'd agree, more or less?

3854. **MR. TEEVENS:** Yes.

3855. **MR. KHAN:** Thank you.

3856. And then just breaking that part down, so corrosion is a process; correct?

3857. **MR. TEEVENS:** Yes, sir.

3858. **MR. KHAN:** And it's a process that acts on metals; correct?

3859. **MR. TEEVENS:** Yes.

3860. **MR. KHAN:** Or other materials ---

3861. **MR. TEEVENS:** Other materials, yes.

3862. **MR. KHAN:** --- as you pointed out, but ---

3863. **MR. TEEVENS:** In this case it's a metal.

3864. **MR. KHAN:** --- in this case, in a metal. And it strips electrons from an anode and puts it on a cathode?

3865. **MR. TEEVENS:** Correct.

3866. **THE CHAIRPERSON:** Mr. Khan, I just would like some clarification. Are you seeking to challenge Mr. Teevens' expertise as a corrosion engineer? Could you tell us where this is going please?

3867. **MR. KHAN:** Sure. I was just confirming that this is what he has done. I'll move on to a more contrasting section in moment. I just want to make sure we're all certain on what we talk about when we use this word "corrosion".

3868. **THE CHAIRPERSON:** Mr. Teevens -- Mr. Khan -- sorry -- I think that we all recognize that we're trying to be efficient with the use of our time here and I'd ask you to move along to whatever your specific point is that you're wanting to make here with respect to qualifying this expert so that we can move forward please.

3869. **MR. KHAN:** Mr. Teevens, you'd agree with me that soil subsistence is a geotechnical area?

3870. **MR. TEEVENS:** Soil subsistence or soil subsidence?

3871. **MR. KHAN:** Pardon me; subsidence. Thank you, sir.

3872. **MR. TEEVENS:** Is a what?

3873. **MR. KHAN:** Geotechnical area.

3874. **MR. TEEVENS:** I would say ultimately, yes, it is.

3875. **MR. KHAN:** And it requires knowledge as geotechnical expert?

3876. **MR. TEEVENS:** To predict how it's going to behave I would say, yes; that's correct.

3877. **MR. KHAN:** And you would agree with me that Broadsword Engineering doesn't do ---

3878. **THE CHAIRPERSON:** Mr. ---

3879. **MR. KHAN:** You would agree with me that Broadsword Engineering doesn't do geotechnical assessments, sir?

3880. **MR. TEEVENS:** That's correct.

3881. **MR. KHAN:** And you would agree with me, sir, that Broadsword Engineering doesn't do environmental assessments at all, sir?

3882. **MR. TEEVENS:** No, that's not correct. We have worked in conjunction with -- in joint initiatives, we have worked with environmental engineering companies to a -- to a common purpose.

3883. **MR. KHAN:** And those engineering companies would be like a Terra Environmental, correct? Or a Golder and Associates, sir?

3884. **MR. TEEVENS:** Correct.

3885. **MR. KHAN:** And so companies would hire Terra and Golder to do environmental assessments, correct?

3886. **MR. TEEVENS:** They have that option of either hiring them directly or having us sub them out, but more often than not, it's done as -- as a team effort with the environmentalists on part of that team, hired by the client.

3887. **MR. KHAN:** So, if I understand it correctly, they would come to you, but

you would then contact Terra or Golder and Associates to do the environmental work, correct?

3888. **MR. TEEVENS:** To do the environmental assessment, I would, yes.

3889. **MR. KHAN:** I'll just end there.

3890. **THE CHAIRPERSON:** Thank you very much, Mr. Khan.

3891. The Board recognizes Mr. Teevens as an expert in corrosion engineering, as his résumé has demonstrated and has been tested. The Board's also interested in hearing his opinions with respect to the impacts of corrosion on the environment as a layperson.

3892. We recognize that Mr. Teevens' credentials aren't as an environmental excerpt and parties are always able to argue weight that his evidence should be afforded during final argument.

3893. And Mr. Teevens, I would just ask you to make sure that you ensure that your evidence that you provide resides within the framework of the Stream 3, which is the financial aspects and the list of issues as set out by the Board.

3894. **MR. TEEVENS:** Yes, ma'am.

3895. **THE CHAIRPERSON:** Thank you. With that, are we ready to proceed further?

3896. **MR. VOGEL:** Yes, we are, Madam Chair, thank you.

3897. **THE CHAIRPERSON:** Thank you, Mr. Vogel.

3898. **MR. VOGEL:** Mr. Teevens, then, you were responsible for the preparation of the paper at Appendix 6 in CAPLA's initial Pre-filed Evidence?

3899. **MR. TEEVENS:** That's correct.

3900. **MR. VOGEL:** And is the content of that paper accurate to the best of your knowledge and belief?

3901. **MR. TEEVENS:** Yes, it is.

3902. **MR. VOGEL:** Do you have any changes or additions to that evidence?

3903. **MR. TEEVENS:** No, I don't.

3904. **MR. VOGEL:** And do you adopt that as your evidence in-chief in this proceeding?

3905. **MR. TEEVENS:** Yes, I do.

3906. **MR. VOGEL:** And very briefly and by way of summary, referring to your report, at page 3, you've addressed, starting there the long-term consequences associated with the pipeline following abandonment with respect to external and internal corrosion. Could you just, by way of summary, tell me about that?

3907. **MR. TEEVENS:** The long-term consequence of internal/external corrosion is even with best mitigative efforts provided to a specific pipeline region there is a finite time that that pipeline region or segment will last, and so there is the ability to slow the corrosion to perhaps acceptable levels both internally and externally.

3908. **MR. VOGEL:** All right. And at page 4 in your report you've listed a number of significant environmental and safety issues which result from what you described as inevitable corrosion if not maintained.

3909. And then over at page 5 you set out a number of conclusions with respect to removal of abandoned large-diameter pipes and continuing maintenance until the time it is removed, which is the basis for CAPLA's proposed removal/perpetual maintenance option here.

3910. Why are you recommending that the Board adopt as the technical assumption in this proceeding removal or perpetual maintenance as the basis for estimating abandonment cost?

3911. **MR. TEEVENS:** The primary reason for it is at the end of the pipeline life, the way the Act currently reads once the line is abandoned the NEB no longer has jurisdiction over it, and if the pipeline operator is no longer around, then that leaves the landowner to deal with the liability.

3912. **MR. VOGEL:** Thank you, Mr. Teevens.

3913. Ms. Cheung, included in CAPLA's initial Pre-filed Evidence at Exhibit C-1-6K, which is Appendix 9 in that evidence, is a paper entitled "Pipeline Abandonment -- Can a Pipeline Company Under NEB Jurisdiction Recover Abandonment Costs in Its Tolls," dated May 13th, 2008.

3914. Was that prepared by you or under your direction?

3915. **MS. CHEUNG:** Yes, sir.

3916. **MR. VOGEL:** And at Tab 9A in the Pre-filed Evidence is a copy of your curriculum vitae.

3917. And, Madam Chair, again, I propose to qualify Ms. Cheung as an expert in toll design, and specifically with respect to the feasibility of providing for abandonment costs through a toll increment.

3918. Ms. Cheung, referring to your CV, I see that you have a chemical engineering degree from the University of Toronto.

3919. **MS. CHEUNG:** That's correct.

3920. **MR. VOGEL:** And you were employed by TCPL for a period of some 18 years, from 1981 through '99.

3921. **MS. CHEUNG:** That's correct.

3922. **MR. VOGEL:** And your responsibilities there included facilities planning and transportation planning and development.

3923. Is that right?

3924. **MS. CHEUNG:** That's correct.

3925. **MR. VOGEL:** And looking at page 1 of your curriculum vitae, that included your involvement in TCPL's applications for regulatory approvals over that period of time?

3926. **MS. CHEUNG:** That's correct.

3927. **MR. VOGEL:** That would include evidence provided at both facilities and tolls proceedings before the National Energy Board.

3928. Is that right?

3929. **MS. CHEUNG:** That's correct.

3930. **MR. VOGEL:** And in terms of your responsibility at those proceedings, I understand that included addressing various issues, including economic feasibility,

facilities planning, cost of service, toll forecast, market forecast, fee service and tolling matters.

3931. Is that right?

3932. **MS. CHEUNG:** That's correct.

3933. **MR. VOGEL:** And you've also testified at other NEB proceedings on behalf of other companies and industry groups?

3934. **MS. CHEUNG:** That's correct.

3935. **MR. VOGEL:** With respect to similar issues?

3936. **MS. CHEUNG:** Not exactly, no.

3937. **MR. VOGEL:** All right, with respect to other issues. You have testified before the Board before in connection ---

3938. **MS. CHEUNG:** With respect to other issues, yes.

3939. **MR. VOGEL:** All right. And you, as I understand it, did participate in the design and development of the cost of services and toll forecast model used by TCPL in these various NEB hearings?

3940. **MS. CHEUNG:** That's correct.

3941. **MR. VOGEL:** And, Madam Chair, I'm requesting that the Board accept Ms. Cheung's qualifications as an expert in toll design and specifically with respect to feasibility of providing for abandonment costs through a toll increment.

3942. **THE CHAIRPERSON:** Are there any parties who wish to question Ms. Cheung?

--- (No response/Aucune réponse)

3943. **THE CHAIRPERSON:** Thank you.

3944. Mr. Vogel, the panel accepts Ms. Cheung as an expert with respect to toll design, specifically with respect to the feasibility of collecting abandonment costs as part of the toll design -- as part of the tolls.

3945. **MR. VOGEL:** Thank you, Madam Chair.

3946. And again, briefly by way of summary, referring to your paper, Ms. Cheung, starting at page 2, you've reviewed the relevant provisions of the *NEB Act* and the rates with respect to abandonment and decommissioning and then you discuss the accounting treatment of abandonment costs.

3947. And then at page 9 in your report you provide a conclusion concerning the Board's jurisdiction with respect to the recovery of future abandonment costs in the pipeline's current cost of service.

3948. What is your opinion in that regard?

3949. **MS. CHEUNG:** I believe that the Board does have jurisdiction over the recovery of the cost of abandonment either before it's abandoned or after -- or either before, when the pipeline is in operation or it can make regulations such that it can allow the pipeline to recover the abandonment costs during the operation of the pipeline when the pipeline is no longer in existence.

3950. **MR. VOGEL:** And finally, with respect to your paper, was it accurate to the best of your knowledge? Is it accurate to the best of your knowledge and belief?

3951. **MS. CHEUNG:** Yes, sir.

3952. **MR. VOGEL:** Do you have any additions or changes you wish to make to the paper?

3953. **MS. CHEUNG:** No, sir.

3954. **MR. VOGEL:** Do you adopt it as your evidence in-chief in this proceeding?

3955. **MS. CHEUNG:** Yes, sir.

3956. **MR. VOGEL:** And finally, Mr. Core, with respect to Exhibit C-1-6A, CAPLA's initial pre-filed evidence, and again by way of summary at page 6 in that evidence, you have excerpted the conclusions from the Broadsword report, and at page 15 of that evidence you've excerpted the conclusions from the Cheung report.

3957. And then at page 18, you set out a default technical option proposed by CAPLA as the basis for preliminary abandonment cost estimates, and I'll just read that into the record.

"Such risk can only be eliminated by the default option of removal

of large diameter pipelines in agricultural lands where all pipelines in a common corridor have been abandoned or one or more pipelines continue to be operated adjacent to abandoned pipelines that have not been removed. Those adjacent abandoned pipelines must be maintained as though operating until removal is triggered by the cessation of operation of all pipelines in the corridor." (As Read)

3958. Mr. Core, what is it that you're asking the Board to do in this proceeding?

3959. **MR. CORE:** We're asking the Board to take all risk of abandonment away from landowners. And in this proceeding you're looking at the financial aspects of that.

3960. Our default position then is removal or maintenance into perpetuity to protect landowners.

3961. I think you have to realize that the people at this table here are different than the rest of the people in this room. They own the land that these pipes are going to be either abandoned in or taken out of, and so we have a responsibility to look after that land.

3962. We live with the pipeline. The pipeline affects our families, affects our farms, affects our businesses, and so we have a responsibility to protect those issues. And we also have a stewardship responsibility that comes to us from public interest to look after the land.

3963. Aboriginal and non-Aboriginal landowners have a responsibility to protect that land, and it's not just our families that we're protecting but the future of that land.

3964. And so our feeling is that right now, we need to start collecting for the default position to protect us and our property through removal of pipelines and perpetual maintenance.

3965. **MR. VOGEL:** Thank you, Mr. Core.

3966. Those are my questions and the panel is available for cross-examination.

3967. **THE CHAIRPERSON:** Thank you, Mr. Vogel.

3968. Alliance Pipeline Ltd. ...?

--- (No response/Aucune réponse)

3969. **THE CHAIRPERSON:** BP Canada Energy Company…?

--- (No response/Aucune réponse)

3970. **THE CHAIRPERSON:** Enbridge Pipelines Inc. ...?

--- (No response/Aucune réponse)

3971. **THE CHAIRPERSON:** Imperial Oil Resources…?

--- (No response/Aucune réponse)

3972. **THE CHAIRPERSON:** Kinder Morgan…?

--- EXAMINATION BY/INTERROGATOIRE PAR MR. FORRESTER:

3973. **MR. FORRESTER:** Ms. Cheung, you'd agree with me that part of your evidence was based upon your view as to the jurisdiction of this Board?

3974. **MS. CHEUNG:** Correct.

3975. **MR. FORRESTER:** And in particular, your view of its jurisdiction as to what happens upon abandonment?

3976. **MS. CHEUNG:** That's correct.

3977. **MR. FORRESTER:** And you've concluded that this Board will not have jurisdiction after the abandonment application is made.

3978. Is that correct?

3979. **MS. CHEUNG:** No, that is not correct. After the abandonment application is made, the Board will make a ruling, and until the pipeline is deemed to be abandoned, the Board still has jurisdiction over it.

3980. **MR. FORRESTER:** My point being that your view is that once the pipeline is deemed by this Board to be abandoned, you based your opinion on the fact that they no longer have jurisdiction.

3981. Is that correct?

3982. **MS. CHEUNG:** That's correct.

3983. **MR. FORRESTER:** You'll agree with me that you have no legal training. Is that correct?

3984. **MS. CHEUNG:** That is correct.

3985. **MR. FORRESTER:** You'll agree with me that the ultimate determination of whether or not this Board has jurisdiction is a legal question?

3986. **MS. CHEUNG:** Yes.

3987. **MR. FORRESTER:** Thank you.

3988. **THE CHAIRPERSON:** Spectra Energy Transmission...?

--- EXAMINATION BY/INTERROGATOIRE PAR MR. DAVIES:

3989. **MR. DAVIES:** It's still morning. So good morning, lady and gentlemen.

3990. Let's get out of the way at the outset the question that everybody is dying to know the answer to. Who is CAPLA's favourite pipeline?

--- (Laughter/Rires)

3991. **MR. VOGEL:** That's making an assumption.

3992. **MR. DAVIES:** Eerie silence.

3993. I started to count the number of times that CAPLA used the word "risk" in its various pieces of evidence and I stopped counting at about 100. And let me say that's not at all a criticism.

3994. But suffice it to say that CAPLA wants the Board to make decisions in this case to ensure that landowners are not put at risk for the costs of pipeline abandonment, right?

3995. You don't all have to answer, but one of you has to answer.

3996. **MR. KRAAYENBRINK:** That's true.

3997. **MR. DAVIES:** And obviously there is a difference between minimizing

risk and eliminating risk. And, Mr. Core, I heard in your comments this morning that -- or what I took from your comments this morning was that it is the position of CAPLA that steps must be taken to eliminate the abandonment cost risk to landowners.

3998. Is that right?

3999. **MR. CORE:** That's right.

4000. **MR. DAVIES:** Is it the position of CAPLA that steps must be taken to eliminate the risk to landowners irrespective of the cost and impact that taking those steps might have on pipelines and their shippers?

4001. **MR. CORE:** Yes.

4002. **MR. DAVIES:** Okay. If I could have you turn up, please, your initial evidence filing. It's Exhibit C-1-3B and it's page 9 of the document.

4003. And if you were to go back to page 8, Mr. Core, you'll see that what you are doing here in your evidence is outlining some proposed principles.

4004. **MR. CORE:** Yes.

4005. **MR. DAVIES:** And then over on page 9, Principle V at the top says:

> *"All feasible measures are taken to eliminate for landowners the risk of future costs and liabilities and to reduce the risk posed to the health and safety of people, society and the environment."* (As Read)

4006. And I wonder if you could explain to us what you had in mind when you used the term "all feasible measures"?

4007. **MR. CORE:** I think all feasible measures can be looked at from where you come from. From a landowner perspective, all feasible measures are any measures that will eliminate our risk. And if in the short term the elimination of that risk is financing for the perpetual maintenance or removal of the pipeline, that has to be done in the short term because it's been too many years since this issue's been addressed at all.

4008. So we need to start now. And in the long-term, what we have to do is -- we're not able to, at this point, determine the exact cost of what's going to happen if pipelines are left in place, but there is going to be costs when pipelines are left in

place.

4009. The same impacts that we have today when we're farming will be the same impacts we have when pipelines -- if they're abandoned in place, and then the problem is there's more impacts and it's the financial aspects of those impacts if the pipelines are abandoned in place. There's nobody to finance those impacts if they're abandoned in place.

4010. If the pipeline collapses, we've got safety issues; we've got financial issues; we've got impacts on our farms; we've got environmental issues, we've got the potential for corrosion and the movement of water between properties and possible contamination flow.

4011. We've got all these issues to deal with. And so a feasible -- ultimately, we've got to address those issues. So feasibility comes, from our perspective -- we want no risk left with us. These pipelines -- we chose to be farmers; we didn't choose to be pipeline landowners.

4012. So feasibility, from your perspective, all we've heard here today is the feasibility of reducing the risk. These pipelines were imposed on our properties.

4013. Whether easements agreements were signed or not, they were imposed on our properties through expropriation. So feasibility is a word that I think comes from different perspectives in this room.

4014. **MR. DAVIES:** Well, there's lots of what you said in there that if we had a couple of days, we could explore. But let me ask you this.

4015. Do you agree with me that at the end of the day, it's up to the Board to decide what measures are feasible?

4016. **MR. CORE:** I would suggest that abandonment has been identified for 60 years. The first pipeline that went into Mr. Lewington's farm back in 1950, whatever year it was, he identified abandonment. It was not addressed.

4017. In 1975, in an arbitration hearing, he identified abandonment. It was not addressed.

4018. In 2002, we talked before this very Board -- it was in 2002, they came to talk to landowners and CAPLA and we addressed the issue of abandonment funding, having a fund for abandonment. We addressed the issue of abandonment, that we needed to look at it. It was not done.

4019. You have a paper in front of you from 1985 that this Board did a discussion paper on abandonment, and we didn't even realize that that paper existed until 2006 or 2007 because of hearing on an Enbridge application. So there was a discussion paper in 1985.

4020. At that time, there was discussion of a generic hearing on abandonment, and it was decided by the Board that they wouldn't have a generic hearing, that they decided that they would continue to address this issue at toll hearings. And I can keep talking.

4021. The thing is, is that what also was decided there, if you look at the conclusion on the second page of that document, it says that as long as pipelines are to be removed, pipeline companies will continue to look for tolls to cover the cost of abandonment.

4022. And it's quite interesting that just a few years later, those very regulations that proposed pipeline removal were changed.

4023. In 1996, you had a document, a technical document that talked about pipeline abandonment. In 1997, you had a legal document that talked about pipeline abandonment, and in the conclusion of that, they said, "*If a pipeline were insolvent, we don't know who would be responsible*."

4024. And also, in those documents we talked about the jurisdictional responsibility of the NEB if abandonment were to happen in place and approved.

4025. So, I mean, yeah, maybe it is up to this Board to do something and it's time this Board did something and it's time that you people worked with them to do it.

4026. And coming from our perspective, instead of sitting here and worrying about tolls, et cetera, it's time that you looked after the property that these pipes are on and protect the public interest because of stewardship responsibilities, too. It's time.

4027. It's time that you listened and understood the landowner perspective. We are not against pipelines. We support pipelines. We support the industry, but we also have to protect ourselves.

4028. **MR. DAVIES:** Did I hear in there, then, an agreement that, yes, it is up to the Board to decide what measures are feasible?

4029. **MR. CORE:** Yes, it is up to the Board to make that decision, and the time is now.

4030. **MR. DAVIES:** And the Board, you would agree, acts in the Canadian public interest?

4031. **MR. CORE:** The Board also acts in the Canadian public interest, and landowners and farmers have a Canadian public interest that is imposed on us now. As time has gone on, that imposition has changed. There's been an evolution.

4032. There's been an evolution and a discussion of expropriation and the fact that expropriation enforces things on us that we don't ask for. There needs to be a discussion about that. And the reality is that -- well, go ahead. I'll stop there for now.

4033. **MR. DAVIES:** I was going to say, you mentioned earlier that you could keep talking, and you can, but it's not me that's going to miss my flight.

--- (Laughter/Rires)

4034. **MR. VOGEL:** Don't worry about me.

4035. **MR. DAVIES:** Does CAPLA agree that in deciding what steps to be taken to address abandonment costs, the Board not only should, but must, have regard for the interests of all parties, including landowners, pipelines and shippers?

4036. **MR. NESS:** There's a term that I haven't heard being used here on Monday, Tuesday and today so far, and that's "public interest". The funds are basically public funds and I believe the public has to have a say in how these funds are administered and stored.

4037. And the atmosphere of the hearing so far, I get the impression -- whether right or wrong, I get the impression that industry seems to think that the money is already theirs before it's even collected.

4038. And all that does is enhance our perspective that industry is kind of still in the land of entitlement and exclusiveness, and we want industry to become partners with us, the landowner, in looking after this issue of abandonment and the costs related with it.

4039. So I believe that the Board has got a significant task ahead of them to assure the public that they're going to have input on keeping their fingers on any funds that are raised to keep accountability in the picture.

4040. **MR. DAVIS:** And I -- sorry, Mr. Core, did you want to add?

4041. **MR. CORE:** Yes, I do.

4042. I thinks it important to realize when you say we have to take into account those -- these different interests, in the public interest, one interest that has never been taken account of is landowners, and all the documents that have been produced to date on abandonment -- and that's the only issue we're going to discuss here, is abandonment -- it's admitted in the 1985 document that landowners were never consulted.

4043. You look at who was involved in the '96 and the '97 document -- I might have those years wrong -- landowners were never consulted.

4044. Until now, landowners have never been consulted. So the interests -- in the public interest -- not all stakeholders have been consulted until now. And now we're trying to be compromised and not heard at this hearing. Okay?

4045. I keep hearing everybody talk about the technical issues are going to be solved in Stream 4. Everybody keeps talking about Stream 4. Already Stream 4 has been changed while we're attending this hearing. I don't know how we can wait for Stream 4. Give us a sense of security that Stream 4 is going to do anything for us.

4046. So what we're saying here is, at this point in time, to protect the public interest -- and the public interest is our farms and property owners, because the land is here and the land will always be here and that's the public interest -- then you need to start collecting something now and it needs to be based on something that will protect landowners in Canada and will protect our land, in the public interest.

4047. And the only solution that we can find at this point in time, the only responsible solution at this time, is to collect for our default position because nobody has come up with anything. And landowners could maybe be satisfied with that. That is the feasible way of reducing our risk to as minimal a spot as we can. It's the only feasible solution coming out of this.

4048. And if you collect too much -- everybody here has talked about reviewing this every so many years -- then you can reduce it. Let's start out high and reduce it low, because nothing's been done for 60 years. Nothing's been done. You've identified this and you leave it.

4049. And if we leave it until Stream 4, nothing's going to happen, because just in the last three days, Stream 4 has already made a clear shift away from specific principles to entirely general -- to a general approach.

4050. So how can we trust -- how can we trust, how can the Canadian public trust that anything is going to be done in Stream 4 when the record shows that

nothing's been done?

4051. **MR. DAVIES:** Trust me, Mr. Core, if I wasn't interested in your views, I wouldn't be asking you questions.

4052. But my simple point was, putting aside what's happened in the past, and I'm not going to debate that with you, we're now here in this hearing room. We have views being expressed by landowners. We have views being expressed by pipelines. We have views being expressed by shippers.

4053. And we can agree that the Board, in making its determination, is going to have to have regard for and balance all of those views, right?

4054. **MR. CORE:** And hopefully landowners' views will be balanced in there.

4055. **MR. DAVIES:** Absolutely. I think we're completely on the same wavelength on that one.

4056. Now, let me try these on you, and I'm speaking generally -- if a measure could be taken that would materially reduce the abandonment cost risks to landowners with little impact to pipelines and their shippers, I think you and I could agree that that measure should probably be taken, right?

4057. **MR. CORE:** Repeat the question.

4058. **MR. DAVIES:** Sure. There's no -- these aren't tricky. I'm not trying to pull a fast one.

4059. If a measure could be taken that would materially reduce the abandonment cost risk to landowners with little impact -- with little impact to pipelines and their shippers, then I think we could conclude that that measure should probably be taken, right?

--- (A short pause/Courte pause)

4060. **MR. CORE:** I think I have a question in return. I don't quite understand why you would say "little impact" ---

4061. **THE CHAIRPERSON:** Mr. Core, you're here to provide evidence, not to ask other parties questions. If you could answer the counsel's question it would be much appreciated.

4062. **MR. CORE:** Okay. I want to clarify what you're saying. Little impact --

did I understand that you said that that would have little impact on the shippers?

4063. **MR. DAVIES:** And the pipelines, yes. So in other words, if you have a measure that can significantly reduce landowners' risk on the one side and on the other side it would have little impact on shippers and their pipelines, then that's probably a good measure to take.

4064. **MR. CORE:** I think if we look at the question of what this hearing was about, it wasn't about minimizing the risk of landowners upon abandonment. It was that we were to have no risk upon abandonment.

4065. **MR. DAVIES:** And that probably leads me to my second general suggestion, then. I won't wait for your answer to the first one. Let me ask the second one.

4066. If a measure could be taken that would only marginally reduce the abandonment cost risk to landowners with a very significant adverse impact to pipelines and their shippers, is it your position that that measure should nonetheless be taken?

--- (A short pause/Courte pause)

4067. **MR. CORE:** There's no simple answer to any of your questions, Mr. Davies. I think when the pipelines were installed or forced on our land, I don't think that anybody asked us any of these questions, and I think it was put in the public interest in the 1950s. And, you know, I just give history here a bit so we can put your question in perspective.

4068. In the 1950s, there was a debate about pipelines going into our properties across Canada. It was to move western energy to the eastern market and so the government felt, after a great deal of debate, that expropriation was appropriate, okay?

4069. And so in the public interest, you know, you expropriated or held expropriation over our heads to put pipelines in our property. There was no discussion about the costs to us of those pipelines going in the property and there was no discussion whether it was a minimal cost or a maximum cost and discussion of abandonment was never discussed.

4070. So it's in the public interest, in my opinion, that we have to address this risk to landowners and whatever the costs may be we'll have to go there. And I think it's in the public interest that they have -- if we're going to have standards put on us, set by society as stewards of the land, then I would say to you that it would be at

whatever cost.

4071. Energy is bought by the public and the costs of addressing our issues, yes, have to be addressed by the public. And so it is at whatever the cost is, as we see it for our default position of pipeline removal or maintenance into perpetuity.

4072. **MR. DAVIES:** So if I suggested to you that in assessing the appropriateness of any measure to address abandonment costs, the Board would have to balance what reduction in risk would accrue to landowners with the costs and impacts that would be imposed on pipelines and their shareholders, you would disagree?

4073. **MR. CORE:** Yes, zero risk.

4074. **MR. DAVIES:** I guess that's pretty clear.

4075. **MR. NESS:** Could I just expand on the answer a little bit?

4076. Right now because pipelines were imposed on landowners, we actually have landowners sitting in a deficit position today because of the seven things that were imposed on us with the certificate. We have a deficit in the risk area. We have a duty of care, duty of vigilance, liability, adverse effect, no enablement to recover hearing costs, and no rights and remedies.

4077. So we're today in a deficit position to start the game.

4078. **MR. CORE:** Mr. Davies -- oh, I can't ask a question, can I? Well, I'm so sorry.

4079. Would you clarify something -- well, I can't ask a question. Sorry.

4080. **MR. DAVIES:** I got the answer, Mr. Core.

4081. **MR. CORE:** I didn't get the answer.

4082. **MR. DAVIES:** You can ask me a question once we're finished here today.

4083. I wonder if I could have you turn, please, to Exhibit C-1-11 which are CAPLA responses to information requests, and in particular your response to Westcoast Information Request 5?

4084. **MR. CORE:** Before you proceed, I have a question of the Board -- no, I

4085. **THE CHAIRPERSON:** No, no questions of the Board either.

4086. **MR. CORE:** I thought this was quasi-judicial and I thought that this was -- okay, fine.

4087. **THE CHAIRPERSON:** Mr. Core, let's proceed with the cross-examination as it's established. Thank you, Mr. Core.

4088. **MR. DAVIES:** So what I was directing you to was your response to Westcoast Information Request 5, which is part of Exhibit C-1-11. And, actually, if you go back to the preamble, please, on the previous page, thank you.

4089. You'll see that in the preamble with regard to Reference B, Westcoast refers to its evidence where it states that requiring it to now collect retirement costs from its gathering and processing shippers would place it a competitive disadvantage with owners of provincially-regulated gathering and processing facilities who are not subject to such requirement. And what we solicited in the request was CAPLA's views about the issue.

4090. In the first sentence you indicate that all pipeline landowners, whether provincially or federally-regulated, deserve at least a minimum level of protection from the costs and liabilities associated with pipeline abandonment. And I was interested in your choice of the words "minimum level of protection."

4091. Can you tell me what you meant there?

4092. **MR. CORE:** Well, I would interpret from my perspective that when we say "minimum", we mean no risk.

4093. **MR. DAVIES:** Okay. So minimum really means maximum?

4094. **MR. CORE:** It depends on -- it depends on how you view the word.

4095. **MR. DAVIES:** Okay. Is it the ---

4096. **MR. CORE:** In my opinion, it's the minimum that can be done. The minimum is to take our risk away.

4097. **MR. DAVIES:** Is it the position of CAPLA that Westcoast should be required to now collect and set aside funds for abandonment of all of its gathering and processing facilities?

4098. **MR. CORE:** Yes.

4099. **MR. DAVIES:** Westcoast advised, in its evidence yesterday, that its processing facilities were located on lands owned in fee simple by Westcoast.

4100. Do you advocate that Westcoast be required to now collect and set aside funds for abandonment of facilities that are located on its own lands?

4101. **MR. CORE:** Yes.

4102. **MR. DAVIES:** Okay. And what abandonment cost risks do the landowners that CAPLA represents have with respect to Westcoast's processing facilities?

4103. **MR. CORE:** I don't think I can answer that question.

4104. **MR. DAVIES:** Well, would the answer be none?

4105. **MR. CORE:** Ask the question again, please.

4106. **MR. DAVIES:** Sure. What abandonment cost risks do the landowners that CAPLA represents have with respect to Westcoast's processing facilities?

4107. **MR. CORE:** I would say none.

4108. **MR. DAVIES:** Westcoast also advised in its evidence yesterday that 90 percent of its gathering pipeline system is located on Crown land. And couldn't we agree that with respect to that portion of Westcoast's gathering system, the members of CAPLA have no abandonment cost risk?

4109. **MR. CORE:** Actually, we feel that maybe we do have an interest in that we wear two hats, and outside of our responsibilities as the Canadian Alliance of Pipeline Landowners' Associations, we also are part of the public that maybe hasn't heard of these hearings because there's no funding to participate. And so there's a lot of people that you don't hear.

4110. So I actually feel -- or not me but my cohorts and CAPLA feel that we have a responsibility to also act in the public interest. And if abandonment potentially causes environmental consequences on public land, or even potentially, you know, as we rethink what you asked about the property that you own yourselves, eventually, in the public interest, what are the impacts of abandonment and what are the impacts of abandonment on the property that's sold by you later on?

4111. So I would say that we do have an interest.

4112. **MR. DAVIES:** Thank you very much for your responses.

4113. You wouldn't tell me who your favourite pipeline company is, but tell me, who's your favourite pipeline company lawyer?

--- (Laughter/Rires)

4114. **MR. VOGEL:** Keep working at it.

4115. **MR. DAVIES:** Thank you, Madam Chair.

4116. **THE CHAIRPERSON:** Thank you, Mr. Davies.

4117. I realize I made an error in going down the order of appearances; so let me back up and correct myself.

4118. Does Pouce Coupé have any questions of this panel?

--- (No response/Aucune réponse)

4119. **THE CHAIRPERSON:** Thank you very much, Mr. Khan.

4120. Suncor Energy Marketing...?

--- (No response/Aucune réponse)

4121. **THE CHAIRPERSON:** TransCanada PipeLines...?

4122. **MR. DENSTEDT:** Thank you, Madam Chairman.

4123. The questions by the previous cross-examiner have allowed me not to ask any questions, and where we have any disagreement with CAPLA, it's clear on the record and we can deal with that in final submissions.

4124. **THE CHAIRPERSON:** Thank you, Mr. Denstedt.

4125. Okay. Canadian Association of Petroleum Producers...?

--- (No response/Aucune réponse)

4126. **THE CHAIRPERSON:** Alberta Department of Energy...?

--- (No response/Aucune réponse)

4127. **THE CHAIRPERSON:** Does Board counsel have any questions?

4128. **MR. JOHNSTON:** Yes, Madam Chair.

--- EXAMINATION BY/INTERROGATOIRE PAR MR. JOHNSTON:

4129. **MR. JOHNSTON:** Good afternoon, panel. My name is Paul Johnston. I'm with the National Energy Board and I do have some questions for you this afternoon.

4130. The first question -- and this is more a confirmation because Mr. Core, in your opening and on your cross-examination with Mr. Davies, you may well have answered the question, but I just want clarification on CAPLA's default position.

4131. So I wondered if I could refer you to two different portions of your evidence. First of all, Exhibit C-1-6A, and it's on page 18. So maybe I'll go through this first and then I'll give you the other citation and ask for your comment.

4132. CAPLA states that to ensure fulfillment of the principle established by the Board, and that principle being that landowners will not be liable for costs of pipeline abandonment, it supports a default option of removal of large diameter pipeline and agriculture lands where all pipelines in a common corridor have been abandoned.

4133. And then if I may refer you to the Reply Evidence, which is found in Exhibit C-1-13B at page 10. I'll just give you a moment to find that.

--- (A short pause/Courte pause)

4134. **MR. JOHNSTON:** The conclusion in the Reply Evidence is that CAPLA's removal/perpetual maintenance default option is the only technical assumption that accomplishes the goal of no liability for landowners.

4135. My question is just confirmation that the default option proposed by CAPLA does include perpetual maintenance as a potential option?

4136. **MR. CORE:** Yes, it does.

4137. **MR. JOHNSTON:** If I can refer you to another exhibit in your evidence,

and this is Exhibit C-1-9B, pages 16 and 17? So it begins at the last paragraph, and in CAPLA's second Written Evidence filing it states:

> *"...the Board must adopt in Stream 3 the technical default option proposed by CAPLA...and must require the commencement of collection of funds sufficient to finance the default option immediately."*

4138. And when you were speaking with Mr. Davies, you made mention of this being at any cost.

4139. My question is whether there's a risk that implementation of the default option could result in a material increase in tolls and, in some situations, a change in competitive dynamics that could ultimately result in one or more pipelines being abandoned much earlier than anticipated had funding for the default option not been required in all circumstances?

4140. **MR. CORE:** And what is the question?

4141. **MR. JOHNSTON:** Whether -- if the Board were to adapt the default option in all circumstances, could there be cases where the resulting change of implementing that policy would actually result in pipelines being abandoned more quickly than had the default option not been required? So whether this would cause -- whether you believe that this would cause potential for that to happen?

4142. **MR. CORE:** I'm an expert on some things, but not on others. From a landowner perspective, I would say that through my travels and everything else and everybody I've talked to, I'm an expert on landowner issues.

4143. And so what I want to say in response to your question is, is that pipelines -- pipelines imposed on our farms make us uncompetitive with our neighbours, and as time goes on that uncompetitiveness becomes greater and greater until abandonment is addressed. Actually, these show up on our balance sheets now.

4144. So the answer to your question is, that's not our concern, because no one thought of us when we imposed pipelines on our property and did not address the abandonment issue.

4145. **MR. JOHNSTON:** So, from your perspective, are there any -- are there any negatives of the default option?

4146. **MS. CHEUNG:** I may add to that earlier response that if you start the collection of those funds early enough, that you will actually avoid the situation that

you have described in your question.

4147. **MR. JOHNSTON:** Thank you.

4148. **MR. CORE:** My question is, are you referring directly to pipelines within the same corridor or are you saying all pipelines?

4149. **MR. JOHNSTON:** No, my question concerns the default option proposed of either removal of all large-diameter pipeline in common corridors or perpetual maintenance; do you see any negatives to this as always having to occur?

4150. **MR. CORE:** From a landowner perspective, no.

4151. **MR. JOHNSTON:** Do you see any negatives from any other perspective?

4152. **MR. CORE:** I would say from a public interest perspective and a taxpayer and a person that's paying for energy, no.

4153. **MR. JOHNSTON:** And does the public interest perspective include pipe -- efficiency for pipelines and pipeline companies?

4154. **MR. CORE:** Yes, it does. And efficiency includes abandonment, and if abandonment is not included in that efficiency, then the National Energy Board is irresponsible in even discussing efficiency topics because that is part of something that needs to be discussed and included in efficiency.

4155. Because the issue of addressing abandonment is actually an efficiency issue and it hasn't been addressed, from my perspective.

4156. **MR. JOHNSTON:** Could you elaborate, then, on the efficiency issue?

4157. **MR. CORE:** From a public interest perspective, if you don't address the issue now while you have tolls coming in -- again, we can go back to the intergenerational thing of who's paying for what when it happens, and that's an issue of efficiency, because who's paying and then death spirals and everything else?

4158. Now is the time to address the issue and the only way to address the issue, from our perspective, is the default position. Otherwise, you're leaving us with risk. So, you know, I can't see any negatives to it.

4159. From an efficiency perspective, it just hasn't been put in the equation before. It has to be put in the equation now.

4160. **MR. JOHNSTON:** And does the default option include any ability for exceptions?

4161. **MR. CORE:** I wasn't sure I heard your last word there.

4162. **MR. JOHNSTON:** Does the default option -- in your view, is there a criteria that should be considered for there to be any exceptions to the default option?

--- (A short pause/Courte pause)

4163. **MR. CORE:** When you say exceptions to our default position, are you referring to the two choices in the default position?

4164. **MR. JOHNSTON:** Yes.

4165. **MR. CORE:** Because there's two choices there. Or are you referring to the package of our default position?

4166. **MR. JOHNSTON:** The two choices of your default position, although if the package is different, then you can certainly elaborate on that.

4167. **MR. CORE:** We don't see any exceptions to our default position of pipeline removal or maintenance into perpetuity. We don't see any exceptions from that because there are no exceptions.

4168. Abandonment in place leaves -- leaves us open to financial risk down the road. If a company is insolvent and there's nobody there to cover those costs, you're leaving -- you're leaving landowners totally open to risk -- landowners or the government. As of right now, it's landowners, because the government has not alleviated any risk from us whatsoever.

4169. **MR. JOHNSTON:** I have a question on the point of the solvency risk you've mentioned that ties into that.

4170. The question is, should the Board ultimately determine that the default option that you've proposed should be adopted as an assumption used to create preliminary cost assumptions, and collection based on this assumption starts as soon as the preliminary cost assumptions are prepared?

4171. Please explain how this will provide certainty that funds will be available to cover all costs of abandonment at the time of abandonment?

4172. **MR. CORE:** Again, we're making assumptions, and what we've tried to do here is find an assumption that we feel -- and I guess I have to use -- makes our risk zero or minimizes it as close to zero as we can come up with.

4173. And we have a responsibility of landowners to try and come up with the way to get to zero, and this is the only way we can see at this point that we can protect ourselves, is with the default position. There's no other solution at this time.

4174. Is there risk of underfunding? We hope not. But we hear people talking about waiting and discussing these issues further. In the meantime, we have to discuss raising money for the maximum position, and that's the position that we're taking, is the default position.

4175. **MR. JOHNSTON:** When you say commencement should -- commencement should begin immediately, practically speaking, what do you mean?

4176. **MR. CORE:** As soon as a decision is made at this hearing.

4177. **MR. JOHNSTON:** And can you -- if you could explain how that would work, how would that impact preliminary cost estimates?

4178. **MR. CORE:** I think, if I read the 1985 document properly and some documents that have been produced since then, there is some recognition of abandonment costs and what it costs to take pipes out of the ground.

4179. And there was a discussion, I think, and it was the '85 document, there was discussions -- and in some appendages to that -- there was discussions about what it costs to remove pipes. In fact, I think there was some research done on that.

4180. There's companies in the U.S. that remove pipelines from the ground. I can give you their website and I'm sure those costs can be provided.

4181. I think there was a factor that was used, a recommendation in one of the documents that I read that talked about you multiply the cost of construction of a pipeline to take it out. I think there is a number that can be used to start collecting and it's irresponsible if we don't start collecting today.

4182. **MR. JOHNSTON:** If you could show me in your pre-filed materials filed to date information that supports the conclusion that collection for abandonment should begin immediately?

4183. You've cited the 1985 report and we have that, but is there any other information that you've filed, including portions of that report, that you'd like to refer

to, to support the conclusion for immediately starting collection?

4184. **MR. CORE:** I can't refer directly to something. What we're doing is making, I would suppose, as a landowner, we're suggesting that we weren't protected, and there's nothing -- nothing today that is protecting us from abandonment consequences. There's no funds available if a company were to be insolvent. So that -- that's the position we take on that.

4185. **MR. KRAAYENBRINK:** And if I could add to that is for -- about companies being insolvent, is you take GM. I don't think a few years ago that they thought they'd be in the position they are today.

4186. **MR. JOHNSTON:** The next question may be grounds that you've covered already with Mr. Davies and you're certainly welcome to refer back to that portion, but I believe there's some additional issues here.

4187. I mean, you filed evidence on your position of pipeline abandonment and the considerations that are important, from your perspective. Are there any other considerations from other interested parties that the Board should be using to balance in its decision?

4188. **MR. CORE:** From our perspective, we represent landowners across Canada. From our perspective, for once, we'd like our perspective balanced in a decision.

4189. May I refer back to your question, your previous question for a moment? I thought -- had time to think for a minute. I think the accumulation of all the documentation that we have put in our evidence proves that collection of funds for abandonment should happen tomorrow.

4190. And I can even produce for you a letter that was presented to the National Energy Board and read to them in front of the then-Chair of the National Energy Board -- and I will produce that if I am requested -- read by Margaret Vance talking about abandonment fundings and the desperate need for it and that the issue of abandonment be addressed in 2002 in Sombra, south of Sarnia, Ontario, and she talked about this very issue and it was ignored.

4191. We're here today, and the longer you leave it, the later it's going to get, we're going to have death spirals and it's going to be too late. It's going to be too late.

4192. **MR. JOHNSTON:** And my earlier question was -- what I was hoping for is there were places in your evidence that you could refer me to support the position

of immediate collection. I understand you said the evidence as a whole speaks to that, but if you're able to pinpoint other places that would be helpful.

4193. **MR. CORE:** And I don't think I can, right at the moment, unless we refer to the 1985 document, but I don't have that.

4194. **MR. JOHNSTON:** And again on the issue of efficiency considerations, when the Board's making its decision can you elaborate on the issue of how, taking into account the public interest and all the other factors, the Board is to consider how efficiency considerations should enter into the solution?

4195. **MR. CORE:** I think the situation we're in is we've got to rethink where we're going here. The consumer pays. Pipeline industry is fully regulated and the consumer pays. And you have a responsibility to get the cost of the impacts of pipelines back from the consumer.

4196. So basically what you're doing is by worrying about efficiencies, as such, and leaving us with risk you're making us subsidize the consumer, and the consumer, if they knew that, would not be happy, because also the consumer, the very consumer that you and the public interest that the NEB regulates and is supposed to act on behalf of, expects us to be stewards of the land, protect the land and make sure that it's protected for future generations.

4197. So when you talk about efficiencies, you haven't considered efficiencies for the past 50 years because you've not included that perspective of the public interest in it.

4198. So, you know, I almost think that that question -- I don't want to say it's irrelevant, but until you take our perspective and our responsibilities into this equation I don't see the discussion.

4199. **MR. JOHNSTON:** I understand. I wasn't attempting to make any judgment about use of the word, I was asking the question and just was interested in your feedback. So I appreciate that.

4200. In reference to the stated default option that we've discussed, in your IR 2.2 Response to the National Energy Board, states that without the removal, perpetual maintenance, default option proposed by CAPLA, the Board must consider other options to eliminate landowner risk.

4201. And then you go on to say that -- and this was in response to a National Energy Board question:

> *"Pooling of funds across the industry may be an answer but the end result must be that there are sufficient funds in place to cover the cost of abandonment of every pipeline that is abandoned."* (As Read)

4202. My question is whether pooling or, as we've been asking in terms of questions at the hearing, whether partial pooling for the residual risk eliminates the requirement of the default option?

4203. **MR. CORE:** No. Pooling -- we've discussed this amongst ourselves before we sat here today and the default option, we have to collect for it, whether it's in a pool or not, but -- you know, would you like me to go further to describe how we see this pooling idea?

4204. **MR. JOHNSTON:** Certainly. That would be helpful.

4205. **MR. CORE:** We support the industry, in that they collect for their own pipeline. We support that idea. We don't support their concern about money being left over that it belongs to them because we have a concern about risk.

4206. Who's taking the risk here? And the risk is landowners. Nobody else is taking the risk here. We're left with the pipe.

4207. So we see a pipeline company collecting for the default position, and say there's money left over after the pipe's removed or after the end of time if we're going to maintain the pipe into perpetuity, we see that money that's being left goes into an orphan pipeline fund or a pool, not back to a pipeline company, not back to the shippers but into a pool to protect us against pipeline companies that are insolvent or don't exist to maintain those pipes into perpetuity.

4208. So, you know, that's the way we see it.

4209. **MR. JOHNSTON:** So you would support then collecting for each pipe, either for removal or perpetual maintenance, and then also the potential of having money set aside for pooling purposes in case there wasn't enough money at the end. Is that correct?

4210. **MR. CORE:** Yes.

4211. **MR. KRAAYENBRINK:** And can I add to that? I don't think that extra money cannot go to the companies, because what that's going to create is the companies are going to want to go and abandon these pipelines as cheaply as possible to put as much money in their pockets at the end of the day.

4212. **MR. JOHNSTON:** And so if there is a surplus that goes either to pooling or -- I'm sorry, what was the other area that it could go to?

4213. **MR. CORE:** I really wish Mr. Goudy could talk to you, but he can't.

4214. The view that we have is, is that we have to go back that this is the public's money, the consumer's money. And I guess the way we'd like to put it is, is that at the end of the day if the pipeline is cleaned up and there's no issues left and nothing that needs compensated, no impacts on our farms or the land or anything else, which will be quite significant -- and I'm not sure you'll see that day but it's a possibility -- then that money belongs to the consumer because the consumer paid it.

4215. So, you know, I guess at the end of the day the money -- you know, it's the responsibility of the consumer to pay these costs under the regulatory regime that we have and so the money belongs to the public if -- if the risk is gone.

4216. **MR. JOHNSTON:** I understand.

4217. I want to ask you next about governance, and this is a topic that's come up in information requests already to date in the proceedings.

4218. In your information request to the National Energy Board 2.1 which is Exhibit C-1-11B, and I'll focus on the second-last paragraph and the last paragraph -- you state that one possible role for landowners would be memberships on the boards of directors that oversee funds that are collected.

4219. Your evidence also states that it is important for landowners to have a stable and meaningful role in Board processes that oversee management of funds.

4220. Other than the evidence you've already filed, and I'm quoting here from Mr. Ness earlier where you said you want industry to be partners with landowners, how would this happen? How would you effectively be involved in the governance process?

4221. **MR. CORE:** Again, we've had discussions over the last couple of days while we were putting in time here and the way we see it is, is that the Board would have a committee or an oversight committee that would oversee all of the pipeline collections and, you know, and that we'd have an input from that perspective, that we would have somebody within that oversight committee or whatever to view all of the collections from all of the pipelines, not each individual pipeline.

4222. That would be an impossibility and it would be impossible to find enough

people who are knowledgeable in addressing and oversighting something like that, but we see it as a Board-mandated position that somebody, some sort of a landowner or a representative of landowners be there to monitor what's being done with the money, and that there is enough being collected.

4223. **MR. JOHNSTON:** And should the Board determine that funds should be collected and a trust-type model was used, if you could elaborate, though, on how landowners would be partners with industry on these type of committees?

4224. **MR. NESS:** When I was referring to a partnership I wasn't referring to the financial partnership. I was referring to a partnership that arises where there is regular communication and that the company discovers and communicates the landowners' concerns to industry.

4225. That's where there is a deficit right now, is industry doesn't seem to want to get down to the basic concerns that we have and it starts -- it starts when a company is granted a certificate to build a pipe.

4226. We're immediately swamped with land agents, the second biggest storytellers in the world, and their tactics do nothing to enhance relationships between landowners and the industry.

4227. So we're looking for a communication partnership where there is joint decisions and extensive communication that is not there now.

4228. **MR. JOHNSTON:** And in terms of participation on the oversight committee that you're speaking of can you think, though, of ways that it could be a partnership with industry or do you see the role of landowners as more adversarial to protect what would be their interest?

--- (A short pause/Courte pause)

4229. **MR. CORE:** We wouldn't see our position as adversarial whatsoever. I think the only position when anybody would be adversarial on such a position would be if you saw that the funds weren't being collected and invested responsibly.

4230. When you say a partnership you're on a committee. It's like a board of directors you monitor. The only time you would become -- I don't even see how the term adversarial would come about because you're monitoring. It's like a policing.

4231. There may be challenges if you don't see the proper collection being done but I don't see it as adversarial. What we're doing is protecting the interests and not just reducing the risk but doing what the mandate of this hearing is, is that it's not to

leave any risk with landowners for abandonment.

4232. **MR. JOHNSTON:** Is there anything else you wanted to add about fund governance?

--- (A short pause/Courte pause)

4233. **MR. KRAAYENBRINK:** I think it's really important that right at the outset here as these funds are collected that there is tremendous effort put in to collecting the proper funds immediately so that we don't run into what you're talking about.

4234. We have to all do due diligence here because not only -- everybody sitting in this room is at risk if not enough funds are collected and we, as individuals here, are willing to accept whatever that cost is but the panel here as landowners are certainly not willing to accept any risk; again, alluding to the fact -- and Dave touched on that -- is these pipelines were imposed on us.

4235. We had no choice whether these lines were going in. And if we didn't sign on the dotted line we were just going to get expropriated which a number of these people have been.

4236. So that's why, as I said, as a public person who uses energy, I'm willing to pay for the abandonment fund but I'm not as a landowner willing to take the risk of the abandonment.

4237. **MR. JOHNSTON:** I want to refer you now to another party's evidence, and we've asked this question of all parties to date. It's the Reply Evidence of Kinder Morgan which is Exhibit C-15-96 on page 3. I'll give you an opportunity to look through that.

4238. Kinder Morgan provides an example of the implications of timing on the collection of abandonment funds. They conclude that any proposal that allowed parties to defer the collection of abandonment funds could lead to the deferral of collection of abandonment costs in order to remain competitive, back-end collection of abandonment costs and a greater risk that abandonment costs could not be recovered from shippers because collection may occur in periods of distress.

4239. My question is whether you agree with all or portions of Kinder Morgan's conclusions and why?

--- (A short pause/Courte pause)

4240. **MR. CORE:** I'll have to qualify my answer. I had to think about that. I knew there was a problem with it. We agree with those, but the risk is left to landowners, not to the company. So we're left with the risk. We agree with those assumptions, but we're left with the risk.

4241. **MR. JOHNSTON:** And if you could elaborate on how you're left with the risk in this context.

4242. **MR. CORE:** Well, all of those are a risk. The risk of abandonment is landowners'. If there's a shortage of money to cover our default position, we're at risk. If there's not enough money there to take the pipe out of the ground, we're at risk. If there's not enough money there to maintain the pipe into perpetuity, we're at risk.

4243. **MR. JOHNSTON:** I want to ask you now about the letter sent by the Board on January 14th, 2009, concerning the issue of whether principles in the pension context may have application for abandonment funding.

4244. And as I've said to other panels, I'm not interested in drilling deep into any of these particular definitions. I guess my first question is whether any of you have background in the pension area.

4245. **MR. CORE:** No.

4246. **MR. JOHNSTON:** I'll keep my question, then, on a very general level, and that is, generally speaking, do you see some of the principles from the pension context having application? Should they be used for abandonment funding?

4247. And if so, if you can describe on a general level how they would apply or if you have any concerns about the pension context, I'd like to hear those as well.

4248. **MS. CHEUNG:** I do have some comments on that correspondence, that -- let's start with the governance principles first. There were 11 principles stated. That's on page -- it says page 5, but it's really the last page in that Board document.

4249. I think all of the governance principles are sound, with the addition, I would say, that the governance objectives would be approved by the NEB and that Principle 11, that the government -- the governance review -- that it should be more than just a review, but also that if there are changes, that the changes would be approved by the NEB as well.

4250. **MR. JOHNSTON:** And ---

4251. **MS. CHEUNG:** And the other one is the regular review, that it has to be mandatory and not just voluntarily undertaken by the company itself.

4252. And then, in terms of the glossary of terms, I only -- you know, I think lawyers would have a field day with a lot of these terms, and the only comment I could provide on that is that the plan sponsor should be the pipeline and that the stakeholders would include the landowners, and the pipe -- the plan administrator would include the pipeline, but there has to be a separate fund administrator, similar to a trustee in a pension fund. And the only experience I have with a pension plan is I am a recipient of a pension plan.

4253. **MR. JOHNSTON:** I understand. Thank you.

4254. Any additional comments?

4255. **MR. CORE:** I just want to add that at the preliminary conference that we had, or pre-conference that we had, and we talked about some of these issues, I think I informed the companies that we would support them in their issue of the tax consequences of collecting this money.

4256. You know, there were issues about after/pre-tax dollars, et cetera. We're supportive of the industry as to how they collect this and that it should be before-tax dollars that's put into the fund. You know, I just want to qualify that.

4257. We're supportive of this being done, because it's in the environmental interests and the interests of landowners that the funds be put away, and that the interest collected on those funds aren't taxable until the money is used. And if it's used to clean up the pipe, it shouldn't be taxable then either.

4258. **MR. JOHNSTON:** And if tax implications take some time, does that have any bearing on your recommendation in terms of when collection should begin?

4259. **MR. CORE:** No. Collection needs to begin right away as far as we're concerned.

4260. **MR. JOHNSTON:** And just one final question. Going back to the issue of potential analogies with pensions, there's been a lot of media discussion lately about drops in the value of pension funds.

4261. Do you have any of suggestions as to how such impacts could be protected against or mitigated against should something similar to pension funding be used in the abandonment context?

4262. **MR. CORE:** As far as we're concerned, this money has to be safe. You know, it can't be invested in anything at risk, because it has to be there when the time comes that abandonment takes place.

4263. Does anybody else want to say anything? Before you quit asking questions, I'd like to go back to your issue of efficiency. Am I allowed to?

4264. **MR. JOHNSTON:** Certainly, you can comment on the issue of efficiency.

4265. **MR. CORE:** I don't think the true cost of pipelines has ever been addressed, and I think it's in the public interest that it finally be addressed, and that's about efficiency, because we're moving in -- the world has evolved and the industry has been subsidized too long by landowners.

4266. And I don't think the public understands that they've been subsidized by landowners and I think it's time that the true cost of moving energy across Canada be represented, because then that efficiency of recognizing that cost will be recognized in the cost of energy, and then other choices will be made about energy.

4267. Not that I want to undermine the oil and gas industry or pipeline industry, it's just only responsible that the true costs of moving energy be addressed. If it's going to be subsidized, it should be subsidized by the government or the consumer. That's a choice they should make. It should not be subsidized on the backs of landowners.

4268. **MR. KRAAYENBRINK:** And if I could even add to that, everybody else in this room, I'm sure and positive is getting paid today and all week long, except us landowners.

4269. It's all coming out of our back pocket, and that's one deficiency that even after today you should talk about. And that really has to change because that is really, really unfair.

4270. Because let's go and put this all in reverse. If the company and the abandonment fund would be deficient, how many of you would want to be next in line to go and put your own personal money towards that fund? Because that's where -- exactly where we're sitting as landowners, and that is not fair.

4271. **MR. CORE:** I want to go back to -- I didn't respond to your question about do we have some evidence to show that -- that I can provide that shows that we should start collecting tomorrow. And I guess, you know, I said collectively our evidence says that.

4272. But I think if you go -- you know, I've been flipping through the background paper, because I do read a lot of documents and sometimes I forget what's in them. But I want to refer back to the background paper on negative salvage value, and I want to say to you that when you read the conclusion on page 2: ...

> *"In conclusion, as long as pipeline regulations require the companies to remove their facilities after abandonment, unless otherwise approved by the Board, then the companies can be expected to continue to seek the Board's view on what will need to be removed so that the funds can be set aside."*

4273. Everybody today has talked about evidence. This is evidence that states that we should have been collecting that many years ago, in 1985. We shouldn't be discussing it today. It should have been -- so the only thing that has evolved -- we talk about technical change and what can -- and that with engineering design, et cetera, that things will change over the years.

4274. Well, the only thing that changed since 1985 -- the only thing that's changed since 1985 is regulatory change. That's the only evolution that changed since 1985 was the fact that the regulations were changed to address the pipeline company's problem about collecting tolls for abandonment. And that's the only evolution that we've seen in a number of issues, is change from a regulatory perspective.

4275. And another thing that was brought up over the last few days was the fact that some easement agreements say that pipelines -- there's a legal agreement that pipelines be removed and there's other ones that say that they don't have to be removed.

4276. Well, the other evolution that's occurred since we signed those easement agreements is regulatory change that affects the covenants in those easement agreements. So what matter does it make what the easement agreement says?

4277. We have easement agreements today that say that we have a choice as to whether the pipe is removed or maintained into perpetuity, but the fact is, until you people make sure that those covenants and those easement agreements are there and they're covenants that are made to us between pipeline companies and landowners, there will continue to be evolution, but it won't be the evolution that the companies have talked about here; it will be about regulatory change affecting those covenants.

4278. We need the regulatory change to back up the covenants and the new easement agreements, and we need to get on the fact that we need a generic easement

agreement that addresses the issues of today. The world has evolved. Abandonment is a responsibility in the public interest and decisions have to be made, and it's getting to be too late to collect.

4279. I have evidence, and I can present it to you, a document from a hearing where the President of then Inter-provincial Pipelines stated that his pipelines were only designed to last 35 years. And now I hear from pipeline companies that they're going to last forever, and I haven't seen the evidence to prove that. And you're asking us to produce certain evidence here today.

4280. There's been lots of statements here today that I've heard that back up certain positions that landowners should take a risk. Landowners and government should take a risk, and that's not the case. Our solution is the only responsible solution to take at this time.

4281. I think it's an embarrassment -- it's an embarrassment that we've gone since 1985 -- look at this document -- I didn't know it existed. We talked about abandonment funding in 2002 in front of a person who was responsible for writing this document, and it wasn't identified to us until we took part in an Enbridge Line 9 Toll Hearing, because that was the result of this document.

4282. The result of this document -- there was a decision to be made whether it should be a generic hearing about abandonment funding or whether it should be at toll hearings and where it should be.

4283. Landowners were never consulted about whether there should be a generic hearing. Landowners were never asked anything about this. It wasn't even identified to them, and yet a decision was made to leave it to toll hearings.

4284. How many landowners -- even with the experience that our associations and the knowledge that our associations have, would never have identified that we could address abandonment and negative salvage value, something that we didn't even understand what the words meant, that it would be our interest to take part in toll hearings since 1986 when the decision was made. Nobody identified to us to participate.

4285. There's no funding for us to participate. We're taking here today risk right now for abandonment. We spent a few hundred thousand dollars to be here at our own expense. And why? Because this documentation was never presented to us, even when we brought it up.

4286. And then you people stand here today and tell us to take some risk? Take risk? We're taking risks today being here.

4287. And so what I'm going to say to you is if you read this document, they talk about the nuclear industry in the U.S. and that they're collecting funds for abandonment. They're responsible.

4288. These documents -- and I don't know whether they were hidden on purpose from us or whether they got misplaced. It's unbelievable that they were never presented to us.

4289. And so now we're here. Now's the time -- our default position is the only position. I see Stream 4 being diluted, diluted at the very time that we're at this hearing. I get a document that says, "We're changing the principles of Stream 4 and we're all waiting for Stream 4 to happen."

4290. Well, I have to tell you maybe I'm a little passionate about this, but I'm getting tired of being told, "Trust us. Trust us." There is no trust. These pipes were enforced on our property.

4291. Our property is being -- and maybe I won't be so dramatic, but our property -- these pipes are being enforced. It affects our farms. It affects our families. It affects the future of our farms. It affects the value of our farms. You're going to abandon pipes and corridors.

4292. There's a corridor in Ontario under National Energy Board regulations with a pipe abandoned in it and the people don't even understand what their rights are, and I can identify that corridor to you. I'm dealing with those people right now. That pipe was put in and then because it was -- it leaked, they left it and built another one, and it's in their property. Has that been addressed?

4293. Abandonment funding has to start tomorrow and it has to start based on our default position. You can lower the fees as you come up with different assumptions later that guarantee we don't have a risk. You can lower those fees, but it's going to be too late if you have to raise them. So let's start at a responsible place and go from there.

4294. Thank you.

4295. **MR. JOHNSTON:** Thank you, Mr. Core. Let me just check with my colleagues and see if there are any additional questions.

4296. I have no additional questions. Thank you very much, Madam Chair.

4297. **THE CHAIRPERSON:** Please excuse us for a minute.

--- (A short pause/Courte pause)

4298. **THE CHAIRPERSON:** Thank you very much.

4299. The Panel has no further questions of this panel.

4300. Mr. Vogel, do you have any re-direct arising?

4301. **MR. VOGEL:** I have no further questions, Madam Chair.

4302. Perhaps if the panel could be excused then?

4303. **THE CHAIRPERSON:** Thank you very much. The Board thanks you very much for the evidence that you've provided and you're excused. Thank you.

4304. **MR. CORE:** I wish to make an apology for using the term "you people". I have to admit that I was impassioned at the time and I apologize to anybody who may have taken that wrong and I should have been more respectful.

4305. Thank you very much.

4306. **THE CHAIRPERSON:** Thank you, Mr. Core.

4307. The panel is excused.

--- (The witnesses are excused/Les témoins sont libérés)

4308. **THE CHAIRPERSON:** That brings us to the end of the CAPLA panel and the only panel remaining is the CAPP panel.

4309. It would be the Board's preference to sit at 8:30 on Monday morning to deal with the CAPP panel. And at that point that will bring us to the end, subject of any undertakings, to the end of the evidentiary portion.

4310. I believe Board counsel have talked to other counsel and it is our view that we would finish the evidentiary portion on Monday and then proceed to hear final arguments starting at 8:30 on Wednesday morning.

4311. Are there any parties that wish to offer any perspectives other than what I'm outlining at this point?

4312. **MR. VOGEL:** Thank you, Madam Chair.

4313. I should perhaps indicate we don't have any questions for CAPP, and we would propose then to request leave not to be here on Monday, but we will return on Wednesday then for the argument.

4314. **THE CHAIRPERSON:** Thank you for informing us of that, Mr. Vogel.

4315. **MR. VOGEL:** Thank you.

4316. **THE CHAIRPERSON:** Any other parties who want to speak to the proposed plan?

--- (No response/Aucune réponse)

4317. **THE CHAIRPERSON:** Then we will reconvene on Monday morning at 8:30 for CAPP's panel and we will commence oral final argument at 8:30 on Wednesday morning.

4318. Thank you very much, everyone.

---Upon adjourning at 1:25 p.m./L'audience est ajourneé à 13h25

NATIONAL ENERGY BOARD
OFFICE NATIONAL DE L'ÉNERGIE

Hearing RH-2-2008
Audience RH-2-2008

Land Matters Consultative Initiative (LMCI) Stream 3
Pipeline Abandonment - Financial Issues

Troisième volet de l'Initiative de consultation relative aux questions financières (ICQF)
Cessation d'exploitation de pipelines - Questions financières

VOLUME 6

Hearing held at
L'audience tenue à

National Energy Board
444 Seventh Avenue West
Calgary, Alberta

January 28, 2009
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RH-2-2008

IN THE MATTER of the Land Matters Consultative Initiative (LMCI)
Stream 3 - Pipeline Abandonment - Financial Issues

HEARING LOCATION/LIEU DE L'AUDIENCE

Hearing held at Calgary (Alberta), Wednesday, January 28, 2009
Audience tenue à Calgary (Alberta), Mercredi, le 28 janvier 2009

BOARD PANEL/COMITÉ D'AUDIENCE DE L'OFFICE

S. Leggett	Chairperson/Présidente
K. Bateman	Member/Membre
L. Mercier	Member/Membre

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- Mr. R. Power

BP Canada Energy Company
- Ms. C. Worthy

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- Ms. M. Yohemas

Foothills Pipe Lines Ltd.
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- Ms. N. Berge
- Mr. M. Keen

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- Ms. L.R. Aufricht

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Canadian Association of Petroleum Producers (CAPP)
- Mr. N.J. Schultz

Governments/Gouvernements

Alberta Department of Energy
- Mr. C. King

National Energy Board/Office national de l'énergie
- Mr. P. Johnston
- Ms. J. Saunders

ERRATA

Tuesday, January 20, 2009 - Volume 1

Paragraph No.:	Should read:
313: "...for example, of group one companies of auditing the activities of the utilities that it oversees of enforcing breaches has not satisfactorily achieved the objective of behaviour..."	"...for example, of group one companies, or auditing the activities of the utilities that it oversees or enforcing breaches, has not satisfactorily achieved the objective of a behaviour..."

Thursday, January 22, 2009 - Volume 3

Paragraph No.:	Should read:
2128: "The vintage of the pipeline may have an impact just because of the material was used in the construction of facilities."	"The vintage of the pipeline may have an impact just because of the material used in the construction of facilities."
2157, 2160 and 2162: "**MR. DAVIES:** ..."	"**MR. VOGEL:** ..."
2310: "...over a period of time, I suppose, to waiting for the event..."	"...over a period of time, as opposed to waiting for the event..."
2320: "Well, there's so many factors that go into the comparative environment. This may be -- it may certainly be one additional item but it's very difficult to say whether it's going to outweigh any of the other comparative issues."	"Well, there's so many factors that go into the competitive environment. This may be -- it may certainly be one additional item but it's very difficult to say whether it's going to Outweigh any of the other competitive issues."
2396: "And would this seem logical, true, if there were only partial poolings?"	"And would this same logic be true if there were only partial poolings?"

ERRATA

Friday, January 23, 2009 - Volume 4

Paragraph No.:	Should read:
3591: "Just at the standpoint where the Board asks you to provide a set of..."	"Just as the standpoint were the Board to ask you to provide a set of..."

Monday, January 26, 2009 - Volume 5

Paragraph No.:	Should read:
4380: "...before the entire basis was even close to being exhausted."	"...before the entire basin was even close to being exhausted."
4474: "...or proposals that are invasive."	"...or proposals that are innovative."

TABLE OF CONTENTS/TABLE DES MATIÈRES

--- Upon commencing at 8:29 a.m./L'audience débute à 8h29

4691. **THE CHAIRPERSON:** We are ready to proceed with final argument this morning.

4692. Are there any preliminary matters to raise in advance of moving forward to preliminary argument?

4693. **MR. DENSTEDT:** Good morning, Madam Chair.

4694. TransCanada has one undertaking that's still outstanding. We are still waiting to hear back from the publisher, hopefully today, on whether we will be allowed to submit that article, but we'll keep the Board advised.

4695. **THE CHAIRPERSON:** Thank you, Mr. Denstedt.

4696. Okay. If there are no other preliminary matters, we'll call on final argument, as we mentioned, from a top-down, bottom-up approach, using the Order of Appearances.

4697. And so I call Alliance Pipeline Ltd. to start.

--- (No response/Aucune réponse)

4698. **THE CHAIRPERSON:** BP Canada Energy Company...?

--- (No response/Aucune réponse)

4699. **THE CHAIRPERSON:** Enbridge Pipelines Inc. ...?

--- FINAL ARGUMENT BY/ARGUMENTATION FINALE PAR MR. CROWTHER:

4700. **MR. CROWTHER:** Good morning, Madam Chair and Members.

4701. It is my pleasure to present the argument in-chief of Enbridge Pipelines Inc.

4702. I have provided the court reporters with a copy of my notes but caution that my remarks may occasionally vary from them. My notes include headings and I would ask that they be recorded in the transcript.

4703. Evidentiary references are also included and I also ask that in the interest

of efficiency, they be recorded in the transcript that I don't have to take time to read them. This is a customary approach, Madam Chair, and I assume it's acceptable to you.

4704. **THE CHAIRPERSON:** Yes. Thank you, Mr. Crowther.

4705. **MR. CROWTHER:** Thank you.

4706. This argument treats the principal issues set out in the amended list that was attached to the Board's letter of April 21, 2008 -- Exhibit A-8A.

4707. I will not address all of the issues but the Enbridge Written Evidence did *[Ex. C-10-3B]* and I therefore recommend it, as well as the Enbridge Reply Written Evidence *[Ex. C-10-12B]* and responses to information requests *[Ex. C-10-5B, C-10-6B, C-10-7B, C-10-8B, C-10-9B, C-10-10B, and C-10-14B]* for your careful review and consideration.

4708. One question that was not identified in the List of Issues but is nevertheless important and worthy of some discussion is: What should be the outcome of this hearing?

4709. In its January 17, 2008 letter, the Board stated that one of the potential outcomes of this Land Matters Consultation Initiative would be the development of a set of principles that will guide the Board in its future decisions with respect to the financial matters related to pipeline abandonment. *[See Ex. A-2C, "Land Matters Consultation Initiative Stream 3: Financial Issues Relating to Pipeline Abandonment Discussion Paper", section 2.1 (p. 7 - 1st bullet)]*

4710. Enbridge agrees that that should be the outcome of this proceeding.

4711. Kinder Morgan recommends that, if collection of abandonment funds were to be required, then the NEB should schedule test cases for one or two major pipelines and volunteers Enbridge for that duty *[Ex. C-15-3B, A2b (p. 4); 2T1868-71]*.

4712. I should say that Enbridge appreciates the thought -- but does not share Kinder Morgan's apparent enthusiasm for test cases -- at least not in these circumstances. In my submission, they would be unlikely to be productive and should not be directed.

4713. There was also some discussion -- by way of correspondence -- before this hearing began about the possibility that the NEB might issue a draft proposal or draft guidelines.

4714. Enbridge sees merit in that sort of approach -- especially now that the Board will have the benefit of both the testimony of the various parties and the arguments that you will hear today.

4715. There is, however, the important caveat, that if the Board were to issue a draft proposal or draft guidelines, it would be essential that it nevertheless remain at least open to approving any alternative that may be presented.

4716. Having made those introductory comments, I'll turn to the substance of my argument.

4717. There are two overarching principles to which Enbridge adheres unequivocally in the present context.

4718. First, abandonment of an NEB-regulated pipeline in a manner and to a standard required by this Board is the obligation of the pipeline. At the appropriate time in the future, Enbridge will be required to satisfy the Board that its plan for abandonment and its ability to execute that plan are acceptable having regard to both the prevailing facts and circumstances and the applicable statutes, regulations and regulatory requirements *[Ex. C-10-3B, A4 (p. 3)]*.

4719. Enbridge, not landowners, will be responsible for abandonment and the process for abandoning its pipelines.

4720. The second principle is that the cost of abandoning facilities is one of the costs of providing pipeline service. Therefore, Enbridge and its shareholders are aligned with landowners in their desire to ensure that sufficient funds are collected from shippers to pay whatever costs of facility abandonment may actually be incurred.

4721. Enbridge is surely not alone among the pipelines in having a strong incentive to collect the necessary abandonment funds -- and it is submitted that the Board can, and should, take considerable comfort in that reality.

4722. These are, of course, slightly different expressions of the two key principles that the Board itself enunciated in its January 17, 2008 letter concerning its proposed approach to the Land Matters Consultation Initiative.

4723. **Should the Board require collection of abandonment funds?**

4724. The simple answer, so far as Enbridge is concerned, is "yes". The detailed answer is, of course, considerably more nuanced.

4725. By which I mean that Enbridge is of the view that NEB-regulated pipelines should begin collecting abandonment funds when a reasonably accurate estimate of future abandonment costs can be made *[Ex. C-10-3B, A3 (p. 7)]*.

4726. Although it may be possible to estimate current abandonment costs now, Enbridge firmly believes that an estimate of future abandonment costs cannot be made until abandonment is reasonably foreseeable *[Ex. C-10-8B, NEB-EPI-1.1]*.

4727. The proposition is a basic one: If the end of the economic life of a facility cannot be reasonably foreseen -- if the abandonment date is indeterminable -- then one simply cannot make a reasonable estimate of the abandonment costs.

4728. It is also submitted that no pipeline should be required to commence collection of abandonment funds until certain key elements or details are resolved. I will comment further about those details in a moment.

4729. However, once the details were ironed-out -- which, admittedly could take some time -- perhaps a couple of years *[1T621; 2T1175-78]* -- then all NEB-regulated pipelines would be required to begin collecting abandonment funds unless the Board were to approve deferral of collection for any one of them.

4730. The opportunity for pipeline companies to seek deferral is essential to the flexibility that is inherent in the sort of robust policies and processes that this Board makes a habit of implementing and Enbridge views it as a fundamental aspect of its position in this proceeding.

4731. I will more fully address the deferral proposal shortly. However, I should first explain what Enbridge means when it says that there are certain key elements that must be in place before any abandonment fund collection begins.

4732. **Key Elements**

4733. Be clear, this isn't about manufacturing excuses for postponing appropriate collection.

4734. It is, instead, about ensuring efficiency and establishing the framework and basic rules that are necessary to ensure appropriate treatment of the funds once they start coming in the door in amounts that could easily total multiple millions of dollars.

4735. Enbridge does not support collecting nominal amounts -- of which I will say more later -- but even nominal collections should not begin in a vacuum.

4736. The following are the key elements requiring resolution before any

collection of abandonment funds should begin:

4737. **Technical Assumptions About Abandonment**

4738. Unless nominal collections were to be imposed, then it would be necessary for the Board to provide direction as to the appropriate abandonment standard. Otherwise, it would not be possible for pipeline to develop a reasonable estimate of the amount of abandonment funds to be collected. *[1T355]*

4739. **Tax Treatment**

4740. There is a strong consensus among the parties that it is status quo vis-à-vis taxation of abandonment funds -- including initial contributions and interest or other investment returns -- is highly inefficient and ought to be revised. *[See, for example: 1T600-03; 2T1032; 2T1530-34; 3T2425-27; 4T3249-59; 4T3451-53; 4T3462-64; 4T4255-57]*

4741. Enbridge submits that it would be much better if collection of abandonment funds were to await the necessary changes to the *Income Tax Act*. If not, a significant portion of the amounts collected from shippers would not go to paying abandonment costs but to paying taxes instead. *[5T4418-20]*

4742. By the way, Enbridge shares the view -- expressed by CAPP and perhaps others -- that the Board has an important role to play in at least framing the relevant issues for the Department of Finance, and, more importantly, in highlighting the public interest aspects of the problem. *[5T4424]*

4743. The pipeline industry has already initiated, and continues to actively pursue, efforts to secure the legislative amendments that would be necessary to address the income tax issue, but the Board is encouraged to lend as much assistance as it is able in that regard.

4744. **Approach to Segregating and Maintaining the Funds**

4745. Again, there would appear to be agreement among the parties that some sort of trust would be the optimal solution for segregating and maintaining abandonment funds collected from shippers.

4746. Therefore, collection should not begin until the basic trust structures and principles are established. Access to funds, trust governance and development of the trust indentures would be important issues in this respect. *[1T605]*

4747. Simply stated, abandonment funds should not be collected from shippers

until at least the principle rules about how the funds are to be held, who can access them and under what circumstances, are established.

4748. **Investment Policy and Guidelines**

4749. It would make little sense for abandonment funds to be collected if they could not then be prudently invested. Better to avoid the associated opportunity costs by leaving the monies in the hands of the shippers; therefore, investment policies and guidelines should be approved by the Board before any collection begins. *[1T605]*

4750. **Updating, Monitoring and Reporting**

4751. And finally in the list of key elements, the processes for updating, monitoring and reporting by each pipeline under the direction and oversight of the Board should also be in place before any monies are collected from shippers. *[1T606]*

4752. Among other things, those processes would facilitate transparency for landowners and shippers, who will, naturally, be interested in knowing that abandonment funds are being collected in appropriate amounts and being properly handled.

4753. **Collection Deferral**

4754. The next topic to be addressed is that of collection deferral.

4755. I suppose that it can be said that the Enbridge proposal that pipeline companies be permitted to seek deferral of abandonment fund collection has attracted a fair amount of attention.

4756. It is, as I have already stated, a fundamental aspect of the Enbridge position in this proceeding. I submit that it is also reasonable, practical and responsible.

4757. Here, in a very summary fashion, is what Enbridge proposes:

4758. All pipelines that are regulated by the Board should be required to collect abandonment funds unless the NEB were to approve deferral of collection. *[1T259]* In essence, abandonment of the relevant pipeline facilities would be presumed to be reasonably foreseeable, unless deferral were to be approved. *[Ex. C-10-3B, A3a (p. 8)]*

4759. As Enbridge sees it, a “blanket” deferral would not be available; rather

deferral of abandonment funds collection would only be granted by application on a pipeline-by-pipeline basis.

4760. The Board could approve collection deferral if it were to be satisfied, on the balance of probabilities, that the expected life of a specific facility is of such duration that the time of abandonment is not reasonably foreseeable.

4761. An abandonment event that could reasonably be expected to occur within a time horizon established by the NEB would be reasonably foreseeable by definition. The Board would establish that time horizon pipeline by pipeline *[2T1028]*, based on a consideration and appropriate balancing of factors such as the length of collection period that would be necessary to avoid adverse impacts (such as rate shock) on toll payers; intergenerational equity; the risks of over-collection or under collection; opportunity costs in relation to other, potentially more productive, uses for the capital; and the competitive landscape. *[Ex. C-10-8B, NEB-EPI-1.8 (b)(d)]*

4762. Any deferral that the Board may approve would likely not be indefinite. Rather, if a deferral were to be granted in respect of any particular facility, it would most probably be for a specified period. Further, all aspects of the deferral -- including the length of the deferral period -- would be subject to periodic and routine review by the Board.

4763. You will know that deferral of abandonment fund collection is opposed by certain parties for basically three reasons:

4764. First, there is the suggestion that deferral would create intergenerational inequities.

4765. Second, some argue that the risk of under collection would be increased if collection were to begin later.

4766. Third, some other of the pipeline -- some of the other pipeline companies -- excuse me -- raise concerns that deferral would cause competitive advantages and disadvantages.

4767. Let me address each of those arguments in turn, beginning with intergenerational inequity.

4768. **Intergenerational Inequity**

4769. As Dr. Mansell explained, intergenerational equity is only one of the many principles for which this Board has regard in determining just and reasonable rates. Further, although the concept of intergenerational equity may be, as Dr. Mansell put it

in his testimony, attractive at a high level, it's not quite so clean and neat when it comes to putting it into operation. *[1T787]*

4770. Intergenerational equity and several of the other issues arising from the criticisms of the deferred collection option are addressed in detail in the Wright Mansell Report. Rather than reiterate that discussion, that I will simply commend the report to you. *[Ex. C-10-12B, Appendix "A"]*

4771. There are also many elements that must be addressed in assessing the possible impact of collection deferral on intergenerational equities. One of those would be a comparison of the length of the proposed deferral versus the expected economic life or time arising of this facility in question.

4772. Dr. Mansell put it this way:

> *"...it really depends on what specific time horizons we're talking about, because it makes a big difference whether it's 20 years or it's from zero to 20 years, 20 to 40 years, 40 to 60 years.*
>
> *If, in the context of 60 years, it's a deferral of five years, the implications in terms of many things; toll impact and any intergenerational equity issues is much smaller. [In some cases] it's almost insignificant..." [1T786]*

4773. Further, intergenerational equities cannot be gauged in the abstract.

4774. For example, the existing toll structure may be front-end loaded -- such that current shippers would bear more of some of the costs of service than later shippers. *[1T788]*

4775. Mr. Curry of Westcoast cited return on rate base as an example. *[3T2884]*

4776. Mr. Robertson of Pouce Coupé also recognized that there are many elements, other than abandonment costs, that affect the intergenerational equities of tolls. *[3T2364]*

4777. Similarly, it must be recognized that over-collection from early shippers could itself be inequitable. Commencing collection before abandonment is reasonably foreseeable can make the estimates of abandonment timing and abandonment costs even more speculative and less reliable for toll purposes. *[Ex. C-10-8B, NEB-EPI-1.8 (d)]*

4778. As Dr. Mansell pointed out, in such circumstances, intergenerational

equity may suggest that the cost of abandonment should be collected from later shippers and not the earlier shippers that are already carrying the front-end load. *[1T788]*

4779. Nor should it be blithely assumed that the shippers on the system would change during the deferral period. *[1T793]*

4780. Finally, for the reasons given by Dr. Mansell, an abandonment funds surcharge is unlikely to be of sufficient magnitude to impact any intergenerational equity or inequity that may already exist. *[1T794]*

4781. In that regard, it is noteworthy that the Kinder Morgan evidence regarding the magnitude of the abandonment charge that it calculated in respect of its Vancouver jet fuel pipeline (being between 22 percent and 50 percent of its annual revenue requirement) *[2T1496-1497]* confirms the reasonableness -- one might say the conservativeness -- of the assumption in the Wright Mansell analysis that abandonment costs might roughly equal a pipeline's annual revenue requirement. *[Ex. C-10-12B, Appendix "A"; 2T1186-88]*

4782. All of this suggests that it would be quite wrong for the Board to make an a priori assumption, as parties such as Kinder Morgan and TransCanada would have it do, that a deferral of collection of abandonment funds will inevitably lead to intergenerational inequities. Or, if it did, that the inequities would be of such a degree as to make the resulting tolls unjust or unreasonable.

4783. The proper approach would be to consider the question of intergenerational equities on a case-by-case basis, if and when deferral applications were to be made.

4784. The response about the risk of under collection is next.

4785. **Risk of Under Collection**

4786. Some parties argue that deferring collection of abandonment funds will exacerbate a risk of under collection -- in part because, in their view, a shorter collection period will increase the magnitude of the annual collections that are required and, thus, the prospects for rate shock, et cetera.

4787. Kinder Morgan appears to go furthest by asserting that allowing parties to defer collection would lead to a greater risk that abandonment funds would not be collected because collection may occur in periods of shipper distress. *[Ex. C-15-9B, at p. 3]*

4788. Kinder Morgan also worries that what it calls a "truncation" of the economic life of a pipeline facility -- perhaps as a consequence of political developments, would mean that insufficient monies would be available to pay for facility abandonment. *[2T1484]*

4789. I submit, with respect, that these are simplistic and impractical views that ought to carry very, very little weight.

4790. As Dr. Mansell explained:

> *". . . [T]here is a fairly long period of time . . . in terms of the life of most pipeline systems.*
>
> *What we're asking is when you shorten or lengthen time periods what is the . . . impact on the risk and is that impact material; technically yes, if you shorten the time period by definition there is fewer years. Does it materially affect the risk relative to the other issues that are involved or other issues that determine risk?*
>
> *So [Enbridge's] answer is it depends. It depends on whether you're shortening it from 20 years down to five or whether you're shortening it from 50 years down to 35 years, for example." [1T635-637]*

4791. Of course, Enbridge is not advocating that the Board should approve a deferral of collection that would result in anything like a reduction of the collection period from 20 years to 5 years.

4792. There are two other critical points to keep in mind when considering this question of whether immediate collection is necessary:

4793. First, collections that stretch over lengthy periods wouldn't come free of charge -- so to speak.

4794. In fact, not only must the administrative costs and burden arising from prolonged collection be accounted for, it must also be recognized that there could be very significant opportunity costs when alternative, potentially more productive, uses for the monies collected are considered. *[1T653-54; Ex. C-10-8B, NEB-EPI-1.8 (d). See also Ex. C-10-12B, Appendix "A"]*

4795. It should not be presumed that any compounding of returns on the abandonment funds would offset those opportunity costs. *[4T3294; 4T3491]*

4796. Second, as I've already said -- but this point bears emphasizing -- the Enbridge proposal is not for indefinite deferral. The Board would have ample opportunity to revisit the appropriateness of the deferral period.

4797. Enbridge, for one, is completely confident in the Board's ability -- in the context of these periodic reviews and adjustments and with the use of appropriate checks and balances -- to ensure that a deferral would not lead to a greater risk that abandonment costs could not be recovered from shippers. *[1T809]*

4798. Once again, those parties that oppose the concept want this Board to assume that a deferral of collection of abandonment funds will increase the risk of under collection. The expert evidence of Dr. Mansell supports the opposite conclusion.

4799. In any event, Enbridge respectfully submits that the far better time to consider that question would be in the context of a deferral application if and when one were to be made.

4800. This is probably an opportune point at which to suggest that the Board should take considerable comfort in the fact that -- as explained in the Westcoast Written Evidence *[Ex. C-22-3, at pp. 2 ff]* -- the applicable accounting standards *[As reflected in the relevant sections of the CICA handbook and the International Accounting Standards]* require pipeline companies to properly account for asset retirement obligations.

4801. This means, among other things, that the companies are required to assess on an annual basis whether to recognize such liabilities and, if so, their fair value. *[Ex. C-22-3, at p. 2]*

4802. Compliance with such requirements is a matter that is subject to verification by independent financial audit. This is yet another layer of important protection against the risk that deferral would result in a collection shortfall.

4803. **Competitive Impacts**

4804. Turning last to the concerns expressed about collection deferral creating competitive advantages or disadvantages, Kinder Morgan is the principal advocate of that position, but TransCanada voices similar sentiments and urges vigilance on the part of the Board against setting up mechanisms under which there would be differences between appliance transporting similar products under similar circumstances in terms of the timing for commencement -- commencing collection of abandonment funds. *[4T3442]*

4805. Enbridge offers several responses on this point.

4806. First, competition issues would be one of the factors that the Board could consider in its assessment of any deferral application that it may receive.

4807. Kinder Morgan says that it would object to commencing collection of abandonment funds if its competitors were not required to do so. *[2T1704-05]*

4808. That may mean that Kinder Morgan would oppose some, or perhaps all, deferral applications, in which case the Board could have the benefit of its views about competitive impacts in "live" cases.

4809. Now, at the risk of testing the Board's patience, I will say for a third time that the Board ought not to be making *a priori* assumptions; in this instance, that deferral of collection of abandonment costs would automatically translate into adverse competitive impacts upon other pipelines.

4810. Kinder Morgan and TransCanada are asking you, Madam Chair and Members, to do exactly that.

4811. Second, the option of deferral would be available to any pipeline that may choose to pursue it. Moreover, the expected economic lives of competing pipelines will likely be of similar length such that their abandonment fund collection could begin more or less contemporaneously. *[Ex. C-10-8B, NEB-EPI-1.8 (d); 3T2133-34]*

4812. Third, even if all pipelines were to be required to begin collecting abandonment funds at the same time, that would not mean that they would be collecting them in the same amount.

4813. Each pipeline's particular circumstances, including the nature of the relevant facilities and the period of collection, et cetera, would mean that there could be dramatically different abandonment costs being collected one pipeline to the next. *[1T772-73]*

4814. Finally, there are many factors other than abandonment cost surcharges that would impact the competitiveness of pipelines, including their vintage, cost structure, toll structure and resulting tolls. *[1T776-77]*

4815. The existence or not of an abandonment surcharge in a pipeline's tolls would, at most, be a small factor in determining which barrels or gigajoules move on which pipelines. *[1T809]*

4816. In summary, Enbridge submits that none of these concerns, whether they

be about alleged intergenerational inequities, supposed risks of under collection or hypothetical competitive dislocations, should dissuade the Board from endorsing the Enbridge proposal that pipelines be able to seek deferral of abandonment fund collection in appropriate circumstances.

4817. **The technical assumptions that should be used to create preliminary cost estimates**

4818. The list of issues for this Stream 3 proceeding includes the question of what technical and financial assumptions should be used to create preliminary cost estimates.

4819. Clearly, however, that does not mean that this is either the place or the time to resolve how pipelines should be abandoned. That should happen in Stream 4 of the LMCI process, in which Enbridge is participating actively and in good faith.

4820. As explained in the Enbridge Written Evidence, Enbridge is hopeful that the Stream 4 process will yield useful guidance respecting the technical assumptions that should be made for purposes of estimating future abandonment costs. *[Ex. C-10-3B, A2a (p. 6)]*

4821. In any event, Enbridge is of the view that the Board ought to provide the pipeline companies that it regulates with direction as to what it considers to be the appropriate form of abandonment. *[1T433]*

4822. Preferably, any such direction would be informed by analysis and discussion and guidance emerging from Stream 4.

4823. The immediate question is whether any technical assumptions should be made in the meantime. Enbridge says, "No." As the CAPP witness, Mr. Jardine, said in his testimony on Monday, we have an opportunity to get this right and get a practical solution. *[5T4512]*

4824. There should be no unnecessary or inordinate delay, but neither should there be a rush to start collecting abandonment funds. Remember that not one of the pipelines that participated in this proceeding has yet recognized a liability for asset retirement obligations on its financial statements. *[2T1601-02; 3T2117-18; 3T2545; 4T3220-21]*

4825. This should be taken to mean that none of them can make a reasonable estimate of that liability, because the timing of abandonment is not yet determinable. *[Ex. C-22-4A, NEB-WEI-1.1 (a); 2T1580-1590; 2T1604; 3T2111-12; 3T2919-20; 3T2921-24; 3T3008-09; 4T3223-24, 3229]*

4826. As I mentioned previously, Enbridge recommends against the Board requiring pipelines to begin collecting abandonment funds from their shippers before the Stream 4 process results in useful guidance regarding the appropriate method of abandonment.

4827. However, if that recommendation were to be rejected, then Enbridge proposes that abandonment in place should be assumed, but only for the short-term purpose of facilitating estimation and collection of abandonment funds in the meantime.

4828. I recognize that CAPLA has made a different recommendation -- its default option. However, Enbridge is convinced that its proposal is the most practical in the circumstances and especially if collection of abandonment funds were to commence in advance of any resolution of the income tax issues to which I alluded earlier. *[1T434-36]*

4829. **Nominal Collection**

4830. I mentioned before that Enbridge is opposed to the notion of nominal collections. Let me explain why.

4831. The idea of NEB-regulated pipelines collecting some nominal amount of abandonment funds is promoted by TransCanada.

4832. The basic rationale, so far as I can understand it, is that TransCanada believes it to be important that it and the rest of the pipeline industry be seen by landowners to be taking a concrete step toward addressing the issue of pipeline abandonment. *[4T3289]*

4833. The problem, though, is that, as even TransCanada admits, a nominal collection amount by its very nature is not cost-based and would bear no relationship to reality, or at least not to actual abandonment costs or timing. *[4T3290]*

4834. Indeed, it must be acknowledged that, especially for pipelines with very long expected economic lives, like those that comprise the Enbridge system, a so-called nominal collection, say, in the order of one-half to one percent of overall revenue requirement as mooted by TransCanada, could in fact be excessive.

4835. There is also the potential problem identified by CAPP that a nominal collection could undermine the vital goal, which landowners share, of establishing a tax-efficient collection framework. *[5T4630-33; 4T4255-57]*

4836. Tax-efficient treatment of abandonment fund collection is of such critical importance that the Board should be extra cautious to avoid anything that might imperil that objective. Moreover, a nominal collection may do little to convince landowners of any real progress on the pipeline abandonment file.

4837. Nominal collection looks and feels to Enbridge like a rush to collection simply for collection's sake. As I observed a moment ago, Enbridge is firmly of the view that this is something that must be done right -- not in a rush.

4838. **"Pooling" or an "Orphan Pipeline" Fund**

4839. Issue 5b on the Board's list asked, "Should a portion of the funds be pooled for use across industry?" and an orphan pipeline fund was given as an example.

4840. The answer provided in the Enbridge written evidence was "no." Each pipeline company is responsible for abandonment of its individual facilities and therefore each pipeline company should collect and set aside its own abandonment funds.

4841. Pooling of funds for use across industry could result in cross-subsidization among pipeline companies and by shippers on distinct facilities. *[Ex. C-10-3B, A5c (p. 9). See also 1T856-96 and 1T939-976]*

4842. Nothing that it has heard in this hearing has caused Enbridge to change its mind on this issue and indeed it would appear that the opposition to pooling is universal among the pipelines and their customers. *[See, for example, Ex. C-2-4, at p. 11]*

4843. The thought of pooling abandonment funds seems to have sprung from concerns, one, about the so-called residual risk, the risk that pipelines will collect insufficient funds to pay all of the abandonment costs that they must incur; and two, concerns about orphan pipelines.

4844. However, the only reasonable conclusion that can be drawn from the evidence in this proceeding is that although it could be recognized on some theoretical or hypothetical level *[1T356-58; 1T686-89; 1T710-13]*, the residual risk would be so small as to be virtually non-existent. *[1T714-15; 2T1793-97; 3T2259-60; 3T2736-38; 4T3333-34]*

4845. CAPLA takes the position that steps must be taken to eliminate the risk to landowners irrespective of the cost and impact that taking those steps might have on pipelines and their shippers. *[4T4000-01]*

4846. With the greatest of respect, that position is neither reasonable nor practical.

4847. Enbridge accepts that it is impossible to eliminate all risk. However, the minute residual risk that concerns us here most certainly does not provide sufficient cause for the Board to require some pooling of abandonment funds, even on what was described as a portion of the funds basis.

4848. The same can be said for the suggestion that pipeline companies contribute to some sort of orphan fund. *[2T966-68]*

4849. You may recall that Mr. Hrynchyshyn put it this way:

> *"Enbridge's view is that it's not -- simply not practical to 100 percent eliminate that risk and, therefore, we don't have anything practical to put in -- to suggest as being put in place to 'guarantee' that.*
>
> *Again Enbridge's view is that an adequately designed, appropriately designed process with sufficient oversight and governance will reduce that risk and achieve the outcome that stakeholders want out of this process." [1T697-98]*

4850. CAPP offered a similar perspective stating that:

> *"It is not reasonable for toll payers to fund each and every possible outcome however remote." [3T2082]*

4851. As Enbridge would envision them, the processes of calculating, collecting and managing abandonment funds would be subject to close scrutiny by the Board as well as a governance and reporting regime that itself would require Board approval. *[1T606]*

4852. Among other things the estimates of abandonment costs would be reviewed by, and updated for, the Board on a routine basis. *[1T676; 1T814-15]*

4853. The same would be true in respect of the amount of funds collected and the investment performance. *[1T675-76]*

4854. The investment policy and guidelines would also be subject to Board approval and could, for example, dictate varying risk profiles over time, with more conservatism being required as abandonment approached. *[2T1121-26]*

4855. Finally, in the highly unlikely event that all of these measures were to fail, then at least in the Enbridge case the company would be there to backstop any hypothetical deficiency that may occur. *[1T474]*

4856. It may be possible to invent scenarios in which, for various reasons, such a backstop would not be available. However, in my respectful submission, it would be unreasonable for the Board to see that as a realistic possibility in all but the rarest of cases.

4857. As to the concerns that orphan pipelines -- concerns about orphan pipelines -- excuse me -- Enbridge returns to its response to NEB-Enbridge 1.6. *[Ex. C-10-8B]*

4858. Given that all pipelines under NEB jurisdiction would be subject to the same regulatory requirements and oversight, there should not be any orphan pipelines. *[See also Ex. C-2-7B, NEB-CAPP-1.8 (a)]*

4859. One important reason is that under the Enbridge proposal and with the exception of those for which collection deferral is approved, all pipelines would be required to begin collecting abandonment funds in the relatively near future. That collection would be based on proper assumptions, as approved by the Board, about matters such as the timing, method and cost of abandonment.

4860. Those assumptions would be periodically reviewed and updated and the abandonment fund collection requirements for each pipeline would be adjusted accordingly. The alarm bells would be ringing long before any pipeline could become an orphan.

4861. **Conclusion**

4862. I conclude by offering the assurance that Enbridge appreciates the difficulty of the task that is facing the Board in this proceeding. The issues are nearly as complex as they are important.

4863. Through its participation in this process Enbridge has endeavoured to assist the Board in its efforts to find fair, efficient, and practical solutions to those issues.

4864. The best solutions will be those that are flexible because they will then be sufficiently robust to work in the unique circumstances that relate to each of the many different pipelines that are subject to the Board's jurisdiction.

4865. Those are my submissions in-chief.

4866. I thank you, Madam Chair and Members, for your patience and attention, but I would be pleased to answer any questions you may have.

4867. **THE CHAIRPERSON:** Thank you, Mr. Crowther.

4868. The Board has no questions of you.

4869. **MR. CROWTHER:** Thank you, Madam Chair.

4870. **THE CHAIRPERSON:** Thank you for your submissions.

4871. I call next on the list Imperial Oil Resources.

--- (No response/Aucune reponse)

4872. Kinder Morgan Canada…?

--- FINAL ARGUMENT BY/ARGUMENTATION FINALE PAR MR. FORRESTER:

4873. **MR. FORRESTER:** Good morning, Madam Chair, Board Members.

4874. In this Stream 3 hearing, the Board has asked industry, shippers, landowners how it should deal with the financial aspects of pipeline abandonment.

4875. In essence, the Board has asked what is the most efficient and effective method of ensuring sufficient funds are available to properly abandon pipelines when abandonment occurs in time and over time, or how should we deal with the financial risk surrounding pipeline abandonment.

4876. The difficult task for the Board will be to balance the competing interests of industry, shippers, landowners, other stakeholders that are not present in this hearing and the public interest. The good news is that most participants in the hearing have demonstrated a general consensus from which planning may start.

4877. Points of consensus include, number one; landowners should not be liable for the financial cost of abandonment. The risk is to be borne by shippers.

4878. Number two; abandonment is based upon the economic life of any pipeline, which is based upon a number of complex factors which are not currently

known to any degree of certainty.

4879. Three; despite the economic life being uncertain it is reasonably foreseeable that there must be financial funds set aside to deal with abandonment when it occurs.

4880. Number four; the collection of funds ought to start in a timely manner.

4881. Number five; there must be an appropriate mechanism to ensure that the funds are collected in the most tax efficient manner.

4882. Number six; there must be an appropriate mechanism to deal with ensuring the funds are both transparent and available for any eventual abandonment, with a broad consensus developing around the implementation of a trust fund.

4883. Number seven; the funds set aside must be managed in a prudent and conservative manner to ensure sufficient money is ultimately available for abandonment.

4884. And number eight; the pooling of funds poses a significant risk of moral hazard and may lessen the motivation of participants to properly and adequate assess abandonment costs and to take necessary steps to collect those costs.

4885. While there has developed a broad consensus in relation to when the collection of funds should commence there are extremes.

4886. One party urges the Board to commence immediately, based on the highest cost option available to removal all degree of risk from landowners, regardless of whether or not this is realistic or practical.

4887. Another proposes collection should occur when abandonment obligations must be placed on a company's accounting books as an asset retirement obligation; and the third takes the position that no funds should be collected at all until the end of the life is eventually reasonably foreseeable.

4888. On the issue of timing of collection, Kinder Morgan agrees with the majority of the industry participants that collection ought to occur in a timely manner, which means sooner rather than later.

4889. As we've heard time and time again, there is no current imminent material risk that any of the federally regulated pipelines will become uneconomic in the immediate future.

4890. We have also heard that most industry participants are of the view that they'll require approximately 18 to 24 months to complete Stream 4, determine reasonable estimates of abandonment costs, and ensure the appropriate trust mechanisms are in place after the completion of the Stream 3 hearing process.

4891. While the approach does not fall on either end of the extremes, it is a reasonable timeframe, we submit, to ensure the Board's ultimate goal, that commencement of collection to ensure funds commences and will ensure that there are funds to deal with abandonment.

4892. Because abandonment can be dealt with in a timely manner, as proposed by -- Kinder Morgan is of the view that an interim notional or nominal collection is not appropriate.

4893. It is by definition arbitrary; and indeed, we have heard evidence that it will raise immediate concerns regarding administering the funds, reporting on the funds, effecting existing settlements and contracts, and will potentially remove the urgency of having the Department of Finance consider any tax consequences or changes.

4894. On the risk and reward issue, while there's much consensus, there was also some divergent views. One participant took the position that they should receive any surplus funds for the pipeline company; another was of the view that the risk sits with the pipeline company and should be dealt with the way -- should be dealt with in the accounting way.

4895. Kinder Morgan supports the middle position that was endorsed by most participants that abandonment funds are a proper cost of service, properly recoverable by a pipeline company from shippers. And if it is a cost of service that is being recovered, any surplus is to the shipper's account.

4896. Although to be clear, Kinder Morgan is of the view, as are most participants, that a proper initial estimate for collection, with yearly reviews, and more frequent reviews as abandonment becomes imminent, makes any risk of over or under collection remote.

4897. On deferred collection the issue is that if the Board sets up a mechanism to allow one pipeline to defer its collection, the Board may in fact indirectly be forcing another pipeline company, similarly situated, to apply for a deferral in order to remain competitive in the marketplace.

4898. If there is a significant toll differential resulting from such a deferral, this would change the competitive balance between the companies and may force other companies to apply for a deferral, which, in turn, would defeat the purpose of

handling abandonment funds collected in a timely manner.

4899. Upon considering the issues where the parties agree and where the parties disagree and after careful consideration of the issues discussed in this hearing, Kinder Morgan proposes that the Board consider the following in any elements of its order that arises from this particular hearing:

4900. Number one; that abandonment funds are a legitimate cost-of-service and sufficient funds must be available to effect abandonment.

4901. Number two; such funds are a mandatory, regulatory requirement, payable over and above any settlements or contracts and that the most transparent method for collection of these funds, supported by most participants, is a surcharge, in addition to pipeline tolls, where they're set by contract, incentive agreements or other settlements.

4902. Number three; that pipeline companies be given a reasonable period of time during which to propose reasonable and supportable estimates regarding abandonment costs.

4903. They should follow the conclusion of Stream 4 which we propose be included in a timely manner following which each pipeline would be required to submit estimates based upon the principles established by the Board, for the Board's approval.

4904. Given the parties' submissions in this hearing, a realistic target for estimates is in the realm of 24 months from the issuance of this hearing's order.

4905. Number four; Stream 4 should also include a consideration of, and ultimately a setting out of, the regulatory framework for annual review of estimates and further refining of estimates as the asset approaches actual abandonment.

4906. Number five; for Group 1 pipelines a trust mechanism should be developed by the end of the 24-month period, such that funds can be set aside in trust for abandonment of the particular pipeline asset in question, and administrative details can be agreed upon, with input from industry.

4907. Abandonment collection should be over and above current tolls and this matter will need to be addressed in current settlements.

4908. Number six; Group 2 pipelines should develop a recommended mechanism to deal with the above issues which may include opting into the Group 1 trust mechanism. This will deal with pipelines, such as Kinder Morgan's Express

Pipeline, which may wish to opt into Group 1 mechanism, as it will already have the administration and methodology set up for that particular issue.

4909. Number seven; the NEB should support the tax efficient treatment of abandonment costs, and we propose it should strike a working committee composed of a number of the participants in this hearing to work towards securing the treatment in the next 24 months.

4910. Number eight; the NEB, we propose, should set out a regulatory framework for the oversight of the trust mechanism, including reporting and an application requirement to assess the funds.

4911. Landowners and other stakeholders should have an opportunity for involvement and input into the Board processes, developing for assessing its efficiency and administration of funds and the prudent management of funds.

4912. And finally, we propose that the Board issue a draft proposal regarding these issues and give all of the stakeholders an opportunity to comment.

4913. Kinder Morgan would like to take this opportunity, specifically to thank the Board, industry colleagues, CAPP and CAPLA for its respectful and helpful discussion of what Kinder Morgan deems to be a very important issue and we look forward to working towards a workable and practical solution with all parties.

4914. Those are our submissions.

--- (A short pause/Courte pause)

4915. **THE CHAIRPERSON:** Thank you for your patience, Mr. Forrester. The Board has no questions of you.

4916. **MR. FORRESTER:** Thank you.

4917. **THE CHAIRPERSON:** Thank you.

4918. Pouce Coupé Pipe Line Ltd. ...?

--- FINAL ARGUMENT BY/ARGUMENTATION FINALE PAR MR. JEFFREY:

4919. **MR. JEFFREY:** Good morning, Madam Chair, Members of the Board. These comments in final argument are presented on behalf of Pouce Coupé Pipe Line Ltd.

4920. I did hand a copy of these remarks to the hearing reporter already with the usual request that even though I do not orally refer to the various headings, citations, and references to the record that are contained in the version I handed over, that those be included in the transcript.

4921. This hearing was convened to address financial issues related to pipeline abandonment *[Ex. A-1, p. 1]* and not to address whether any particular method of abandonment ought to apply to all pipelines in all circumstances.

4922. This panel is considering measures to avoid landowners being left with any of the costs that arise at or after the time of pipeline abandonment.

4923. Pouce Coupé's positions on each of the issues the Board has framed are set out in its direct evidence *[Exhibit C-19-5]* and I do not propose to repeat those here. Rather, my submissions will focus on the following specific items:

4924. First, the Board's jurisdiction;

4925. Second, who should collect funds and how;

4926. Third, how funds should be retained;

4927. Fourth, the discussion around pooling of funds, surpluses, deficiencies;

4928. Fifth, accessing the funds;

4929. Sixth, taxation; and

4930. Seventh, implications of existing easement terms.

4931. So let me deal with each of those in order.

4932. **NEB jurisdiction to order a toll surcharge** *[This responds to Issue #7 on the NEB's list of Issues. Ex. A-8A, p.8]*

4933. First, your jurisdiction to order a toll surcharge. Now, you do have a broad discretionary power to determine tolls that pipeline companies may charge shippers. This includes collecting tolls in respect of future abandonment activities. *[Trans Mountain Pipe Line Co. v. Canada (National Energy Board), [1979] 2 F.C. 118 (Fed. C.A.); TransCanada Pipelines Ltd. v. Canada (National Energy Board), 2004 FCA 149]*

4934. And this arises under Part IV of the *NEB Act*, specifically within the broad power to determine a just and reasonable toll under section 62, and the even more comprehensive power in section 59 to, and I quote:

"*...make orders with respect to all matters relating to ... tolls...*"

4935. So I would suggest there can be no doubt that the Board has the power to require its inclusion in tolls and thereby its collection.

4936. The more interesting question is whether the Board can dictate what a company does with the money after its collection.

4937. I would suggest to you there are limitations on your ability to do that, but not in this case with respect to abandonment. In our view, the Board does enjoy this power, at least insofar as it pertains to directing that such funds be deposited into an abandonment trust fund or segregated account and setting any necessary terms of such trusts.

4938. Now, in our view, you have that power pursuant to your comprehensive jurisdiction described in section 12 *[s. 12(1)(b), See Schedule A]* in conjunction with your express statutory responsibility over both pipeline abandonment -- and there I'd refer you to sections 49 and 51.1 *[See Schedule A]* -- and from section 59 that I referred to, "all matters relating to...tolls" *[NEBA, s. 59]*.

4939. The NEB does not, however, have jurisdiction to oversee any pooled funds, at least not that we can ascertain from the *National Energy Board Act*. That would include matters such as managing an orphan fund or to direct residual or surplus funds flow anywhere outside the scope of the Board's existing jurisdiction.

4940. Pouce Coupé also notes that, contrary to the apparent assumption of some through this process, the NEB does not necessarily lose jurisdiction over a federal pipeline after an abandonment order is effective.

4941. Now, Madam Chair, I had not planned to elaborate on that further, but I'd be pleased to do so if you wish.

4942. **THE CHAIRPERSON:** We are interested in hearing more, but we don't want to disrupt the flow of your presentation.

4943. **MR. JEFFREY:** I'd rather be disrupted.

4944. **THE CHAIRPERSON:** Okay. Well, we'd like to hear more. Thank you.

4945. **MR. JEFFREY:** Jurisdiction, of course, has two elements in this context. The first is whether you have constitutional jurisdiction, and that I would not expect is in any doubt.

4946. The second aspect of jurisdiction is what is in question: Has Parliament, in fact, given you that authority under the *NEB Act*, and, specifically, the authority to deal with matters of abandonment after you have granted leave to abandon or after an order for abandonment takes effect.

4947. And so here I would refer you to -- actually, I do have some excerpts from the Act, if that would assist you. And what I've done is I've excerpted sections 12, 49 and 51.1, and the point of doing this is really to -- section 12 is this more umbrella jurisdiction that you enjoy, and it's with respect to things that are found elsewhere in the act. The powers that you enjoy are under section 12.

4948. So then it takes us to 49 and 51.1. And if you notice the wording in 49(2), here we're dealing with the powers of an inspection officer:

> *"For the purpose described in subsection (1), an inspection officer may at any reasonable time have access to and inspect any lands or pipeline, including a pipeline that is under construction or -- past tense -- has been abandoned,"* (As Read)

4949. So after abandonment, you continue to have jurisdiction. And I would suggest that same sense is inferred from section 51.1, which I've also underlined the operative words, and this is:

> "*If the ... officer has reasonable grounds to believe that a hazard to the safety or security of the public or of employees of a company or a detriment to property or the environment is being or will be caused by..."* (As Read)

4950. "Caused by" -- past tense, so in the future may be caused by a previous event.

> "*... the construction, operation, maintenance or abandonment of a pipeline, or any part of a pipeline;*" (As Read)

4951. So it's from those provisions that we certainly understand Parliament to be empowering you with the ability to deal with matters post-abandonment.

4952. Now, the Board did, in MHI-96 -- this is the matter relating to Manitou

Pipelines -- suggest that jurisdiction does end there, and I'll simply refer you to page 21, the paragraph near the top of the page that does say:

> "*The NEB will cease to exercise jurisdiction over the abandoned line as a physical pipeline within the meaning of the Act.*" (As Read)

4953. And, respect, I think that's incorrect. It is precisely in respect of the physical elements of a pipeline that the *NEB Act* has given you at least some jurisdiction by virtue of section 12. I think that is broadened; you can make orders of various kinds, you can make inquiries and determinations into matters post-abandonment.

4954. Moving, then, Madam Chair, if I may, to the second topic.

4955. **Who should collect funds and how?**

4956. Pouce Coupé supports collection through a toll surcharge. The surcharge is an open and transparent mechanism to collect money for abandonment costs. *[1 Tr. 225, para. 2; 2 Tr. 1513]* Such costs are legitimate life-cycle costs of providing pipeline service. *[1 Tr. 429; 2 Tr. 1466]*

4957. The surcharge would be calculated proportionate to a shipper's use of a particular pipeline system, in most cases, in keeping with proper cost causation rate principles, but vary pipeline to pipeline according to the unique circumstances of each. *[Ex. C-19-4, p. 4, q. 1(b); Ex. C-19-4, p. 8, q. 4(a)]*

4958. Pouce Coupé favours earlier rather than later collection, but recognizing, as has been said by those before me, that there are some necessary determinations to be made before collection can commence. But this would ensure that sufficient abandonment costs are recovered over a pipeline's economic life and minimize the toll impacts over that period.

4959. Pouce Coupé believes that earlier collection is more consistent with the principle of intergenerational equity and best protests landowners from liability. Also, later commencement means that a larger surcharge will be required at that later time. *[3 Tr. 2422]*

4960. Pouce Coupé supports conservative collection rates, *[for example, by possible front end loading]* and embedding conservatism in making technical assumptions; for example, by assuming that no new advances in technology occur before abandonment and that fund performances will remain low.

4961. Pouce Coupé believes that these measures will ensure that adequate money is available for abandonment.

4962. All pipeline companies under your jurisdiction should be required to set aside funds to cover costs associated with future abandonment activities. This approach protects all landowners equally against abandonment costs. *[Ex. C-19-4, p. 7, q. 3(a)]*

4963. It is also the approach that will least affect the competitive position of pipelines relative one to another.

4964. Westcoast suggested that its uniqueness warranted a form of exemption from any comprehensive direction. *[Ex. C-22-3, p. 3, para. 2]*

4965. It said this approach would hurt the competitiveness of its gathering and processing assets in relation to its provincially regulated competition. *[Ex. C-22-3, p. 6, para. 1; 3 Tr. 2592]*

4966. If the Westcoast approach were followed of delaying until the other level of government directed collection, it may never happen. One of the regulators needs to start; this is a leadership role that the NEB has played in the past. In any event, Westcoast conceded that it does in fact have NEB-regulated competitors. *[3 Tr. 2601; 3 Tr. 2605]*

4967. Finally in this regard, Westcoast requested its light-handed regime in order to have flexibility to compete with other gathering and processing undertakings. In our respectful submission, it should not now say that its light-handed regime prevents it from being competitive if the Board requires known future costs be set aside now.

4968. If anything, Westcoast will have a greater ability than other federally regulated pipelines to contend with any competitive implications of a surcharge being levied.

4969. Certain parties raised the possibility that the NEB could distinguish between Group 1 and Group 2 companies, or between the type of assets that are regulated, for example gathering and processing assets, when deciding whether to order parties to collect. *[CAPP and Westcoast]*

4970. With respect, these distinctions are unhelpful analytically to determine whether to collect and set aside money for abandonment purposes. In particular, Group 1 and Group 2 designations are used to distinguish between two approaches to financial regulation and reporting.

4971. Yet, both sets of companies are subject to comparable physical regulation and, in any event, crop lands traversed by Group 1 and Group 2 pipelines face comparable abandonment risks. Two classes of landowners ought not to be created on the basis of distinctions in pipeline financial regulation or reporting.

4972. Competition *[Reasons for Decision, GH-5-98, para. 293: "In addition to economic feasibility, however, there are other public interest considerations which have benefits and costs. In general, the public interest is served by allowing competitive force to work, except where there are costs associated that outweigh these benefits."]* and accounting principles serve the public interest *[4 Tr. 3606]*. They ought not to become its master.

4973. CAPP suggested that many Group 2 companies were not aware of this proceeding. *[5 Tr. 4452]*

4974. With respect, the Hearing Order was widely circulated among industry participants and they have had opportunity to participate but chose not to. In fact, many members of CAPP are Group 2 companies, and CAPP certainly knows about this proceeding.

4975. And, contrary to CAPP's assertions, many Group 2 companies are registered as interested parties in this proceeding; however, have chosen not to act actively participate in this dialogue. *[Ex. C-08-01 (BP Canada Energy Company); Ex. C-11-01 (EnCana Corporation)]*

4976. And so no further dialogue with Group 2 companies is necessary before collection should start. CAPP says these are large diverse companies with strong balance sheets. In effect, "they are good for it."

4977. Yet, it regularly asserts that pipeline utilities are less risky than producers. If CAPP is correct in that assertion, then there is greater reason to ensure Group 2 companies that are producers must set aside funds now. *[5 Tr. 4392]*

4978. Elevated to its highest, though, CAPP's request with respect to Group 2 companies is really a request for flexibility and we would suggest that can be accommodated. *[Ex. C-2-4, p. 5, 8.4]*

4979. Pouce Coupé believes that Group 2 pipelines should be subject to the requirement to plan for, collect, and set aside funds for abandonment. *[Ex. C-19-4, p. 5, q. 5(b)]*

4980. However, Pouce Coupé recognizes the variability in the attributes of many Group 2 pipelines under the Board's jurisdiction, and therefore recognizes that there

may be innovative approaches to the collection mechanism used, and the accounting, uses, access and reporting of funds collected for abandonment.

4981. Companies should be able to present these alternatives to the Board when they bring their system-specific forecasts forward, those forecasts to set the amount to be collected.

4982. So in Pouce Coupé's view, the Board should direct all pipelines to start payments to a fund and place the onus then on individual pipeline companies to, in effect, show cause for their particular case why they should be granted any administrative accommodation around perhaps the timing or the manner of collection.

4983. Moving then to the third subject of this set of closing remarks:

4984. **How should funds be retained?**

4985. Pouce Coupé supports placing money collected through toll surcharges in a trust account. *[Ex. C-19-4, p. 9, q. 5(a)]*

4986. Within each trust account, the funds would be segregated by pipeline system, *[Ex. C-19-4, p. 9, q. 5(a)]* although administered by the same trustee. The trustee would be able to invest all company funds together, to get economies of scale for investing and lower administrative expenses, while accounting for each pipeline system separately.

4987. A trust account is the only mechanism that protects money collected through toll surcharges from a pipeline company's creditors, in the event that scenario arises. *[1 Tr. 853]*

4988. Funds should be specific to each pipeline asset and not pooled across the industry so that in the event of a sale of a pipeline, the funds will follow the asset.

4989. The trustee would periodically report on, say, an annual or semi-annual basis, the amount of money collected in the period and the amount accumulated in the fund. This would have the effect of mitigating the prospect of over- or under-collection of funds.

4990. Moving to the fourth topic:

4991. **Pooling of Funds and Surpluses or Deficiencies**

4992. Pouce Coupé opposes pooling of funds across the industry. *[Ex. C-19-4, p. 9, q. 5(c); 3 Tr. 2379; 3 Tr. 2393]*

4993. It submits that pipeline companies should bear the risk associated with the performance of the trust account while shippers should bear the cost of intra-year collection of funds. *[3 Tr. 2252; 3 Tr. 2256]*

4994. In return for assuming the risk, any over-collection ought to be to the pipeline company's account. *[2 Tr. 1137; 3 Tr. 2383; 3 Tr. 2387]*

4995. Moreover, pooling would result in cross-subsidization and is contrary to the principle of individual responsibility for cost causation.

4996. During the course of the hearing the prospect was raised that surpluses from abandonment funds could be pooled so as to create a type of residual risk fund. *[2 Tr. 963; 2 Tr. 1078; 2 Tr. 1385-1386]*

4997. Pouce Coupé opposes the creation of such a fund. Transferring surpluses into such a fund, instead of surpluses reverting back to the pipeline company is only fair if pipeline companies will also be allowed to invoice past shippers for any fund deficiencies.

4998. Obviously that is not palatable or, more likely, even feasible. Neither should be the reciprocal loss of any surplus to pipeline companies.

4999. Pouce Coupé believes that mechanisms such as conservatism of assumptions, as already described, regular updates of preliminary cost estimates as end of life approaches *[Ex. C-19-4, p. 6, q. 2(b)]*, periodic reporting of fund performance and fund usage *[Ex. C-19-4, p. 10, qq. 5(a) and 5(b)]*, random spot audits *[Ibid.]*, existing compliance enforcement measures and periodic reviews of fund performance *[Ex. C-19-4, p. 10, q. 5(k)]*, are sufficient measures that mitigate any risk of under-collection of abandonment funds.

5000. Next, the fifth topic:

5001. **Accessing the funds**

5002. The distinction between Group 1 and Group 2 companies is of greater relevance here when applied to the way money is accessed from the fund. Pouce Coupé favours a light-handed regulatory approach *[3 Tr. 2334-2338]* at least in respect of Group 2 pipeline companies.

5003. This approach means that money should be available at the discretion of the company but obviously in accordance with the terms of the fund's constating documents, NEB oversight and existing regulatory requirements associated with

abandonment and decommissioning *[3 Tr. 2229; Ex. C-19-4, p. 10, qq. 5(a) and 5(c)]*.

5004. Pouce Coupé believes that, for administrative purposes, funds should be available without prior NEB approval because requiring NEB approval of every expense would create an undue administrative burden on pipeline companies and the Board *[3 Tr. 2237-2239]*.

5005. It would also be an unnecessary drain on the funds in the abandonment trust accounts. This is especially true given that abandonment will be a process, as other parties before you acknowledged, that takes place over time *[Exhibit C-2-4 at A2c; Exhibit C-26-4 at p. 3 of 21; 4 Tr. 3359]*.

5006. A light-handed approach would favour all parties to this proceeding; such an approach has been (successfully) implemented by the Board with respect to financial regulation of Group 2 companies, and that's since 1985 *[3 Tr. 2402]*.

5007. Dr. Mansell confirmed, in general terms, that after fund collection commences, it would be sensible, going forward to look at ways in which the regulatory burden could be minimized *[1 Tr. 309-311]*.

5008. In Pouce Coupé's view, the Board's experience with lighter-handed regulation enables it to do that immediately and start, at least for Group 2 companies, with this lighter-handed approach to accessing funds.

5009. During the hearing, CAPLA suggested that a light-handed approach created a risk of misappropriation *[3 Tr. 2232]*. With respect, this is simply wrong.

5010. The fund's constating documents would limit and impose conditions on how money is removed from such funds *[3 Tr. 2223-2225]*. The fund will be overseen by professional independent trustees that could only release money when the conditions of the trust permit.

5011. Moreover, as a matter of law, any misappropriated money would be recoverable against the individuals who assisted in any such misappropriation through the doctrine of knowing receipt or knowing misappropriation of trust funds.

5012. These mechanisms provide personal (and not just corporate) remedies against individuals who misappropriate trust funds and create strong deterrence against any type of misappropriation *[For a full discussion on this issue see Perell, P. "Claims Against Strangers or Intermeddlers for Breach of Trust or Fiduciary Duty" (1998) 21 Advocates' Q. 94; Air Canada v M & L Travel Ltd., [1993] 3 S.C.R. 787; Gold v Rosenberg, [1997] 3 S.C.R. 767; Citadel General Assurance Co. v Lloyds*

Bank Canada, [1997] 3 S.C.R. 805].

5013. We have contained some fuller discussion and references in our footnote for the Board's assistance. Now those remedies against trustees, of course, are in addition to any remedy that the NEB could impose, and might wish to impose as a regulator *[3 Tr. 2243]*.

5014. So on this topic, to clarify *[Sec 3 Tr. 2326-2330 and Ex. C-19-5, p. 10, q.1.7(b)]*, Pouce Coupé supports abandonment funds for decommissioning purposes being available whenever an asset is not being replaced *[2 Tr. 1150; Ex. C-19-5 p. 10, q. 1.7(b)]*.

5015. Pouce Coupé submits that a company should have immediate access to the money in the abandonment fund and should be required to report, at least annually, to the NEB all such uses, subject always to the NEB's independent audit process *[3 Tr. 2237, Ex. C-19-4, p. 9, qq. 5(a) and 5(c)]*.

5016. These regulatory accountability measures in the past have been both effective and cost effective, enabling the Board to elicit from pipeline companies the behaviour it seeks.

5017. Next, Madam Chair, the topic of taxation.

5018. **Taxation**

5019. Pouce Coupé strongly encourages the Board to aggressively and expeditiously work to arrange for abandonment dollars collected through a toll surcharge to be tax exempt *[Ex. C-19-4, p. 4, q. 1(a)]*.

5020. Now, we certainly recognize this is not your decision but we do, with respect, suggest that your overtures in this regard might be perceived, and with a little less bias, and given greater weight to the powers that have that authority.

5021. All parties view tax efficient collection to be of importance. The consequences for tax-inefficient collection were well illustrated by Mr. Van der Put and Ms. Leong on behalf of TransCanada *[4 Tr. 3450 - 3474]*.

5022. In particular, they illustrated that industrial users, such as pulp and paper mills, auto manufacturers and metals fabricators, are going through very difficult times *[4 Tr. 3458]*.

5023. As ultimate consumers, they will be the ones that bear the burden associated with abandonment costs, despite CAPP's suggestion to the contrary. As

such, collecting one dollar for abandonment and getting only 70 cents in return, as would happen under the current tax regime, is unacceptable *[4 Tr. 3463]*.

5024. The tax collector should not be able to replenish the federal treasury at the expense of struggling industry.

5025. To be clear, Pouce Coupé does not support indefinite deferral of collection until income tax inefficiency is resolved, although it certainly prefers expeditious resolution of that issue *[3 Tr. 243-2431]*.

5026. Pouce Coupé raises this issue to urge the Board, as part of its public interest mandate, to do all it can to ensure the issue is resolved as soon as possible. In the interim, the NEB can progress on other necessary steps to direct collection commencement so that, whether or not favourable tax treatment will be granted, collection can commence just as soon as possible.

5027. Finally then, Madam Chair, our seventh topic:

5028. **Implications of Existing Easement Terms**

5029. And we think it goes without saying that landowners had an opportunity to negotiate the method of abandonment and also compensation or costs associated with that when they negotiated for the taking of their land *[3 Tr. 2269; 3 Tr. 2271; 3 Tr. 2459]*.

5030. That would not apply to those landowners who chose not to engage in those negotiations but left the taking of the land to the process of right of entry. But as the evidence shows, some landowners in their easement agreements have specified the required -- have specified that abandonment -- let me start again -- have specified that upon abandonment the pipeline need not be removed from their property.

5031. They were compensated for the allocation of risk set out in those easement agreements and the burdens and interferences with their proprietary rights. In the case of abandonment-in-place they assumed the risk of leaving the pipe in the ground and were compensated for it.

5032. As the undertaking response from Pouce Coupé demonstrates, 94 percent of the private lands held -- and I should interject, as I intended to at the outset -- copies of that undertaking response are available at the back of the room for those that may not have been able to retrieve it off their systems yesterday afternoon.

5033. But 94 percent of the privately held lands, which is three-quarters of the route of Pouce Coupé's system, are covered by easement agreements for which

landowners said, in exchange for consideration you need not remove that pipeline when you abandon the system.

5034. So what should that -- how should that affect these proceedings? Well first, by its recommendations coming out of this process, in our submission, the Board should not proceed in a way that would either interfere with the terms of such agreements or that would in some blanket fashion override the terms of such agreements.

5035. This would include not proceeding in a manner that would facilitate double collection of compensation by landowners, and thereby double payment by pipeline companies and their shippers.

5036. Second, the Board should ensure continued flexibility to pipeline companies and landowners negotiating mutually acceptable easement terms.

5037. So there isn't something specific, at this stage of the process, we would suggest that what you do by way of recommendations coming out of this pro-set, not foreclose the ability on a pipeline-specific basis when companies come back before you to flexibly accommodate what may have already been negotiated.

5038. CAPLA has implied that such agreements were negotiated under duress and therefore ought to be unenforceable. Interestingly this was not the position of CAPLA when it was represented, also by Messrs. Vogel and Goudy, in a claim against Enbridge that went to the Ontario Court of Appeal *[Canadian Alliance of Pipeline Landowners' Assn. v. Enbridge Pipelines Inc., 2008 ONCA 227]*.

5039. In that Court, Messrs. Vogel and Goudy, on behalf of CAPLA sought to claim damages under easement agreements. These damages could only be claimed if they believed easements agreements were enforceable. They also say that circumstances and easement agreements have changed since they were first entered into.

5040. First, it is not open to this Board to directly re-write easement agreements, whatever the vintage. Second, Undertaking Response 2 shows that all of Pouce Coupé's easement agreements are relatively recent, some just a few years ago.

5041. With that, Madam Chair, those are all of Pouce Coupé's submissions, subject to any questions the Panel may have.

5042. **THE CHAIRPERSON:** Give us a minute, please.

--- (A short pause/Courte pause)

5043. **THE CHAIRPERSON:** Thank you, Mr. Jeffrey.

5044. We do have a few questions for you, and I'll turn the microphone over to Mr. Bateman.

5045. **MEMBER BATEMAN:** Thank you, Mr. Jeffrey.

5046. In your argument, you had addressed the matter of Westcoast and stated that, in your view, Westcoast would be better able to contend, presumably, in a competitive environment if they were subject to some sort of obligation with respect to abandonment funds.

5047. Could you explain to the panel what it is that you meant when you said they would be better able to contend?

5048. **MR. JEFFREY:** Yes, Mr. Bateman.

5049. The comment was a comment relative to other pipeline companies that do not enjoy the flexibility in the setting of the price of their services that Westcoast enjoys for those two zones of their system.

5050. And so for other pipeline companies, it will simply be an increment on top of the existing toll, whereas, as Westcoast explained, it may be necessary for Westcoast to maintain the same toll but absorb that cost in effect, but it is then able to compete.

5051. It has been given the tools already by the Board to compete and so in respect of competition that it faces, it has that ability that other pipelines do not have.

5052. **MEMBER BATEMAN:** And would I conclude that if they were to absorb the cost that that would have an impact on their return?

5053. **MR. JEFFREY:** Absolutely it would impact their return, but their return for those segments is not determined in the same fashion as the return of the standard cost of services-priced utilities.

5054. **MEMBER BATEMAN:** Thank you.

5055. Another question is, is you had indicated that it is Pouce Coupé's position that the Board should not have direct involvement with respect to the spending of funds where a facility or some sort of a replacement is involved.

5056. Did I understand that correctly?

5057. **MR. JEFFREY:** Yes, sir. And I was thinking there, if I might interject, of the type of suggestion that if there are residual funds then it might pass over to a university or to a -- I think those are beyond the scope of the corners of the Act that you can, at present, dictate.

5058. **MEMBER BATEMAN:** Would it be your position then that the Board's involvement would be limited to the conditions of the trust?

5059. **MR. JEFFREY:** I have to think about that. You certainly have the jurisdiction, the power to require certain matters be included within the terms and conditions of a trust that is acceptable to you. I'd hesitate to say that you can't do anything more than that but nothing comes to mind immediately.

5060. **MEMBER BATEMAN:** In developing your argument, you had pointed out that on some sort of a reoccurring basis, perhaps an annual review, there would be an accounting by a company such as Pouce Coupé with respect to expenditures that had occurred.

5061. Would you provide your views as to what process would follow if, as a result of that review, the Board questioned or disapproved of certain expenditures?

5062. **MR. JEFFREY:** Well, the Board has the power in subsequent rate processes to -- what would the word be -- to react to something it felt untoward. You have the ability to make tolls interim immediately upon any concern, and then making adjustments back to the date that they were made interim. And you can direct that a company would need to replace if you felt dollars were inappropriately spent.

5063. I mean, you have the ability -- if there's an application for approval to spend money out of a fund, you still have the ability after the fact to say, "Well, despite us giving you the approval you imprudently spent those dollars." So you have the authority already to act in that way, and I'd suggest this is very similar.

5064. **MEMBER BATEMAN:** Thank you.

5065. In connection with the issue of tax and what the Board's approach should be, you had stated that part of the Board's public interest mandate would be to do all that it can.

5066. Would you provide the Panel with what you would be proposing or what would be contemplated in all that the Board can do?

5067. **MR. JEFFREY:** Well, I'm grateful for my friend Mr. Crowther and the suggestions in his argument. We certainly agree with those; liaising with the Treasury Board, helping it to understand the public interest merit of that sort of tax treatment.

5068. I don't, frankly, know if there are other mechanisms such as you have under, I think, it's Part II of the Act, to be advising the Minister that oversees the workings of this Board, and for that individual to advance the issue. Those are a couple that come to mind.

5069. **MEMBER BATEMAN:** And those activities would largely be independent. Have you in mind that there would be activities where you would expect the Board or propose that the Board be involved directly with pipeline companies, shippers, or landowners on those issues?

5070. **MR. JEFFREY:** And I'm sorry; do you mean by involved with those companies in the sense that Mr. Forrester was contemplating there might be a committee, a ---

5071. **MEMBER BATEMAN:** Yes.

5072. **MR. JEFFREY:** --- multi-partied committee?

5073. With respect to Kinder Morgan, we would think not. We would suggest that it's better just independent to come from the Board, not necessarily this Panel but through your administrative processes.

5074. **MEMBER BATEMAN:** With respect to your argument regarding easements and the fact that there are landowners who have executed agreements for consideration where a pipeline -- a pipe might reside permanently in the ground, obviously the Board would not be party to or have reason to be party to such an agreement.

5075. So I'm interested in understanding your view that the Board should not take steps in some manner that would amount to rewriting such an agreement.

5076. **MR. JEFFREY:** The comment is in the context of what I would suggest is a necessary inference from those agreements, that the parties came to agreement on those terms, on those provisions, and that the compensation paid was in respect of that set or basket of terms and agreements.

5077. Now, I would concede that if this Board or a provincial environmental regulator set a condition that says land must be returned to its pristine fashion, by

operation of law that will override the terms of the agreement.

5078. But what we are suggesting is that you don't, by your recommendations at the close of this process, foreclose the possibility that when pipeline companies come forward with their calculation of what dollars will be required, that there cannot be some recognition that the price has already been paid to leave the pipeline in place, and that's insofar as, let's say, pipeline regulation as opposed to provincial environmental regulation.

5079. **MEMBER BATEMAN:** My last question has to do with the argument that you have raised that the Board does indeed have jurisdiction continuing once an abandonment order is in place.

5080. If I look at section 51.1 you had pointed out in the particular words under 51.1(1) "where a company or a detriment to property or the environment is being or will be caused by (a) abandonment of a pipeline," would you give me your view as to whether there would be a significant distinction between the words "will," which appears in the legislation, and had the word been "has" in terms of the Board's authority post-abandonment?

5081. **MR. JEFFREY:** I would accept that if the word used was "has" it would be clearer that Parliament was contemplating these powers after the time of abandonment, as, I'd suggest is the case in section 49, without any doubt.

5082. But the law is understood to be always speaking and I think we would find that that phrase would entitle the Board and an inspector to exercise the powers referred to here after an abandonment, if that inspector believes, has reasonable grounds to believe, that one of those events will be caused in the future.

5083. But you're still after the time of abandonment but the effects may be perceived to be future and the inspector has the power, after the time of abandonment to deal with the consequences of abandonment but may still be future.

5084. **MEMBER BATEMAN:** Thank you. Those are all my questions.

5085. **THE CHAIRPERSON:** Mr. Jeffrey, I just had a couple of questions of clarification for you.

5086. When you were talking about a trust being established you said that the trustee would report on a semi-annual or annual basis, and if you said it I missed it, who would the trustee be reporting to?

5087. **MR. JEFFREY:** That's a good catch. Actually we would contemplate

the trustee reporting to the pipeline company which would bear the responsibility for ultimately performance and management. But that -- we were suggesting that accessing the funds would be a matter of annual report to the Board, should it ever occur, and that also there would be an annual report to the Board by the pipeline company.

5088. So the trustee would not be, in that sense, reporting to the Board, but you have regulatory authority over the pipeline companies and they would in turn report to you.

5089. **THE CHAIRPERSON:** And then just to follow-up on that; you did talk about the accessing of the funds, and I heard you talk about the light-handed approach, and you mentioned NEB oversight, but I wasn't clear on what you were thinking of in terms of NEB oversight. You've talked about the annual report in terms of accessing of funds.

5090. Is there anything else that you would see in the NEB oversight on that part?

5091. **MR. JEFFREY:** Yes. In that regard we also contemplate the Board exercising its audit powers from time to time and its enforcement and compliance process, as and when necessary.

5092. **THE CHAIRPERSON:** And could you talk a little bit more about that, in terms of what you were contemplating in terms of the Board's audit powers, given that the trustee would not be reporting to the Board?

5093. So I'm assuming that's the accessing and the funds, and also the compliance and enforcement piece; could you give us a little more detail on your thoughts about those two pieces of NEB oversight?

5094. **MR. JEFFREY:** Okay. The oversight, again, is in respect of the pipeline company, not the trustee and it would be the pipeline company that satisfies the trustee that the preconditions to release of funds have been met and the trustee then would release the funds to the pipeline company.

5095. The Board would receive, we would suggest, annual reports of any such activities and be able to review those, seek further information, as it may require, pursuant to sections 11 and 12 of the Act.

5096. It also would have the ability, and does exercise ability, to audit pipeline companies from time to time and assess whether there is full and accurate disclosure in those annual reports, and the Board does have its compliance and enforcement

process often working in a stepped fashion to, with least intrusion, try and encourage a change in behaviour and where that fails it then escalates and has the ability to prosecute, or recommend for prosecution.

5097. **THE CHAIRPERSON:** And so in terms of the compliance and enforcement aspect, when you're talking about accessing funds, maybe I'm missing something but I'm just not able to draw the link between those two.

5098. **MR. JEFFREY:** I'm sorry, and if this is helpful, what we're contemplating is that the fund would build up over time through the levying of a surcharge. But before the ultimate end of asset life, there are occasions -- we would suggest most often it will be the case -- that perhaps one line, a lateral, a spur, tanks, certain parts of the entire undertaking are no longer necessary for utility service.

5099. And funds should be available to be accessed, dollars should be available to be accessed out of the fund for those interim purposes, and indeed for the longer process that will be required at end of life. There will need to be some studies, assessments, engineering work, before the actual work takes place.

5100. Those dollars should be available to be drawn out of the fund and we're suggesting that should be handled in a light-handed fashion, subject always to the reporting and regulatory oversight you enjoy.

5101. **THE CHAIRPERSON:** So would that then, again, go back to the agreements of the trust? Is that what you're saying, that that aspect of it, in terms of what funds would be available for, what purposes, would go back to the trust agreement?

5102. **MR. JEFFREY:** Yes, that's correct.

5103. **THE CHAIRPERSON:** And so in terms of the Board's oversight on the light-handed regulation aspect of compliance and enforcement of that piece, are you suggesting that there's a role for the Board to be identifying in advance of a company, that maybe there's some part of service that should come out of service at this point and should be abandoned? Did I hear you say that?

5104. **MR. JEFFREY:** No, Madam Chair, that would be the obligation of the pipeline company to satisfy the existing requirements for leave, prior to abandonment or decommissioning now.

5105. Your oversight would not be of the trustees and so if you come to the conclusion that they have, perhaps incorrectly, released moneys from the trust fund,

your recourse is against the pipeline company as it's part of the risks, we suggest, that pipelines necessarily will have to bear going forward, and again, part of the justification for the pipeline companies recovering any surplus from out of the fund.

5106. **THE CHAIRPERSON:** And so I may be the only one in the room who's not understanding the compliance and enforcement piece and if so, I apologize for that, but could you summarize for me what you see as the Board's oversight role with respect to compliance and enforcement that you've talked about, in terms of accessing funds?

5107. **MR. JEFFREY:** If the Board comes to the conclusion following receipt of reports or following an audit process that funds have been inappropriately used from out of the trust, then it can, among other things, use its enforcement powers to remedy that.

5108. **THE CHAIRPERSON:** Thank you for that clarification, Mr. Jeffrey.

5109. **MR. JEFFREY:** Thank you for the opportunity.

5110. **THE CHAIRPERSON:** Those are all the Panel's questions. Thank you very much.

5111. The Board will take a quick -- well, we'll take a break at this point and reconvene at 10:50, please.

5112. Thank you.

--- Upon recessing at 10:25 a.m./L'audience est suspendue à10h25
--- Upon resuming at 10:52 a.m./L'audience est reprise à 10h52

5113. **THE CHAIRPERSON:** Spectra Energy Transmission, please?

--- FINAL ARGUMENT BY/ARGUMENTATION FINALE PAR MR. DAVIES:

5114. **MR. DAVIES:** Thank you, Madam Chair and Members. Good morning.

5115. I've also given a copy of my notes to the court reporters and would ask that they include the headings and evidentiary references in the transcript.

5116. I'm pleased to present to you this morning the final argument of Westcoast Energy Inc. or as it's been referred to in this hearing, Spectra Energy Transmission.

5117. The objective of this Stream 3 proceeding, as expressed by the Board, is to

determine the optimal way to ensure that funds are available when abandonment costs are incurred.

5118. I looked up the definition of the word "optimal" in my Oxford dictionary. "Optimal" means "best or most favourable". So a choice needs to be made. There are options available, and it is necessary to choose that option that is the best or most favourable.

5119. Now, the Board, of course, must make its decisions with regard to the overall public interest.

5120. So in deciding how to ensure that funds are available when abandonment costs are incurred, your mandate is not to choose the way that is the best or most favourable for landowners, nor is it to choose the way that is the best or most favourable for a particular pipeline company or for toll payers.

5121. Your mandate is to choose the option that is the best or most favourable having regard to the interests of all stakeholders, including landowners and pipelines and toll payers.

5122. Now, Madam Chair and Members, I realize that I'm not telling you anything here that you don't already know. It's trite for me to stand before you and say that the Board must make its decisions in the public interest. But I need to say it anyways, and I need to emphasize it because of the position that CAPLA has taken in this proceeding.

5123. If there was any doubt about the CAPLA position before I conducted my cross-examination last Friday, there was certainly no doubt remaining by the time I was done.

5124. CAPLA was very clear. CAPLA wants the Board to make decisions to ensure that landowners have zero risk of liability for abandonment costs *[T. V4, 4071-4072]*.

5125. CAPLA wants the Board to take all steps to eliminate risk to landowners, irrespective of the cost that taking those steps might have on pipelines and their shippers *[T. V4, 4000-4001]*.

5126. If a step can be taken to reduce the risk to landowners, even just marginally, then CAPLA demands that the step be taken, even if it is economically efficient or causes significant impact to others because landowners, according to CAPLA, are entitled to zero risk.

5127. So this case is largely about risk and that fact certainly doesn't make it a novel case for the National Energy Board. All of your cases involve, to one degree or another, an assessment of risk. Indeed, your job is largely one of doing risk assessment.

5128. And there are really two approaches that can be taken to risk assessment. One is easy and the other is hard.

5129. The easy approach to risk assessment is for parties to say, as CAPLA says, we will not tolerate any risk at all. I certainly understand why CAPLA would take that approach, but if we all took that approach, none of us would ever get out of bed in the morning because of the chance that we might get hit by a bus.

5130. It's the wrong approach to risk assessment. It's the wrong approach to risk assessment because ignores the probabilities of risk realization. It's also the wrong approach to risk assessment because it ignores the adverse consequences of trying to reduce the risk, for some, to zero.

5131. The hard approach to risk assessment is to make a considered and thoughtful assessment of the magnitude and probability of the risks, to assess and appropriately balance conflicting interests, and to arrive at a judgment that is the best or most favourable for the overall public interest.

5132. And it is, of course, this hard approach that the Board must take because this is the approach mandated by your statutory public interest obligation. And that is why, when we all read National Energy Board decisions, we see the Board assessing the different interests of stakeholders, and we see the Board balancing costs and benefits, and we see the Board directing that steps be taken to reduce risk levels to within acceptable limits.

5133. What we don't see the Board doing is risk assessment that requires the attainment of a zero risk standard. None of us could achieve that standard even if we stayed in bed all day.

5134. And please, Madam Chair and Members; don't misunderstand me here. I am not suggesting, in any way, that landowners should be liable for the costs of pipeline abandonment, nor am I suggesting that landowners should be put at risk for the cost of abandonment.

5135. What I am saying is that the residual risk to landowners can never be eliminated and that steps to reduce the risk ought not be taken at any cost.

5136. In this case, as in all other cases, the hard approach to risk assessment

needs to be taken. There is a balancing that needs to be done.

5137. Now, I want to turn to the Westcoast proposals, and explain to you why the adoption of those proposals would meet your public interest mandate. But before I do that, let me just make one other comment that relates to CAPLA.

5138. My wife sometimes accuses me of being insensitive -- you know, not being in tune to her feelings. I actually attribute that to my legal training. But even to an insensitive guy like me, the feelings of the CAPLA witnesses came through loud and clear last Friday.

5139. They are angry. They are frustrated. They are concerned, not only about abandonment issues, but about many other issues unrelated to abandonment *[TV3, 4010]* and they are certainly passionate.

5140. And of course, nobody wants any landowner to be unhappy. Westcoast and the other pipelines certainly don't. The Board, I'm sure, doesn't. There clearly remains work to be done with pipeline landowners.

5141. But what I would caution, in the context of this Stream 3 proceeding is this: The focus needs here to be, not on trying to make CAPLA happy, but on choosing the optimal way to ensure that funds are available when pipeline abandonment costs are incurred. This should not be treated as a public relations exercise.

5142. I point, as an example, to the proposal of TransCanada to commence collecting a nominal amount from shippers. TransCanada tells us that this would:

> *"...clearly send a signal to the public at large, to landowners in particular, that they're not going to be held liable for the cost of abandonment, that steps are being taken to begin to collect those funds." [T. V4, 3289]*

5143. Well, with respect, this ought not be about trying to send a comfort signal, particularly when the signal would introduce inefficiencies and could trigger unintended accounting outcomes. *[T. V3, 3100-3103, 2959-2966]*

5144. The objective here should not be to do something quick for the purpose of appeasement. We agree with CAPP; the objective should be to get this right.

5145. So with that, let me turn to the Westcoast proposals. And I want to deal separately with the proposal for the Westcoast transmission system and the proposal for the Westcoast gathering and processing system because, as you know, they are

different proposals driven by different circumstances. One size does not fit all for these different Westcoast assets.

5146. **Transmission Assets**

5147. Starting then with the transmission system. Westcoast is required by accounting rules to recognize a liability for an asset retirement obligation when the timing of the abandonment is determinable and a reasonable estimate of the fair value of the obligation can made.

5148. The Westcoast proposal is that at that time, when the asset retirement obligation is recognized, Westcoast would make application to the Board to commence collecting funds from its shippers to cover the asset retirement obligation.

5149. Westcoast would be prepared to set those funds aside in a dedicated trust account administered by a third party trust company.

5150. The virtues of the Westcoast proposal in respect of the timing of collection are discussed in the Westcoast evidence. *[Exhibit C-22-3. p.3]*.

5151. As Mr. Curry explained, Westcoast looked at the first issue on the Board's Issues List; namely, whether funds should be collected and set aside to cover future abandonment costs, and it concluded that there is a perfectly good framework already in place, as prescribed by the accounting rules, that addresses the issue. *[T. V3, 2979 -2981]*

5152. So Westcoast identified no need to re-invent the wheel.

5153. Using the existing accounting framework, when a pipeline company recognizes an asset retirement obligation, the specific retirement costs sought to be recovered by that company would be examined by the Board, having regard to that company's best estimate of its actual retirement obligation, based on its own individual facts and circumstances.

5154. This is consistent with the way that the Board examines every other cost which a pipeline seeks to include in its tolls.

5155. Our proposal for the timing of collection is similar in concept to the Enbridge proposal. Enbridge too advocates that the collection of abandonment funds should commence when the timing of the abandonment is reasonably foreseeable and a reasonably accurate estimate of future abandonment costs can be made. *[T. V1, 224]*

5156. Enbridge would have the Board authorize a "deferral" of funds collection until the timing of abandonment is determinable. We wouldn't advocate that. We don't look at it as a "deferral" because we consider that we would be starting to collect when it is appropriate to do so. *[T. V4, 3079]*

5157. But that aside, the parties share essentially the same view as to when collection should properly begin; that is, when the timing of abandonment is determinable.

5158. Our proposal is different than those of the remaining pipelines and of CAPLA.

5159. We don't agree that collection of abandonment funds should commence within three years following Stream 4 completion, as proposed by Kinder Morgan *[Exhibit C-15-9B, p.1]* or that it should commence following the requisite assessment, as proposed by Pouce Coupé, *[Exhibit C-19-4, 3a.]* or that it should commence as soon as practical, as proposed by TransCanada *[Exhibit C-26-4, p.5]* or that it should commence immediately, as proposed by CAPLA *[T. V4, 4175-4176]*.

5160. These are all proposals for unnecessary and suboptimal premature collection, in our submission.

5161. I see that Mr. Denstedt and I are wearing the same suit today. That may be where the similarities end.

--- (Laughter/Rires)

5162. **MR. DAVIES:** Let me make two general observations about the Westcoast proposal.

5163. The first observation is that the Board is not bound to follow the accounting rules in deciding when the collection of abandonment costs should commence. The rules are rigorous and will compel pipeline companies to deal with asset retirement costs in an orderly and efficient way well in advance of when those costs will need to be incurred.

5164. But, nevertheless, it is open to the Board, if it chooses, to ask us to make a guess when abandonment might occur and to have us estimate and collect abandonment costs based on that guess, and yes, it will be a guess *[T. V3, 3015]*.

5165. The remaining life of the Westcoast Transmission System is indeterminate, and by definition you cannot determine that which is indeterminate, which is, for example, why when Mr. Robertson of Pouce Coupé was asked to

estimate the timing of abandonment of his pipeline he could only offer a guess that it might be anywhere up to 1,000 years and even then couldn't deny that it might be 1,000 years *[T. V3, 2113-2114]*.

5166. My second observation is that if the Board were to direct Westcoast to begin funding the abandonment of its transmission facilities, it wouldn't be Westcoast providing the funds. The transmission system is subject to cost-of-service regulation.

5167. So if we're directed to collect we must increase our tolls. It's not our money that would go into the trust fund, it's money provided by our toll payers.

5168. And, Madam Chair and Members, please keep that in mind when you're considering the pronouncements of Kinder Morgan and Pouce Coupé and TransCanada about the need to start abandonment funding sooner rather than later. They are not offering up their money, they are being nobly generous with the money of their shippers.

5169. So could the Board direct that collection of abandonment costs start earlier than would follow from the accounting rules? Yes, it could. And if it did, Westcoast would just increase its mainline tolls in order to recover the costs.

5170. Why then would Westcoast not jump onto the sooner-rather-than-later bandwagon? Why the reluctance to take toll payer money? Premature collection would certainly be the popular thing to do, from the perspective of trying to gain favour with CAPLA. But in the assessment of Westcoast, it just wouldn't be the appropriate thing to do, for two main reasons.

5171. The first reason I've already mentioned: You would have to guess at the timing of abandonment. And furthermore, because the timing of abandonment is indeterminate, you couldn't make a reasonable estimate of the fair value of the retirement obligation. So you would really have no good basis to decide how much money to start collecting *[T. V3, 2801-2803]*.

5172. The second reason is that you would be taking cash from toll payers before you need to. The toll payer could otherwise use that cash for other purposes. It's just not efficient to trap funds to pay for an asset retirement liability before that liability is even recognized. *[T. V3, 3020-3021]*

5173. You know, it's funny, the news this morning is all about our government making available gobs of money to stimulate the economy, and here we are talking about stowing away dollars before we really need to. It just doesn't make good economic sense.

5174. So those are the main reasons that Westcoast has chosen not to jump on the sooner-rather-than-later bandwagon. We don't agree that the premature collection of abandonment costs would be appropriate.

5175. Now, we recognize that the earlier that collection starts the more time that there would be to accumulate funds and earn interest on them, but by adhering to the accounting rules the result would be that collection of abandonment costs would commence at least 20 years, and more likely 30 or 40 years, in advance of the abandonment date *[T. V3, 3027-3030]*. That is the evidence that is before you.

5176. So not only do we consider premature collection to be inappropriate, we also consider it to be unnecessary. The accounting rules are effective to ensure that pipeline companies recognize and deal with an asset retirement obligation well in advance of the abandonment date.

5177. Would premature collection reduce the risk of having insufficient funds in the trust account at the end of the day? Yes, it would make a very small risk even smaller. But in Westcoast's view, you don't want to start collecting before it's necessary to do so, because, as I said, there is no good basis to decide how much to start collecting and there is a significant opportunity cost on the capital of shippers.

5178. What you want to do, in our submission, is start collecting at the right time, and that time, we believe, is when the timing of the abandonment is determinable. *[T. V3, 2797-2806]*

5179. We also recognize that earlier collection might alleviate, to some extent, intergenerational inequity among shippers, but this is hardly a sufficient reason for premature collection of abandonment costs.

5180. There are already intergenerational inequities embedded in pipeline tolls, like, for example, the front end loading of the return on rate base. Adding a surcharge to the tolls for abandonment costs 20 or more years before abandonment is not going to cause a significant change in the inter-temporal toll pattern. *[T. V3, 2893-2996]*

5181. We would refer you in this regard to the assessment presented by Dr. Mansell in his report. *[Exhibit C-10-12B, pp. 37-38]*

5182. And along the same lines, we don't believe that premature collection is required to address death spiral concerns.

5183. As I mentioned, under the Westcoast proposal, collection of abandonment costs would commence at least 20 and more likely 30 or 40 years prior to abandonment. This would be ample time to allow funds to be collected in an orderly

and efficient manner. *[T. V3, 3041-3046]*

5184. That completes my submissions with respect to the Westcoast proposal for its transmission system. Let me now turn to the proposal for the Westcoast gathering and processing system.

5185. **Gathering and Processing Assets**

5186. The Board has established two fundamental principles to guide its decision making in this proceeding. The first principle is that landowners will not be liable for costs of pipeline abandonment. The second principle is that abandonment costs are a legitimate cost of providing service and are recoverable upon Board approval from users of the system.

5187. Now, as I've discussed, satisfying the second principle is not problematic for pipelines operating in a cost-of-service environment. They add the abandonment costs to their tolls and their shippers pay them.

5188. But Westcoast Gathering and Processing System is an entirely different animal. It is unique among Group 1 pipelines regulated by this Board. It does not operate in a cost-of-service environment; it operates in a competitive environment.

5189. More specifically, Westcoast Gathering and Processing System is subject to the framework for light-handed regulation, which was negotiated between Westcoast and its shippers and which was approved by the Board back in 1998.

5190. Pursuant to the framework, Westcoast bears the utilization risk associated with its gathering and processing facilities and Westcoast must compete for business in order to attenuate that risk.

5191. Madam Chair, I've provided you a document which should be in front of you, entitled "Key Documents Related to the Board's Decision on the Framework for Light-Handed Regulation" dated June 1998. Copies are available in the back of the room as well.

5192. And if you turn to the document, you'll see a few pages in a Table of Contents. Chapter 1, you will see, provides some brief background; chapter 2 is the NEB Decision Approving the Framework; chapter 3 is the NEB Order; chapter 4 is the Application for Approval of the Framework, to which the framework document itself is attached; and chapter 5 is a list of other relevant documents.

5193. And if I could have you turn to chapter 4 and there are page numbers in the bottom corner and I'm looking at page 7. And at page 7, if you're with me,

Madam Chair, under the heading "Introduction", there is provided a summary of the Introduction section of the framework and I want to read it to you.

5194. It says:

> *"The introduction section of the framework describes the intent of the parties to provide for a new model of financial regulation for Westcoast' s gathering and processing services to address the increasing competition in the provision of those services by Westcoast and the requirements of Westcoast's shippers for arrangements which meet their individual competitive situations. The framework represents a joint industry solution for the ongoing regulation of Westcoast' s gathering and processing services by replacing the existing system of active financial regulation by the Board with a complaints-based system. The framework is designed to allow market forces to govern the relationships between Westcoast and its shippers in Zone 1 and Zone 2. The parties believe that the implementation of the framework, taken together with the requirement already contained in the settlement that service over new gathering and processing facilities is to be tolled on an incremental basis, will further increase competition."*

5195. That's the end of the quote.

5196. And then if I could have you look over on page 9, under the heading "Asset Utilization and Disposition Policy," we see this in the first sentence, and I quote:

> *"The Asset Utilization and Disposition Policy section of the framework establishes the principle that, as part of the proposal for light-handed regulation Westcoast is responsible for the utilization of its gathering and processing facilities in Zone 1 and Zone 2."*

5197. And that is unique, in terms of the Group1 pipelines that you regulate.

5198. And then over on page 15, we see the framework document itself and I want to direct your attention to the goals of the framework which are set out in paragraph 2.

5199. The goals are:

5200. In (a), to provide shippers and Westcoast with the opportunity to negotiate

service requirements as they would in a competitive market;

5201. In (b), to the greatest extent possible, to rely on commercial arrangements instead of regulatory oversight;

5202. In (c), to ensure no unjust discrimination;

5203. In (d), to provide Westcoast the flexibility to compete without the ability to exercise significant market power.

5204. And here, Madam Chair and Members, please take out your pens and underline the words "to provide Westcoast the flexibility to compete".

5205. And while you're at it, you could also write yourself a note in the margin that says, "contrary to what Mr. Jeffrey seems to believe, imposing a surcharge that would reduce Westcoast's return would not enhance Westcoast's ability to compete, particularly when its competitor's returns would not likewise be reduced".

5206. The goals go on in (e), to provide Westcoast the incentive to increase its competitiveness in the provision of services to its customers;

5207. In (f), to reduce barriers to entry for the provision of gathering and processing services in B.C. In other words, Madam Chair and Members, to make it easier for companies to compete with Westcoast.

5208. And in (g), to place the responsibility for the recovery of existing investment costs entirely on Westcoast and to place the responsibility for the cost of new facilities on Westcoast and those shippers requiring the new facilities.

5209. Now, I'll leave it to you to read the details of the framework if you wish. I've covered the highlights. The mantra is competition. Tolls are negotiated in the competitive marketplace.

5210. Westcoast takes the facility utilization risk and, in return, is to be provided with the flexibility to compete. That is the bargain that was struck; that is the bargain that was approved by this Board.

5211. Now, Westcoast owns approximately 3,000 kilometres of gathering pipelines in British Columbia. There are about 30,000 kilometres of other gathering pipelines in the province that are provincially regulated *[T. V3, 2611-2632]*.

5212. Of the 3,000 kilometres of gathering pipelines owned by Westcoast, about 300 kilometres is located on agricultural lands *[T.V3, 2896]*. The rest is primarily on

Crown land in very, very remote areas *[T. V3, 2902]*.

5213. Westcoast owns five processing plants in British Columbia. There are 42 other processing plants and central dehydration facilities in the province that are provincially regulated *[Exhibit C-22-6]*.

5214. Westcoast's five plants are all located on lands that are owned in fee simple by Westcoast *[Exhibit C-22-4A, response to CAPLA IR 1.2(b)]*.

5215. So who are these competitors to Westcoast that own most of the gathering and processing facilities in British Columbia? They are, for the most part, the gas producers whose gathering and processing facilities are, with very few exceptions, subject to provincial regulation *[T. V3, 2642, 2602-2603]*.

5216. And what is the nature of the competition? Well, as Mr. Rae of Westcoast told you, gathering and processing is a commodity business in British Columbia so the competition is focused on price *[T. V3, 2579]*.

5217. And as Mr. Rae explained, Westcoast is in the market every day, negotiating with its customers one-on-one. The deals are done at the margin. Westcoast charges the price that the customer will pay, having regard to that customer's alternatives.

5218. If Westcoast charges a customer a 40 cent fee for gathering and processing, it's because that's what the market will bear. It's because the customer's alternative is 40.5 cents or 41 cents. That's how negotiations go in a competitive marketplace. Westcoast would charge this customer more than 40 cents if it could, but it can't *[T. V3, 2574-2577]*.

5219. And what does this all mean for the collection of abandonment costs? Well as I said, gathering and processing is a business where the deals are done at the margin.

5220. At some point, when the timing of abandonment of gathering and processing facilities in northeastern B.C. is determinable, Westcoast will recognize on its books a liability for the fair value of the asset retirement obligation. And Westcoast competitors will do the same and the competition will continue on a level playing field.

5221. Both Westcoast and its customers will have to price their services in the market in order to ensure that they recover their abandonment costs in addition to all their other costs. That's the way that the market works. *[T. V3, 2843-2845, 2954-2957]*

5222. So, could the Board step into the market and direct Westcoast to collect and set aside abandonment costs for its gathering and processing facilities? It could. We're not suggesting that the Board would be prohibited from making such a direction but consider the consequences.

5223. Westcoast would have an obligation to collect and set aside abandonment costs, which its competitors, who are largely provincially regulated producers, would not have.

5224. Think about what would happen in the context of the hypothetical negotiation that we've been discussing. The customer would not be prepared to pay more than 40 cents for gathering and processing service from Westcoast, because abandonment costs need not be built into the price of its provincially regulated alternative.

5225. So, if Westcoast wants the business, it must accept the 40 cents that the market will pay and then set aside some of that 40 cents for abandonment costs.

5226. And therein lies the problem. The Board has determined as a fundamental principle that abandonment costs should be recovered from the pipeline's customers.

5227. But Westcoast wouldn't be able to recover abandonment costs from its customers, because the customers have provincially regulated alternatives that aren't required to recover abandonment costs.

5228. So Westcoast would not be able to increase its tolls to collect; the abandonment funding would have to come out of Westcoast's pocket.

5229. And not only would this result be completely contrary to the customer pay principle that the Board has espoused, it would also be completely contrary to the goals of the framework for light-handed regulation that the Board has approved.

5230. The bargain under which Westcoast has been operating for the past 10 years is that it accepted utilization risk for its processing and gathering facilities on the basis that it would be provided the flexibility to compete.

5231. Were the Board to direct Westcoast to collect and set aside funds for future abandonment, it would put Westcoast at a competitive disadvantage to provincially regulated companies, which would frustrate the very bargain upon which the framework is based.

5232. Recall that when I was discussing risk assessment, I said that the easy

approach is the wrong approach because it ignores the probabilities of risk realization and it ignores the adverse consequences of trying to reduce the risk for some to zero.

5233. This is precisely why it would be inappropriate for the Board to require Westcoast to collect and set aside abandonment costs for its gathering and processing facilities; because such a requirement would ignore both the probability of risk realization and the adverse consequences to Westcoast of trying to make a small risk smaller.

5234. It's not the case that landowners will be liable for the costs of abandoning these facilities; Westcoast bears that liability. Westcoast is a very large company with significant assets.

5235. Westcoast will discharge the abandonment cost liability, like its other liabilities, by managing its ongoing business to ensure that it has sufficient funds to pay abandonment costs when those costs are incurred. That's what companies operating in a competitive environment do.

5236. Now, is there a risk that when Westcoast abandons its gathering and processing system decades or centuries from now, it may not have the money to abandonment -- to fund abandonment?

5237. Yes, I suppose there is a risk, in the same way that there is a risk of me getting hit by a bus when I walk back to my office today. But the risk is clearly very, very small. And it makes no sense for the Board to try to make that very, very small risk smaller when the consequences of doing so would be to take money directly out of Westcoast's pocket and impair its ability to compete.

5238. Now, CAPLA, of course, has raised an issue about Westcoast's position in respect of its gathering and processing business. And, of course, with regard to the 300-some kilometres of Westcoast gathering pipelines on agricultural land, CAPLA wants the landowners to have zero abandonment cost, full stop, end of story.

5239. CAPLA, though, did have two suggestions for us. It suggested that Westcoast could apply to transfer its gathering and processing assets out of federal jurisdiction, or it could lobby provincial governments to impose the same funding obligations on provincially regulated companies. *[Exhibit C-1-11, response to Westcoast IR 5]*

5240. The first suggestion is simply not a viable one. The Supreme Court of Canada has told Westcoast that its gathering and processing business is under federal jurisdiction. That's the final legal answer, unless CAPLA can find out a way to reinstitute appeals to the Privy Council.

5241. With regard to the second suggestion, I suppose it is possible that someday provincial governments could adopt the same abandonment funding rules that the National Energy Board chooses, though I seriously doubt that such an outcome would be attributable to the lobbying efforts of Westcoast; it would more likely be the result of consultation between this Board and its provincial counterparts, which I note is contemplated in respect of Stream 4 issues.

5242. But, in any event, if such an outcome did materialize, if the abandonment funding rules were made the same federally and in British Columbia, then certainly the financial issues surrounding the future abandonment of Westcoast's gathering and processing facilities could be revisited.

5243. But, Madam Chair and Members, the Board must make its decision based on the circumstances as they now exist.

5244. And my submission to you is that when you do your risk assessment based on the current circumstances -- when you consider the minimal chance of realization of the abandonment cost risk to Westcoast's gathering pipeline landowners, and when you consider the adverse competitive consequences to Westcoast of trying to reduce that minimal risk further, you can only reasonably arrive at one conclusion, and that is that Westcoast should not be required to collect and set aside funds to cover future gathering and processing abandonment costs.

5245. That is the decision that would serve the public interest.

5246. Madam Chair, Members, that completes my submissions respecting the Westcoast gathering and processing assets, and as well completes my argument on behalf of Westcoast.

5247. Thank you very much for listening. I'd be pleased to try to respond to any questions.

5248. **THE CHAIRPERSON:** Thank you, Mr. Davies. The Panel has no questions.

5249. **MR. DAVIES:** Thank you very much.

5250. **THE CHAIRPERSON:** Suncor Energy Marketing Inc. ...?

--- (No response/Aucune réponse)

5251. TransCanada PipeLines Limited...?

--- FINAL ARGUMENT BY/ARGUMENTATION FINALE PAR MR. DENSTEDT:

5252. **MR. DENSTEDT:** Good morning, Madam Chair and Board Members.

5253. I, too, have provided my notes to the court reporter and I would ask that the headings and evidentiary references be included in the transcript.

5254. I'd like to apologize at the outset for not calling Mr. Davies this morning and finding out what he was wearing. That's a faux pas that I'm guilty of.

5255. Madam Chair, this is a very important proceeding. It's important to TransCanada because it owns more than 40,000 kilometres of pipeline, and the abandonment of that system will be significant.

5256. The outcome of Stream 3 will affect landowners, shippers and pipeline companies. It will affect the question of who pays, when those costs are paid, and how much is required to be paid.

5257. It will affect competition among pipelines, regardless of whether those pipelines are NEB regulated or whether they are located in Canada or not.

5258. No one disputes the costs of abandonment are a recoverable cost of service, and everyone here agrees that provision needs to be made for collecting those costs. The purpose of Stream 3 is to identify a fair and reasonable process that will ensure funds are available when abandonment costs are incurred *[LMCI Approach document, p. 5]*.

5259. The Board has no small task ahead of it. Its public interest test requires it to consider all stakeholders' interests and ensure that whatever process is developed is fair to all parties.

5260. TransCanada believes the adoption of a framework or guidelines, based on fundamental principles, will provide the guidance needed to achieve a fair process *[Ex. C-26-4, p. 5]*.

5261. TransCanada is asking the Board to issue guidelines that would provide for the collection of abandonment funds into a segregated trust account. Collection could begin with a nominal "placeholder" amount, subject to certain preconditions which I'll discuss later in my argument *[1TR226]*.

5262. TransCanada's approach is consistent with the potential outcomes

identified by this Board in its Stream 3 guidance documents *[Ex. A-02B, p. 7; E. A-08A, pp. 3-4]*.

5263. So let me start by providing to the Board the principle framework TransCanada believes should underpin the collection of abandonment funds.

5264. **Principles**

5265. TransCanada has attempted, in its evidence, to put forward a position that moves this important issue forward in a responsible fashion, but which also gets at the heart of the issues the Board must wrestle with. That means landowners cannot be left holding the "bag" for abandonment costs, but it also means that the "right" amounts must be collected to ensure scarce capital resources are used appropriately.

5266. The Board launched Stream 3 by identifying two key principles. First, abandonment costs are a legitimate cost of providing service and are recoverable upon Board approval from users of the system and; second, that landowners will not be liable for the costs of pipeline abandonment *[LMCI Approach, p. 5]*.

5267. Obviously, Madam Chair, TransCanada agrees with those basic principles.

5268. TransCanada has articulated additional principles in its written evidence *[Ex. C-26-4, p. 4]* and its Opening Statement *[1TR226]* which are intended to amplify the Board's starting principles. Let me walk you through those additional principles.

5269. As a third principle, TransCanada believes that the collection of abandonment costs should begin as soon as practical.

5270. As reflected in its written evidence *[Ex. C-26-4, p. 10]*, to do so otherwise would increase intergenerational inequity between shippers. The fact there may exist intergenerational inequity is no excuse for not minimizing that risk.

5271. As per the Board's first principle, and in keeping with the toll principle of user pay and cost causation, abandonment costs are a cost of service item. It would be unfair to continue to allow existing shippers to transfer the cost of abandonment to future shippers.

5272. Fourth, the funds collected for abandonment should be used for abandonment, and they should be managed in a way that minimizes the amount of capital that must be collected. Amounts collected should reflect an estimate of abandonment costs based on standard technical assumptions *[Ex. C-26-4, p. 15; C-26-6B, IR 1.1 and 1.8; 1TR226]*.

5273. That means collection should be done through a trust which segregates funds from general corporate revenues, and which provides transparency to the process.

5274. A trust also immunizes the funds from potential corporate insolvency. At the same time, a trust need not be complex or over complicated. A trust can be a relatively simple, single-purpose trust, which would be most efficient *[4TR3579-3581]*.

5275. Any funds collected, and the growth of those funds within the trust, should be accorded efficient tax treatment. Efficient tax treatment would avoid unnecessarily tying up scare capital that could be more productively employed in the economy.

5276. It would also allow the abandonment funds to grow with the least cost to toll payers, minimizing any market distortions that might result from increased tolls *[Ex. C-26-4, p. 10]*.

5277. Fifth, this framework should be applied consistently among pipelines that transport similar products under similar circumstances. Different treatment could lead to market distortions and economically inefficient outcomes.

5278. The Board must ensure that the collection of abandonment funds does not provide a competitive advantage to one system over another, whether or not those pipelines are regulated by the NEB, and whether or not the pipelines are located in Canada.

5279. TransCanada has been clear on this point in its evidence *[Ex. C-26-04, p. 8j; C-26-6B, IR 1.3]*.

5280. Similarly, regard must be had to competitive impacts on toll payers. CAPP told the Board that producers are -- and I quote "in distress right now" *[5TR4490]* and that too severe an impact to producers' netbacks from the collection of abandonment funds could leave some producers in a loss position *[5TR4502]*.

5281. The Board must balance all of these competing issues and concerns in order to ensure a fair outcome in this process.

5282. Sixth; abandonment should be recognized as a process rather than an event. TransCanada has told the Board that, practically speaking, pipeline companies will begin abandoning some assets while continuing to operate others *[Ex. C-26-4, pp. 3 and 20]*.

5283. There is no "drop dead date" upon which all pipes simultaneously stop

operating and all shippers disappear. The framework being discussed must be administered in a way that recognizes this operational reality.

5284. Systems will be abandoned asset by asset and pipeline by pipeline, with careful review and scrutiny in each case occurring before, after and during abandonment activities. The abandonment funds will, in effect, be undergoing constant review during this period.

5285. And let me quote Mr. Van der Put's evidence to underscore this:

> *"Abandonment isn't a one-time event. It's a process that's going to take place over a period of years. And whereas early on in the process of abandonment we may find more instances perhaps of situations where we've found ourselves to be a little bit underfunded or over-funded, we will -- as we gain experience with carrying out the abandonment activities, we'll get better and better certainly at determining what the required funds are and be able to make adjustments in terms of those collection amounts so that once we do get to the end, if you will, the likelihood that there would be either a surplus or a deficit should be pretty darn small." [4TR3559-3560]*

5286. Madam Chair, the reality of Mr. Van der Put's evidence is that as we get closer to the final steps in the abandonment process, the cost estimates will become more and more accurate, reducing the risk of under-collection (or over-collection for that matter) which in turn reduces the ultimate risk to the landowner *[4TR3318-3320]*.

5287. Madam Chair and Board Members, let me contrast that principled approach to the issue of CAPLA's "default" position.

5288. CAPLA suggests that landowners will bear the "ultimate risk" of abandonment *[2TR1749-1750; 1759-1760; 1795-1796]* and as a result, the Board should adopt a "default position" requiring the removal of all pipe for calculating abandonment costs *[Ex. C-1-6A, p. 16, 18-19; Ex. C-1-9B, pp. 16-17]*.

5289. I don't need to go through my comments on the public interest test. I think Mr. Davies has addressed that completely and we'd associate ourselves with those remarks.

5290. But let me just conclude on the point of CAPLA's default option by saying that what CAPLA is urging on the Board is an abandonment of your obligation to consider the public interest, and that's inappropriate.

5291. **TransCanada's Approach - Timing**

5292. Let me turn now to a more detailed discussion of TransCanada's proposal and, in particular, let me focus on the timing of that.

5293. Every other party that has filed evidence in this proceeding agrees that abandonment funds should be collected *[Ex. C-1-6A, p. 16; Ex. C-2-4, p. 4; Ex. C-10-3B, p. 3; Ex. C-15-3B, p. 1; Ex. C-10-4, p. 4; Ex. C-22-3, p. 1]*. Where the debate departs is when that collection should start.

5294. TransCanada has recommended that the timing of collecting abandonment funds should be as soon as practical *[Ex. C-26-04, p. 13; Ex. C-26-056B, IR 1.2, pp. 1-2; 1TR226]*.

5295. This is, in fact, one of the principles in TransCanada's framework. TransCanada's evidence is that collecting as soon as practical means taking the time required to put trust mechanisms in place, address tax efficiency, prepare abandonment cost estimates, and deal with issues such as existing toll settlements. *[Ex. C-26-6B, IR 1.2, pp. 1-24; TR3250-3258]*

5296. Early collection reflects the fact that abandonment is a cost-of-service item and should be collected over as much of the remaining life of the asset as is possible.

5297. Mr. Van der Put stated, when cross-examined by Board Counsel, as follows, and quote:

> *"All we can do, from my perspective, at a very high-level is go back to the principle that abandonment costs are a legitimate cost of providing service to shippers on a pipeline and, as such, then should be borne by shippers who contract for service on that pipeline throughout its economic life.*
>
> *And to the extent that there is a departure from that, to the extent that there are periods of time, for example, at the front-end of a pipeline's economic life, where shippers are not contributing to covering the abandonment costs, then necessarily there is, in some degree, intergenerational inequity which is being created, and the longer the period of time when no abandonment funds are being collected, then arguably the greater the intergenerational inequity." [4TR3481-3482]*

5298. Mr. Van der Put and Ms. Leong also explained that collecting sooner will also allow for more interest to accumulate on invested funds, reducing the overall

amount of funds that will have to be collected from shippers *[4TR3485-3492]*.

5299. In addition to the time value of money benefits of collection early, there is also a significant benefit in real dollars that can be achieved by tax efficient treatment. And let me quote you the example given by Ms. Leong; quote:

> *"For every 70 cents, for example, that we have to collect from the shippers ...under today's current tax regime, we would have to collect an extra 30 cents, assuming a 40 percent tax rate. And so that would mean for every 70 cents, an extra 30 cents could have gone into the trust or a mechanism whereby the compounding interest will actually add to the growth and the funds." [4TR3463]*

5300. And CAPP provided a similar example, and I quote:

> *"At a 33 percent tax rate you'd have to collect $1.49 to put a dollar into a fund -- that 49 cents seems to be an inefficient or inappropriate cost if a tax efficient structure would allow you to increase the toll by a dollar and put a dollar directly into a fund to cover abandonment cost.*
>
> *So essentially, the tax increases the cost without providing any additional benefit to the parties. It doesn't assist the pipeline in having more funds available to cover abandonment. It takes more funds out of the producers or the shipper's pocket, and it doesn't help the landowners to any degree." [5TR4418-4419]*

5301. During cross-examination by Board Counsel, Mr. Van der Put explained that all parties agreed this a critical issue, tax efficient treatment and is a need for all parties, including the Board, to pursue the expeditious resolution of the tax issue in order for collection to commence as soon as practical *[4TR3472; 4TR3258]*.

5302. These issues need to be determined prior to collecting for detailed abandonment costs.

5303. **Nominal approach**

5304. So now let me turn to TransCanada's proposal around a nominal or a placeholder fee which there's been some debate about.

5305. TransCanada recognizes that the determination of collection amounts based on detailed abandonment cost estimates will take some time. In light of that timing issue, TransCanada has proposed the collection of a nominal amount in

advance of the calculation of technical estimates *[lTR226; 4TR3243]*.

5306. TransCanada's proposal is consistent with the Board's suggestion in its Ruling Number 1 *[Ex. A-08A, p. 3]* that consideration of a nominal or "placeholder" amount would not be foreclosed. TransCanada submits that prior to implementing a nominal approach several things must first occur:

5307. One; all parties must select third party trust companies and draft trust indentures.

5308. Two; the Board will need to issue investment guidelines that will be included as part of the trust indenture;

5309. Three; all parties, including the Board, must take steps to address the tax efficient treatment of funds collected in trust accounts.

5310. And four; all parties, including the Board must consider how existing settlement agreements would be affected by a nominal surcharge for abandonment costs.

5311. The benefit of the nominal or placeholder charge means that these steps can be taken in parallel with the technical steps to be considered in Stream 4 which are required to calculate detailed abandonment cost estimates.

5312. And let me, again, quote Mr. Van der Put in response to Mr. Davies on this issue. Quote:

> *"The intent of proposing the collection of a nominal amount is to get the process started.*
>
> *It's recognizing that it's important for us to take a concrete step collectively towards addressing the issue of pipeline abandonment and, you know, clearly send a signal to the public at large, to landowners in particular, that they're not going to be held liable for the cost of abandonment, that steps are being taken to begin to collect those funds."*

5313. And he went on to say:

> "*There's no intent, by its very nature, to tie a nominal amount to specific costs. There would be the intention then to ultimately replace that nominal amount with a cost-based collection amount that, as I suggested, would be based on the conclusion of Stream 4*

> *in terms of the scope of the abandonment effort, which would then facilitate calculation of abandonment costs, supported with a full retirement study to identify the abandonment of facilities would take place." [4TR3288-3290]*

5314. The trust mechanism that TransCanada is proposing is not overly complicated and does not pose a significant delay in commencing collection. Ms. Leong explained to Board Counsel during cross-examination that setting up trusts should be deliberately kept simple. She said:

> *"I don't think we need to overcomplicate what we need to do here.*
>
> *I think -- and perhaps I'm oversimplifying, but the way I see it is we... do need to collect some money, whether or not it's today or tomorrow, and that money needs to grow over time to ensure that we can discharge that liability when the time comes.*
>
> *So the workings are something similar to pensions, but can be very well simplified." [4TR3579-3581]*

5315. TransCanada also submits that determining the quantum of a nominal amount can be kept simple.

5316. Mr Davies asks, "What do you have in mind is that all stakeholders then would come to an agreement on the nominal amount?" And Mr. Van der Put agreed and explained further that TransCanada expected, and I quote:

> *"Something in the order of a half a percent to one percent of revenue requirement that would have a 'nominal impact' on tolls." [4TR3281-3286]*

5317. The advantage of starting to collect a nominal amount is that it moves the Stream 3 initiative directly forward. TransCanada understands that the concerns of Enbridge and CAPP about collecting a nominal amount relate to imprecision *[2TR1172; 3TR2082]*.

5318. No party has suggested that collecting a nominal amount risks over-collection. However TransCanada's position is that imprecision is not a sufficient justification to do nothing and under-collecting is preferable to not collecting.

5319. Madam Chair and Board Members, you should think of this like an RRSP which was alluded to by CAPP, *[5TR461 1-4612]* the idea is to get started soon and put something away on a regular basis, even if it is only a placeholder amount.

5320. **Accounting Approach**

5321. So let me turn to Spectra's suggestion that the timing of collection should be determined by the Asset Retirement Obligation, or "ARO" under Generally Accepted Accounting Principles *[Ex. C-22-3, p. 2]*.

5322. And contrary to Mr. Davies' assertion, TransCanada agrees with Spectra that the CICA accounting standards have a great deal of rigour in determining financial liabilities.

5323. However, where we differ is that TransCanada believes that an accounting obligation to reflect certain legal liabilities is not a substitute for a regulatory policy device to ensure abandonment funds are collected.

5324. The CICA Handbook Section 3110 requires an ARO to be recorded if two things occur; (1) a legal obligation exists, and (2) a reasonable estimate of the fair value of the ARO can be made *[Ex. C-22-4B, p. 2]*.

5325. With respect, Madam Chair, the CICA Handbook, Section 3110 should not set regulatory policy. The role of accounting is to reflect regulatory and financial transactions, not to determine them. The Board must be mindful of the distinctions between regulatory obligations and accounting procedures.

5326. When cross-examined by Board Counsel I think Ms. Leong said it best. "To the extent -- and I quote:

> *"To the extent that there is a difference between the asset retirement expense that is going through the annual financial statements and the revenue in the form of what the Board determines is the appropriate collection, that amount, under current GAAP, is set up or may be set up as a regulatory asset or a liability, depending on whether or not it's a positive or a negative difference.*
>
> *The one thing I do want to comment is that in my mind the key accounting -- the key objective of accounting is to fairly present financial transactions on the financial statement of a company, and it really in no way should drive regulatory policies or framework. So I actually see the determination of future abandonment costs, the recovery of that, very independent from the accounting of that action." [4TR3605-3607]*

5327. It should not matter to the Board whether or not, as a result of establishing abandonment funds for either a nominal amount or Stream 4 based amounts, whether the pipeline companies come closer to having to book AOR liabilities or not. It is not relevant to the determinations you must make.

5328. Faced with a regulatory issue that must be addressed, the Board must address it, and the accountants will determine how to reflect the consequences of that regulatory decision in the company's financial statements.

5329. Finally, relying only upon the AOR procedure will create uncertainty as to when the collection of abandonment funds will begin because the determination, whether and when to collect or not collect, is left to the company *[3TR2542-2543]*.

5330. **TransCanada's Approach - Mechanics**

5331. Let me describe briefly how TransCanada sees the mechanics of the trust and the abandonment funds working.

5332. In TransCanada's proposal it would first see the Board issue formal guidelines to parties as an outcome of this Stream 3 process *[1TR226]*.

5333. Each pipeline company would apply to the Board under those guidelines for approval of the trust indenture that would govern each trust. This indenture would incorporate the ability for portions of the abandonment funds to follow a portion of the pipeline asset if it left NEB jurisdiction and provide for the treatment of any surplus or shortfall and contain the approved investment guidelines *[1TR226; 4TR3514; 4TR3529]*.

5334. Third, the day-to-day governance of each trust would be delegated to an independent professional trust company whose core function consists of administering trust funds *[4TR3503]*.

5335. Next, the Board would exercise oversight of trust fund performance on a regular basis and approve any necessary upwards or downwards adjustments to the abandonment costs that need to be collected over the life of the fund *[1TR226]*.

5336. And finally, pipeline companies would access the funds only upon receipt of leave to abandon from the Board under an application pursuant to section 74 of the *National Energy Board Act [Ex. C-26-4, p.16]*.

5337. TransCanada anticipates that because abandonment will be a process rather than a single event, there will be a time period during which pipeline companies will be both contributing to and making withdrawals from the trust funds

[Ex. C-26-4, p.3; 4TR3560].

5338. After taking into account the resources of a fund, shippers, the pipeline company and potentially government, there is no reasonable prospect that landowners will be at risk of any under-funding.

5339. Mr. Van der Put explained this to Mr. Vogel in cross-examination, that the risk to landowners was "almost negligible" given the strict regulation of the pipeline industry, regular periodic reviews proposed for abandonment funds and the associated opportunities to address collections in response to newer information *[4TR3318-3320]*.

5340. There is, therefore, no need for additional measures, such as financial assurances or pooled funds.

5341. Ms. Leong explained TransCanada's position that a robust review mechanism associated with the collection of abandonment funds is the best approach, and I quote:

> *"Periodic review is not just -- it's robust and this is why we need to ensure that the framework does respond to changes in circumstances or changes in legislation.*
>
> *The robustness will have to come from, for example, the frequency and how periodic the review is. In earlier years perhaps a five-year period, but as we move through time, perhaps we can tighten up that to an annual review.*
>
> *The other area where I think the robustness has to come in is also, if we adopt some sort of a trust or pension mechanism, the investment policy is very important and, again, robust enough that the investment policy can respond to the time as well." [4TR3501-3504]*

5342. During the hearing, Board counsel cross-examined CAPP on the nature of provincial abandonment funds for oil and gas wells in both Alberta and British Columbia *[4TR4540-4551; 4569-4588]*. TransCanada would caution the Board in looking to those as analogues.

5343. The upstream industry is fundamentally different than regulated pipelines. There are thousands of wells and pipelines that are not subject to ongoing financial regulation such as NEB regulated pipelines.

5344. Further, and as CAPP noted, the upstream industry and regulators together recognized an existing issue of orphaned sites that needed to be addressed. No such issue of orphaned sites exist for NEB regulated pipelines *[5TR4541-4551]*.

5345. The Stream 3 process is designed to avoid such issues from ever arising. As Mr. Van der Put stated, the world of NEB regulated Group 1 pipelines is restricted to "relatively few well-capitalized players." *[4TR3334]*

5346. There is no need to implement an orphan pipeline fund in these circumstances.

5347. TransCanada agrees with Enbridge when it stated that pooled funds present a "morale hazard" that breaches the principle of user-pay and cost-causation *[2TR951]*.

5348. TransCanada also noted that funds need to be able to follow the pipeline if there is a change in jurisdiction which might be impeded if funds were pooled *[4TR3514-3518]*.

5349. Madam Chair, let me be clear, TransCanada is ultimately responsible for the abandonment of the pipelines for which it holds title and certificates.

5350. Under TransCanada's approach, the pipeline is responsible to ensure that the abandonment fund has sufficient monies to cover abandonment costs. It is the pipeline company's responsibility to seek to recover any shortfalls from its shippers, *[4TR3564]*, and if there is any shortfall it is the pipeline and not the landowners that will be subject to that risk.

5351. TransCanada expects that with the proper management any overdue -- over or under collection will be minimal and not material, eliminating the need for any pooled fund for orphan facilities *[Ex. C-26-4, p.18; 4TR3560]*.

5352. But let me repeat: TransCanada owns the pipeline, it's ultimately responsible, and TransCanada will take the lead in ensuring abandonment is completed to the standard of the day.

5353. Madam Chair and Board Members, let me turn to three additional issues I'd like to touch on, one of which is financial assurances and the place of Stream 4 relative to CAPLA's "default option" and, finally, the need for flexibility to address competitive impacts.

5354. **TransCanada Has Not Proposed Financial Assurances**

5355. In respect of financial assurances, which came up during cross-examination, TransCanada has not proposed the use of financial assurances to address the issue of abandonment costs in this proceeding.

5356. Board counsel asked CAPP on Monday morning for CAPP's views on an apparent TransCanada position that financial assurances could be required of TransCanada shippers for abandonment costs, citing transcript paragraph 3640 *[5TR4555]*.

5357. Let me take you to that paragraph where Ms. Leong commented as follows:

> *"But assuming that these are prudently incurred costs and Board authorized costs, at the end of the day if we need an additional mechanism to ensure protection, protection at the ultimate risk of under-recovery is assured, then a financial assurance imposed on our shippers would be one element that could actually achieve that goal."*

5358. But, Madam Chair, Ms. Leong's comment was made in this context: It responded to a hypothetical question that was part of a comprehensive four paragraph response and continued an earlier exchange with the Chair *[4TR3619-3629]*.

5359. Let me be clear, TransCanada does not believe financial assurances are required for abandonment costs.

5360. **Stream 4 is the Forum for Technical Assumptions**

5361. With respect to Stream 4 and technical assumptions, CAPLA has asked that this Board order the pipelines to begin collection of abandonment funds immediately, based on the most conservative technical assumption that all pipelines be removed.

5362. Madam Chair and Board Members, pipeline removal is an issue of "retirement options" and that issue is specifically identified by the Board as a matter to be considered in Stream 4 in its discussion paper. A determination of that issue at this time is outside the scope of this proceeding.

5363. Further, the Board has ruled twice on this issue *[1TR411; 4TR3893]* that this proceeding deals only with the financial aspects of abandonment and not the technical aspects.

5364. The Stream 4 Discussion Paper lists retirement options as outstanding

issues and notes that the effects of corrosion, subsidence and how to deal with water crossings will all be addressed during that process *[Stream 4 Discussion Paper, pp.11 and 16]*.

5365. These retirement options identified by the Board for consideration in Stream 4 include whether the pipeline can be abandoned in place, removed in its entirety, some combination of both, or if it can be used for some other purposes. Those matters are to be considered in Stream 4 and not here.

5366. Finally, Madam Chair, it is doubtful, in any event, if the imposition of a toll component based on a worst-case default option that will exceed by definition the cost of service to which it relates -- namely, abandonment -- could constitute a toll that is just and reasonable within the context of Section 70 -- 62 of the *National Energy Board Act*.

5367. It is therefore abundantly clear, Madam Chair and Board Members, that the concerns expressed by CAPLA about abandonment in place, the effects of corrosion and the necessity of its default option can and should be considered as part of Stream 4.

5368. **Flexibility to Address Competitive Effects**

5369. Finally, let me turn to the flexibility needed to address competition. TransCanada submits that all parties should be concerned about how the collection of abandonment costs will impact competition.

5370. NEB-regulated pipelines compete regularly with U.S. and provincially regulated pipelines, which may not collect abandonment costs from shippers via tolls.

5371. Thus, the Board may be required in the future to adjust collection amounts as a result of the competitive impact of collecting abandonment costs *[Ex. C-26-4, p. 8; Ex. C-26-8; IR 2.3, pp. 1-2]*.

5372. Failure to address this potential competitive impact could further result in de-contracting, increasing tolls and ultimately reduce the ability of the pipeline to collect adequate funds, referred in this process to a "death spiral" *[4TR3613]*.

5373. Simply put, being uncompetitive will reduce the amount of abandonment funds that would otherwise be collected and reduce the capital available for abandonment.

5374. Let me refer you to Mr. Van der Put's evidence on this point, and I quote:

> *"One of the factors that we have pointed to is the issue of the risk of changes to the competitive dynamics between pipelines.*
>
> *If pipelines are treated differently, and particularly pipelines that transport similar products under similar circumstances, then one can take similar circumstances to mean, in part, perhaps serving the same supply basin or the same market area.*
>
> *I would suggest that one of the issues that the Board should be mindful of with regards to competitive factors is to certainly be vigilant with regards to that issue and set up a mechanism whereby there would not be differences between pipelines transporting similar products under similar circumstances in terms of the timing for commencing collection of abandonment costs…" [4TR3440-3442]*

5375. This concern also exists for producers. Costs have risen for producers at the same time as commodity prices have declined, and CAPP has testified that the industry is presently "in distress". *[5TR4490]*

5376. As Mr. Van der Put stated:

> *"We're well aware and very sensitive to the fact that shippers obviously are directly affected by the quantum of the collection amount." [4TR3456]*

5377. TransCanada's position remains that the Board should be sensitive to the impact that increased tolls for abandonment costs may have on both pipelines and toll payers in respect of competition and that should be considered in any conclusions or principles they arrive at as a result of this process.

5378. The concern surrounding the prospect of creating a competitive disadvantage was articulated by the Board in RH-2-2002 Reasons for Decision, at page 34, and I quote:

> *"With respect to the second factor, the Board is of the view that a 25-year economic planning horizon is more in line with the planning horizon used by competing pipelines. To require the Mainline to operate under a proposed 30-year (CAPP) or 35-year (FSG) planning horizon could be unfair to the Mainline, as it may place it at a competitive disadvantage should competing pipelines be fully depreciated sooner than the Mainline."*

5379. And, finally, TransCanada submits that this issue is appropriate for inclusion in any multilateral or international Board consultations concerning future integration of North American energy infrastructure with other regulators.

5380. **Conclusion**

5381. In conclusion, Madam Chair, TransCanada believes this process is a very important one. There is time to get it right, but we must also be prepared to move forward in a responsible manner, and TransCanada has put forward its position with those goals in mind.

5382. Thank you for your time this morning and this week, and if you have any questions, I'm happy to attempt to respond.

5383. **THE CHAIRPERSON:** Give us a minute, please.

--- (A short pause/Courte pause)

5384. **THE CHAIRPERSON:** Thank you, Mr. Denstedt, for your patience. We do have some questions for you.

5385. Madam Mercier.

5386. **MEMBER MERCIER:** Good afternoon. I have a question for you but it's mainly maybe because my attention maybe wandered for a few seconds.

5387. But it's got to do with the last part of your argumentation, and it was about the flexibility to address competition. And I just want to make sure that I understand things right.

5388. So you mentioned that a pipeline might be required to come to the Board to address us with some issue where there would be a lot of competition. What I'd be interested to understand a bit better is what is the message you wish to convey to the Board about if you encounter some competition that was not, I would say, forecasted, if that's what I understood?

5389. Can you just enlighten me a little bit about that?

5390. **MR. DENSTEDT:** Absolutely. Let me do this -- probably by way of an example is the best approach.

5391. There's two competing principles at play, the first being that all pipelines transporting similar products to similar markets should be treated the same and we

should be ready to embrace that principle.

5392. But at the same time, because there are pipelines that NEB-regulated facilities might compete with who are not under NEB jurisdiction, either provincially or internationally, that there should be enough flexibility in this process that would allow those pipelines faced with that dilemma to come to the Board and us and seek some sort of relief on a tolling basis.

5393. Because if the pipeline was not allowed to do that and they were being competed with unfairly by, for example, a pipeline in the United States, shippers may flood to that pipeline. Then, the toll for the collection of abandonment funds would then have to increase on the Canadian line.

5394. Further, shippers would roam and you'd end up with that death spiral of which we've spoken. So there has to be enough flexibility in the process that allows the Board to consider those types of things.

5395. **MEMBER MERCIER:** If I understand well, it would be like with due principle but it would be like exceptional measure that would have to be brought up from time to time.

5396. **MR. DENSTEDT:** Yeah, I think that's a good way of putting it; exceptional or extraordinary circumstances.

5397. **MEMBER MERCIER:** Okay, that answered my question. Thanks.

5398. **THE CHAIRPERSON:** Mr. Bateman.

5399. **MEMBER BATEMAN:** Mr. Denstedt, would you elaborate on the statement that you had made that an accounting obligation to require ARO documenting is not a substitute for a regulatory obligation to ensure abandonment funds are available when needed?

5400. **MR. DENSTEDT:** Sure. Quite simply, Mr. Bateman, is this proposition: The Generally Accepted Accounting Principles are there to reflect real world transactions and when a transaction occurs, the accountants look at the information in the GAAP and determine how to reflect that on a company's financial statements to accurately reflect the company's financial situation.

5401. But whether or not a transaction should occur -- for example, putting aside money for abandonment -- is a completely separate issue from the accounting procedure.

5402. The Board should decide is this an issue that we need to address today? Is this something that's important that money should be set aside for? And that decision should be taken first, and once that decision is taken, then that becomes a transaction that TransCanada would have to comply with.

5403. They'd have to set aside funds for abandonment and then they'd go back and they'd look at GAAP and they'd see how do we need to reflect that in our financial statements.

5404. So they are divorced and, by necessity, the policy decisions, particularly regulatory policy decisions, should be made on whether in fact it's needed or not needed from a regulatory perspective and whether that's in the public interest.

5405. **MEMBER BATEMAN:** Thank you.

5406. **THE CHAIRPERSON:** Thank you very much, Mr. Denstedt. Those are all our questions.

5407. **MR. DENSTEDT:** Thank you.

5408. **THE CHAIRPERSON:** Mr. Vogel, it would be CAPLA's turn. Now, would you like to have a quick break before you proceed or are you okay to continue on?

5409. **MR. VOGEL:** Perhaps everybody would enjoy stretching their legs.

5410. **THE CHAIRPERSON:** Let's take a 10-minute stretch break. We'll come back at 12:35.

5411. And just before we do that, I should let you know that it's the Board's intention to continue on. We seem to be moving through final argument at a reasonably brisk pace.

5412. So it would be our intention to continue on sitting the hours that we have sat before, to take a break at 1:30 for a quick bite to eat and then reconvene and finish up anything that is remaining after that point. So with everybody's indulgence, that will be the way we proceed.

5413. We'll be back at 12:35. Thank you.

--- Upon recessing at 12:25 p.m./L'audience est suspendue à 12h25
--- Upon resuming at 12:34 p.m./L'audience est reprise à 12h34

5414. **THE CHAIRPERSON:** Canadian Alliance of Pipeline Landowners' Association, please.

--- FINAL ARGUMENT BY/ARGUMENTATION FINALE BY MR. VOGEL AND MR. GOUDY:

5415. **MR. VOGEL:** Thank you, Madam Chair, Members of the Board.

5416. I'm pleased to present the final argument of the Canadian Alliance of Pipeline Landowners' Associations. We also have prepared and distributed for the use of the Board and for the Board staff and the reporter a written version of this argument that provides evidentiary and transcript references.

5417. So I will not include those references in my oral argument but I do request that those be included in the transcript as well as the headings in the written version, and the transcript should then reflect my oral argument.

5418. **Introduction**

5419. By way of introduction, Madam Chair, in its correspondence of January 17, 2008 establishing the Land Matter Consultation Initiative, the Board stated:

> *"The Board's objective for this review is to achieve the potential outcomes identified in the Proposed Approach (attached) so that the land matters are appropriately and effectively included in the Board's public interest considerations." [Exhibit C-I-6B. NEB correspondence of January 17, 2008 establishing LMCI, p. 1]*

5420. With respect to "Stream 3: Pipeline Abandonment - Financial Issues", the key principles identified by the Board as "fundamental to its future decisions with respect to the financial matters related to pipeline abandonment" include the principle that "landowners will not liable for costs of pipeline abandonment *[NEB correspondence February 25, 2008 attachment, amended LMCI Proposed Approach, p.4]*.

5421. The outcomes to be achieved by the Board in this proceeding, as set out in that document, include "identification of technical abandonment assumptions to be used to estimate abandonment costs" *[Ibid. p.5]*.

5422. The Board has expressed the key issue to be decided as "what is the optimal way to ensure that funds are available when abandonment costs are incurred?" *[Ibid. p.5]*.

5423. Accordingly, the key issue in this proceeding is to determine the optimal method of ensuring that necessary funds are available upon abandonment to implement the assumed technical abandonment option which fulfills the Board's fundamental principle that "landowners will not be liable for costs of pipeline abandonment".

5424. That is the fundamental public interest principle which was established by the Board as the foundation of this proceeding and it is what differentiates the Board's consideration of public interest in this proceeding as opposed to other proceedings.

5425. In the Board's balancing of public interest in this Stream 3 hearing the fundamental underlying principle of the whole process is that landowners are not to be liable for the cost of pipeline abandonment.

5426. To this end, in this proceeding, the issues to be determined by the Board include:

5427. What funds? That is the Board's issue 2(a), what technical and financial assumptions should be used to create preliminary estimates for abandonment costs.

5428. When? That's the Board's Issue 3. If companies are required to set aside funds, when should the collection of funds commence and;

5429. How? Board's Issue 4 and 5. If companies are required to set aside funds how should the funds be set aside and how should the funds be governed?

5430. I will be dealing, in my submissions, with the first question, "What Funds?" Mr. Goudy will then address the second and third question, that is "When" and "How" and I will then have some brief concluding remarks.

5431. Dealing with the question of "What Funds", on behalf of CAPLA, Dave Core has testified that "We're asking the Board to take all risk of abandonment away from landowners ... Our default position then is removal or maintenance into perpetuity to protect landowners *[Transcript, Vol 4, paras, 3959-3960]*.

5432. In this proceeding, CAPLA has proposed as the "default option" technical assumption for preliminary estimates of abandonment costs:

> *"The removal of large diameter pipelines in agricultural lands where all pipelines in a common corridor have been abandoned. Where one or more pipelines continue to be operated adjacent to abandoned pipelines that have not been removed, those adjacent*

> *abandoned pipelines must be maintained as though operating until removal is triggered by the cessation of operation of all pipelines in the corridor.... Only in this way can the Board address the concern of all parties 'that financial reserves are available ... to cover the costs of the necessary work' and ensure that landowners do not bear the risk of post-abandonment liabilities and costs." [Exhibit c-1-6, CAPLA's Initial Pre-filed Evidence, pp 18-19]*

5433. With respect to landowner risk, in considering what technical assumption will eliminate the risk for landowners of abandonment costs and liabilities in my submission the first question that must be asked is what land use, environmental and safety impacts result from abandonment in place.

5434. The removal/perpetual maintenance technical assumption proposed by CAPLA is based upon the only expert evidence filed in this proceeding with respect to the inevitable corrosion of pipelines abandoned in place in agricultural lands and the resulting land use, environmental contamination and safety impacts.

5435. Broadsword Corrosion Engineering Ltd. are corrosion specialists with extensive qualifications and experience in addressing pipeline corrosion issues.

5436. In Broadsword's expert report "Pipeline Corrosion Related Technical Issues and Long-term Landowner Impacts" Broadsword has recommended the following to address landowner concerns with respect to their potential liability for abandonment costs:

> *"Until abandonment of all pipelines in a multiple pipeline corridor and their mandatory removal, unless the pipeline owner can demonstrate the disconnected (abandoned) pipeline does not enhance corrosion of itself or adjacent common or foreign pipelines, the pipeline owner should be responsible for its perpetual maintenance or, in default, its removal. For the NEB to require otherwise may be a contravention of the CEA Act." [Exhibit C-1-6, CAPLA's Initial Pre-filed Evidence, Appendix 6, Broadsword Report, p.10]*

5437. This recommended "default option" is based upon Broadsword's expert opinion, as set out there, that:

> *"The physical disconnection of a cathodic protection system results in 'guaranteed corrosion' and hence increased wasteage and increased direct and indirect pollution. While the fine-tuning of the cathodic protection system of adjacent operating pipelines*

may minimize the problems discussed elsewhere in the report, location and proximity of the abandoned pipeline to other structures can be expected to impact the mitigative efforts of these pipelines. Even where the cathodic protection of the abandoned pipeline is maintained, there is no doubt that as the abandoned pipeline 'ages' and the external coating conductance increases with increased disbondment, the costs of maintaining a system will escalate non-linearly. Carlson et al. reported in their August 2001 paper that the current requirements rise by a factor of 5 times over the design life of the pipelines. Hence it is easy to see the reluctance on the part of pipeline owners to maintain abandoned pipelines when the costs can and will be substantial" [Ibid. p.11].

"At abandonment, current regulations require and CSA Z662-2007 Code infers that the pipeline must be disconnected from the cathodic protection grid. As was stated previously, the removal of the pipeline assures its eventual failure, possibly accelerated by:

Proximity to parallel power lines and potential for induced AC voltage on the pipeline;

Abandonment line section or region at crossings including water courses, roads, railway and common or foreign pipeline crossings;

Telluric earth current activity…" [Ibid, p. 13]

5438. So the implication of all of this, Madam Chair, is of course that the regulations must be changed to remit continuing cathodic protection on abandoned pipelines or those pipelines have to be removed to prevent the problems which result from the -- what Broadsword has referred to as "guaranteed corrosion" of pipelines abandoned in place.

5439. In Broadsword's opinion, this technical assumption is the basis for estimating abandonment costs is necessary because, as Pat Teevens testified last week:

"At the end of the pipeline life, the way the Act currently reads once the line is abandoned the NEB no longer has jurisdiction over it, and the pipeline operator is no longer around. then that leaves the landowner to deal with the liability." [Transcript, Vol. 4, paras. 3910, 3911]

5440. Broadsword's conclusions with respect to the "guaranteed progressive

deterioration of abandoned pipelines", related impacts and resulting costs and liabilities are consistent with similar Board and industry conclusions in their analysis of pipeline abandonment issues since 1985.

5441. In the Board's 1985 Background Paper, the Board observed:

> *"The main problem associated with [abandonment in place without continuing maintenance] is that it can be expected that an abandoned pipeline which is not maintained will eventually collapse due to the effects of corrosion. The surface soil depression that subsequently develops may become a safety hazard and present a host of environmental and land use problems."*

5442. And in the same report:

> *"… the best course of action is to either remove or maintain large and medium diameter abandoned pipelines." [Exhibit C-I-13C, CAPLA Reply Evidence, Appendix A. NEB "Background Paper on Negative Salvage Value", Sept.1985, p.1]*

5443. So with respect to the technical assumption options before the Board in this proceeding, my submission is that the evidentiary record is clear that the inevitable corrosion of pipelines abandoned in place will result in land use, environmental and safety issues.

5444. With respect to the nature of those issues and the related potential liability and costs that may result from these impacts, as excerpted in CAPLA's Reply Evidence, the industry's Pipeline Abandonment Steering Committee identified these safety, environmental and land use problems resulting from abandoned pipelines in its 1996 "Discussion Paper on Technical and Environmental Issues" as including disruption of drainage, physical obstruction to future development, interference with management practices such as deep ploughing, topsoil loss and safety hazards resulting from ground subsidence, prevention of farm equipment crossings and soil and water contamination *[Exhibit C-1-13B, CAPLA Reply Evidence, pp. 5-6 referring to Appendix C. PASC "Pipeline Abandonment: A Discussion Paper on Technical and Environmental Issues," Nov. 1996].*

5445. Similar observations and impact analysis are provided in the Board's 2008 LMCI Stream 4 Discussion Paper as excerpted in CAPLA's Second Evidence filing *[Exhibit C-I-9B, CAPLA Second Evidence Filing, pp. 5-6 referring to Appendix B, NEB "LMCI Stream 4: Physical Issues of Retirement and Reclamation Discussion Paper," Feb. 2008].*

5446. As discussed in this evidence, the creation of post-abandonment conduits for groundwater and contaminants and eventual subsidence following pipe collapse will interfere with agricultural operations and land use imposing on landowners production losses, equipment repair costs, potential liability for personal injuries and environmental impacts, and diminished land values.

5447. In addition, until pipeline removal, landowners will continue to experience the same operational and land use restrictions as from an operating pipeline; that is, increased compaction, reduced production, whole farm quality impacts, opportunity costs, agricultural and future land use limitations, et cetera *[Exhibit C- -9B, CAPLA Second Evidence Filing, p.13]*.

5448. Mr. Core has testified:

> "*...we're not able to, at this point, determine the exact cost of what's going to happen if pipelines are left in place, but there is going to be costs when pipelines are left in place. The same impacts we have today when we're farming will be the same impacts we have when pipelines -- if they're abandoned in place, and then the problem is there's more impacts and it's the financial aspects of those impacts if the pipelines are abandoned in place.*
>
> *If the pipeline collapses, we've got safety issues; we've got .financial issues; we've got impacts on our farms; we've got environmental issues, we've got the potential for corrosion and the movement of water between properties and possible contamination flow.*
>
> *We've got all these issues to deal with. And so a feasible -- ultimately, we've got to address those issues. So feasibility comes, from our perspective -- we want no risk left with us. These pipelines -- we chose to be farmers; we didn't choose to be pipeline landowners." [Transcript, Vol. 4, paras. 4008-4011]*

5449. So, again, my submission to you is that the record is clear that the land use, environmental and safety issues which result from pipelines abandoned in place create a risk of liabilities and costs.

5450. In the Board's consideration of a technical assumption which will protect landowners from this risk, the next question then is, currently, who bears the residual risk for these liabilities and costs?

5451. In 1985, the pipeline companies had a regulatory obligation to remove

abandoned pipelines -- and I've provided to you the reference there; the discussion of the 1985 regulatory requirement for removal, which is in the Board's 1985 Discussion Paper *[Exhibit C-1-13B, CAPLA Reply Evidence, p. 4]*.

5452. At that time, as excerpted in CAPLA's Reply Evidence, the Board supported the companies' concern that the risk of removal costs be addressed on the basis that:

> "*When an entire pipeline's useful economic life is exhausted and it is incapable of generating further operating revenues, the opportunity for adjusting the tolls to pay for the abandonment will have lapsed. It is probably with this concern in mind that companies are now seeking adjustments in their tolls to provide for the collection of negative salvage funds prior to the exhaustion of the useful life of the pipelines;*
>
> *In conclusion, as long as the Pipeline Regulations require the companies to remove their facilities after abandonment, 'unless otherwise approved by the Board', then the companies can be expected to continue to seek the Board's view on what will need to be removed so that funds can be set aside. Today, it is evident that it will be necessary to remove many facilities but the annual cost to be set aside is generally still small, relative to cost of service." [Exhibit C-I 13B, CAPLA Reply Evidence, pp. 4-5 referring to Appendix A, NEB "Background Paper On Negative Salvage Value", Sept. 1985, pp. 1,2]*

5453. The Board has recognized -- and again, I've provided the reference in the Stream 4 Discussion Paper to you -- that:

> "*...responsibility for enforcing response to problems that may occur on retired pipeline rights-of-way that was previously federally regulated appear uncertain*." *[Exhibit C-I-13D, NEB "LMCI Stream 4: Physical Issues of Retirement and Reclamation Discussion Paper", Feb. 200S. p. 7]*

5454. And despite Pouce Coupé's submissions to the contrary this morning to you, in my submission, the law at this point is clear, based on the *Manitou* case and other cases decided by this Board.

5455. And also as reflected in the Board's own Filing Manual Guide B requirements, which provide that pipeline companies are required to give notice to landowners on abandonment that the Board will no longer have jurisdiction after the

abandonment, my submission is clear at this point that the law is that the Board does not have jurisdiction to address issues post-abandonment.

5456. In addition, as identified by the Board in its LMCI Stream 3 Discussion Paper:

> "*...the costs to fund abandonment (and possibly decommissioning) could be incurred when there may not be sufficient company revenue to cover them. Hence, funding in advance is an important consideration.*" *[Exhibit A-2 C, NEB" LMCI Stream 3: Financial Issues Related to Pipeline Abandonment Discussion Paper," March 2008, p. 9]*

5457. That's from the Stream 3 Discussion Paper.

5458. As a result of the Board being without jurisdiction to address post-abandonment impacts, the effect of the regulatory amendments in the late l980s that eliminated the regulatory obligation for pipeline removal and permitted abandonment in place has been to shift the burden of risk for abandonment liabilities and costs from the companies to landowners.

5459. Landowners now bear the risk of abandonment liabilities and costs for which they may have no regulatory remedy and, in any event, to which the companies may no longer be available to respond.

5460. As also excerpted in CAPLA's Reply Evidence, the industry itself has identified in its 1997 "Legal Issues Relating to Pipeline Abandonment: A Discussion Paper" that:

> "*Termination of the right-of-way may result in the ownership of the pipeline reverting to the landowner. This will be by virtue of the terms of the right-of-way agreement and the fact of the abandonment;*
>
> *...the legal obligation on the part of a pipeline operator may exceed the life in fact of the operator*;
>
> *A landowner...may be liable in the event of loss or injury suffered as a consequence of improper abandonment, subject to a right of contribution and indemnity against the pipeline company. Environmental contaminants legislation might also impose obligations on a landowner in the event of contamination resulting from improper abandonment.*" *[Exhibit C-I-13B, CAPLA Reply*

Evidence, p. 7 referring to Appendix D, PASC "Legal Issues Relating to Pipeline Abandonment: A Discussion Paper", May 1997, pp. 8, 10]

5461. My submission to you is that to fulfil the Board's principle that "landowners will not be liable for costs of pipeline abandonment," landowners must be assured that sufficient funds are available upon abandonment for CAPLA's removal/perpetual maintenance default option.

5462. To do otherwise is to leave landowners with the risk of costs and liabilities for land use, environmental and safety impacts resulting from pipelines abandoned in place.

5463. As Mr. Core has testified:

> "*Now is the time to address the issue and the only way to address the issue, from our perspective, is the default position. Otherwise, you're leaving us with risk; [Transcript, Vol. 4, para. 4158]*
>
> *Abandonment in place...leaves us open to financial risk down the road. If a company* is *insolvent and there's nobody to cover those costs, you're leaving -- you're leaving landowners totally open to risk -- landowners or the government. As of right now, it's landowners, because the government has not alleviated any risk from us whatsoever."*

5464. So CAPLA's default option is the removal/perpetual maintenance default option as it's developed and set out in its Pre-filed Evidence.

5465. In its LMCI Stream 3 Discussion Paper, the Board proposed established a default methodology, stating:

> "*There may be benefit to establishing a default methodology or even a default charge (in units such as dollars per volume unit per kilometre), with provisions setting out any conditions that may allow for variation from the default. While review provisions always exist for NEB tolls or tariff orders, this approach would attempt to streamline the calculation of appropriate charges, with some pre-specified criteria for variation." [Exhibit A-2C, NEB "LMCI Stream 3: Financial Issues Related to Pipeline Abandonment Discussion Paper," March. 2008, p.17]*

5466. CAPLA's removal/perpetual maintenance default technical assumption for

preliminary estimation of abandonment costs provides such a default methodology that accomplishes the Board's objective of relieving landowners of the risk of abandonment liabilities and costs and that is independent of the Board's LMCI Stream 4 consideration of "principles defining the end state of land post-abandonment". *[NEB correspondence dated February 25, 2008 attachment, amended LMCI Proposed Proposed, pp. 5-6]*

5467. In LMCI Stream 4, the Board has indicated "a potential starting point for determining the desired end state after a pipeline is abandoned" -- and that's a potential starting point -- "is that NEB's goals 1 and 2 continue to be met." *{Ibid, p.6]*

5468. While the removal/perpetual maintenance option is the only technical option that accomplishes the NEB's goal that landowners not be at risk for abandonment liabilities and costs, the Board's adoption of this technical assumption in Stream 3 as the basis for setting abandonment funding requirements assures only the availability of necessary funds for this purpose.

5469. Importantly, it does not predetermine the "principles defining the end state of land post-abandonment" in Stream 4 or the result of future abandonment applications.

5470. With respect to the possible relevance of stream -- the Stream 4 outcome to this proceeding, CAPLA, I can tell you, is presently reviewing the Board's draft report on Stream 4 and the letter which came out of last week with respect to -- of January 21st, 2009 with respect to the revised draft principles.

5471. CAPLA will be providing comments in due course, but it's clear that those draft principles will not provide any assistance in Stream 3 with respect to when pipelines are to be removed or maintained and when pipelines are to be abandoned in place.

5472. Presumably those criteria, to assist in determining those issues, are to be developed by the multi-stakeholder study group that’s to be formed some time this year. But there’s no indication as to how many months or years it may take to develop these criteria.

5473. It seems obvious that Stream 4 will not be providing any guidance to assist in the determination of the appropriate technical assumption in Stream 3 in the foreseeable future. In fact, it appears the industry has made no progress in this regard since 1996.

5474. So, in my submission, the Board is left in the position where it can and should proceed with its Stream 3 initiative and adopt the removal/ perpetual

maintenance, technical assumption for the purpose of preliminary abandonment cost estimates as the only technical assumption which protects landowners from the risk of abandonment costs and liabilities.

5475. That will ensure that sufficient moneys are generated for this purpose, but it leaves open the possibility that the eventual result of Stream 4 or individual pipeline abandonment applications may, on a site-specific basis, permit something less.

5476. This removal/perpetual maintenance default technical assumption is again consistent with the Board's own analysis and conclusions from 1985 to date that have continued to endorse removal of large diameter pipelines -- 10 inches or more -- from agricultural land as the preferred default option on abandonment.

5477. Beginning with its table analysis of abandonment options in the 1985 background paper, and then the same analysis in its LMCI Stream 3 and Stream 4 discussion papers, the Board's position has remained constant. *[Exhibit C-1-6 C, D, E, CAPLA's Initial Pre-filed Evidence, Appendices 2, 3 and 4; Exhibit C-1-9B, CAPLA's Second Evidence Filing, p. 5]*

5478. As noted in the Board's LMCI Stream 3 discussion paper, where the Board in 1985 sample scenarios suggested removal of only 20 or 30 percent of below ground pipe, the Board expressly stipulated perpetual maintenance of the remainder. *[Exhibit C-1-13C, CAPLA Reply Evidence, Appendix A, NEB "Background Paper on Negative Salvage Value" Sept. 1985, p. 18; NEB "LMCI Stream 3: Financial Issues Related to Pipeline Abandonment Discussion Paper", Mar. 2008. p. 12]*

5479. Presumably the same stipulation applies to the Board's Stream 3 discussion paper suggestion that standardized cost calculations might assume 30 percent of pipe removal. *[Exhibit A-2C, NEB "LMCI Stream 3: Financial Issues Related to Pipeline Abandonment Discussion Paper". Mar. 2008. p.16]*

5480. Clearly in default of perpetual maintenance then, the Board's own table analysis continues to support removal of large diameter pipelines from agricultural land.

5481. With respect to the technical assumption to be selected by the Board in this proceeding as the basis for preliminary estimates of abandonment costs I do want to respond to some of the industry positions that have been advanced in this position.

5482. **Industry position**

5483. In its LMCI Stream 4 discussion paper the Board has identified its filing manual mandate to ensure that landowners have their rights protected and that

abandoned pipelines are not a liability to current and future owners. *[Exhibit C-1-13D, NEB "LMCI Stream 4: Physical Issues of Retirement and Reclamation Discussion Paper", Feb. 2008, pp. 5-6]*

5484. Industry positions advanced in this proceeding neither protect landowner rights nor relieve them of the risk for abandonment liabilities and costs for which they may have no recourse.

5485. More specifically, addressing firstly:

5486. **Abandonment in place leaves landowners at risk**

5487. The suggestion from the industry participants that determination of the preliminary technical assumption with respect to the method of abandonment should await the outcome of Stream 4 *[Exhibits C-10-3B, C-15-3B, C-19-4, C-26-4, Initial Pre-filed Evidence-Enbridge, p. 6, q. 2a; KMC, p. 4, q. 2b; Pouce Coupé, q. 2a; TCPL, p. 11, q. 12]* and Enbridge's proposal that, for the purposes of Stream 3, abandonment in place should be assumed to be the required method of abandonment *[Exhibit C-10-3B, Enbridge Initial Pre-filed Evidence, p. 6, Question 2A]*, provide no assurance that sufficient funds will be available upon abandonment to fund removal/perpetual maintenance to eliminate for landowners the risk of abandonment liabilities and cost.

5488. In this regard -- and these are quotations from Enbridge's cross-examination -- Enbridge acknowledges that:

> "*In order to estimate abandonment costs you have to have a technical assumption with respect to the method of abandonment. [Transcript, Vol. 1, paras. 336 and 337]; uncertainties with respect to the costs that may result from the technical assumption of abandonment in place contribute to the potential risk that at the date of abandonment the amount of the funds collected and set aside will differ from the abandonment costs that are incurred [Transcript, Vol. 1, paras. 342, 343]. For any pipeline it's going to be difficult, if not impossible, to accurately predict the cost consequences of dealing with issues that might be created by this technical assumption of abandonment in place [Transcript, Vol. 1, paras. 345, 346]; and that whatever that risk is [Enbridge says], that the collected fees will be less than the actual cost is not a risk that should be borne by landowners." [Transcript, Vol. 1, paras. 361, 362]*

5489. Kinder Morgan acknowledges that:

> *"The technical assumptions that must be made to create preliminary abandonment cost estimates includes the technical assumption with respect to the portion of the pipeline to be abandoned in place with or without cathodic protection removed. [Transcript, Vol. 2, paras. 1728-1730] If KMC was simply to make an arbitrary assumption, such as that all the pipelines would be abandoned in place, and the Board were to eventually require removal of the whole pipeline, there is a considerable risk that the amount collected would be wrong [Transcript, Vol. 2, paras. 1736, 1737]. That then creates the risk of a substantial deficiency in the funding of abandonment costs [Transcript, Vol. 2, paras. 1741, 1742]. The ultimate risk there of the funding deficiency is being borne by the landowners [Transcript, Vol. 2, paras. 1749, 1750], and, again, whatever that risk may be of insufficient funding is not a risk that should be borne by landowners." [Transcript, Vol. 2, paras. 1768, 1769]*

5490. Pouce Coupé similarly considers:

> *"The potential probability of that risk to be there, I would imagine, fairly small." [Transcript, Vol. 3, para. 2258].*

5491. And Westcoast agrees that:

> *"While there is a chance of a risk but it would not be material [Transcript Vol. 3, para. 2738], nevertheless, "whatever that risk is, Spectra's position in this proceeding is that that is not a risk which should be borne by landowners." [Transcript, Vol. 3, paras. 2739-2741]*

5492. TCPL agrees that:

> *"The companies will have to make a technical assumption with respect to the scope of abandonment, including the extent to which the pipelines may be required to be removed on abandonment or allowed to remain in place with or without continuing maintenance." [Transcript, Vol. 4, paras. 3305-3309]*

5493. And similarly acknowledges that:

> *"...there's a risk that, you know, that yeah, there could be under-funding [Transcript, Vol. 4, para. 3325]; whatever that risk of*

insufficiency -- insufficient funding, again, it's not a risk that should be borne by landowners." [Transcript, Vol. 4, paras. 3347, 3348]

5494. Enbridge admits that the Board's 1985 conclusion that:

> *"The best course of action is to either remove or maintain large and medium diameter abandoned pipelines Enbridge admits is certainly one solution to ensure that landowners are not required to bear the risk of post-abandonment, liabilities and costs associated with abandonment in place. [Transcript, Vol. 1, paras. 529, 530] If the Board's technical assumption is that pipelines will be maintained in place and then removed and not abandoned in place, the cost of that technical assumption could be reasonably estimated, that would be an important step in being able to reasonably estimate cost and that technical assumption could be applied to determine the size of the funds required." [Transcript, Vol. 1, paras. 563-568]*

5495. That's Enbridge's evidence again.

5496. With respect to this 1985 Board conclusion concerning removal/perpetual maintenance KMC agrees that:

> *"It is certainly one solution to ensure that landowners are not required to bear the risk of post-abandonment liabilities and costs." [Transcript, Vol. 2. paras. 1773-1775]*

5497. TCPL agrees:

> *"It is a potential solution but not necessarily the best solution [Transcript, Vol. 4, paras. 3360, 3361] pending consideration of potential environmental effects and the safety issues and the land use issues, all of which would impact a decision on a site-specific basis as to whether or not abandonment in place was appropriate." [Transcript, Vol. 4, paras. 3367, 3368]*

5498. Pouce Coupe:

> *"Does not have the expertise to say whether one is better than the other." [Transcript, Vol. 3, paras. 2211, 2212]*

5499. And Spectra similarly:

> *"Is not qualified to answer questions about preferred methods of removal." [Transcript, Vol. 3, paras. 2743, 2744]*

5500. Secondly, dealing with these industry positions:

5501. **No maintenance or time-limited maintenance leaves landowners at risk.**

5502. Similarly, Enbridge's suggestion that the time period of ongoing maintenance would be determined by the abandonment plan *[Exhibit C-10-8B, Enbridge response to NEB IR 1.10]* and TCPL's contemplation that any ongoing maintenance would be for a defined period of time *[Exhibit C-26-6B, TCPL response toNEB IR 1.4]*, in my submission, will simply delay the guaranteed progressive pipeline deterioration and related land use, environmental and safety impacts addressed in CAPLA's expert evidence.

5503. While these positions are consistent with CEPA's proposition that one of the broad assumptions that apply to the pipeline abandonment matrix for all diameter ranges and land use categories is that cathodic protection will be discontinued in all cases. *[Exhibit C-1-9B, CAPLA Second Evidence Filing, p. 9 reference to CEPA, Pipeline Abandonment Assumptions, September 2006 to April 2007, pp. 7-8]*

5504. And again, I've provided the reference to the CEPA report which is in the CAPLA pre-filed evidence.

5505. They fail to address the risk for landowners of liabilities and costs resulting from these eventual inevitable impacts. And in this regard KMC agrees that:

> *"Abandonment funds collected should be sufficient for ongoing maintenance of pipelines abandoned in place. [Transcript, Vol. 2, paras. 1779-1780] There should be sufficient funds to permit this ongoing maintenance to occur indefinitely." [Transcript, Vol. 2, paras. 1787-1788]*

5506. Thirdly:

5507. **Current company assets do not address residual risk**

5508. In its pre-filed evidence Enbridge has identified the potential risk that at the date of abandonment the amount of funds collected and set aside will differ from the abandonment costs that are incurred. *[Exhibit C-10-3B, Enbridge Initial Pre-filed Evidence, p. 13, q. 6]*

5509. TCPL has recognized that "there will always exist some element of risk that insufficient funds will be collected before a pipeline is abandoned". *[Exhibit C-26-6B, TCPL Response to NEB IR 1.7]*

5510. And if funds were not set aside for abandonment costs, the pipeline could be left at risk for these costs. If there is no fund -- this is from TCPL's evidence. If there is no fund and no pipeline company left after abandonment, landowners or the government could be at risk.

5511. Again, and this is acknowledged by TCPL, this contravenes the principle that customers who benefit from a service should bear the cost of providing the service and the principle that landowners should not be liable for these costs" *[Exhibit C-26-4, TCPL Initial Pre-filed Evidence, p. 9, g.8]*.

5512. CAPP acknowledges a risk to government, although it would "not expect that there would be a risk to the landowner" *[Exhibit C-2-7B CAPP response to NEB IR 1.8]*.

5513. So to address this risk, Enbridge proposes only that it is "confident that it will have more than sufficient financial means to satisfy its pipeline abandonment obligations, *[Exhibit C-10-3B, Enbridge Initial Pre-filed Evidence, p.3. q.4]* and Westcoast is similarly "confident that it would have sufficient financial reserves in place when the retirement costs are incurred, irrespective of whether it establishes a dedicated abandonment account" *[Exhibit C-22-4, Westcoast response to CAPLA IR 1.2(b) -(f)]*.

5514. However, Enbridge at least acknowledges that the extent of its resources to address abandonment costs and liabilities "cannot be known at present" *[Exhibit C-10-10, Enbridge response to NEB IR 2]*.

5515. As a result, landowners remain at risk for abandonment liabilities and costs for which they may not have recourse.

5516. In this regard, again, quoting from Enbridge's cross-examination:

> *"Enbridge agrees that "if a pipeline is abandoned in place there will be certain costs and liabilities incurred at the time of abandonment and potentially thereafter as issues may arise with respect to those pipelines abandoned in place." [Transcript, Vol. 1, paras. 441 -443]*

5517. And with respect to the possibility of its own resources being sufficient to

deal with those costs Enbridge says:

> *"Sitting here today we don't know what those assets may or may not be or the mix of them [Transcript, Vol. 1, paras. 475,476] and "beyond abandonment I also don't know what the balance sheet might look like [Transcript, Vol. 1, para. 480]. It acknowledges that "the obligations of a pipeline operator ... may exceed the life of that entity [Transcript, Vol.1, paras. 497-500] and, accordingly, that "whatever funding provision is made for abandonment liabilities and costs as a result of this Stream 3 proceeding, it must be sufficient so that landowners are not left bearing liability for those liabilities and costs [Transcript, Vol. 1 , para. 518].*
>
> *"Westcoast's view is simply "in terms of if there was an ultimate short-fall, how would you deal with that. I think you'd have to obviously deal with that at the time. I'm not sure we need to decide that today." [Transcript, Vol.3. para. 3059].*

5518. Well, with all due respect, Madam Chair, that is exactly why we are here today. The purpose of this Stream 3 proceeding is to ensure that the residual risk of a funding deficiency has been addressed in the technical assumption made by the Board so that the landowners don't continue to bear this risk.

5519. And finally, this issue about easement agreements; easement agreements do not determine the technical option.

5520. Westcoast has suggested that retirement options "could be influenced ... by the provisions of right-of-way agreements" (which can contain different obligations at the time of abandonment), *[Exhibit C-22-4A, Westcoast Response to NEB IR 1.6*] and Pouce Coupé suggests that "some land acquisition agreements may have recognized such costs and the compensation paid" *[Exhibit C-19-5, Pouce Coupé Response to CAPLA IR 1.2(c)]*.

5521. Land rights acquired by pipeline companies under standard form easement agreements are limited to those rights necessary for the construction and operation of the pipeline and damage claims released cannot extend to abandonment costs and liabilities not yet incurred.

5522. In any event, even easement agreements which may expressly provide that the company is not obliged by the provisions of the easement agreement to remove the pipeline -- which is the usual wording -- do not preclude ultimate Board determination that removal is required to protect landowners from abandonment liabilities and costs.

5523. The objective of Stream 3 is to ensure that sufficient funds are available for this purpose at the time of abandonment.

5524. In this regard, Pouce Coupé acknowledges that “some” [easement agreements] have dealt with the issue of abandonment but not necessarily the costs *[Transcript, Vol. 3, paras. 2276, 2277]* and even then easement agreement provisions simply provide “that the pipeline entity is not required to remove any of the pipe” *[Transcript, Vol. 3. para. 2455]*.

5525. So despite Pouce Coupé’s submissions again this morning to the contrary, in my submission, that does not -- any such provision does not mandate pipelines being abandoned in place. It does not displace the Board’s jurisdiction on an abandonment application to determine the appropriate method of abandonment.

5526. Neither does such a provision address who is going to be responsible for liabilities and costs which may be incurred in connection with and following the abandonment and it doesn’t deal with whatever liabilities landowners may thereafter incur under provincial environmental legislation with respect to liabilities and costs.

5527. All those agreements provide for is simply that the pipeline entity is not required to remove under the Easement Agreement the pipe but as I say, subject to contrary determination by the Board.

5528. Also, in any event, with respect to expropriated parties, Pouce Coupé has acknowledged that they may or may not have had the opportunity to deal with abandonment costs.

5529. CAPLA’s proposal that the technical assumption adopted by the Board in this proceeding fund the removal perpetual maintenance option, in my submission, does no more than ensure funding of what are the company’s current abandonment obligations.

5530. As I’ve said, upon an abandonment application under Section 74 of the *NEB Act*, Guide B of the Board's current Filing Manual requirements requires the company to notify landowners "that if the Board approves the abandonment, the Board will no longer have jurisdiction over the pipeline" and that the company develop contingency plans "to protect the landowner should subsequent land issues arise following the abandonment of the facility and surrender of the easement" *[Exhibit C-1-13G, CAPLA Reply Evidence, Appendix E, NEB Filing Manual, Guide B, p.4B-3]*.

5531. However, CAPLA's Pre-filed Evidence in this proceeding demonstrates

that current practice with respect to such abandonment applications does not include provision for the risk to landowners of abandonment liabilities and costs from pipelines abandoned in place *[Exhibit C-1-13B, CAPLA Reply Evidence, pp 7-8]*.

5532. I've provided there to you the reference to CAPLA's Reply Evidence which includes by way of an example, Enbridge's 2004 application for abandonment of a portion of its Line 1 NPS-20 pipe in Alberta and the environmental and socio-economic assessment which you'll see was filed as part of that application, originally in support of an order for abandonment in place.

5533. Neither identifies or assesses potential landowner impacts as discussed in the Board's and in the Pipeline Advisory Abandonment Committee discussion paper, including the future restrictions on land use and agriculture practice and potential for subsidence resulting from pipe corrosion with safety concerns and the impacts on agricultural practice or the potential for the corroded pipeline to become a conduit for groundwater and other contaminants; flooding -- none of those potential impacts are even mentioned in this example of an ESA from Enbridge's application.

5534. For the Board to require pipeline companies to make financial provision for CAPLA's removal/perpetual maintenance default technical assumption is only to ensure sufficient funding upon abandonment of the companies' regulatory removal obligation at the time many of these existing pipelines were constructed (and which underlie their acquisition of easement rights).

5535. Similarly, regulatory obligations with respect to pipeline removal upon abandonment and continued company liability despite surrender until the pipe is removed continue to apply in other jurisdictions including Alberta, Iowa and British Columbia. *[Exhibit C-1-13B, CAPLA Reply Evidence, pp 8-9]*.

5536. And again, those references are provided there in CAPLA's Reply Evidence, the *Alberta Pipeline Act*, and regulation impose a continuing regulatory liability on pipeline operators for post-abandonment costs and regulations.

5537. The regulatory provisions in Iowa provide the landowner with an option of requiring pipeline removal on abandonment, failing which the company remains liable for the damages. And since 1997 British Columbia has refused to permit pipeline abandonment's unless the pipeline is removed and the lands are restored.

5538. Recent landowner settlements also provide for easement agreement amendments which impose equivalent obligations on pipeline companies, including Enbridge and Westcoast affiliate Union Gas, and CAPLA has proposed in its LMCI Stream 1 response the same mandatory minimum easement agreement provisions *[Exhibit C-1-6, CAPLA Initial Pre-filed Evidence, pp 12-14]*.

5539. I've also provided there reference to CAPLA's Pre-filed Evidence which sets out the language of those easement agreement amendments. And you'll see in the case of Enbridge, Enbridge has agreed that it cannot surrender the easement without landowner consent and until that time it's required to either maintain, including cathodic protection or remove the abandoned pipe.

5540. Union has agreed to remove the pipe at the landowner's option upon surrender of the easement.

5541. My submission to you is that CAPLA's removal/perpetual maintenance default technical assumption simply assures sufficient funding to address these obligations.

5542. With respect to the regulatory feasibility of CAPLA's proposal, CAPLA has pre-filed in this proceeding the expert report of Ms. Cheung with respect to the regulatory feasibility of recovering the costs of its removal/perpetual maintenance default option through current tolls.

5543. As established by the Broadsword report, these are the costs for which reasonable provision must be made now to eliminate for landowners a risk of post-abandonment liabilities and costs.

5544. Ms. Cheung has extensive knowledge and experience with respect to toll design. She has provided her expert conclusion that:

> *"It is clear that the Board not only has jurisdiction over the abandonment of pipeline facilities but it also has the discretion to implement regulations that govern the abandonment of pipeline facilities for the protection of landowners from both safety and financial perspectives. This discretion encompasses the recovery of future abandonment costs in the pipeline's current cost of service if necessary. As the Board noted in its 2008 paper, its negative salvage value is the responsibility of the pipeline company and it is 'part of the full life-cycle cost of providing the service of transmitting hydrocarbons'. In that regard, one could conclude that the pipeline should be allowed to recover such costs from shippers through the transportation tolls. However, even in the absence of such collection, the pipeline company must remain financially responsible for all costs, not the landowners."*
> *[Exhibit C-1-6K, CAPLA Initial Prefiled Evidence, Appendix 9, Cheung Report, pp 9-10]*

5545. Madam Chair, Mr. Goudy will now deal with the questions of when and how concerning abandonment funding, and then I have some brief concluding remarks. Thank you.

5546. **MR. GOUDY:** First, with respect to the question of when funds should be collected, all NEB-regulated pipeline companies must be required to commence the accumulation of funds sufficient to cover the cost of the removal/perpetual maintenance option as soon as possible. At present, landowners are at risk for the cost of pipeline abandonment.

5547. This situation, which is contrary to the Board's principle that "landowners will not be liable for costs of pipeline abandonment" *[NEB correspondence February 25, 2008 attachment, amended LMCI Proposed Approach, p.4]*, will not change until the Board requires companies to begin setting aside funds to cover future abandonment costs.

5548. As Mr. Ness stated:

> *"Right now because pipelines were imposed on landowners, we actually have landowners sitting in a deficit position today because of the seven things that were imposed on us with the certificate. We have a deficit in the risk area. We have a duty of care, a duty of vigilance, liability, adverse effect, no enablement to recover hearing costs, and no rights and remedies. So we're today in a deficit position to start the game." [Transcript, Vol. 4, paras. 4076-4077]*

5549. The accumulation of future abandonment costs must also begin as soon as possible in order to mitigate or avoid the risk that insufficient funds will be collected during the economic life of the pipeline.

5550. Enbridge advocates the ability of companies to defer the commencement of collection of funds until a time when the abandonment of a pipeline is "reasonably foreseeable". *[Exhibit C-10-3 Initial Written Evidence - Enbridge, p. 7, A-3]*

5551. In Enbridge's submissions today this sort of flexibility is a habit of the Board. In this case, CAPLA would submit, it is a habit that must be reconsidered, just as the Board has revisited its 1986 decision to ignore the funding of abandonment costs until the companies would make a toll application for such.

5552. Kinder Morgan has identified that allowing a deferral of the collection of abandonment costs would lead to:

> *"a. The deferral of collection of abandonment costs in order to remain competitive;*
> *b. Back-end collection of abandonment costs; and c. A greater risk that abandonment costs could not be recovered from shippers because collection may occur in times of shipper distress."*
> *[Exhibit C-15-9B, Reply Written Evidence - KMC p. 3]*

5553. Further, Kinder Morgan explained that it disagreed with Enbridge's proposal to wait to begin accumulating funds until abandonment is "reasonably foreseeable" because "there is significant risk throughout the abandonment life. If the abandonment life could be truncated and if it were truncated there would not be monies available for removing the facilities." *[Transcript, Vol. 2, para. 1481]*

5554. Commencement of the accumulation of future abandonment costs now rather than later reduces risk for landowners of the future costs of abandonment both because it spreads the burden of funding over the remaining economic life of the pipeline (intergenerational equity) and because it allows the funding to take greater advantage of compounding the interest.

5555. TransCanada stated:

> *"But if we assume that there's a risk of too early a collection or over collection, when it comes to comparing that to the impact of early compounding interest, then there is a balancing. So the balancing is how soon, and from a compounding interest, I think our fundamental investment principles tell us that the earlier the better." [Transcript, Vol. 4, para. 3491]*

5556. The goal in accumulating the future costs of pipeline abandonment in advance is to remove the risk to landowners that they will be liable for these costs, which are properly the responsibility of the pipeline companies.

5557. The Board should reject Westcoast's proposal to leave the collection of future abandonment costs to a time when accounting principles require companies to recognize the liability for these costs on their balance sheets.

5558. As Mr. Core noted:

> *"...pipelines imposed on our farms make us uncompetitive with our neighbours, and as time goes on that uncompetitiveness becomes greater and greater until abandonment is addressed. Actually, these show up on our balance sheets now..." [Transcript, Vol. 4, para. 4143]*

5559. As rigorous as Westcoast may say accounting standards are today following the well-publicized accounting scandals in Canada and the United States, such standards should not hold up the Board's initiative to address landowner risk. TransCanada agrees.

5560. TransCanada says:

> *"So the extent that I don't agree that the accounting has a lot of rigour I just wanted to point out that it really shouldn't drive what the Board determines. So if at this point in time the Board determines that it's appropriate to collect an amount, given all the regulatory principles that are in place, then it really shouldn't delay just because there is no asset retirement obligation being recorded on the company's balance sheet." [Transcript, Vol. 4, para. 4143]*

5561. And Pouce Coupé also reiterated that in final argument today.

5562. Through its proposals to delay the commencement of accumulation of future abandonment costs according to its application of accounting principles and to avoid the obligation to accumulate abandonment costs in advance for its NEB-regulated gathering and processing pipelines, Westcoast, I would submit, is attempting to un-ring the bell.

5563. The Board principle that landowners not be liable for pipeline abandonment costs is well-established, and it is time to put in place the mechanisms that will ensure that the principle becomes a reality.

5564. Westcoast ignores the principle all together when it seeks to justify its proposal that some NEB-regulated landowners will be protected by the advance collection of future abandonment costs while others will not be so protected, saying:

> *"What we're asking for is that landowners in the gathering and processing business be treated the same as in the federally regulated context as they are in the provincially regulated context. We think that is the fairest outcome." [Transcript, Vol. 3, para. 2776]*

5565. In CAPLA's submission, the Westcoast proposal is neither fair nor in accordance with the Board principle that landowners not be liable for the costs of pipeline abandonment. All NEB-regulated pipeline landowners are deserving of the

same level of protection from future abandonment costs and liabilities.

5566. Westcoast, however, is concerned foremost with its own profitability. When asked about the segregation of funds to cover the future abandonment costs of its gathering and processing facilities, Westcoast replied:

> *"So if I was required to segregate, set aside funds and segregate them, then I have two choices; I can either not provide the service because I can't compete or I would accept -- have to accept an inadequate return on my investment." [Transcript, Vol. 3, para. 2575]*

5567. For Westcoast, it really comes down to protecting shareholder interests over landowner interests. "The practical matter", Westcoast continues:

> *"...is that we would absorb the surcharge and it would be taken out of our return to our shareholders." [Transcript, Vol. 3, para. 2650]*

5568. With respect, this process is about pipeline companies, their shareholders and their customers taking responsibility for their facilities so that landowners do not have to.

5569. And with respect to Spectra's suggestion that landowners want to stay in the proverbial bed all day because they don't want to get hit by a bus, I think that's laughable. A landowner has no interest or benefit to derive from assuming risks related to abandoned pipelines.

5570. I'm assuming that Mr. Davies has an interest or has some benefit to derive from getting out of this hearing room today and risking being hit by a bus to get home to his wife tonight.

5571. Pipeline landowners don't derive any benefit from the risk of abandonment costs and liabilities. There's simply no benefit that they could take from that. And so I think the analogy is a wrong one.

5572. And, of course, the Board has dealt -- as Enbridge's counsel, I think, discussed this morning -- the Board's dealt with risk in previous decisions, risk in facilities hearings and in tolls hearings, and in those hearings it's balanced the interests of stakeholders as part of the discussion of the public interest.

5573. But there's been no process before the Board in the past, perhaps with the exception of facilities abandonment applications -- and to my mind -- to my

understanding, landowners were not involved in those proceedings.

5574. There's been no other proceedings before the Board where the landscape that results from the decisions that the Board makes would make -- lies empty of all parties except for the landowner; in making decisions in facilities approval processes and in tolls hearings, the landscape that comes after that decision involves all the stakeholders.

5575. When making a decision about pipeline abandonment, ultimately, there's just -- there's just the land and the landowner left.

5576. CAPLA submits that, for that reason, the landowner interest should be given special consideration by the Board above the interests of other stakeholders because, at the end of the day, it's the landowner that's left with the land and the pipe.

5577. To move on to the question -- move away from the questions of timing and on to the question of how abandonment costs should be collected. I submit that process and timing are closely linked in addressing landowner risk for costs of pipeline abandonment.

5578. The economic principles previously discussed dictate that the accumulation of funds to cover future abandonment costs should begin as soon as possible.

5579. What is possible depends upon the process that the Board will undertake from this point forward. None of the industry participants in LMCI Stream 3 provided the information necessary to establish preliminary costs estimates for abandonment funding purposes in this proceeding.

5580. A further generic proceeding will be required in order to prepare estimates and set abandonment cost funding goals to be applied to all NEB-regulated pipelines.

5581. CAPLA supports the collection of funds to cover future abandonment costs by pipeline companies through tolls charged to their shippers. End users have a responsibility to pay for the cost of the facilities they use, including the costs associated with the disposition of those facilities following the end of their economic life. Landowners should not have such a responsibility.

5582. The funds that are collected by pipeline companies from their shippers must be protected from the risk of seizure by creditors of the pipelines as well as from undue investment risk.

5583. Therefore, CAPLA supports the establishment of pipeline- specific trust

funds to be maintained and administered by independent third-party trustees.

5584. As previously stated, preliminary cost estimates should be established through an additional regulatory process immediately following the conclusion of LMCI Stream 3.

5585. The Board should require pipeline companies to provide the company specific information identified by the Board as "essential to develop estimates for standard cost elements" regarding the future costs of the removal/perpetual maintenance abandonment option.

5586. This secondary process could be established as a generic hearing to design and institute an industry-wide methodology for the estimation of future abandonment costs that would be applicable to all Board-regulated pipeline companies, whether or not they chose to participate in the proceeding.

5587. This process could also design and institute a methodology by which the amount of the annual contribution toward the future cost of abandonment would be calculated, based on the estimated remaining life of an individual pipeline. Pipeline companies would then be required to submit to the Board abandonment cost estimates based on the generic method as part of their tolls filings.

5588. CAPLA does not support the collection of a nominal amount by pipeline companies in advance of setting the preliminary cost estimates for pipeline abandonment upon which subsequent collections would be based.

5589. Just as the creation of a deferral option as proposed by Enbridge is likely to lead to all companies delaying the commencement of abandonment funding in order to maintain their competitive positions, the establishment of a nominal charge by the Board at this point provides an opportunity for pipeline companies to delay the establishment of abandonment cost estimates on the basis that at least something is being done in the interim.

5590. Instead, the Board should not delay in taking the steps necessary to set preliminary estimates and to set tolls to be charged to shippers. The time required to set up nominal charges will most likely extend the time required to reach the necessary point where appropriate amounts are being collected towards the future cost of pipeline abandonment.

5591. We don't share Enbridge's concern expressed this morning that the nominal amount may turn out to be an over collection, but we agree that collection of a nominal amount is not what is required to provide assurance to landowners, and

neither is Enbridge's deferral option. I think they're really at opposite ends of the same spectrum.

5592. Therefore, CAPLA sees that under-collecting of a nominal amount now may not, as Mr. Denstedt said, be better than no collection, in these circumstances. We can appreciate the intention of TransCanada's proposal, but we see that the potential downside may outweigh the benefit.

5593. The Board would have oversight of the fund collection and management process, and annual or biannual reporting on fund performance would be required.

5594. Landowners must have a role in fund oversight and management, which may include memberships on the boards of abandonment funds and must include funded participation in Board regulatory processes involving the collection and management of abandonment funds.

5595. As noted by Mr. Kraayenbrink regarding this hearing:

> *"... everybody else in this room, I'm sure and positive, is getting paid today and all week long, except us landowners. It's all coming out of our back pocket, and that's one deficiency that even after today you should talk about. And that really has to change because that is really, really unfair."* *[Transcript, Vol. 4, paras. 4268-4269]*

5596. In particular, CAPLA proposes that the Board establish a standing committee or board involving landowner representatives to oversee and audit the overall collection of abandonment funds by all individual pipelines regulated by the National Energy Board.

5597. Participation in such a committee, in addition to meaningful and funded participation for landowners in Board processes, including section 74 applications for abandonment, will help to establish and maintain landowner confidence that pipeline companies and their customers, not pipeline landowners, will be fully responsible for the costs of pipeline abandonment.

5598. Transparency, as suggested by industry participants in this hearing, isn't good enough. Perhaps some answers may come from LMCI Streams 1 and 2, but we submit that there's a role for the Board to play in Stream 3 -- in the Stream 3 process to enable and include landowners in the process, in the future process to be established.

5599. The idea that landowners can continue as they do today, to read documents

released by the Board as filed by pipeline companies, does not address their concern about leaving their risk for abandonment costs to be decided without their ongoing knowledge and input.

5600. And besides, it's been the landowner experience that important information filed by companies with the Board is subject -- often subject to confidentiality restrictions, confidentiality that is requested by companies and granted by the Board to the exclusion of landowners.

5601. In addition to its ongoing oversight of fund collection and management, the Board must also institute a process for the regular periodic review of abandonment cost assumptions to ensure that the incremental amounts being collected will be sufficient to cover the future cost of abandonment, taking into consideration changes in various factors affecting that cost.

5602. Landowners must play a key role in this review process and their participation must be fully funded. The review of the generic cost assumptions established by the Board could be conducted as part of a generic hearing every three to five years.

5603. As part of the separate fund performance reporting obligation and review process, including tolls applications, pipelines companies would be required to demonstrate on a regular basis that their pipeline-specific application of the generic cost assumptions remains correct and that their collection of funds remains on target.

5604. Amounts collected in an abandonment fund to cover the future cost of abandonment would be available only to cover the cost of abandonment activities which have been approved by the Board as a result of a section 74 abandonment application.

5605. As with all other Board regulatory processes in which the interests of landowners are directly affected, landowners must have a full and meaningful role in abandonment application processes and their participation must be fully funded.

5606. CAPLA submits that the cost of landowner engagement in the abandonment regulatory process is a proper cost of abandonment that should be included in the Board's determination of abandonment cost estimates.

5607. Access to amounts in abandonment funds required to cover Board-approved abandonment costs would require Board assent and compliance with any other conditions established as part of the trust underlying the fund.

5608. In CAPLA's submission, Pouce Coupé's position that the risk of misuse by

pipeline companies of abandonment funds collected by shippers is outweighed by concerns about the administrative burden of an approval process should be rejected by the Board as self-serving and irresponsible. *[Transcript, Vol 3, paras 2249-2250]*

5609. Pouce Coupé and Westcoast both advocate a light-handed approach, and CAPLA would submit that the Board took such a light-handed approach when it revised its Abandonment Regulations in the late 1980's, when it decided to let companies off the hook, as Mr. Vogel has explained, so that it has taken until today for landowner abandonment concerns to be recognized.

5610. In our submission, light-handed regulation is not the appropriate way to deal with the abandonment of pipelines and the protection of landowners. Westcoast's light-handed framework was not one for which landowners bargained.

5611. Landowners rely on Board regulation, not on self-regulation by companies; not when we're dealing with abandonment and abandonment cost funding.

5612. To address the very real possibility that one or more pipeline companies in the future may be financially unable to address abandonment funding shortfalls, where the amounts collected are insufficient to cover the cost of abandonment at the time that the cost is incurred, in which case landowners will be left at risk for the costs and liabilities associated with abandonment, the Board must also institute an alternative source of funding to cover "orphan pipelines".

5613. CAPLA suggests that this alternative source of funding could be an orphan pipeline fund created by the Board to which each regulated pipeline company would be required to contribute, including the contribution of surplus amounts in abandonment funds left over following the completion of abandonment activities for particular pipelines, or it could be a legislated obligation on the part of government to cover the cost of pipeline abandonment where a pipeline company defaults on that obligation.

5614. And briefly on the issue of surplus that may remain in a pipeline abandonment fund once the costs of abandonment have been covered, CAPLA submits that the Board should avoid setting up a system in which surplus funds are directed in advance to the pipeline company.

5615. There is an incentive in that case, we would submit, especially for a company whose prime concern is return to its shareholders, to under-spend and cut corners on abandonment activities so that a surplus will remain for the benefit of shareholders.

5616. All National Energy Board-regulated pipeline landowners are at risk of the costs of pipeline abandonment and are deserving of equal protection from the costs of pipeline abandonment.

5617. It must be recognized that orphan pipelines are a risk to landowners, not because, as Board counsel suggested, they are "a pipeline or associated facility which does not have any legally responsible or financially able party to deal with its abandonment and reclamation," but exactly because when pipeline companies and their customers have failed in their responsibilities, it will be landowners who are legally responsible under federal and provincial environmental legislation and the common law for the harmful and costly effects of corroding abandoned pipelines.

5618. This residual risk is real. It's legislated into reality. Likewise, what is real is the presence of the pipelines in the ground; they are there. With respect, addressing this risk now is both reasonable and practical.

5619. Enbridge's response on this issue is that the risk isn't there because landowners can rely on the company and its assets. And one question that arises is, What happens if the pipeline is sold to another company?

5620. The answer given by industry is that the sale would have to be approved by the Board, but that gives little comfort to landowners who struggle to participate in Board approval processes in which they must pay their own costs.

5621. And, finally, Pouce Coupé mentioned this morning in its response -- or, in its submissions that personal liability as a form of insurance that funds will not be misused was a possibility.

5622. And CAPLA would submit that if industry is not prepared to address residual risk of orphan pipelines through an orphan pipeline fund or some similar mechanism, then perhaps the answer is to remove the legislated liability for landowners that they have coming out of provincial and federal environmental legislation, and institute liability for officers and directors of pipeline companies that default on the payment of abandonment costs.

5623. Mr. Vogel will now provide some concluding remarks.

5624. **THE CHAIRPERSON:** Thank you, Mr. Goudy.

5625. **MR. VOGEL:** Just briefly by way of conclusion, Madam Chair, I'd like to turn to the evidence of CAPLA's panel.

5626. On behalf of CAPLA and Canadian Pipeline Landowners, Mr. Core has

testified:

> *"I don't think the true cost of pipelines has ever been addressed, and 1think it's in the public interest that it finally be addressed, and that's about efficiency, because we're moving in -- the world has evolved and the industry has been subsidized too long by landowners.*
>
> *And I don't think the public understands that they've been subsidized by landowners and I think it's time that the true cost of moving energy across Canada be represented, because then that efficiency of recognizing that cost will be recognized in the cost of energy, and then other choices will be made about energy.*
>
> *Not that I want to undermine the oil and gas industry or pipeline industry, it's just only responsible that the true costs of moving energy be addressed. If it's going to be subsidized, it should be subsidized by the government or the consumer. That's a choice they should make. It should not be subsidized on the backs of landowners. [Transcript, Vol 4, paras 4265-4267]*
>
> *Abandonment funding has to start tomorrow and it has to start based on our default option. You can lower the fees as you come up with different assumptions later that guarantee we don't have a risk. You can lower those fees, but it's going to be too late if you have to raise them. So let's start at a responsible place and go from there." [Transcript, Vol 4, para 4293]*

5627. CAPLA's removal/perpetual maintenance default option is the only technical assumption which assures the availability of sufficient funds to eliminate the risk for landowners of abandonment liabilities and costs.

5628. This technical assumption is based upon the expert evidence filed by CAPLA in this proceeding and is consistent with the Board and industry's own analysis and conclusions from 1985 to date.

5629. Adoption by Board of the removal/perpetual maintenance technical option as the basis for preliminary determination of abandonment costs assures only the availability of funding of the legal obligations of the companies at the time many existing pipelines were constructed and easement rights acquired, the current easement commitments of at least some industry participants, and the standard form easement agreement commitments proposed by CAPLA in LMCI Stream 1.

5630. The end result of LMCI Stream 3 and any subsequent related process must be the collection by pipeline companies of funds sufficient to cover the cost of the removal/perpetual maintenance abandonment option.

5631. All pipeline companies regulated by the Board must be included, and CAPLA proposes that the amounts necessary to fund abandonment costs be collected beginning as soon as possible as tolls by pipeline companies from their shippers.

5632. The amounts collected should be accumulated in trust funds subject to each pipeline -- specific to each pipeline maintained and administered by an independent third party trustee. The Board must establish a process for the periodic review of abandonment cost assumptions in which landowners have a meaningful and funded role.

5633. CAPLA also proposes that the Board establish a standing committee involving landowners which will have oversight and audit authority with respect to all pipeline abandonment funds.

5634. In the Board's review of principles to guide retirement and reclamation in its LMCI Stream 4 discussion paper, the Board has concluded:

> *" ... land use and the landowner's perspective with respect to aesthetics and convenience are the most important considerations;*
>
> *... reclamation should be commensurate with likely adverse effects and their potential significance. Related to this concept is the recognition of uncertainty inherent in assessments of future impacts, which may infer that impact to the environment should be as low as reasonably achievable."*

5635. That is the precautionary principle.

> *"Considerations of safety and mitigation of impacts on the environment, people and society lead to an integrated and sustainable approach to decision-making with respect to energy development. Consideration of the needs of future generations is of primary importance when deciding on an appropriate retirement and reclamation methodology." [Exhibit C-1-13D, NEB "LCMI, Stream 4: Physical Issues of Retirement and Reclamation Discussion Paper", Feb 2008, pp 4-5]*

5636. That's the principle of sustainable development.

5637. If you apply those same principles to the Board's consideration of Stream 3 issues, CAPLA respectfully requests that the Board require companies to begin immediate collection of abandonment costs based on CAPLA's removal/perpetual maintenance technical assumption and that, as the parties bearing the residual risk, landowners be afforded a meaningful role in governance and application of collected funds.

5638. Those are my submissions, Madam Chair, and I would be happy to answer any questions.

5639. **THE CHAIRPERSON:** Thank you, Mr. Vogel.

--- (A short pause/Courte pause)

5640. **THE CHAIRPERSON:** Thank you, Messrs Vogel and Goudy. The Board has no questions.

5641. **MR. VOGEL:** Thank you, Madam Chair and Board Members.

5642. **THE CHAIRPERSON:** This appears to be a reasonable time to take a late lunch for all of us.

5643. According to the clock I always look at, I understand there could be some differences between my clock and your clock, but it's 10 to 2:00 and I would suggest that we return at 2:30 to continue on with CAPP's final argument.

5644. Thank you everyone.

--- Upon recessing at 1:48 p.m./L'audience est suspendue à 13h48
--- Upon resuming at 2:30 p.m./L'audience est reprise à 14h30

5645. **THE CHAIRPERSON:** We're back everyone.

5646. I call upon the Canadian Association of Petroleum Producers now, please.

--- FINAL ARGUMENT BY/ARGUMENTATION FINALE PAR MR. SCHULTZ:

5647. **MR. SCHULTZ:** Good afternoon, Madam Chair, Members of the Board.

5648. These are the submissions of the Canadian Association of Petroleum Producers and I have provided copies to the Court Reporter and also to the interpreters to assist them.

5649. Madam Chair, Members of the Board, never in the history of the Board has so much agreement masqueraded itself in the guise of litigation.

5650. My apologies to Winston Churchill.

5651. It is what the parties agree on in this hearing that is remarkable.

5652. Indeed, the extent of agreement struck me as remarkable when -- along with the pipelines and landowners -- CAPP first learned in the fall of 2007 that the Board was going to work towards the establishment of abandonment funds.

5653. The opportunity then -- as it is now -- is to take that agreement and fashion it into a decision that has the resounding support of the parties and that will become the sound declaration of principle that makes government inaction on tax changes unthinkable.

5654. This is what is agreed -- or agreed to by almost all in this room:

5655. First, abandonment is the responsibility of the pipeline;

5656. (2) The landowner should not be liable;

5657. (3) Abandonment costs are legitimate for cost of service and collection in tolls;

5658. (4) A trust arrangement is required;

5659. (5) The trust arrangement should be tax efficient;

5660. (6) The Board will play a key role from beginning to end in relation to the various individual trusts established;

5661. (7) Technical issues necessary for estimating costs will be informed by the work of Stream 4;

5662. (8) Each pipeline subject to the trust requirement will need to bring forward studies to determine the timing of collection and the amount to be collected;

5663. (9) Periodic review of the assumptions and amounts will be required over time;

5664. (10) The pipeline will be when the last dollars have to be spent and the pipeline has fully and finally stopped providing service to anyone, the pipeline will be

responsible for any deficiency in its abandonment fund;

5665. (11) Tax efficiency for the fund will require the Government of Canada to make revisions to the income tax rules;

5666. (12) Pipelines will be in business for a very long time into the future; abandonment is not imminent, there is time to get it right.

5667. Given the magnitude of future abandonment costs when they are ultimately incurred, an economically inefficient mechanism is completely unacceptable.

5668. It is because the NEB method of cost of service regulation by itself would lead to an inefficient outcome that an economically efficient mechanism is necessary.

5669. Why would anyone collect $1.49 of abandonment costs when only $1.00 is needed? Yet as Mr. Johnson explained the timing and tax treatment of revenue collected by pipelines under cost of service regulation leads to just this result.

5670. And by the way, I might note that the $1.49 is driven off a 33 percent tax rate. If Mr. Johnson had used a 40 percent tax rate in the example you'd need to collect something in the order of $1.65 for every dollar needed.

5671. A change in tax regulations to allow tax deductibility of the funds collected for deposit into the trust fund is necessary to avoid the inefficient result.

5672. We understand that the Government of Canada -- before acting on this -- requires a regulatory requirement by which this Board -- sorry -- requires a regulatory requirement by this Board for the collection of the fund. You have it in your power to establish that necessary pre-requisite.

5673. You also have it in your power to recommend the needed change to the government.

5674. Abandonment, among other things, has a safety aspect to it. Your own material on abandonment emphasizes safety.

5675. Part II of the *NEB Act*, Sections 26(1)(b) and 26(1.1)(b) require that you must do certain things when pipeline safety is an issue;

> *"(1)(b) The Board shall study and keep under review the safety of pipelines;"*

> *"(1.1) (b) The Board shall report...such measures within the jurisdiction of Parliament as it considers necessary or advisable in the public interest for...the safety of pipelines...."*

5676. Not only may the Board advise the government on this, it has a positive obligation to do so.

5677. Surely it must be plain for all to see that having to collect half again as much as is needed for pipeline abandonment costs just to pay an unnecessary tax makes no sense. When all the various risk factors that have been talked about in this proceeding are stacked up, one risk factor trumps all others: The risks of imposing an economically inefficient mechanism on the pipeline industry.

5678. Half again. That is what we are talking about -- half again.

5679. Think of this: You can have a dollar of funds available for abandonment for every $1.49 you collect under standard regulated cost of service, or you can have $1.49 of funds available for abandonment for every $1.49 you collect under an efficient mechanism. Half again as much is what you can get with an efficient mechanism.

5680. Is the need for a tax-efficient mechanism different than what happens in Alberta for producer abandonment costs? Absolutely. And for good reason.

5681. For one thing, producers are not regulated on standalone cost of service with the gross-up for taxes that comes with the build up of cost into regulated revenue.

5682. Producers take the price in the market, and what is left after costs are netted out is their net revenue knew. Costs, like the regulated costs of transportation, matter a great deal to producers. Producers are the only toll payers presenting evidence in this hearing.

5683. As Mr. Jardine explained, the great majority of wells and related facilities in Alberta have, as the assurance of abandonment and reclamation, the corporate assets of the ongoing business of the producer. There is no abandonment fund such as the Board proposes for pipelines.

5684. The orphan arrangement in Alberta is designed to make a general fund unnecessary.

5685. Producers collectively cover off a very small residual of historic orphans through the orphan fund with the primary emphasis on payment for abandonment by

the producer responsible. The asset test is one critical layer in this mechanism, and enforcement by the ERCB is another.

5686. This is the key difference: When the or natural gas producer incurs an abandonment expense, it is, as Mr. Johnson told us, a deduction from their general revenues and there is no mismatch or mistiming of expense and deduction.

5687. As Mr. Johnson also told us, recognizing the CICA accounting requirement for abandonment liability impacts the shareholder by way of the accrual on the financial statements and the offset against the assets of the company otherwise available to support further investments. However, no cash changes hands and cash flows to the company are unaffected.

5688. But this is quite different from the impact of taxes under cost of service regulation where the pipeline revenue is determined by the costs and then there must be a gross-up for income tax.

5689. The inefficient use of capital does nothing to advance the Board's goals. It comes with a cost to society and the economy from lost investment. It could have the perverse effect of stimulating premature abandonment.

5690. When we remember that pipelines exist only because they serve the public interest, it would be truly perverse to unnecessarily put their ongoing viability at risk.

5691. The inefficient use of capital is utterly unacceptable in the context of a regulatory reform project as significant as this. Half again. Half again in the context of what will ultimately amount to billions of dollars.

5692. Imagine that $3 billion is collected from toll payers and $1 billion of that disappears into standalone income taxes that might or might not be paid to Revenue Canada, depending on the tax position of the company owning the pipeline. It is outrageous to imagine this, let alone have that happen.

5693. Tax deductibility of the earnings of the fund would also contribute to tax efficiency and should be part of any proposal. This is like an RRSP. The taxation would occur when the funds are withdrawn, but then the offsetting expense would also occur at that time as well.

5694. I do not want that to get lost. My emphasis on the "half again" point is to drive on the most plainly visible inefficiency. Tax-free earnings within the fund are also important.

5695. Landowners expressed clearly their frustration -- indeed anger -- with

having pipelines on their land. Let's turn that energy -- along with the energy of all parties -- in the direction of Ottawa to get cracking on what is an entirely reasonable proposal for tax efficiency. Similar things have been done before and they can be done here.

5696. As Mr. Jardine said, CAPP fears that if the inefficient cost of service approach is implemented to begin collection of some nominal amount, the momentum to effect change will be blunted and the opportunity for change will slip further away.

5697. Collection of a nominal amount would be symbolic. It would add little to the ultimate goal, but it would entrench inefficiency and it would give sway to arbitrariness. Nominal amounts are not arbitrarily collected for other pipeline costs.

5698. Collection of abandonment funds immediately, even a nominal amount, would, as Mr. Jardine explained, likely put parties who have made deals based on known toll levels into loss positions.

5699. CAPP has proposed a multiparty working group to advance this cause and is pleased that others have taken this up favourably in their arguments.

5700. Achieving the goal of establishing a sound economically efficient trust structure for abandonment costs requires a balance of risks and opportunities. Nothing in life is absolutely risk-free.

5701. The focus on residual risks feels like it has grown beyond proportion to the risk.

5702. The cost of eliminating all risk is infinite and would simply lead to the end of the business of pipelining in Canada. That is not in the public interest. The *NEB Act* is there because pipelines are in the public interest. The goal is to have regulation that achieves the balance that ensures the overall public interest is served.

5703. The probability of a shortfall of funds is low. The magnitude of any shortfall is also low. The risk is low.

5704. The Board will be reviewing the arrangements of each pipeline with a fund on a regular and periodic basis. Necessary adjustments to funding will be made.

5705. As Mr. Jardine told us, pipelines are not in the habit of underestimating their costs. Although, to be clear, CAPP is not advocating the over-collection that Pouce Coupé seems to propose.

5706. The bulk of pipeline miles in Canada are owned by major corporations that

have ongoing other lines of business. Many of the large pipelines would be taken down in stages over time, such that experience would be gained that could be fed into the periodic review process.

5707. Let me pause to observe that taking big pipelines down in stages implies that what is needed for abandonment will be completed at the time each stage of abandonment is completed.

5708. The landowner proposal to defer major work until the pipeline is completely out of service is unreasonable and, in fact, the riskiest of proposals. It would defer all major costs to the last minute. It also deprives the industry of experience and knowledge as the process of abandonment takes place.

5709. Far better to have the ability to move forward in stages for the large systems when the experience and knowledge gained can be put to work in the next stages, in refining cost estimates and fund requirements, and when there are still toll payers.

5710. This would also contribute to the performance measurement, continuous improvement and assessment of effectiveness identified in the draft Stream 4 Principles for End State of Land Post-Abandonment.

5711. In this regard, the landowner proposal that all pipe be removed from agricultural land as the default option is too extreme. This matter requires more thought with further input from Stream 4 and the studies of individual pipeline companies as to what is appropriate for their situation.

5712. The 1985 NEB paper mentioned by CAPLA must be kept in perspective. It was an NEB *staff* discussion paper, not an NEB decision and not an NEB requirement.

5713. While the likelihood that a TransCanada PipeLines would misjudge its abandonment costs need is low, if it did happen, there is a large corporation standing behind the residual liability. We are told often enough by pipelines that it is these residual long-term risks, albeit low risks, that justify their allowed equity returns.

5714. Many Group 2 pipelines are owned by large corporations as part of their ongoing oil and gas operations, and for them, their corporate assets and corporate responsibility provide an appropriate assurance of abandonment.

5715. This is consistent with the approach to their provincially regulated facilities. Remember also that many of these pipes are sausage links and are minor in the total scheme of the oil and gas industry.

5716. Westcoast's gathering and processing is also under a light-handed regulatory framework where Westcoast takes all the asset risk. This is in line with other gathering and processing businesses which are provincially regulated.

5717. As such, CAPP agrees that Westcoast will conduct itself -- and the Board should accept that it will -- Westcoast will conduct itself like any other such business and recognize the costs in accordance with CICA requirements and will rely on its general revenue generation to support this and all other liabilities.

5718. As Mr. Jardine stated, the approach coming out of this hearing will not fit all pipelines and the Board must remain open to a dialogue with the many Group 2 pipelines that are not present in this proceeding.

5719. Let us remember this as well: There are no orphan NEB pipelines. In fact, many NEB pipelines pre-date the NEB and are still going concerns. Retirement experience on most of these pipes is minimal and abandonment has been rare.

5720. The pipelines will be in business for a long time to come.

5721. Abandonment has yet to become determinate for CICA purposes and the CICA standard is both rigorous and practical.

5722. So the Board will be managing for future abandonment for a very long time.

5723. It has the time to consider the studies pipelines will need to do to consider possible timing of collection of abandonment funds for their pipeline and the magnitude of those funds.

5724. The necessary tax changes can be pursued while other work continues. There is work in Stream 4 that needs to be completed. Pipelines will need to bring forward their studies of their possible future abandonment timing and potential costs.

5725. The issue of settlements and agreements will resolve itself during that time.

5726. The fund is an end-of-life fund. It is not a fund for retirements by an ongoing business.

5727. The abandonment fund established by a pipeline is only needed when the pipeline moves beyond being a going concern, where, as a going concern, plant additions and retirements are properly and adequately funded by the ongoing shipper

base.

5728. This is important.

5729. Recognition of the very limited role of the fund will ensure that the fund does not become a giant bucket for all pipeline retirements. It will keep the size of the fund in proportion to the real need. It will prevent the unnecessary collection of funds and prevent further inefficient removal of capital from the marketplace.

5730. There is no intergenerational equity issue here that need be a concern. The ongoing business will run as it has for years and will continue to do so for years to come. The additions and subtractions of plant will be funded and paid for in the usual way. No special abandonment fund is needed for the ongoing business.

5731. This is why CICA does not require the recognition of retirement costs the day pipelines go into operation. This is why the NEB will have to make decisions about when to start collecting for abandonment and also why the NEB will have to make decisions in advance as to when funds should be deployed from the fund for authorized uses.

5732. The next steps are few in number but they are critical to the success of this regulatory reform project.

5733. Getting an economically efficient mechanism is critical to ensuring that the very large funds that will eventually need to be collected are fully available when needed -- every dollar.

5734. Every last dollar collected should be available for the purpose for which it is collected. No collection should begin until an economically efficient mechanism has been established.

5735. The latest date collection would begin would be when a company has recognized the cost under CICA rules. The CICA standards are rigorous and practical and have much to offer by way of guidance on this matter.

5736. Stream 4 needs to bring forward the information needed by pipeline companies to develop their studies.

5737. Pipeline companies will then need to bring forward their individual studies for consideration.

5738. Fear of the unknown, and, even worse, the distant unknown, is normal, but nothing good comes of fear-based thinking. The Board has a unique opportunity to

get this regulatory reform project right. Let's seize that opportunity.

5739. Winston Churchill speaking on October 29, 1941 at Harrow School said this:

> *"You cannot tell from appearances how things will go. Sometimes imagination makes things out far worse than they are; yet without imagination not much can be done. Those people who are imaginative see many more dangers than perhaps exist; certainly many more than will happen; but then they must also pray to be given that extra courage to carry this far-reaching imagination. But for everyone, surely, what we have gone through in this period -- I am addressing myself to the school -- surely from this period of 10 months this is the lesson: never give in, never give in, never, never, never, never in nothing, great or small, large or petty -- never give in except to convictions of honour and good sense. Never yield to force; never yield to the apparently overwhelming might of the enemy.*
>
> *Do not let us speak of darker days; let us speak rather of sterner days. These are not dark days; these are great days -- the greatest days our country has ever lived; and we must all thank God that we have been allowed, each of us according to our stations, to play a part in making these days memorable in history."*

5740. Madam Chair, Members of the Board, this is an historic proceeding. We started the proceeding the same day as another historic moment. Let us make the outcome of this proceeding memorable for all the best reasons of conviction and good sense.

5741. Let us seize this opportunity to make the remarkable agreement on what is needed to take the remarkable agreement on what is needed and fashion it into a decision that has resounding support and becomes the sound declaration from which only one outcome is thinkable, the creation of an economically efficient fund that will provide landowners the great assurance that the funds will be there when the pipelines on their properties reach end of life.

5742. Thank you.

5743. **THE CHAIRPERSON:** Thank you very much, Mr. Schultz.

5744. We have no questions.

5745. Alberta Department of Energy?

--- FINAL ARGUMENT BY/ARGUMENTATION FINALE PAR MR. KING:

5746. **MR. KING:** Good afternoon, Madam Chair, Panel Members.

5747. For the record, my name is Colin King and I'm pleased to provide final argument on behalf of the Alberta government.

5748. I intend to provide some comments respecting provincial public policy and I would ask for your indulgence and your patience, with the promise that we'll get to where we need to go and shortly. I expect my comments will take about 15 to 20 minutes.

5749. Let me state upfront that Alberta supports the Board's stated objective towards developing a lasting set of principles which can guide future decisions respecting financial matters related to pipeline abandonment and commends the Board for launching the LMCI initiative and this Stream in particular.

5750. Alberta's comments relate predominately to financial issues respecting pipeline abandonment and looks forward to the informed discussion of technical issues taking place in Stream 4 of the LMCI process.

5751. Alberta has had a strong interest in this proceeding, and by way of background, let me begin by confirming that Alberta formerly intervened in the RH-2-2008 proceeding on March 18th, 2008, Exhibit Number C-30-1.

5752. In our intervention notice Alberta specifically asked for an addition to the list of issues. We specifically asked that the final disposition of any funds collected and any potential or remaining liabilities be added to the issues list.

5753. Alberta then attended both of the Board's pre-hearing procedural conferences and asked that the Board add to the final list of issues the matter of surplus abandonment funds as well as how pipeline abandonment funds might travel in the event pipeline jurisdiction moves.

5754. The Board granted that request in its procedural Ruling No. 1, Exhibit Number 8A-8-1.

5755. Since that time, multiple parties have filed evidence and advanced proposals respecting how surplus funds might best be dealt with. We're not taking a formal position on this particular issue but wish that it be the subject of constructive

and informed discussion within these proceedings, and it clearly has throughout.

5756. We note in particular that several proposals respecting surplus funds have been advanced, and I understand those possibilities to at least include, allowing pipelines to retain any surplus funds as profit, explained by way of symmetries of risk, the possibility of surplus funds being paid back to shippers, which as a royalty collector has some appeal, and third, the potential direction of surplus funds or possibly abandonment toll surcharge funds towards the creation of a residual or orphan fund intended as a financial backstop in the event a pipeline licensee experiences financial distress at the time of abandonment.

5757. Again, this is yet another possible option which has some logic and appeal, particularly given Alberta's own strong history via its own orphan fund program.

5758. Each of those approaches had some logic and some appeal, and to be clear, we're not taking a position on any particular one. Perhaps a compromise between all three could be considered optimal. We don't know.

5759. We don't have the specific answer, and likely a specific answer on that particular issue, and perhaps some of the other issues on the Board's list need not be determined with exact precision for many years to come, considering that it appears many or most NEB-regulated pipelines are unlikely to seek decommissioning and abandonment until many years from now into the future, and that leads into a theme of our argument, flexibility and discretion.

5760. What is clearly a priority matter before the Board is the first issue on the Board's list of issues, whether the Board should require pipeline companies to set aside funds to cover future abandonment costs. In regards to this primary issue Alberta can state a few comments.

5761. Alberta believes that landowners should not be liable for the cost of abandonment and that the abandonment costs are a legitimate cost of providing service. Pipelines must ultimately have the funds available to address abandonment costs.

5762. To the extent that mechanisms currently available to the Board are insufficient to properly address abandonment cost issues, Alberta supports separate tolling for pipelines, paid for by shippers, and the establishment of abandonment funds. To be clear, regardless of the mechanism chosen, abandonment costs should be addressed. Now is the time.

5763. Alberta also supports tax efficiency in the collection and management of funds for abandonment and shares concerns of other parties that ordering an

immediate collection of some nominal placeholder funds on an interim basis may create more costs than any benefits which may be associated.

5764. Alberta does not sense that abandonment for most NEB pipelines is immediate and believes that a fair and practical balance should be found respecting the timing and the collection of any funds.

5765. Alberta believes that the Board has the time to properly develop a thoughtful and comprehensive approach which will likely be revisited from time-to-time as needs and assumptions develop. It is entirely reasonable to expect any abandonment fund will be periodically revisited.

5766. Whatever generic model the Board may develop, we encourage the Board to encourage flexibility -- incorporate -- pardon me -- incorporate flexibility and discretion to the extent that it can to allow the Board sufficient discretion to deal with any unique and unanticipated needs or other issues that might develop long into the future.

5767. We have listened to the evidence with an open mind, we have listened with interest to all the possibilities, and we resist further commenting on the particulars of various possible approaches in great detail, because we sense, with a few possible exceptions, there is far more alignment of principles and positions than there is disagreement.

5768. And we believe that the Board should take the time necessary to draw on these commonalities to develop a thoughtful and enduring approach to which all stakeholders can have the necessary certainty to operate with confidence to which they are owed.

5769. In light of that, I'd like to make just a few short confirming comments respecting Alberta public policy within the context of these LMCI proceedings and ask your patience.

5770. Last year, the Alberta government, based on its evaluation of the broader Alberta public good, decided that it would not object to TransCanada's application respecting which regulatory jurisdiction the NOVA Gas Transmission Pipeline System should operate.

5771. There were many factors and good reasons that went into that decision, not the least of which was our understanding of the precise technical legal question of lawful jurisdiction itself, but also a practical realization that taking an unprincipled approach towards regulatory jurisdiction over the NOVA System would only result in creating unnecessary uncertainty and delay in regulatory processes, to the detriment

of the Alberta-based energy industry, all Canadians and the trust which the United States, Alaska, British Columbia, the Northwest Territories and the Yukon Territory and all other provinces should have in and reasonably expect from Alberta.

5772. Notwithstanding the legal and economic reasoning underlying and supporting our decision held during the Jurisdictional Stream of the NOVA proceeding, Alberta also held an unspoken but fundamental belief and perception that the National Energy Board conducts itself in a transparent and fair manner.

5773. Alberta understands from the benefit of long experience before this Board that it has done so in the past and Alberta believes that it will continue to do so into the future: Listening to all Canadian concerns and interests when making decisions with respect to the development, operation and subsequent decommissioning of energy infrastructure.

5774. The National Energy Board makes its decisions based on a fair balancing of the interests of all stakeholders, and in the end, must base its decision on what is in the public interest.

5775. With that in mind, Alberta is confident that the National Energy Board will take into consideration the reasonable claims and needs of Alberta landowners in the context of abandonment where and to the extent they exist and that the National Energy Board would implement flexible policies in the context of determining that public interest.

5776. Madam Chair, those complete my comments in chief. I have nothing in reply and would be pleased to answer any questions to the extent that I can.

5777. **THE CHAIRPERSON:** Thank you, Mr. King, the Panel has no questions.

5778. **MR. KING:** Thank you.

5779. **THE CHAIRPERSON:** Are there any other registered parties here who wish to present final argument?

--- (No response/Aucune réponse)

5780. **THE CHAIRPERSON:** Are there any parties who wish to have some time before proceeding with reply argument?

--- (No response/Aucune réponse)

5781. **THE CHAIRPERSON:** Hearing none, we will start from the bottom and work our way back up.

5782. Canadian Association of Petroleum Producers…?

5783. **MR. SCHULTZ:** No, thank you.

5784. **THE CHAIRPERSON:** Canadian Alliance of Pipeline Landowners Associations…?

--- REPLY ARGUMENT BY/RÉPLIQUE PAR MR. VOGEL:

5785. **MR. VOGEL:** Very briefly, Madam Chair.

5786. I'd like to thank Mr. Schultz for bringing Winston Churchill's insight to this proceeding, and I simply submit that in view of the fundamental principle underlying this proceeding that landowners not be liable for costs; that, in Winston Churchill's words, the solution of honour and good sense here can only be to adopt CAPLA's default technical assumption as the basis for estimating abandonment costs.

5787. Those are my submissions. I think Mr. Goudy also has a brief submission.

--- REPLY ARGUMENT BY/RÉPLIQUE PAR MR. GOUDY:

5788. **MR. GOUDY:** Madam Chair and Board Panel, I have a very brief reply submission with respect to something that was said on behalf of the Alberta government and it's just with respect to surplus.

5789. I think there was a suggestion made that, because the issue of the -- of a possible surplus would arise so far down the road, it won't -- obviously, we won't know whether there's a surplus or not until the abandonment costs have been covered and that may not take place for many years down the road.

5790. There was some suggestion that, because of that, it would not be necessary or it might not be necessary for the Board to deal with the issue of surplus at this time. But I would submit that it may nevertheless be necessary, and probably is necessary, for the Board to deal with the issue now if -- if we're taking -- going down the road of using trusts to underlie the abandonment funds.

5791. If we do use trusts, then I would submit that, as part of the creation of those trusts, surplus that would remain at the end of the day is an issue that needs to

be dealt with in advance, now, as it has been in pension funds.

5792. There was a lot of discussion in this proceeding about the possible similarities of abandonment cost funds to pension funds, and surplus that would exist at the end of the day in a pension fund is something that's dealt with in the -- in the constating documents of the trust, and I think it would have to be here as well.

5793. Those are my submissions.

5794. **THE CHAIRPERSON:** Thank you both, Messrs. Goudy and Vogel.

5795. TransCanada PipeLines Limited…?

--- REPLY ARGUMENT BY/RÉPLIQUE PAR MR. DENSTEDT:

5796. **MR. DENSTEDT:** Thank you, Madam Chairman, just a couple of quick comments.

5797. First of all, more of a clarification. My friend Mr. Goudy quoted Ms. Leong as not agreeing that there was rigor with the CICA handbook. That in fact is the opposite of what she agreed to.

5798. It was one of the few things she did agree with Spectra on, so I need to point it out that she did think the CICA handbook had some rigor to it.

5799. But in respect of CAPLA's final submissions, I've got three topics I'd like to discuss. First is the governance of the actual trust funds. I believe I heard my friend suggest that those trust funds should have landowner involvement through some sort of a joint board to govern the administration of those trust funds.

5800. TransCanada disagrees with that. The goals of the funds should be efficiency, transparency and certainty, and it's TransCanada's view that when the Board issues guidelines on the investment policies for those trust funds and when the -- which the landowners will have input into -- and when those technical assumptions for the estimation of abandonment funds are made, which the landowners will have input into, and when each pipeline comes forward with an application to have those detailed estimates approved, the landowners will have input into that.

5801. And the regular reviews that are to take place to make sure the funds are trued up as time passes, the landowners will have -- be able to participate in that process. And at the end, when a section 74 abandonment application is made, the landowners will have an opportunity to participate in that process as well. That

ensures their involvement, ensures transparency and ensures certainty of the process.

5802. My friend seemed to say or suggest to the Board, when he was discussing orphan funds, that the Board can't ignore, and I think his words were, "the real possibility that one or more pipelines may not be able to pay for abandonment." And quite frankly, Madam Chair, there is no evidence on this record to suggest any such thing.

5803. In fact, the evidence is quite to the contrary. Mr. Van der Put's evidence was that there was belts and suspenders and Velcro and duct tape holding up this obligation and that there is a negligible risk to the landowners as a result of that.

5804. And, finally, my friend suggested that a generic hearing might be required to consider the technical assumptions that would go into the estimate of abandonment costs, and that would follow, at some time in the future, this process.

5805. Well, quite frankly, TransCanada believes that it looks like and smells like Stream 4 to us and that if another proceeding is going to be required to consider the technical assumptions that go into the estimate for abandonment costs then one of those assumptions -- one of those technical assumptions which is identified by the Board in its Stream 4 discussion paper is retirement options themselves; whether the pipeline should be abandoned in place; what percentage should be abandoned in place; what should be removed; what percentage should be removed.

5806. Those are all technical assumptions and if they are going to be considered in a later generic hearing or process they're more appropriately dealt with in Stream 4.

5807. Those are all our submissions.

5808. **THE CHAIRPERSON:** Thank you, Mr. Denstedt.

5809. Spectra Energy Transmission, otherwise known as Westcoast?

5810. **MR. DAVIES:** I attended Sir Winston Churchill High School if that counts for anything.

--- (Laughter/Rires)

--- REPLY ARGUMENT BY/RÉPLIQUE PAR MR. DAVIES:

5811. **MR. DAVIES:** I have just a few brief comments to make in response to a couple of the submissions of CAPLA and TransCanada. Let me start with CAPLA.

5812. With respect, my friends, Mr. Vogel and Mr. Goudy took the wrong turn right at the beginning of their argument. Mr. Vogel said, and I quote:

> *"The key issue in this proceeding is to determine the optimal method of ensuring that necessary funds are available upon abandonment to implement the assumed technical abandonment option which fulfills the Board's fundamental principle that landowners will not be liable for costs of pipeline abandonment."* (As read)

5813. He has here, in my submission, improperly framed the issue before you and because of that the rest of his argument and the argument of Mr. Goudy proceed down the wrong track, and let me explain.

5814. And let me do so first in the context of Westcoast's gathering and processing system and then in the context of Westcoast's transmission system.

5815. So first, gathering and processing. The Board has established two fundamental principles to guide its decision making in this proceeding.

5816. The first principle is the one that Mr. Vogel sites in this issue, namely that landowners will not be liable for cost of pipeline abandonment.

5817. The second principle to which Mr. Vogel makes no reference is that abandonment cost should be recovered from pipeline customers.

5818. So, Mr. Vogel says to you, "We need to ensure that landowners will not be liable for the costs of pipeline abandonment". Well, if I wanted to play that game I could respond by saying, "No, we need to ensure that abandonment costs could be recovered from pipeline customers".

5819. The fact is that if we were to play that game both Mr. Vogel and I would be partly right but also partly wrong. The Board has not established one principle as paramount to the other. There must be regard for both principles.

5820. And as I mentioned in my initial argument, in the context of Westcoast gathering and processing assets Westcoast could not now increase its tolls so as to recover abandonment costs from its customers because it's provincially regulated competitors are not required to now recover abandonment costs.

5821. So the issue that we are debating with CAPLA boils down to this; do you require Westcoast to take money out of its own pocket and set it aside, thereby impairing its return and its ability to compete in an effort to make a very small

abandonment cost risk even smaller for landowners who farm over some 300 kilometres of Westcoast gathering pipelines.

5822. That's the question and that proposition, in my respectful submission, would make no sense whatsoever.

5823. And it's not a matter, Madam Chair and Members, as Mr. Goudy suggested, preferring Westcoast's interests to CAPLA interests. It's a matter of balancing those interests.

5824. In the context of the Westcoast gathering and processing assets, it's significant impact to Westcoast on the one hand and little abandonment cost risk to agricultural landowners on the other hand.

5825. And when I say "significant impact to Westcoast" I am not overstating the point. Any abandonment cost required to be set aside that cannot be recovered from customers goes right to Westcoast's bottom line. The Board ought not simply do what CAPLA asks you to do, which is to prefer landowner interests at all costs.

5826. Now, let's look at the issue in the context of Westcoast Transmission System and here the issue is somewhat different.

5827. In respect of its transmission pipeline Westcoast can, like other Group 1 pipelines, increase its tolls in order to recover abandonment costs.

5828. So the issue being debated with CAPLA in the context of the Westcoast Transmission System is this; do you require Westcoast to start collecting asset retirement costs before it even recognizes an asset retirement obligation when there would be no good basis to decide how much to start collecting and there would be a significant opportunity cost on the capital of toll payers in order to make a very small abandonment cost risk even smaller for agricultural landowners.

5829. And here again we say to you that would not be a reasonable thing to do. If collection commences when the timing of the abandonment is determinable and a reasonable estimate of the fair value of the obligation can be made, as Westcoast proposes, that will leave ample time to allow funds to be collected in an orderly and efficient manner prior to the abandonment. There is simply no need or compelling reason for premature collection.

5830. I also have one brief comment to make in response to TransCanada. Mr. Denstedt says that accounting rules should not drive regulatory policy; we agree. And we are not suggesting that the Board must decide that collection of retirement costs

should commence when the retirement obligation is recognized for accounting purposes.

5831. What we are saying, rather, is that the Board should make that decision in the context of Westcoast Transmission System because that is the right time to start collection.

5832. That is the time when the timing of the abandonment is determinable and when the fair value of the retirement obligation can be reasonably estimated and commencing collection at that time will leave many years, at least 20, likely more, to collect funds prior to abandonment.

5833. The proposal is practical and efficient and that's why the proposal should be adopted, in our submission, not just because it is consistent with the accounting rules.

5834. So those are our submissions, in reply. Good luck with your deliberations.

5835. **THE CHAIRPERSON:** Thank you, Mr. Davies.

5836. Pouce Coupé Pipe Line Ltd. ...?

--- REPLY ARGUMENT BY/RÉPLIQUE PAR MR. JEFFREY:

5837. **MR. JEFFREY:** Thank you, Madam Chair, Members of the Board.

5838. My comments in reply are grouped according to the party and in the order that they appeared. So I am starting very briefly with Westcoast and two points here.

5839. The first is, my friend Mr. Davies characterized the evidence of Mr. Robertson as saying that Pouce Coupé would be operating up to a thousand years from now. That is not correct and just to be certain the record is correct, what Mr. Robertson said as well, it is not likely a thousand a years and it's not likely five years, and a few responses prior to that, he said, "We have no specific dates expected at this time, but it could be anywhere in the range of 30 to 50 years."

5840. Second, my friend, unless I misheard, misstated Pouce Coupé's position on the matter of Westcoast and the competition it faces. Pouce Coupé did not say, nor is it its position, that Westcoast is more competitive because it gets a lower return. What we said is that Westcoast has tools to compete already that others do not have.

5841. TransCanada takes issue with the proposal that funds be accessed, dollars be accessed from the funds without the necessity of a prior regulatory process. But I

would point out that in their evidence they acknowledged that the abandonment activities will be a process, and it's our suggestion that it therefore is impractical to have a point-in-time application for dollars when there will be consultation processes prior to abandonment, environmental impact assessment processes, engineering activities -- a range of things.

5842. We just suggest it is going to be much more efficient to allow the dollars necessary for those activities to be drawn out of funds on an as-and-when-needed basis.

5843. That proposal ensures that only so much is drawn down out of the fund, as is necessary, and the reciprocal of that, it means as many dollars remain in the fund as possible, for as long as possible. And perhaps most importantly, it minimizes the portion of the fund that will get used up for regulatory churn.

5844. And those are reasons why Pouce Coupé suggests this is advantageous for all parties.

5845. My friend Mr. Goudy says that "its light-handed approach is self-regulation." Well, it's not. I indicated to the panel already the variety of ways in which the National Energy Board already has the tools to oversee that sort of approach.

5846. He suggests that this proposal is self-serving. Well, I think everybody who's participating here is participating to serve their own interests; that's why they're here. To equate that with irresponsibility, I think, is merely *ad hominem* and of no value to you. The advantages of what has been characterized as a lighter-handed approach to accessing funds, I think, have advantage for all involved.

5847. CAPLA asks you to decide on this default technical assumption, and first, that is outside the scope of Stream 3, that is a Stream 4 matter. Second, you need not do that.

5848. I think the source of this discussion comes from the phrasing of issue 2(a). And I know Mr. Vogel was not at the pre-hearing conference I attended, but at that time, if my memories serves me correctly, the discussion was, "Doesn't Stream 3 have to wait until we're done Stream 4?"

5849. And as the discussion evolved, there was a modicum of consensus that no, it didn't, we could just make some assumptions for purposes of proceeding through Stream 3, and the assumption -- a paramount assumption would be whatever's decided in Stream 4 would then get imported.

5850. And I had understood issue 2(a) to simply mean, "Are there any necessarily technical assumptions that need to be made in order to proceed through Stream 3?" In our view, there are none. Certainly not the one that CAPLA's counsel describes.

5851. There are no necessary technical assumptions in order for you to continue and conclude this process, regardless of the timing of the Stream 4 process outcome.

5852. Mr. Goudy made a pitch for landowners being involved in managing trust funds, and in response to that suggestion we say a number of things. First, participatory rights for interested parties are dealt with at the Board level. That shouldn't translate into having an interest in how funds -- trust funds are going to be invested or managed.

5853. Second, I think what you're after and what parties have been talking about here is independence, a third-party trustee. The pipelines won't be involved in managing those funds. They will be responsible, ultimately, for the outcomes, but they will be placed in the hands of trust companies, third-party trustees. It would be inappropriate to have landowners participate there.

5854. Thirdly, surely you're going to want people with the requisite expertise to manage the investment of those funds.

5855. And fourthly, I'd suggest that CAPLA is careful what it asks for. Those trustees bear a fiduciary obligation for the *corpus* of the trust, and what the law refers to as, "an obligation of the utmost good faith."

5856. Finally, with respect to CAPP's submissions, it cited some, I think it was, 12 points of agreement. He had me following along right up until number 12. Pouce Coupé would not be in agreement with the final of those points, which was that you have decades.

5857. If you'll recall, we were cross-examining Mr. Jardine on that topic and got admission that the supply may be available for decades to come; that doesn't mean that each individual pipeline drawing on that supply will be in existence for decades to come, nor does it -- nor does it mean that the markets being served by individual pipelines will be around for decades to come. And so, we would harken back to the Pouce Coupé position that earlier is better than later.

5858. Finally, with respect to CAPP's submissions, Mr. Schultz indicated that Pouce Coupé seems to support over-collection. We do not. And if our comments were heard that way, then that's my failing.

5859. What Pouce Coupé supports is conservative assumptions used, as-early-as-possible collection, and this will, in a sense, front-end load, but there will be this regular return to the regulator to adjust assumptions, to adjust end-of-life forecasts, to adjust cost forecasts.

5860. And over time, the collection will result in, we would suggest, a pretty accurate amount; unlikely to be far over, unlikely to be far under. But it will, under our proposal, lead to an earlier collection of the dollars, but not an over-collection.

5861. Those are all of Pouce Coupé's comments in reply.

5862. **THE CHAIRPERSON:** Thank you, Mr. Jeffery.

5863. **MR. JEFFREY:** Thank you, Madam Chair.

5864. **THE CHAIRPERSON:** Kinder Morgan Canada Inc. ...? Thank you.

5865. Enbridge Pipelines Inc. ...?

--- REPLY ARGUMENT BY/RÉPLIQUE PAR MR. CROWTHER:

5866. **MR. CROWTHER:** Thank you, Madam Chair, very briefly.

5867. And let me begin by adopting the submissions of TransCanada respecting the CAPLA arguments about governance of the trust funds, and likewise, respecting the assertions from CAPLA about the risks of pipelines either being unable to cover shortfalls in abandonment funds or regarding orphan pipelines.

5868. Mr. Forrester, on behalf of Kinder Morgan, posited a situation in which deferral for one pipeline would cause a significant toll differential that would require another pipeline to also seek deferral. I would say that that example illustrates precisely one of the points that I was attempting to make in my argument in-chief.

5869. Kinder Morgan would have you reject the Enbridge collection deferral proposal on the basis of a number of *a priori* assumptions, such as the assumptions that are inherent in Mr. Forrester's hypothetical example.

5870. Those assumptions include at least two. First, notwithstanding any concerns that might have been expressed or considered by the Board vis-à-vis competitive impacts of the first pipeline's deferral, the Board would have approved it. And second, that the deferral in and of itself would result in a significant toll differential.

5871. A similar point could be made in response to TransCanada. As I heard Mr. Denstedt, he warned that different treatment of different pipelines -- by which I took him to be referring to allowing one pipeline to defer collection while another doesn't -- could yield competitive advantages or disadvantages.

5872. With respect, you cannot reasonably, and therefore shouldn't, make such assumptions here, now, and in the abstract. The Board could -- some would say should -- address issues such as toll differentials and competitive impacts when and if a deferral application is made.

5873. So, Enbridge would urge that you not discard the deferral concept based on nothing more than a list of hypothetical horribles. Rather, the deferral concept should be implemented.

5874. It is reasonable, it is flexible, it is responsible, and it would leave the Board in a position to decide, based on evidence, not assumptions or speculation, whether the concerns of a competing pipeline are valid and its interests are worth protecting in a particular circumstance.

5875. On another point, if I heard him correctly, Mr. Denstedt, on behalf of TransCanada, said again today that one of the reasons for early collection is that it would take advantage of the time value of money.

5876. However, as I alluded in my argument in-chief, that presumes that the interest or a return earned on the funds collected would exceed the opportunity costs that would be incurred in taking those monies out of the hands of the shippers.

5877. There is no evidence to suggest that that assumption would be a safe one, and therefore, in my submission, it is one that you should not make.

5878. Just a couple points in reply to CAPLA. I say first, as I did earlier today, that this is not the time or place to decide how to abandon pipeline facilities.

5879. Nevertheless, CAPLA tells you that it provided, at least as I heard Mr. Vogel -- I hope I heard him correctly -- that it provided the only expert evidence in this proceeding regarding the environmental impact of abandoning pipelines in place.

5880. Well, there are two responses. First, the purpose of this proceeding is not to consider the environmental impacts of any abandonment method, so it's not surprising that other parties may not have filed evidence relevant to those issues.

5881. And second, based on your ruling, as reported at paragraphs 3891 to 93 of Volume 4 of the transcript, the Broadsword evidence is not expert evidence concerning environmental impacts.

5882. And lastly, there were repeated assertions by counsel for CAPLA this afternoon that landowners are currently liable for the costs of abandonment.

5883. I don't have the advantage of seeing the evidentiary references, if any, that Messrs Vogel and Goudy cited in support of their assertions, but, in all frankness, I would say that the only fair reading of the evidence would support the opposite conclusion.

5884. Those are my reply submission. Thank you, Madam Chair and Members.

5885. **THE CHAIRPERSON:** Thank you, Mr. Crowther.

5886. Are there any other matters on a preliminary nature to be dealt with?

5887. Mr. Denstedt, have you got anything to report on the outstanding undertaking?

5888. **MR. DENSTEDT:** I'm informed by Ms. Leong that we'll have it tomorrow morning.

5889. **THE CHAIRPERSON:** Thank you very much.

5890. Then on behalf of the Board, I want to thank all parties for your participation at this hearing.

5891. In addition, on behalf of the Board, I want to thank the court reporters and the sound technicians.

5892. And, finally, I want to thank the Board staff and counsel; the Board very much appreciates their efforts and recognizes that we could not meet our mandate without their support.

5893. Particularly, the Board thanks everyone involved for your indulgence in sitting today beyond the established hours for this hearing.

5894. With that and subject to the outstanding undertaking, this concludes the Hearing on Stream 3 of Land Matters Consultation Initiative, RH-2-2008.

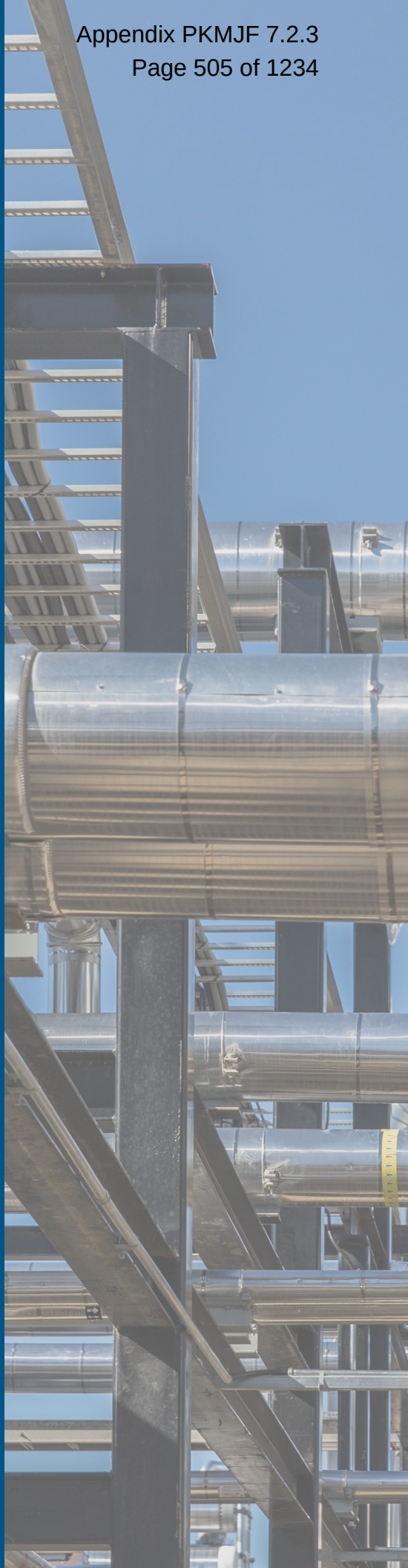
5895. The Board reserves its decision on this matter. Parties will be informed of

the decision in due course.

5896. This hearing is adjourned. Thank you.

--- Upon adjourning at 3:42 p.m./L'audience est ajournée à 15h42

Financial Statements & Notes



CONDENSED CONSOLIDATED INTERIM STATEMENTS OF FINANCIAL POSITION

(unaudited)

($ millions)	**June 30, 2020**	December 31, 2019[1]
Assets **Current assets**		
Cash and cash equivalents	**73**	129
Trade receivables and other	**536**	694
Inventory	**175**	126
Derivative financial instruments (Note 14)	**39**	40
	823	989
Non-current assets		
Property, plant and equipment (Note 4)	**19,255**	18,734
Investments in equity accounted investees (Note 5)	**6,196**	5,954
Intangible assets and goodwill	**6,465**	6,458
Right-of-use assets (Note 6)	**700**	730
Finance lease receivable (Note 6)	**142**	145
Advances to related parties and other assets	**210**	156
	32,968	32,177
Total assets	**33,791**	33,166
Liabilities and equity **Current liabilities**		
Trade payables and other	**755**	1,013
Loans and borrowings (Note 7)	**462**	74
Dividends payable	**115**	110
Lease liabilities	**98**	112
Contract liabilities (Note 10)	**94**	39
Taxes payable	**51**	103
Derivative financial instruments (Note 14)	**26**	6
	1,601	1,457
Non-current liabilities		
Loans and borrowings (Note 7)	**10,312**	10,078
Lease liabilities	**702**	707
Decommissioning provision (Note 8)	**850**	864
Contract liabilities (Note 10)	**241**	192
Deferred tax liabilities	**2,998**	2,919
Other liabilities	**156**	179
	15,259	14,939
Total liabilities	**16,860**	16,396
Equity		
Attributable to shareholders	**16,871**	16,710
Attributable to non-controlling interest	**60**	60
Total equity	**16,931**	16,770
Total liabilities and equity	**33,791**	33,166

[1] Pembina has recast certain comparative information to reflect changes to the Purchase Price Allocation originally presented December 31, 2019. See Note 3.

See accompanying notes to the condensed consolidated interim financial statements

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME

(unaudited)

	3 Months Ended June 30		6 Months Ended June 30	
($ millions, except per share amounts)	**2020**	2019	**2020**	2019
Revenue (Note 10)	**1,268**	1,808	**2,939**	3,776
Cost of sales	**813**	1,292	**1,965**	2,742
Loss (gain) on commodity-related derivative financial instruments	**65**	(16)	**(61)**	10
Share of profit from equity accounted investees (Note 5)	**65**	97	**148**	193
Gross profit	**455**	629	**1,183**	1,217
General and administrative	**59**	76	**120**	150
Other (income) expense	**(20)**	1	**(3)**	4
Results from operating activities	**416**	552	**1,066**	1,063
Net finance costs (Note 11)	**72**	78	**281**	157
Earnings before income tax	**344**	474	**785**	906
Current tax expense	**67**	56	**143**	132
Deferred tax expense (recovery)	**24**	(246)	**75**	(203)
Income tax expense	**91**	(190)	**218**	(71)
Earnings	**253**	664	**567**	977
Other comprehensive (loss) income, net of tax (Note 13 & 14)				
Exchange (loss) gain on translation of foreign operations	**(212)**	(76)	**253**	(161)
Impact of hedging activities	**9**	—	**9**	—
Re-measurement of defined benefit liability	**—**	—	**14**	—
Total comprehensive income attributable to shareholders	**50**	588	**843**	816
Earnings attributable to common shareholders, net of preferred share dividends	**214**	632	**489**	914
Earnings per common share – basic *(dollars)*	**0.39**	1.23	**0.89**	1.79
Earnings per common share – diluted *(dollars)*	**0.39**	1.23	**0.89**	1.78
Weighted average number of common shares *(millions)*				
Basic	**550**	511	**549**	510
Diluted	**550**	513	**550**	512

See accompanying notes to the condensed consolidated interim financial statements

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CHANGES IN EQUITY

(unaudited)

	Attributable to Shareholders of the Company						
($ millions)	Common Share Capital	Preferred Share Capital	Deficit	AOCI[1]	Total	Non-Controlling Interest	Total Equity
December 31, 2019	15,539	2,956	(1,883)	98	16,710	60	16,770
Total comprehensive income							
Earnings	—	—	567	—	567	—	567
Other comprehensive income (Note 13)	—	—	—	276	276	—	276
Total comprehensive income	—	—	567	276	843	—	843
Transactions with shareholders of the Company							
Part VI.1 tax on preferred shares (Note 9)	—	(4)	—	—	(4)	—	(4)
Share-based payment transactions (Note 9)	90	—	—	—	90	—	90
Dividends declared – common (Note 9)	—	—	(693)	—	(693)	—	(693)
Dividends declared – preferred (Note 9)	—	—	(75)	—	(75)	—	(75)
Total transactions with shareholders of the Company	90	(4)	(768)	—	(682)	—	(682)
June 30, 2020	15,629	2,952	(2,084)	374	16,871	60	16,931
December 31, 2018	13,662	2,423	(2,058)	317	14,344	60	14,404
Impact of change in accounting policy	—	—	22	—	22	—	22
Opening value January 1, 2019	13,662	2,423	(2,036)	317	14,366	60	14,426
Total comprehensive income							
Earnings	—	—	977	—	977	—	977
Other comprehensive income							
Exchange loss on translation of foreign operations	—	—	—	(161)	(161)	—	(161)
Total comprehensive income	—	—	977	(161)	816	—	816
Transactions with shareholders of the Company							
Part VI.1 tax on preferred shares	—	(2)	—	—	(2)	—	(2)
Share-based payment transactions	122	—	—	—	122	—	122
Dividends declared – common	—	—	(592)	—	(592)	—	(592)
Dividends declared – preferred	—	—	(61)	—	(61)	—	(61)
Total transactions with shareholders of the Company	122	(2)	(653)	—	(533)	—	(533)
June 30, 2019	13,784	2,421	(1,712)	156	14,649	60	14,709

[1] Accumulated Other Comprehensive Income ("AOCI").

See accompanying notes to the condensed consolidated interim financial statements

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CASH FLOWS

(unaudited)

	3 Months Ended June 30		6 Months Ended June 30	
($ millions)	**2020**	2019	**2020**	2019
Cash provided by (used in)				
Operating activities				
Earnings	**253**	664	**567**	977
Adjustments for:				
Share of profit from equity accounted investees	**(65)**	(97)	**(148)**	(193)
Distributions from equity accounted investees	**116**	140	**239**	310
Depreciation and amortization	**176**	121	**353**	246
Unrealized loss (gain) on commodity-related derivative financial instruments	**101**	(15)	**(8)**	30
Net finance costs (Note 11)	**72**	78	**281**	157
Net interest paid	**(74)**	(53)	**(173)**	(134)
Income tax expense (recovery)	**91**	(190)	**218**	(71)
Taxes paid	**(14)**	(28)	**(200)**	(99)
Share-based compensation expense	**9**	14	**4**	40
Share-based compensation payment	**—**	—	**(44)**	(50)
Net change in contract liabilities	**25**	(9)	**42**	(6)
Other	**(10)**	(4)	**—**	(9)
Change in non-cash operating working capital	**(38)**	40	**(79)**	71
Cash flow from operating activities	**642**	661	**1,052**	1,269
Financing activities				
Bank borrowings and issuance of debt (Note 7)	**552**	—	**1,062**	94
Repayment of loans and borrowings	**(924)**	(546)	**(2,039)**	(599)
Repayment of lease liability	**(17)**	(14)	**(43)**	(32)
Issuance of medium term notes (Note 7)	**505**	800	**1,578**	800
Issue costs and financing fees	**(7)**	(6)	**(11)**	(6)
Exercise of stock options	**1**	29	**83**	115
Dividends paid	**(384)**	(327)	**(762)**	(641)
Cash flow used in financing activities	**(274)**	(64)	**(132)**	(269)
Investing activities				
Capital expenditures	**(211)**	(434)	**(694)**	(795)
Contributions to equity accounted investees	**(2)**	(28)	**(174)**	(61)
Receipt of finance lease payments	**(9)**	—	**5**	—
Interest paid during construction	**(12)**	(9)	**(26)**	(17)
Recovery of assets or proceeds from sale	**—**	6	**2**	6
Advances to related parties	**(11)**	(32)	**(22)**	(42)
Changes in non-cash investing working capital and other	**(167)**	50	**(59)**	77
Cash flow used in investing activities	**(412)**	(447)	**(968)**	(832)
Change in cash and cash equivalents	**(44)**	150	**(48)**	168
Effect of movement in exchange rates on cash held	**(15)**	6	**(8)**	3
Cash and cash equivalents, beginning of period	**132**	172	**129**	157
Cash and cash equivalents, end of period	**73**	328	**73**	328

See accompanying notes to the condensed consolidated interim financial statements

NOTES TO THE CONDENSED CONSOLIDATED UNAUDITED INTERIM FINANCIAL STATEMENTS

1. REPORTING ENTITY

Pembina Pipeline Corporation ("Pembina" or the "Company") is a Calgary-based, leading transportation and midstream service provider serving North America's energy industry. The condensed consolidated unaudited interim financial statements ("Interim Financial Statements") include the accounts of the Company, its subsidiary companies, partnerships and any investments in associates and joint arrangements as at and for the three and six months ended June 30, 2020. These Interim Financial Statements and the notes hereto have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") applicable to the preparation of interim financial statements, including International Accounting Standard 34, *Interim Financial Reporting* ("IAS 34"). These Interim Financial Statements have been prepared following the same accounting policies and methods of computation as the annual consolidated financial statements of the Company as at and for the year ended December 31, 2019 ("Consolidated Financial Statements"), except as noted below, and should be read in conjunction with those Consolidated Financial Statements. The Interim Financial Statements were authorized for issue by Pembina's Board of Directors on August 6, 2020.

Pembina owns an integrated system of pipelines that transport various hydrocarbon liquids and natural gas products produced primarily in western Canada. The Company also owns gas gathering and processing facilities and an oil and natural gas liquids infrastructure, storage and logistics business. Pembina's integrated assets and commercial operations along the majority of the hydrocarbon value chain allow it to offer a full spectrum of midstream and marketing services to the energy sector.

Financial Instruments

Derivative Financial Instruments and Hedge Accounting

Pembina holds derivative financial instruments to manage its interest rate, commodity, power costs and foreign exchange risk exposures. Derivatives are recognized initially at fair value with attributable transaction costs recognized in earnings as incurred. Subsequent to initial recognition, derivatives are measured at fair value with changes in non-commodity-related derivatives recognized immediately in earnings as part of net finance costs, unless hedge accounting is applied, and changes in commodity-related derivatives recognized immediately in earnings. Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative meet the definition of a derivative, and the combined instrument is not measured at fair value through earnings.

Pembina applies hedge accounting to certain financial instruments that qualify for and are designated for hedge accounting treatment. This includes certain designated derivatives used to hedge the variability in cash flows associated with highly probable forecasted transactions arising from changes in interest rates, and designated non-derivative financial liabilities used to hedge foreign exchange risk on Pembina's net investment in foreign operations. Hedge accounting is discontinued prospectively when the hedging relationship no longer qualifies for hedge accounting or the hedging instrument is sold or terminated.

At inception of a designated hedging relationship, formal documentation is prepared and includes the risk management objective and strategy for undertaking the hedge, identification of the hedged item and the hedging instrument, the nature of the risk being hedged and how Pembina will assess the hedging instrument's effectiveness in offsetting the exposure to changes in the hedged item.

For derivatives designated as cash flow hedging instruments, the effective portion of changes in fair value of the derivatives is recognized in other comprehensive income and accumulated in the cash flow hedge reserve. The effective portion of derivative fair value changes recognized in other comprehensive income is limited to the cumulative change in fair value of the hedged items. Any ineffective portion of derivative fair value changes is recognized immediately in earnings. The amount accumulated in the cash flow hedge reserve is reclassified to earnings in the same period or periods during which the hedged expected future cash flows affect earnings.

When hedge accounting for cash flow hedges is discontinued, the amount accumulated in the cash flow hedge reserve remains in equity until it is reclassified to earnings in the same period or periods as the hedged expected future cash flows affect earnings. If the hedged future cash flows are no longer expected to occur, the amounts accumulated in the cash flow hedge reserve are immediately reclassified to earnings.

For non-derivative financial liabilities designated as hedging instruments in a hedge of the net investment in foreign operations, the effective portion of foreign exchange gains and losses arising on translation of the non-derivative is recognized in other comprehensive income and presented in the currency translation reserve within equity. Any ineffective portion of the foreign exchange gains and losses arising from the translation of the non-derivative is recognized immediately in earnings. The amount accumulated in the currency translation reserve is reclassified to earnings on disposal of the foreign operation.

Use of Estimates and Judgments

Management is required to make estimates and assumptions and use judgment in the application of accounting policies that could have a significant impact on the financial results. Actual results may differ from estimates and those differences may be material. By their nature, judgments and estimates may change in light of new facts and circumstances in the internal and external environment. There have been no material changes to Pembina's critical accounting estimates and judgments during the three and six months ended June 30, 2020, except for the general impact of significant uncertainties created by the coronavirus ("COVID-19") pandemic, as discussed below.

Ongoing Impact of the COVID-19 Pandemic

Following the World Health Organization declaring the COVID-19 outbreak to be a pandemic, many governments have taken steps to contain the spread of the virus, resulting in a slowdown of the global economy, which has led to a significant disruption of business operations and a significant increase in economic uncertainty. This uncertainty has created volatility in asset prices, currency exchange rates and a marked decline in long-term interest rates. In addition, the resulting decrease in demand for crude oil has resulted in a decline in global energy prices. Management applied judgment and will continue to assess the situation in determining the impact of the significant uncertainties created by these events and conditions on the carrying amounts of assets and liabilities in the Interim Financial Statements.

2. DETERMINATION OF FAIR VALUES

A number of the Company's accounting policies and disclosures require the determination of fair value for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure based on methods as set out in the Consolidated Financial Statements. These methods have been applied consistently to all periods presented in these Interim Financial Statements.

Ongoing Impact of the COVID-19 Pandemic

Measuring fair values using significant unobservable inputs has become more challenging in the current environment, where events and conditions related to the COVID-19 pandemic are driving significant disruption of business operations and a significant increase in economic uncertainty. Management applied its judgment in determining the impact of the significant uncertainties created by these events and conditions on the assessed fair values of assets and liabilities in these Interim Financial Statements.

3. ACQUISITION

On December 16, 2019, Pembina acquired all the issued and outstanding shares of Kinder Morgan Canada Limited ("Kinder Morgan Canada") by way of a plan of arrangement and the U.S. portion of the Cochin Pipeline system (collectively the "Kinder Acquisition") for total consideration of $4.3 billion.

The purchase price equation, subject to finalization, is based on assessed fair values and is as follows:

As at December 16, 2019 ($ millions)	Previously Reported	Adjustments	Recast
Purchase Price Consideration			
Common shares	1,710	—	1,710
Cash (net of cash acquired)	2,009	—	2,009
Preferred shares	536	—	536
	4,255	—	4,255
Current assets	68	2	70
Property, plant and equipment	2,660	(41)	2,619
Intangible assets	1,254	—	1,254
Right-of-use assets	348	(92)	256
Finance lease receivable	—	116	116
Goodwill	809	28	837
Other assets	9	—	9
Current liabilities	(124)	—	(124)
Deferred tax liabilities	(281)	(13)	(294)
Decommissioning provision	(74)	—	(74)
Lease liability	(348)	—	(348)
Other liabilities	(66)	—	(66)
	4,255	—	4,255

For more information, see Note 6 of the Consolidated Financial Statements. During the six months ended June 30, 2020, Pembina adjusted the purchase price equation to reflect updated assumptions for the identification and classification of leases, which resulted in the recognition of finance lease assets of $118 million, and reductions in the property, plant and equipment of $26 million and in the right-of-use assets of $92 million. Pembina's verification of information supporting the fair value of assets acquired also resulted in a $15 million reduction to the fair value of certain Canadian property, plant and equipment with a corresponding decrease in deferred tax liabilities of $3 million and increase in goodwill of $12 million. Pembina also adjusted the allocation of fair value between Canadian and U.S. legal entities, resulting in a $16 million increase in the deferred tax liability and a corresponding increase in goodwill of $16 million. The purchase price allocation is not final as Pembina is continuing to obtain and verify information required to determine the fair value of certain assets and liabilities including the identification and classification of other provisions relating to income taxes.

4. PROPERTY, PLANT AND EQUIPMENT

($ millions)	Land and Land Rights	Pipelines	Facilities and Equipment	Cavern Storage and Other	Assets Under Construction	Total
Cost						
Balance at December 31, 2019[1]	440	8,803	8,730	1,945	1,493	21,411
Additions and transfers	8	413	225	45	55	746
Change in decommissioning provision	—	(39)	23	—	—	(16)
Foreign exchange adjustments	4	41	16	—	13	74
Disposals and other	—	(6)	(8)	(5)	(13)	(32)
Balance at June 30, 2020	**452**	**9,212**	**8,986**	**1,985**	**1,548**	**22,183**
Depreciation						
Balance at December 31, 2019	16	1,363	1,015	283	—	2,677
Depreciation	2	91	64	98	—	255
Disposals and other	—	(1)	(2)	(1)	—	(4)
Balance at June 30, 2020	**18**	**1,453**	**1,077**	**380**	—	**2,928**
Carrying amounts						
Balance at December 31, 2019	424	7,440	7,715	1,662	1,493	18,734
Balance at June 30, 2020	**434**	**7,759**	**7,909**	**1,605**	**1,548**	**19,255**
Assets subject to operating leases						
December 31, 2019[1]	—	477	514	62	—	1,053
June 30, 2020	**—**	**472**	**513**	**62**	**—**	**1,047**

[1] December 31, 2019 balances have been recast. See Note 3.

5. INVESTMENTS IN EQUITY ACCOUNTED INVESTEES

	Ownership Interest		Share of Profit from Equity Investments 6 Months Ended June 30		Equity Investments	
($ millions)	**June 30, 2020**	December 31, 2019	**2020**	2019	**June 30, 2020**	December 31, 2019
Alliance	**50%**	50%	**56**	86	**2,623**	2,620
Aux Sable	**42.7% - 50%**	42.7% - 50%	**2**	23	**432**	426
Ruby[1]	**-**	-	**61**	60	**1,331**	1,273
Veresen Midstream	**45%**	45%	**27**	23	**1,367**	1,348
CKPC	**50%**	50%	**1**	—	**328**	171
Other	**50% - 75%**	50% - 75%	**1**	1	**115**	116
			148	193	**6,196**	5,954

[1] Pembina owns a 50 percent convertible preferred interest in Ruby.

Pembina has U.S. $2.3 billion in investments in equity accounted investees that is held by entities whose functional currency is the U.S. dollar. The resulting foreign exchange gains and losses are included in other comprehensive income. For the three and six months ended June 30, 2020, Pembina recognized a loss of $110 million and a gain of $138 million (2019: $68 million loss and $145 million loss), respectively.

Financing Activities

Prior to CKPC's decision to defer further investment in the PDH/PP Facility, on February 27, 2020, CKPC closed a syndicated senior secured U.S. $1.7 billion amortizing term facility and a U.S. $150 million revolving facility both of which have been guaranteed equally on a several basis by the owners of CKPC through the completion of construction. The final maturity date of both the term facility and revolving facility is February 27, 2027. The parental guarantee resulted in the recognition of a financial guarantee liability, currently valued at U.S. $15 million, net of amortization, on Pembina's balance sheet, with an offsetting amount recorded as an equity contribution to the investment in CKPC.

On April 27, 2020, Ruby fully repaid its 364-day term loan. Concurrent to repayment, Ruby entered into a new term loan that will mature on March 31, 2021. The term loan will amortize U.S. $32 million in 2020 and 2021 (U.S. $16 million net to Pembina), in two equal payments each year with the first payment executed in June 2020.

On June 30, 2020 CKPC and the lenders agreed to amend and waive certain terms and conditions of the CKPC credit facility. In connection with the amendment, CKPC voluntarily repaid the U.S. $26 million drawn under the non-revolving term loan. CKPC also retained the ability to re-draw and access the full term loan of U.S. $1.7 billion upon resumption of key activities.

6. LEASES

Lessee Leases

Pembina enters into arrangements to secure access to assets necessary for operating the business. Leased (right-of-use) assets include terminals, rail, buildings, land and other assets. Total cash outflows related to leases were $33 million and $64 million, respectively, for the three and six months ended June 30, 2020 (2019: $20 million and $41 million).

Right-of-Use Assets

($ millions)	Terminals	Rail	Buildings	Land & Other	Total
Balance at December 31, 2019[1]	225	238	118	149	730
Additions	—	—	15	—	15
Amortization	(6)	(20)	(10)	(9)	(45)
Balance at June 30, 2020	**219**	**218**	**123**	**140**	**700**

[1] The December 31, 2019 balance of Terminals Right-of-Use Assets has been recast. See Note 3 Acquisition and further discussion below.

Lessor Leases

Pembina has entered into contracts for the use of its assets that have resulted in lease treatment for accounting purposes. Assets under operating leases include pipelines, terminals and storage tanks and caverns. See Note 4 for carrying value of property, plant and equipment under operating leases. Assets under finance leases include office sub-leases and terminal assets.

As disclosed in Note 3, Pembina continued to obtain and verify information required to determine the identification and classification of lessor leases acquired on December 16, 2019 as part of the Kinder Acquisition. Finance lease conclusions completed during the six months ended June 30, 2020 resulted in the recognition of an additional $118 million in finance lease receivables, of which $92 million related to lessee leases recognized at the acquisition date, resulting in the December 31, 2019 right-of-use asset balance being recast for leased terminal assets from $822 million to $730 million.

Maturity of Lease Receivables

As at June 30, 2020 *($ millions)*	**Operating Leases**	**Finance Leases**
Less than one year	158	23
One to two years	146	24
Two to three years	143	21
Three to four years	132	22
Four to five years	117	22
More than five years	927	235
Total undiscounted lease receipts	1,623	347
Unearned finance income on lease receipts		(206)
Discounted unguaranteed residual value		8
Finance lease receivable		149
Less current portion[(1)]		(7)
Total non-current		142

(1) Included in trade receivables and other on the Condensed Consolidated Interim Statement of Financial Position.

Expected credit losses on lease receivables are determined using a probability-weighted estimate of credit losses, measured as the present value of all expected cash shortfalls, discounted at the interest rates implicit in the leases, using reasonable and supportable information about past events, current conditions and forecasts of future economic conditions. Pembina considers the risk of default relating to lease receivables low based on Pembina's assessment of individual counterparty credit risk through established credit management techniques as disclosed in the Consolidated Financial Statements.

7. LOANS AND BORROWINGS

This note provides information about the contractual terms of Pembina's interest-bearing loans and borrowings, which are measured at amortized cost.

Carrying Value, Terms and Conditions, and Debt Maturity Schedule

				Carrying Value	
($ millions)	**Authorized at June 30, 2020**	**Nominal interest Rate**	**Year of Maturity**	**June 30, 2020**	December 31, 2019
Senior unsecured credit facilities[(1)(3)(4)]	4,159	1.57[(2)]	Various[(1)]	**1,213**	2,097
Senior unsecured notes – series A	—	5.57	2020	**—**	74
Senior unsecured notes – series C	200	5.58	2021	**212**	199
Senior unsecured medium-term notes series 1	250	4.89	2021	**250**	250
Senior unsecured medium-term notes series 2	450	3.77	2022	**449**	449
Senior unsecured medium-term notes series 3	450	4.75	2043	**446**	446
Senior unsecured medium-term notes series 4	600	4.81	2044	**596**	596
Senior unsecured medium-term notes series 5	450	3.54	2025	**449**	449
Senior unsecured medium-term notes series 6	500	4.24	2027	**498**	498
Senior unsecured medium-term notes series 7	600	3.71	2026	**603**	498
Senior unsecured medium-term notes series 8	650	2.99	2024	**646**	646
Senior unsecured medium-term notes series 9	550	4.74	2047	**542**	542
Senior unsecured medium-term notes series 10	650	4.02	2028	**662**	398
Senior unsecured medium-term notes series 11	800	4.75	2048	**844**	298
Senior unsecured medium-term notes series 12	650	3.62	2029	**654**	398
Senior unsecured medium-term notes series 13	700	4.54	2049	**713**	714
Senior unsecured medium-term notes series 14	600	2.56	2023	**598**	598
Senior unsecured medium-term notes series 15	600	3.31	2030	**597**	597
Senior unsecured medium-term notes series 16	400	4.67	2050	**397**	—
Senior unsecured medium-term notes 3A	50	5.05	2022	**52**	52
Senior unsecured medium-term notes 5A	350	3.43	2021	**353**	353
Total interest bearing liabilities				**10,774**	10,152
Less current portion				**(462)**	(74)
Total non-current				**10,312**	10,078

(1) Pembina's unsecured credit facilities include a $2.5 billion revolving facility that matures in May 2024, a $500 million non-revolving term loan that matures in August 2022, a $800 million revolving facility that matures in April 2022, a U.S. $250 million non-revolving term loan that matures in May 2025 and a $20 million operating facility that matures in May 2021, which is typically renewed on an annual basis.

(2) The nominal interest rate is the weighted average of all drawn credit facilities based on Pembina's credit rating at June 30, 2020. Borrowings under the credit facilities bear interest at prime, Bankers' Acceptance, or LIBOR rates, plus applicable margins.

(3) At June 30, 2020, includes U.S. $315 million (December 31, 2019: U.S. $454 million).

(4) The U.S. dollar denominated non-revolving term loan is designated as a hedge of the Company's net investment in selected foreign operations with a U.S. dollar functional currency. Refer to Note 14 for foreign exchange risk management.

On January 10, 2020, Pembina closed an offering of $1.0 billion of senior unsecured medium-term notes. The offering was conducted in three tranches, consisting of $250 million issued through a re-opening of Pembina's senior unsecured medium-term notes, series 10, having a fixed coupon of 4.02 percent per annum, payable semi-annually and maturing on March 27, 2028; $500 million issued through a re-opening of Pembina's senior unsecured medium-term notes, series 11, having a fixed coupon of 4.75 percent per annum, payable semi-annually and maturing on March 26, 2048; and $250 million issued through a re-opening of Pembina's senior unsecured medium-term notes, series 12, having a fixed coupon of 3.62 percent per annum, payable semi-annually and maturing on April 3, 2029.

On April 6, 2020, Pembina entered into an unsecured $800 million revolving credit facility with certain existing lenders, which provides additional liquidity and flexibility in Pembina's capital structure in the current market conditions. The credit facility has an initial term of two years. The other terms and conditions of the credit facility, including financial covenants, are substantially similar to Pembina's unsecured $2.5 billion revolving credit facility.

On May 7, 2020, Pembina entered into an unsecured U.S. $250 million non-revolving term loan with a global bank, which provides additional liquidity and flexibility in Pembina's capital structure in the current market conditions. The term loan has an initial term of five years. The other terms and conditions of the credit facility, including financial covenants, are substantially similar to Pembina's unsecured $2.5 billion revolving credit facility.

On May 28, 2020, Pembina closed an offering of $500 million of senior unsecured medium-term notes. The offering was conducted in two tranches, consisting of $400 million in senior unsecured medium-term notes, series 16, having a fixed coupon of 4.76 percent per annum, payable semi-annually, and maturing on May 28, 2050 and $100 million issued through a re-opening of Pembina's senior unsecured medium-term notes, series 7, having a fixed coupon of 3.71 percent per annum, payable semi-annually and maturing on August 11, 2026.

On July 10, 2020, Pembina's $200 million senior unsecured notes, series C, were fully repaid through an early redemption, of which notice was provided to holders on June 5, 2020. The series C notes were originally set to mature in September 2021.

8. DECOMMISSIONING PROVISION

($ millions)	**2020**
Balance at January 1	**867**
Unwinding of discount rate	**9**
Additions	**15**
Change in cost estimates and other	**(39)**
Total	**852**
Less current portion[1]	**(2)**
Balance at June 30	**850**

[1] Included in trade payables and other on the Condensed Consolidated Interim Statement of Financial Position.

Pembina applied a risk-free real return rate of 0.3 percent (December 31, 2019: 0.3 percent) to estimate the present value of the decommissioning provision. Changes in the measurement of the decommissioning provision are added to, or deducted from, the cost of the related property, plant and equipment or right-of-use asset.

9. SHARE CAPITAL

Common Share Capital

($ millions, except as noted)	**Number of Common Shares** *(millions)*	**Common Share Capital**
Balance at December 31, 2019	548	15,539
Share-based payment transactions	2	90
Balance at June 30, 2020	**550**	**15,629**

Preferred Share Capital

($ millions, except as noted)	**Number of Preferred Shares** *(millions)*	**Preferred Share Capital**
Balance at December 31, 2019	122	2,956
Part VI.1 tax	—	(4)
Balance at June 30, 2020	**122**	**2,952**

Dividends

The following dividends were declared by Pembina:

6 Months Ended June 30 *($ millions)*	**2020**	2019
Common shares		
$1.26 per common share (2019: $1.16)	**693**	592
Preferred shares		
$0.61 per Series 1 preferred share (2019: $0.61)	**6**	6
$0.56 per Series 3 preferred share (2019: $0.56)	**3**	3
$0.57 per Series 5 preferred share (2019: $0.61)	**6**	6
$0.54 per Series 7 preferred share (2019: $0.56)	**5**	6
$0.59 per Series 9 preferred share (2019: $0.59)	**5**	5
$0.71 per Series 11 preferred share (2019: $0.71)	**5**	5
$0.71 per Series 13 preferred share (2019: $0.71)	**7**	7
$0.56 per Series 15 preferred share (2019: $0.56)	**4**	4
$0.60 per Series 17 preferred share (2019: $0.61)	**4**	4
$0.63 per Series 19 preferred share (2019: $0.63)	**5**	5
$0.61 per Series 21 preferred share (2019: $0.61)	**10**	10
$0.66 per Series 23 preferred share (2019: nil)	**8**	—
$0.65 per Series 25 preferred share (2019: nil)	**7**	—
	75	61

On June 1, 2020, Pembina announced that it did not intend to exercise its right to redeem the eight million Cumulative Redeemable Rate Reset Class A Preferred Shares, Series 19 shares outstanding on June 30, 2020.

On July 6, 2020, Pembina announced that its Board of Directors had declared a dividend of $0.21 per common share ($2.52 annually) in the total amount of $115 million, payable on August 14, 2020 to shareholders of record on July 24, 2020. Pembina's Board of Directors also declared quarterly dividends for Pembina's preferred shares as outlined in the following table:

Series	**Record Date**	**Payable Date**	**Per Share Amount**	**Dividend Amount** *($ millions)*
Series 1	August 4, 2020	September 1, 2020	$0.306625	3
Series 3	August 4, 2020	September 1, 2020	$0.279875	2
Series 5	August 4, 2020	September 1, 2020	$0.285813	3
Series 7	August 4, 2020	September 1, 2020	$0.273750	3
Series 9	August 4, 2020	September 1, 2020	$0.296875	3
Series 11	August 4, 2020	September 1, 2020	$0.359375	2
Series 13	August 4, 2020	September 1, 2020	$0.359375	4
Series 15	September 15, 2020	September 30, 2020	$0.279000	2
Series 17	September 15, 2020	September 30, 2020	$0.301313	2
Series 19	September 15, 2020	September 30, 2020	$0.292750	2
Series 21	August 4, 2020	September 1, 2020	$0.306250	5
Series 23	July 31, 2020	August 15, 2020	$0.328125	4
Series 25	July 31, 2020	August 15, 2020	$0.325000	3

10. REVENUE

Revenue has been disaggregated into categories to reflect how the nature, timing and uncertainty of revenue and cash flows are affected by economic factors.

a. Revenue Disaggregation

	2020				2019			
3 Months Ended June 30 *($ millions)*	**Pipelines**	**Facilities**	**Marketing & New Ventures**	**Total**	Pipelines	Facilities	Marketing & New Ventures	Total
Take-or-pay[1]	**390**	**177**	**—**	**567**	301	157	—	458
Fee-for-service[1]	**66**	**28**	**—**	**94**	92	24	—	116
Product sales[2]	**—**	**—**	**561**	**561**	—	—	1,210	1,210
Revenue from contracts with customers	**456**	**205**	**561**	**1,222**	393	181	1,210	1,784
Operational finance lease income	**4**	**—**	**—**	**4**	—	—	—	—
Fixed Operating Lease Income	**32**	**10**	**—**	**42**	16	8	—	24
Total external revenue	**492**	**215**	**561**	**1,268**	409	189	1,210	1,808

(1) Revenue recognized over time.
(2) Revenue recognized at a point in time.

	2020				2019			
6 Months Ended June 30 *($ millions)*	**Pipelines**	**Facilities**	**Marketing & New Ventures**	**Total**	Pipelines	Facilities	Marketing & New Ventures	Total
Take-or-pay[1]	**778**	**359**	**—**	**1,137**	574	318	—	892
Fee-for-service[1]	**165**	**58**	**—**	**223**	188	41	—	229
Product sales[2]	**—**	**—**	**1,484**	**1,484**	—	3	2,606	2,609
Revenue from contracts with customers	**943**	**417**	**1,484**	**2,844**	762	362	2,606	3,730
Operational finance lease income	**8**	**—**	**—**	**8**	—	—	—	—
Fixed Operating Lease Income	**69**	**18**	**—**	**87**	31	15	—	46
Total external revenue	**1,020**	**435**	**1,484**	**2,939**	793	377	2,606	3,776

(1) Revenue recognized over time.
(2) Revenue recognized at a point in time.

b. Contract Liabilities

Significant changes in the contract liabilities balances during the period are as follows:

	6 Months Ended June 30, 2020			12 Months Ended December 31, 2019		
($ millions)	**Take-or-Pay**	**Other Contract Liabilities**	**Total Contract Liabilities**	Take-or-Pay	Other Contract Liabilities	Total Contract Liabilities
Opening balance	**8**	**223**	**231**	9	159	168
Additions (net in the period)	**43**	**90**	**133**	4	35	39
Acquisition (Note 3)	**—**	**—**	**—**	—	77	77
Revenue recognized from contract liabilities[1]	**(4)**	**(25)**	**(29)**	(5)	(48)	(53)
Closing balance	**47**	**288**	**335**	8	223	231
Less current portion[2]	**(47)**	**(47)**	**(94)**	(8)	(31)	(39)
Ending balance	**—**	**241**	**241**	—	192	192

(1) Recognition of revenue related to performance obligations satisfied in the current period that were included in the opening balance of contract liabilities.
(2) As at June 30, 2020, the balance includes $47 million of cash collected under take-or-pay contracts which will be recognized within one year as the customer chooses to ship, process, or otherwise forego the associated service.

Contract liabilities depict Pembina's obligation to perform services in the future for cash and non cash consideration which has been received from customers. Contract liabilities include up-front payments or non-cash consideration received from customers for future transportation, processing and storage services. Contract liabilities also include consideration received from customers for take-or-pay commitments where the customer has a make-up right to ship or process future volumes under a firm contract. These amounts are non-refundable should the customer not use its make-up rights.

Pembina does not have any contract assets. In all instances where goods or services have been transferred to a customer in advance of the receipt of customer consideration, Pembina's right to consideration is unconditional and has therefore been presented as a receivable.

11. NET FINANCE COSTS

	3 Months Ended June 30		6 Months Ended June 30	
($ millions)	**2020**	2019	**2020**	2019
Interest expense on financial liabilities measured at amortized cost:				
Loans and borrowings	**91**	74	**178**	145
Leases	**10**	4	**20**	9
Unwinding of discount rate	**4**	4	**9**	7
Finance lease income[1]	**(1)**	(1)	**(1)**	(1)
(Gain) loss in fair value of non-commodity-related derivative financial instruments	**(24)**	—	**22**	3
Foreign exchange (gains) losses and other	**(8)**	(3)	**53**	(6)
Net finance costs[1]	**72**	78	**281**	157

[1] Excludes operational finance lease income from lessor lease arrangements which is included in revenue as this income is generated from physical assets in the normal course of operations.

12. OPERATING SEGMENTS

Pembina's operating segments are organized by three divisions: Pipelines, Facilities and Marketing & New Ventures.

3 Months Ended June 30, 2020 *($ millions)*	**Pipelines**[1]	**Facilities**	**Marketing & New Ventures**[2]	**Corporate & Inter-division Eliminations**	**Total**
Revenue from external customers	492	215	561	—	1,268
Inter-division revenue	36	75	—	(111)	—
Total revenue[3]	528	290	561	(111)	1,268
Operating expenses	107	86	—	(39)	154
Cost of goods sold, including product purchases	—	2	565	(75)	492
Realized gain on commodity-related derivative financial instruments	—	—	(36)	—	(36)
Share of profit (loss) from equity accounted investees	57	14	(6)	—	65
Depreciation and amortization included in operations	102	51	12	2	167
Unrealized loss on commodity-related derivative financial instruments	—	2	99	—	101
Gross profit	376	163	(85)	1	455
Depreciation included in general and administrative	—	—	—	9	9
Other general and administrative	1	4	7	38	50
Other expense (income)	3	1	—	(24)	(20)
Reportable segment results from operating activities	372	158	(92)	(22)	416
Net finance costs	9	6	(12)	69	72
Reportable segment earnings (loss) before tax	363	152	(80)	(91)	344
Capital expenditures	129	62	10	10	211
Contributions to equity accounted investees	—	—	2	—	2

3 Months Ended June 30, 2019 *($ millions)*	**Pipelines**[1]	**Facilities**	**Marketing & New Ventures**[2]	**Corporate & Inter-division Eliminations**	**Total**
Revenue from external customers	409	189	1,210	—	1,808
Inter-division revenue	34	86	—	(120)	—
Total revenue[3]	443	275	1,210	(120)	1,808
Operating expenses	92	82	—	(40)	134
Cost of goods sold, including product purchases	—	1	1,129	(80)	1,050
Realized gain on commodity-related derivative financial instruments	—	—	(1)	—	(1)
Share of profit from equity accounted investees	67	12	18	—	97
Depreciation and amortization included in operations	58	37	15	(2)	108
Unrealized gain on commodity-related derivative financial instruments	—	—	(15)	—	(15)
Gross profit	360	167	100	2	629
Depreciation included in general and administrative	—	—	—	13	13
Other general and administrative	7	4	6	46	63
Other expense (income)	1	—	2	(2)	1
Reportable segment results from operating activities	352	163	92	(55)	552
Net finance costs	3	1	4	70	78
Reportable segment earnings (loss) before tax	349	162	88	(125)	474
Capital expenditures	234	148	47	5	434
Contributions to equity accounted investees	—	—	28	—	28

(1) Pipelines transportation revenue includes $49 million (2019: $10 million) associated with U.S. pipeline revenue.
(2) Marketing & New Ventures includes revenue of $15 million (2019: $95 million) associated with U.S. midstream sales.
(3) During both periods, one customer accounted for 10 percent or more of total revenues, with $164 million (2019: $207 million) reported throughout all segments.

6 Months Ended June 30 *($ millions)*	Pipelines[1]	Facilities	Marketing & New Ventures[2]	Corporate & Inter-Division Eliminations	Total
Revenue from external customers	1,020	435	1,484	—	2,939
Inter-division revenue	71	159	—	(230)	—
Total revenue[3]	1,091	594	1,484	(230)	2,939
Operating expenses	233	182	—	(82)	333
Cost of goods sold, including product purchases	—	4	1,448	(154)	1,298
Realized gain on commodity-related derivative financial instruments	—	—	(53)	—	(53)
Share of profit from equity accounted investees	115	30	3	—	148
Depreciation and amortization included in operations	201	104	25	4	334
Unrealized gain on commodity-related derivative financial instruments	—	(3)	(5)	—	(8)
Gross profit	772	337	72	2	1,183
Depreciation included in general and administrative	—	—	—	19	19
Other general and administrative	10	5	15	71	101
Other expense (income)	3	1	12	(19)	(3)
Reportable segment results from operating activities	759	331	45	(69)	1,066
Net finance costs	16	13	9	243	281
Reportable segment earnings (loss) before tax	743	318	36	(312)	785
Capital expenditures	457	198	25	14	694
Contributions to equity accounted investees	—	41	155	—	196

6 Months Ended June 30, 2019 *($ millions)*	Pipelines[1]	Facilities	Marketing & New Ventures[2]	Corporate & Inter-Division Eliminations	Total
Revenue from external customers	793	377	2,606	—	3,776
Inter-division revenue	66	169	—	(235)	—
Total revenue[3]	859	546	2,606	(235)	3,776
Operating expenses	190	167	—	(83)	274
Cost of goods sold, including product purchases	—	2	2,394	(152)	2,244
Realized gain on commodity-related derivative financial instruments	—	—	(20)	—	(20)
Share of profit from equity accounted investees	146	24	23	—	193
Depreciation and amortization included in operations	115	76	32	1	224
Unrealized loss on commodity-related derivative financial instruments	—	—	30	—	30
Gross profit	700	325	193	(1)	1,217
Depreciation included in general and administrative	—	—	—	22	22
Other general and administrative	17	9	19	83	128
Other expense (income)	2	—	3	(1)	4
Reportable segment results from operating activities	681	316	171	(105)	1,063
Net finance costs	5	3	1	148	157
Reportable segment earnings (loss) before tax	676	313	170	(253)	906
Capital expenditures	426	260	102	7	795
Contributions to equity accounted investees	—	26	92	—	118

(1) Pipelines transportation revenue includes $108 million (2019: $22 million) associated with U.S. pipeline revenue.
(2) Marketing & New Ventures includes revenue of $65 million (2019: $158 million) associated with U.S. midstream sales.
(3) During both periods, one customer accounted for 10 percent or more of total revenues, with $301 million (2019: $438 million) reported throughout all segments.

13. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

($ millions)	Currency Translation Reserve	Cash Flow Hedge Reserve	Pension and other Post-Retirement Benefit Plan Adjustments[2]	Total
Balance at December 31, 2018	348	—	(31)	317
Other comprehensive loss before hedging activities	(161)	—	—	(161)
Balance at June 30, 2019	187	—	(31)	156
Balance at December 31, 2019	134	—	(36)	98
Other comprehensive gain before hedging activities	253	—	14	267
Other comprehensive gain (loss) resulting from hedging activities[1]	11	(1)	—	10
Tax impact	(1)	—	—	(1)
Balance at June 30, 2020	397	(1)	(22)	374

(1) Amounts relate to hedges of the Company's net investment in foreign operations (reported in Currency Translation Reserve) and interest rate derivatives designated as cash flow hedges (reported in Cash Flow Hedge Reserve)(Note 14).

(2) Pension and other Post-Retirement Benefit Plan Adjustments will not be reclassified into earnings.

14. FINANCIAL INSTRUMENTS & RISK MANAGEMENT

Risk Management

Hedge of Net Investment in Foreign Operations

On May 7, 2020, Pembina designated the U.S. $250 million non-revolving term loan it entered into as a hedge of the Company's net investment in selected U.S. functional currency foreign operations. The designated debt has been assessed as having no ineffectiveness as the U.S. dollar debt has an equal and opposite exposure to U.S. dollar fluctuations. Foreign exchange gains and losses on the designated debt are recognized in the currency translation reserve in accumulated other comprehensive income (refer to Note 13).

Interest Rate Risk - Cash Flow Hedge

On May 8, 2020, Pembina designated financial derivative contracts that fix the interest rate on U.S. $250 million of variable rate debt as cash flow hedging instruments. The designated cash flow hedge has been assessed as having no ineffectiveness as the critical terms are aligned. Unrealized gains (losses) on derivatives in designated cash flow hedging relationships are recognized in the cash flow hedge reserve in accumulated other comprehensive income, with realized gains (losses) being reclassified to net finance costs (refer to Note 13).

Fair Values

The fair values of financial assets and liabilities, together with the carrying amounts shown in the condensed consolidated interim statements of financial position, are shown in the table below. Certain non-derivative financial instruments measured at amortized cost including cash and cash equivalents, trade receivables and other, finance lease receivables, advances to related parties and trade payables and other have been excluded because they have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity. These instruments would be classified in Level 2 of the fair value hierarchy. A financial guarantee included in other liabilities has a carrying amount that approximates fair value at the reporting date due to the nature of the underlying development project and is classified in Level 3 of the fair value hierarchy.

	June 30, 2020				December 31, 2019			
	Carrying	**Fair Value[1]**			Carrying	Fair Value[1]		
($ millions)	**Value**	**Level 1**	**Level 2**	**Level 3**	Value	Level 1	Level 2	Level 3
Financial assets carried at fair value								
Derivative financial instruments[3]	**76**	**—**	**76**	**—**	48	—	48	—
Financial liabilities carried at fair value								
Derivative financial instruments[3]	**29**	**—**	**29**	**—**	9	—	9	—
Financial liabilities carried at amortized cost								
Loans and borrowings[2]	**10,774**	**—**	**11,532**	**—**	10,152	—	10,729	—

(1) The basis for determining fair value is disclosed in Note 2.
(2) Carrying value of current and non-current balances.
(3) At June 30, 2020 all derivative financial instruments are carried at fair value through earnings, except for $1 million in interest rate derivative financial liabilities that have been designated as cash flow hedges (December 31, 2019: $nil)

15. COMMITMENTS AND CONTINGENCIES

Commitments

Pembina had the following contractual obligations outstanding at June 30, 2020:

Contractual Obligations	**Payments Due by Period**				
($ millions)	**Total**	**Less than 1 Year**	**1 – 3 Years**	**3 – 5 Years**	**After 5 Years**
Leases[1]	1,111	132	229	177	573
Loans and borrowings[2]	16,362	931	2,633	2,412	10,386
Construction commitments[3]	1,568	416	284	291	577
Other[4]	599	103	152	83	261
Total contractual obligations	19,640	1,582	3,298	2,963	11,797

(1) Includes terminals, rail, office space, land and vehicle leases.
(2) Excluding deferred financing costs. Including interest payments on senior unsecured notes.
(3) Excluding significant projects that are awaiting regulatory approval, projects which Pembina is not committed to construct, and projects that are executed by equity accounted investees.
(4) Includes $38 million in commitments related to leases that have not yet commenced.

Pembina enters into product purchase agreements and power purchase agreements to secure supply for future operations. Purchase prices of both NGL and power are dependent on current market prices. Volumes and prices for NGL and power contracts cannot be reasonably determined and therefore an amount has not been included in the contractual obligations schedule. Product purchase agreements range from one to 10 years and involve the purchase of NGL products from producers. Assuming product is available, Pembina has secured between 35 and 175 mbpd of NGL each year up to and including 2029. Power purchase agreements range from one to 25 years and involve the purchase of power from electrical service providers. Pembina has secured up to 80 megawatts per day each year up to and including 2044.

Commitments to Equity Accounted Investees

Pembina is contractually committed to provide CKPC with funding to construct assets that will form part of CKPC's PDH/PP Facility, subject to certain conditions being met. Following CKPC's decision to defer investment in the PDH/PP Facility, Pembina has deferred future contributions to CKPC.

Pembina has a contractual commitment to advance U.S. $23 million to Ruby by March 31, 2021.

Pembina has commitments to provide contributions to certain equity accounted investees based on annual budgets approved by the joint venture partners.

Contingencies

Pembina, its subsidiaries and its investments in equity accounted investees are subject to various legal and regulatory and tax proceedings, actions and audits arising in the normal course of business. We represent our interests vigorously in all proceedings in which we are involved. Legal and administrative proceedings involving possible losses are inherently complex, and we apply significant judgment in estimating probable outcomes. While the outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolutions of such actions and proceedings will not have a material impact on Pembina's financial position or results of operations.

Letters of Credit

Pembina has provided letters of credit to various third parties in the normal course of conducting business. The letters of credit include financial guarantees to counterparties for product purchases and sales, transportation services, utilities, engineering and construction services. The letters of credit have not had and are not expected to have a material impact on Pembina's financial position, earnings, liquidity or capital resources.

At June 30, 2020 Pembina had $94 million (December 31, 2019: $103 million) in letters of credit issued to facilitate commercial transactions with third parties and to support regulatory requirements.

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STOCK EXCHANGE

Pembina Pipeline Corporation

Toronto Stock Exchange listing symbols for:

COMMON SHARES PPL
PREFERRED SHARES PPL.PR.A, PPL.PR.C, PPL.PR.E, PPL.PR.G, PPL.PR.I, PPL.PR.K, PPL.PR.M, PPL.PR.O, PPL.PR.Q, PPL.PR.S, PPL.PF.A, PPL.PF.C and PPL.PF.E

New York Stock Exchange listing symbol for:

Common shares PBA

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The National Energy Board: Regulation of Access to Oil Pipelines

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Jennifer Hocking
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ABSTRACT:

In the past few years, a number of long distance oil pipelines have been proposed in Canada-Northern Gateway, the Trans Mountain Expansion, Keystone, and the Energy East Project. This article describes the criteria used by the National Energy Board in approving the allocation of capacity in oil pipelines to firm service contracts while requiring that a reasonable percentage of capacity is allocated for uncommitted volumes (common carriage). It explains the economic theory related to regulation of access to major oil pipelines. It reviews and analyzes relevant NEB decisions, which show that the NEB supports well-functioning competitive markets, but will exercise its discretion to resolve complaints where markets are not functioning properly. The article also explains the economic significance of the proposed long distance oil pipelines to Canada and Alberta despite the current low price of crude oil. The article concludes with recommendations for a written NEB policy regarding access to capacity in oil pipelines.

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The National Energy Board: Regulation of Access to Oil Pipelines

I. SIGNIFICANCE OF PROPOSED OIL PIPELINES TO THE CANADIAN ECONOMY

1 Access to capacity in oil pipelines is currently an issue of major significance to the Canadian economy. Oil exports are an important part of the Canadian economy.[1] Western Canadian crude oil production is projected to grow by 156,000 barrels per day (bpd) until 2020, and by 85,000 bpd from 2020 to 2030.[2] Additional oil pipeline export capacity from Alberta is needed in order to accommodate forecasted increases in oil production.[3]

2 The majority of conventional Canadian oil is produced in the Western Canadian Sedimentary Basin (WCSB), which is located in Alberta, northeastern British Columbia, Saskatchewan, and parts of Manitoba and the Northwest Territories.[4] Until the middle of the last decade, Alberta crude oil sold in the United States midwest traded at a premium to world prices because it was closer to markets than international oil, which had to be shipped from tidewater to the middle of the continent.[5] However, since 2010, the US midwest has had a glut of oil.[6] Canada cannot rely on continuing to sell the majority of its exported crude oil to the US midwest. Canada will therefore need to find new foreign markets for its oil. If new foreign markets cannot be accessed for Canadian crude oil, future growth in Canadian crude oil production will be limited,[7] with significant impacts on the Canadian economy.

3 Currently, pipeline capacity to tidewater is tight, meaning that Alberta oil cannot reach overseas markets. This means that Alberta oil has traded at a significant discount relative to North American and world oil prices in recent years. The price discounts can also result in significantly lower tax revenues and royalties for both federal and provincial governments, and lower netbacks for oil producers. The Alberta government relies on energy for a significant portion of its revenues.[8]

4 From 2010 to 2012, there was sufficient pipeline capacity for oil to reach the Cushing Hub in Oklahoma, but much of that oil was then placed in storage tanks at Cushing due to the shortage of pipeline capacity south to the Gulf of Mexico. Within that time frame, the price differential between Western Canada Select (WCS) heavy blend crude (Alberta heavy oil) and the Cushing Hub price of West Texas Intermediate (WTI) light crude[9] widened from only a dollar in November 2010[10] to a record high of $42.50 on 14 December 2012.[11] As additional pipeline capacity is added, the price differential tends to narrow until the new pipeline capacity is filled.[12] Then the price differential will widen until further pipeline capacity is added. For example, the price differential was narrowed in January 2013,

when pipeline capacity in the Seaway Pipeline from Cushing to the Gulf of Mexico was increased.[13] In January 2014, the price differential was narrowed again when the southern leg of the Keystone pipeline system to the Gulf Coast became operational, adding further pipeline capacity to tidewater. By the second quarter (Q2) of 2014, the price differential between WTI and WCS had narrowed further as more crude oil was shipped by rail due to constrained pipeline capacity.[14] As of December 2015, the WTI/WCS price was US$14.82.[15]

5 Developing new markets is best done by developing pipeline capacity to the west and east coasts of Canada, to the US Gulf Coast, and to the US eastern seaboard. New Asian markets can be accessed most cost effectively by pipeline to the west coast of British Columbia and by tanker from there. According to a report by the Canada West Foundation, China and India are the "fastest growing economies in the world,"[16] and demand for oil in these two countries is also growing.[17] In addition, the US Gulf Coast is an important market for Canadian oil, as it has numerous refineries that are equipped to process Canadian heavy crude oil.[18] Further, refineries in eastern Canada are now seeking access to Canadian crude oil as imported overseas crude oil becomes more expensive.[19]

6 Pipelines are the safest, most cost effective, and most energy efficient way for Canadian oil to reach markets,[20] despite opposition to new pipelines, pipeline expansions, and pipeline reversals based on environmental concerns.[21] Russia and the Middle East, as well as other regions, are also taking steps to secure supply links to Asia, including China.[22] If Canada cannot provide reliable crude oil supply to Asia soon, the opportunity will be lost to other world players, and the Canadian economy will be impacted.

A. PIPELINES NEEDED DESPITE LOW PRICE OF OIL

7 Additional oil pipeline capacity is required despite the current low world price of crude oil. Between June 2014 and March 2015 the world price of crude oil fell by over 50 percent for a number of reasons.[23] While some oil projects have been deferred,[24] many developments will continue to produce oil over the coming years. Oil sands projects require large amounts of capital, and take several years to construct;[25] generally they will produce oil for many years. As a result, oil sands production from existing projects and projects nearing completion are expected to continue to expand in the next few years because producers will have significant sunk costs in projects.[26] This will be the case as long as the price of oil stays high enough to cover the marginal costs, including pumping, transportation, and marketing.[27] By contrast, conventional oil investments are short term in nature; conventional oil drilling activity is expected to decline substantially in 2016.[28]

B. SHIPPING OF OIL BY RAIL

8 As a result of constrained oil pipeline capacity, the amount of oil shipped by rail has grown in recent years, although it is still only a fraction of the total amount of crude oil shipped out of the WCSB. There are some short term advantages to transporting crude oil by rail. Rail is a more flexible option than pipelines and can quickly adapt to changing markets.[29] In addition, transportation of crude oil by rail has not, to date, drawn the significant public opposition to crude oil transportation experienced by proposed pipelines in Canada and the US. However, there are safety concerns regarding the shipping of crude oil by rail. In addition, the cost of shipping by rail is roughly double or triple the cost of shipping by pipeline.[30] With the current low price of oil, oil producers are seeking to cut costs, including transportation costs. Rail is now a less attractive option, and the need for increased export pipeline capacity is heightened.[31]

II. OIL PIPELINES AS COMMON CARRIERS

A. THE NATURE OF COMMON CARRIERS

9 NEB regulated oil pipelines have traditionally been described as "common carriers."[32] This means that they are required to transport all oil offered to them, unless the NEB grants an exemption. Section 71(1) of the NEBA is the legislative provision that describes the common carrier obligation for oil pipeline companies, although the words

"common carrier" do not appear in this section or elsewhere in the NEBA. The section states:

> Subject to such exemptions, conditions or regulations as the Board may prescribe, a company operating a pipeline for the transmission of oil shall, according to its powers, without delay and with due care and diligence, receive, transport and deliver all oil offered for transmission by means of its pipeline.[33]

Economists Robert Mansell and Jeffrey Church suggest that a common carrier pipeline is "created by government edict and it, by definition, requires regulation."[34] They suggest that on a common carrier pipeline, "when transmission capacity is insufficient, available capacity must be rationed on a pro rata basis across all customers, usually on the basis of their nominated shipping volumes."[35]

10 A shipper may also apply for an order pursuant to section 71(3) of the NEBA requiring a pipeline company to provide existing or new facilities needed to receive, transport, and deliver hydrocarbons, provided that such an order will not place an undue burden on the pipeline company. Specifically, section 71(3) states:

> The Board may, if it considers it necessary or desirable to do so in the public interest, require a company operating a pipeline for the transmission of hydrocarbons, or for the transmission of any other commodity authorized by a certificate issued under Part III, to provide adequate and suitable facilities for
>
> (a) the receiving, transmission and delivering of the hydrocarbons or other commodity offered for transmission by means of its pipeline,
>
> (b) the storage of the hydrocarbons or other commodity, and
>
> (c) the junction of its pipeline with other facilities for the transmission of the hydrocarbons or other commodity,
>
> if the Board finds that no undue burden will be placed on the company by requiring the company to do so.[36]

The detailed research performed for this paper revealed only one mention of section 71(3) in the context of oil pipelines: the Trans Northern.[37]

11 The NEB has the following definition of "common carrier" in its online dictionary: "A pipeline company that is obligated to ship all product offered to it for transmission, without contract and usually by monthly nominations. In the event that capacity is not available to meet all requests, services are prorated amongst users."[38] This definition is consistent with the remarks of Mansell and Church, but it appears to be a historical definition. It does not reflect current NEB practice, which allows shippers and pipeline companies to enter into contracts for firm service provided that certain criteria are met, as will be discussed below.

12 By contrast, NEB regulated natural gas pipelines are generally described as "contract carriers." Mansell and Church define a contract carrier as a pipeline that "provide[s] transmission service for gas owned by others according to a private contract between the pipeline company and the shipper."[39] Contract carriers are not generally required to ship products from all parties. The NEB regulation of access to natural gas pipelines will be discussed in a subsequent article.

B. COMMON CARRIAGE OBLIGATION SUBJECT TO REASONABLENESS TEST

13 The leading NEB decision on the nature of the common carriage obligation is PanCanadian.[40] In this proceeding, PanCanadian Petroleum Limited (PanCanadian) applied for an order requiring Interprovincial Pipe Line Inc. (IPL) to transport natural gas liquids (NGL) for PanCanadian from Kerrobert, Saskatchewan, to markets in eastern Canada and the US. The composition of the NGL was such that it fit under the definition of "oil" under section 2 of the NEBA, so the pipeline was an oil pipeline subject to the common carriage obligation under section 71(1).

14 Prior to adding another shipper, IPL required consent from existing shippers based on IPL's operating

procedures. Amoco, the only existing NGL shipper on IPL, objected to the provision of service to PanCanadian because PanCanadian had requested that its NGL be commingled with Amoco's product.

15 The Board held that IPL, in not providing public access for NGL to be transported on its pipeline, had failed to comply with its common carrier obligations. The NEB stated that the common carriage obligations of an oil pipeline are relative, rather than absolute obligations, which are tempered by a test of reasonableness. Specifically, the NEB stated as follows:

> [C]ompliance with the common carrier provisions is determined by a test of reasonableness, which is a relative concept. Section 71 of the NEB Act is consistent with [the] common law approach because it permits the Board to tailor the statutory obligations of both oil and gas pipelines to fit any unique circumstances which may exist. Thus, the Board can increase or decrease the statutory common carrier obligations of an oil, gas or commodity pipeline in respect of their carriage of oil, gas or another commodity.[41]

The NEB also noted that no provision in a pipeline company's tariffs could detract from the common carrier obligations imposed by the NEBA.

16 On the concept of reasonableness, the NEB cited Patchett & Sons Ltd v. Pacific Great Eastern Railway Co. in which the Supreme Court of Canada held that a railway company's common carrier obligations to provide reasonable facilities were limited by the concept of reasonable service and that common carriers "cannot be compelled to bankrupt themselves by doing more than what they have embraced within their public profession."[42]

C. WHY WERE OIL PIPELINES ORIGINALLY DESIGNATED AS COMMON CARRIERS?

17 The first Canadian long distance oil pipelines were constructed in the 1950s.[43] Oil pipelines may originally have been designated as common carriers because of the properties of oil as a substance and because of the structure of oil markets at that time.

18 Crude oil is not generally usable in the form in which it is produced from a well in the oil patch. It must be transported to a refinery where it is refined into consumer products such as petroleum, naphtha, gasoline, diesel fuel, asphalt base, heating oil, kerosene, and liquefied petroleum gas.[44] There are many different grades of crude oil, ranging from light oil to heavy oil and bitumen. While light oil is the most valuable, bitumen is dense and highly viscous, and must be diluted with condensate in order to be transported in pipelines. Different grades of crude oil must be transported in separate batches because mixing a higher grade of oil with a lower grade of oil would lower the value of the higher grade of oil.

19 Crude oil is a liquid at ambient temperature. As a result, it is relatively easy and inexpensive to build storage facilities (sometimes known as tank farms or oil terminals) for crude oil at both the upstream and downstream ends of transmission pipelines. These storage facilities can be used to smooth out or ensure regular deliveries to customers.

20 Crude oil in North America has generally been purchased and sold on a short term basis, typically month to month, in "spot markets."[45] Generally, individual end users do not need to have long term contracts on transmission pipelines in order to have security of supply because there are alternative means of transportation for oil.[46] Oil can be delivered by ocean tankers and barges from around the world, other oil pipelines, petroleum product pipelines, rail, or truck.

21 Similarly, Canadian oil pipeline companies traditionally allocated capacity on a short term or month to month basis. Every month, shippers would nominate the volume of crude oil they wished to ship on a given pipeline. As shippers were buying and selling crude oil in spot markets on a monthly basis, this arrangement worked well for them. Oil pipeline companies have often been vertically integrated. In other words, oil pipelines have often been

constructed and owned by oil producers that also refine their own oil.[47] Clearly, vertically integrated pipeline companies have no need for long term transportation contracts.

22 Until 1997, all long distance oil pipelines in Canada were truly common carriers. Historically, shippers did not need the certainty provided by long term firm contracts given the numerous supply and transportation alternatives available to them and relatively easy access to storage. Further, long term contracts would not have fit well with the spot market for oil or with the inability to commingle batches of crude oil.

23 Today, the majority of capacity in the oil pipeline systems in Canada is subject to long term firm contracts. Since 1997, when the Express Pipeline was approved, competition among oil pipelines has been growing. In addition, there have been dramatic changes in oil and gas markets since 2007.[48] Due to technological advances in the production of oil and gas, it is now possible to economically produce large volumes of oil and gas from tight and shale formations in Canada and the US.[49] Also, oil sands production has increased. Rapid growth in WCSB oil sands and US tight oil production has resulted in a surplus of oil in the middle of North America since 2011.[50] As a result, oil export pipeline capacity is tight[51] - for example, both Enbridge and Trans Mountain pipelines have had to significantly apportion volumes shipped.[52]

III. MAJOR LONG DISTANCE OIL PIPELINES TODAY

24 Today, there are four major oil pipeline systems that transport oil production out of the WCSB: Trans Mountain, Express (now Spectra Energy Express Platte), the Keystone Pipeline System, and the Enbridge Mainline. In three of these four major pipeline systems, the majority of capacity is now subject to long term firm contracts with shippers, also known as Transportation Service Agreements (TSAs). Eighty percent of the existing Trans Mountain pipeline is subject to long term firm contracts, with this percentage remaining constant in the proposed expansion.[53] Eighty five percent of the Express pipeline is subject to long term firm contracts.[54] Up to 88 percent of the capacity of Keystone XL is subject to long term firm contracts, and up to 94 percent of Keystone Base is subject to long term firm contracts.[55] Enbridge proposes to have 95 percent of the Northern Gateway Pipeline subject to firm contracts. By contrast, the Enbridge Mainline remains entirely a common carrier pipeline, with no long term contracts.

A. ENBRIDGE PIPELINES

1. ENBRIDGE PIPELINES

25 Enbridge is Canada's largest transporter of crude oil, delivering on average more than 2.2 million bpd of crude oil and liquids.[56] The Enbridge Canadian mainline (formerly the Interprovincial Pipeline) commences in Edmonton, Alberta, and is made up of six pipelines exiting western Canada that transport natural gas liquids, synthetic crude oil, refined petroleum products, light crude oil, condensate, and heavy crude oil.[57] The six lines interconnect with other Enbridge pipelines to serve destinations in central Canada including Montreal, Quebec, and destinations in the US including the Cushing Hub and Toledo. The Enbridge Mainline Pipeline System includes the Clipper Pipeline which runs from Hardisty, Alberta to Gretna, Manitoba, and south to Superior, Wisconsin, in the US.[58] Enbridge intended to expand capacity in the Clipper Pipeline by 2015, but the US portion of the capacity expansion has been delayed pending issuance of a US presidential permit.[59]

26 After extensive negotiations with shippers, Enbridge entered into a Competitive Tolling Settlement Agreement (CTS) with shippers in 2011 for ten years.[60] The tolls are set pursuant to the agreement in which the Enbridge mainline is no longer based on a cost of service toll methodology. Under the terms of the CTS, Enbridge stands to earn a greater return on equity if it accepts more risk with respect to volumes, capital, or other stated factors on a particular project.[61]

27 Enbridge has received approval from the NEB, subject to certain conditions, to reverse (or re reverse) the direction of flow in Line 9 from Sarnia, Ontario to Montreal, Quebec and to expand the capacity of the entire Line 9 to approximately 300,000 bpd.[62] The Line 9 reversal will allow Enbridge to ship crude oil from western Canada to

the Ontario market, an Ontario refinery, and Montreal refineries.[63] Line 9 originally flowed from west to east, but in 1998 it was reversed to flow from east to west to receive oil from overseas. It now makes sense to re reverse the flow of the line given the forecast for substantial growth in western Canadian light crude oil supply.[64]

2. PROPOSED ENBRIDGE NORTHERN GATEWAY PIPELINE

28 The proposed Northern Gateway pipeline (Northern Gateway) would be capable of transporting an average of 525,000 bpd of crude oil from Bruderheim in northern Alberta to the northwest coast of British Columbia at Kitimat.[65] From Kitimat, the oil could be transported to overseas markets, particularly Asia, by tanker. Northern Gateway would transport bitumen diluted with condensate to allow it to flow freely in the pipeline, as well as other oil products. The project includes a parallel condensate pipeline which would transport the used condensate back to Alberta for re use.

B. TRANS MOUNTAIN PIPELINE

29 The existing Kinder Morgan Trans Mountain pipeline transports crude oil and refined products from Edmonton, Alberta to Burnaby, British Columbia.[66] It is currently the only oil pipeline from Alberta directly to the west coast,[67] and it provides access to Asian markets, as well as to other markets in the US and overseas through the Westridge marine terminal at Burnaby, British Columbia.[68] In addition, Trans Mountain delivers oil products to marketing terminals and refineries in central British Columbia, and the Greater Vancouver area. It also connects to a US affiliate at Sumas, on the British Columbia Washington State border, for delivery to refineries in the Puget Sound area in Washington State. Eighty percent of the capacity of the Trans Mountain pipeline is allocated through long term firm contracts.

30 Kinder Morgan proposes to expand the Trans Mountain pipeline. The proposed expansion, if approved by the NEB, would create a twinned pipeline that would increase the nominal capacity of the existing pipeline by almost three times, from 300,000 bpd to 890,000 bpd.[69] Both the City of Vancouver and the City of Burnaby are opposed to the proposed expansion based on environmental concerns.[70] The NEB is scheduled to make its final recommendation to the Governor in Council regarding the project by 20 May 2016.[71]

C. SPECTRA ENERGY EXPRESS PLATTE

31 The Express Pipeline commenced operation in 1997. Express Pipeline was the first long distance oil pipeline in Canada to have long term firm contracts with its shippers for a majority of its capacity.[72] The Express Pipeline has a capacity of approximately 280,000 bpd.

32 The Express Pipeline and the Platte pipeline are now owned by Spectra Energy Express Platte.[73] The Express Pipeline delivers Western Canadian crude oil from Hardisty, Alberta, to Casper, Wyoming, where it interconnects with the Platte Pipeline. The Platte Pipeline transports the crude oil to refineries in the Rocky Mountain and midwest regions of the US.[74] The Express Pipeline and the Enbridge mainline both commence at Hardisty, Alberta, and they compete for crude oil supply from the WCSB,[75] although they serve different markets.

D. KEYSTONE PIPELINE SYSTEM

33 The Keystone Pipeline system can be described as four pipelines:

(1) Keystone Base is already operational and it runs from Hardisty, Alberta, to Steele City in Nebraska, and to Wood River and Patoka in Illinois. More than half of Keystone Base involved the conversion of existing under-utilized natural gas pipeline in Saskatchewan and Manitoba.

(2) The Cushing Expansion is already operational, running from Steele City to the Cushing Hub in Oklahoma.

(3) The Gulf Coast Project, from Cushing to Nederland and Houston, Texas (on the Gulf Coast) commenced operations in January 2014.[76] With the completion of the link to the Gulf Coast, this is the first time that supply from the WCSB has been directly connected to the US Gulf Coast, which, according to Keystone, is a "large, highly desirable, and virtually untapped market."[77]

(4) The Keystone XL Pipeline would extend diagonally from Hardisty, Alberta, to Steele City, Nebraska. The NEB has approved the Canadian portion of Keystone XL.[78] The portion of the Keystone XL Pipeline from the Canadian border to Steele City, Nebraska, was rejected by the Obama administration in the US in November 2015. President Barack Obama stated that the pipeline would not make a meaningful long term contribution to the US economy. TransCanada has filed two lawsuits, one against the Obama administration[79] and one under the North American Free Trade Agreement.[80] Environmental groups have expressed concerns about the potential negative impacts of the Keystone XL Pipeline and the fact that it will transport oil from the Alberta oil sands.

E. PROPOSED ENERGY EAST PROJECT

34 TransCanada filed a combined facilities and tolling methodology application for the Energy East Pipeline with the NEB on 30 October 2014.[81] The NEB is currently reviewing amendments filed by TransCanada in December 2015.[82] The Energy East Pipeline would carry 1.1 million barrels of crude oil per day from Hardisty, Alberta, and Saskatchewan to existing refineries in Montreal, near Quebec City, and Saint John, New Brunswick.[83] Marine facilities would be built in Quebec City and Saint John to allow marine tankers to be loaded with crude for shipment to export markets.[84] The project includes the conversion of portions of the existing underutilized TransCanada mainline from natural gas service to oil service and the construction of new facilities. Currently the refineries in eastern Canada receive oil shipped from overseas, which is expensive.[85] This project, if approved, will provide Canadian refineries with a reliable source of domestic crude oil. It is anticipated to be in service in 2020.[86]

35 TransCanada has estimated that tolls on Energy East will be competitive with west coast access pipelines, presumably because TransCanada would convert some existing gas facilities to oil service. The pipeline would provide an alternative transportation option for WCSB crude oil producers to access eastern Canadian, US, and other international markets.[87] It should also lessen the price discount on Alberta oil. Environmental groups and First Nations have expressed concerns about Energy East.[88]

F. THE DEVELOPMENT OF PIPE ON PIPE COMPETITION FOR OIL PIPELINES

36 In the 1950s, when Interprovincial Pipeline and Trans Mountain Pipeline System commenced operations, neither pipeline had any significant competition in their respective destination markets. At that time, Interprovincial Pipeline was the only long distance oil pipeline transporting oil from Alberta to eastern North America, and Trans Mountain was the only oil pipeline transporting oil from Alberta to the west coast of Canada.

37 As oil and natural gas export markets have grown, more export pipeline capacity has been constructed, and as a result, pipe on pipe competition has developed for both oil and natural gas pipelines. The transportation of oil by rail has also grown as an alternative to pipeline transportation.

38 Today, four major pipelines compete for crude oil supply from the WCSB, although they serve different destination markets: Express Pipeline, Keystone Base, the Enbridge mainline, and Trans Mountain. Based on forecasted WCSB crude oil production, there will be sufficient crude oil volumes for all of these pipelines, as well as the proposed Keystone XL, Trans Mountain Expansion, Northern Gateway, and Energy East pipeline projects until at least 2021.[89]

39 Northern Gateway, if constructed, will compete directly with Trans Mountain for access to Asian markets. Asian

demand for crude oil is forecast to be far larger than the capacity of both an expanded Trans Mountain and Northern Gateway together.[90]

40 Energy East, if approved, would compete in part with the Enbridge mainline once the Line 9 reversal is operational. Both Energy East and Enbridge Line 9 would serve Montreal refineries, as well as other destination markets.[91]

41 If actual oil sands production falls short of forecasted production in the coming years so that there is excess takeaway pipeline capacity from the WCSB, Northern Gateway and Enbridge mainline may be the pipelines to suffer volume risk, as these two pipelines do not currently have firm contracts with shippers. Express, Keystone Base, Trans Mountain, and Energy East all have firm contracts for the majority of the capacity of the pipelines.

IV. ECONOMIC THEORY: WHY SHOULD THE NEB REGULATE ACCESS TO OIL PIPELINES?

42 Western societies generally consider that competitive market economies produce the most efficient outcomes from an economic perspective.[92] However, in natural monopolies, economic theory states that competition is infeasible. Crude oil[93] and natural gas[94] transmission pipelines can be considered to be natural monopolies, at least when the first oil or natural gas pipeline is built in a given market. This is because the incremental cost to an incumbent pipeline owner of shipping one more unit of product in the pipeline is minimal compared to the capital cost that would be faced by a new market entrant wishing to construct another pipeline. This is true until the oil or gas transmission market grows to the point where the incumbent pipeline reaches full capacity.

43 Economic theory states that natural monopolies, including crude oil and natural gas transmission pipelines, should be regulated. Without regulation, the pipeline owner could exact monopolistic or excessively high rates from customers.

A. COMPETITION AND NATURAL MONOPOLIES

44 Alfred Kahn described the benefits of competition thus:

> Competition will weed out the inefficient and concentrate production in the efficient; it will determine, by the objective test of market survival, who should be permitted to produce; it will force producers to be progressive and to offer customers the services they want and for which they are willing to pay; it will assure the allocation of labor and other inputs into the lines of production in which they will make the maximum contribution to total output.[95]

45 According to Kahn, certain industries are natural monopolies because either the technology of the industry or the character of the service provided is such that "the customer can be served at least cost or greatest net benefit only by a single firm ... or by a limited number" of firms.[96] Kahn states that "[a] natural monopoly' is an industry in which the economies of scale - that is, the tendency for average costs to decrease the larger the producing firm - are continuous up to the point that one company supplies the entire demand."[97] As a result, competition will only result in higher social costs and is undesirable.[98]

B. REGULATION AS A SUBSTITUTE FOR COMPETITION

46 In a natural monopoly environment, regulation provides a surrogate for competition.[99] According to Kahn, regulation should be aimed at producing the same results as competition: "the single most widely accepted rule for the governance of the regulated industries is regulate them in such a way as to produce the same results as would be produced by effective competition, if it were feasible."[100]

47 Kahn makes the point that regulation tends to spread and beget more regulation.[101] Regulation can cause unforeseen consequences which in turn need to be regulated. Thus, the goal in regulating public utilities should

always be to create as little regulation as is necessary to mimic the results a properly functioning competitive market would provide. While neither regulation nor competition is a perfect solution, the goal of public utility regulation should be to find "the best possible mix of inevitably imperfect regulation and inevitably imperfect competition."[102]

C. REGULATION TO PROVIDE OPEN ACCESS TO TRANSMISSION PIPELINES

48 One of the major goals of regulation of transmission pipelines is to establish open access to pipelines for third parties.[103] Unlike transmission and distribution, oil and gas production and supply markets can be competitive and are not considered to be natural monopolies.[104] Open access to transmission is fundamental to the establishment of competitive oil and natural gas production and supply markets.[105] Without regulation, open access to transmission would likely never happen. In the absence of regulation, a dominant owner of transmission or distribution pipelines can quickly become the principal barrier to entry of new market players in supply markets.[106] The transmission pipeline owner may control access by extracting monopoly rents from customers, which could theoretically be any price up to the cost of building an alternative system (or switching to another fuel).[107]

D. OBJECTIVES FOR REGULATION OF OIL AND NATURAL GAS PIPELINES

49 Based on the foregoing discussion, the following objectives for regulation of oil and natural gas pipelines can be established:

1. The goal of regulation of natural monopolies should be "to produce the same results as would be produced by effective competition, if it were feasible."[108]
2. In order to encourage the development of competitive oil and gas commodity markets, the regulator ought to establish open access to oil and natural gas transmission pipelines.[109]
3. In developed oil and natural gas transmission networks, competition may exist; therefore the regulator ought not to prevent entry of new firms.[110]

The approach of the NEB will be assessed against these objectives.

V. THE NEB: POLICY AND DECISIONS REGARDING ACCESS TO MAJOR OIL PIPELINES

A. NEB POLICY STATEMENTS: COMPETITIVE OIL AND GAS TRANSPORTATION MARKETS

50 The NEB has noted both in the context of oil pipelines[111] and natural gas pipelines[112] that pipelines tend to be natural monopolies. The approach of the NEB is to encourage competition in pipelines by encouraging the adoption of competitive tolls[113] and the construction or expansion of pipelines that will open up new markets for Canadian producers.[114] Former Chair and CEO of the National Energy Board, Gaétan Caron, emphasized the importance of competitive markets in a speech he gave at the 2013 Canadian Energy Summit, stating:

> [T]he NEB's approach to regulation continues to be premised on the belief that markets work. The Board can step in if, for some reason, markets are not functioning properly, but we believe that well-functioning, competitive markets efficiently balance supply and demand through adjustments in prices. They also lead to competitive, innovative, and robust energy systems.[115]

51 One of the NEB's goals as set out in its Strategic Plan is that "Canadians benefit from efficient energy infrastructure and markets."[116] In order to determine whether NEB regulated pipelines are succeeding in meeting this goal, the NEB periodically assesses "the economic functioning of the pipeline transportation system.[117] The NEB states that "[a]n efficient pipeline transportation system effectively responds to changing market conditions."[118] The NEB recognized in Keystone Base that "the market for oil transportation has evolved and will continue to evolve to embrace commercial arrangements better suited to meet the needs of market participants."[119] As a result,

"under certain conditions and circumstances,"[120] it is acceptable for common carriage oil pipelines to have firm contractual commitments to capacity. In most major oil pipelines in Canada today, the majority of capacity is subject to firm transportation agreements, with the residual amount of capacity being available for uncommitted volumes.

52 Despite supporting the operation of functioning markets, the NEB retains its discretion to regulate pipelines under its jurisdiction where regulation is necessary to the public interest. When a shipper or other directly affected party files a complaint with the NEB regarding treatment by a pipeline company, the NEB will typically hold a hearing to deal with the complaint.[121]

B. DEREGULATION AND OPEN ACCESS TO OIL AND GAS TRANSMISSION PIPELINES

53 The establishment of open access to both oil and natural gas pipelines has been a key objective of the NEB at least since 1986, when the prices of crude oil and natural gas were deregulated. Deregulation occurred as a result of two agreements signed by the governments of Canada, Alberta, British Columbia, and Saskatchewan in 1985: the "Western Accord of 28 March 1985 on Energy Pricing and Taxation" (Western Accord) and the "Agreement on Natural Gas Markets and Prices on 31 October 1985" (Halloween Agreement).[122] These agreements took effect on 1 November 1986, the year after they were signed.[123] Continued open access to both crude oil and natural gas pipelines was key in order to ensure successful oil and gas commodity markets. If producers could not access pipelines, their ability to reach markets would be limited. This issue was more significant for natural gas producers than for oil producers given that oil producers had other transportation options, including rail, trucks, and tankers, as discussed above.

54 The NEB states:

> The Board requires that pipeline companies operate according to the principle of "open access". This means that all parties must have access to transportation on a non-discriminatory basis... . In addition, tolls for services provided under similar circumstances and conditions with respect to all traffic of the same description, carried over the same route, must be the same for all customers.[124]

55 The earliest and most frequently cited NEB decision on open access is TransCanada GH 2 87, a natural gas decision wherein the NEB stated:

> The Board ... considers it essential that all terms and conditions of access to a pipeline be clearly reflected in the tariff in order to ensure that there are no undue service restrictions imposed by pipeline companies involved in the marketing or producing sectors of the natural gas sector. In the Board's view, prospective shippers are entitled to know the conditions of access to a pipeline system in advance of contract negotiations, as this knowledge will allow market participants to make informed supply and market decisions thereby contributing to the efficient functioning of the natural gas market.[125]

56 In numerous decisions regarding both oil and natural gas pipelines,[126] the Board has emphasized the importance of transparency in negotiations with shippers regarding access to capacity and stated that shippers on all pipelines should be given the terms and conditions of access to a pipeline in advance of the open season, so that the shippers and the pipeline company would be on an "equal footing" in negotiations and that there would be no potential for an abuse of market power.[127]

57 In the Keystone Base, the NEB quoted the above passage from TransCanada GH 2 87. It stated that it requires open access to both oil and gas pipelines as "an important prerequisite to enable the effective and efficient operation of the market,"[128] and that open access was particularly important for oil pipeline systems with contracted capacity.[129]

58 In the Northern Gateway Report, the Joint Review Panel (JRP) stated that one of the obligations of a common carrier is "to provide service with reasonable terms and conditions and to make these terms and conditions

available to all categories of shippers and potential shippers in a clear and orderly way."[130] Accordingly, the JRP directed Northern Gateway to prepare a single document containing "all tariff related matters."[131] The JRP also underlined the importance of transparency of terms of access to the pipeline, stating: "Fairness requires that prospective shippers know the terms of access to a pipeline in advance of contracting for capacity. This knowledge will allow market participants to make informed supply, market, and transportation decisions, which will contribute to the efficient functioning of the petroleum market."[132]

59 The foregoing discussion shows that the NEB approach to regulation of access to major oil pipelines is in accordance with the principles of economic theory stated above. A review of NEB decisions regarding access to capacity in oil pipelines is presented below. These decisions demonstrate that the NEB supports competitive markets but will adjudicate concerns raised by shippers or competing pipeline companies.

C. FIRM CONTRACTS ARE NOT INCONSISTENT WITH COMMON CARRIAGE OBLIGATION

60 The NEB has generally held that allocation of capacity to firm service is not inconsistent with the common carriage obligation of an oil pipeline pursuant to section 71(1) of the NEBA, provided that two criteria are met. The two criteria are:

1. The pipeline company must have held a fair and transparent open season whereby any interested shipper could commit to the Firm Service offered; and
2. A reasonable percentage of capacity must be reserved for uncommitted volumes or spot shipments.[133]

61 The determination of what is a reasonable percentage of uncommitted capacity is a matter for the NEB's judgment based on the circumstances of any specific case.[134] In making this determination, the NEB has also considered whether the pipeline company is able to readily expand its facilities, for example, by the addition of pump stations.[135] This approach is consistent with the broad discretion of the NEB regarding the common carriage obligation found in the initial wording of section 71(1).

1. SECTION 71(1) REQUIREMENTS IN THE NEB FILING MANUAL

62 For applications for exemptions from the common carriage requirement of section 71(1) of the NEBA, the Filing Manual requires that the applicant provide evidence that:

-. an open season was held offering all of the capacity to be contracted to anyone interested in shipping; and
-. allowing the exemption is in the public interest.[136]

63 The Filing Manual also states that "[t]he open season must be conducted in a manner which provides all interested shippers the same opportunity to participate and allows adequate time for their consideration of the issues."[137] The Filing Manual indicates that the application should include detailed information regarding the open season as follows:

> A subsection 71(1) application should include copies of all notices of the open season, the timing and method of providing notice, all correspondence between the pipeline and parties interested in contracting with the pipeline and any expressions of [interest] in or concerns regarding the application. The applicant should also provide an indication of the results of the open season and a sample or standard form contract to indicate the arrangements contemplated.[138]

64 It appears that this portion of the Filing Manual is not currently used by the NEB; none of the NEB decisions reviewed refer to it. In addition, the Filing Manual does not reference the second of the two key criteria set out in the

relevant NEB decisions for what are essentially exemptions from the requirements of section 71(1): that a reasonable percentage of capacity must be reserved for uncommitted or "spot" shipments, or, alternatively, that the facilities must be readily expandable.

2. THE IMPORTANCE OF FIRM CONTRACTS FOR CAPACITY IN OIL PIPELINES IN THE CURRENT COMPETITIVE MARKET

65 Most new pipelines today will compete for supply (shipper volumes) with an existing pipeline or pipelines. New pipeline projects require significant upfront investment.[139] Parties have suggested that without firm commitments from shippers, new pipelines[140] and pipeline expansions[141] would not be built. Proponents of new pipelines will tend to offer lower tolls to shippers in order to entice them to ship on the new pipeline instead of an incumbent pipeline, which may have cost of service tolls. In exchange for the lower tolls and guaranteed or "unapportioned" access, the pipeline company will require the shipper to sign a firm service contract or Transportation Service Agreement (TSA).[142] The firm service contracts, in turn, assist the pipeline company in acquiring financing for the pipeline by enabling it to demonstrate to banks and investors that volume risk is shared with shippers.

66 Under a firm service contract, the shipper will commit to ship a specified volume of oil, natural gas, or other products for a specified number of years. If the shipper does not ship the volume of product specified in the firm service contract in a given month, the shipper remains obligated to pay the fixed toll component, which is essentially the reservation charge for the right to transport the oil or gas. For volumes actually transported, the shipper will also pay the variable toll component, which includes a charge for fuel used to operate the pump stations of an oil pipeline.

67 Industry representatives have indicated that the requirement for shippers to sign firm service contracts of 15 to 20 years is a major financial commitment on the balance sheet of a shipper.[143] Oil producers may be required to sign firm service contracts for a specific volume before final financial information about construction costs and tolls on the proposed pipeline is available, and even before the producers know what their own requirements for additional capacity will be.[144] A shipper provided the following hypothetical example: if a shipper signed a firm service contract to ship 50,000 bpd on an oil export pipeline at a toll of approximately $4.50 per barrel, this would be a commitment to pay approximately $1.6 billion over 20 years. A junior producer may not be able to access the financial backing required to make this size of financial commitment.

D. NEB DECISIONS REGARDING FIRM SERVICE IN OIL PIPELINES

68 Most of the NEB decisions approving the allocation of firm capacity on oil pipelines relate to applications for new pipelines with competitive tolls that will compete with existing pipelines.[145] The NEB has also approved the allocation of capacity to firm contracts on an existing pipeline,[146] on an application for expansion of a pipeline,[147] and on a line reversal.[148]

69 The Express Pipeline decision, in 1997, is the first approving the allocation of capacity to firm contracts on a new pipeline.[149] The Express Pipeline would compete for supply from the WCSB with the existing Interprovincial Pipeline. Both pipelines started at Hardisty, Alberta. The Express Pipeline would transport oil to Casper, Wyoming, to access new markets in the US, while the existing Interprovincial Pipeline ran to Chicago, Illinois. The NEB ruled that the firm contracts negotiated by Express were not in contravention of its common carrier obligations.

1. REQUIREMENTS FOR OPEN SEASONS

70 The requirement for a fair and transparent open season is a part of providing open access to transportation capacity. An open season must be done in a "fair and transparent manner"[150] and all potential shippers must have a "fair and equal opportunity to participate."[151] In Express Pipeline, the NEB made the point that all shippers should be made aware that if they do not enter into firm service agreements, they will not get the same services as those entering into the firm service agreements. The phrase "open season" does not appear in the NEBA.[152]

71 Sometimes a pipeline company will have several rounds or stages of open seasons. The pipeline company may learn through a first stage of an open season that there is more demand for capacity than originally anticipated, or that shippers would prefer different terms and conditions of service than those offered. The NEB has approved a single stage open season in the context of a line reversal,[153] a two stage open season in the context of a proposed pipeline,[154] and a three stage open season in the context of an application for expansion of capacity on an existing pipeline.[155]

2. WHAT CONSTITUTES A REASONABLE PERCENTAGE RESERVED FOR UNCOMMITTED VOLUMES?

72 As noted above, the NEB has held that an oil pipeline company must reserve a "reasonable" percentage of capacity for uncommitted shippers to ensure compliance with common carrier obligations. In all except two of the NEB decisions reviewed, the NEB approved the percentage of capacity reserved for uncommitted shippers proposed by the pipeline company. Percentages approved range from 6 percent to 21 percent.

73 In the Vantage Pipeline decision,[156] Vantage Pipeline Canada Inc. (Vantage) proposed to construct a pipeline to transport liquid ethane from North Dakota, US, through Saskatchewan, to interconnect with the Alberta Ethane Gathering System near Empress, Alberta. The NEB considered this pipeline to be an oil pipeline subject to section 71(1) of the NEBA. Vantage reserved 10 percent of the capacity of the pipeline for uncommitted shippers. The NEB found that this was reasonable, in part because Vantage had indicated that the capacity of the pipeline could be expanded if two additional pump stations were added.

74 In the Enbridge Bakken decision, 21 percent of the proposed Bakken Pipeline was reserved for uncommitted shippers. The NEB found that this was reasonable, in part because Enbridge had indicated that the capacity could be expanded should additional space be required by shippers.[157]

75 In the Keystone Base, at the time of the application, 22 percent of the capacity of the proposed pipeline was available for uncommitted shippers.[158] However, Keystone appears to have anticipated future demands for firm service, because it only committed to reserve 6 percent of the nominal capacity of the pipeline for uncommitted volumes in the future. Keystone stated that if additional shipper demand were to materialize, it may offer a portion of the uncommitted capacity through a future open season.[159] The NEB approved this arrangement, presumably in part because the capacity of the pipeline was readily expandable. A major factor in the NEB's approval of the capacity allocation in the Keystone Pipeline was that the shippers had voluntarily signed long term firm transportation contracts.[160]

76 In Express Pipeline, 15 percent of the capacity of the proposed pipeline was reserved for uncommitted shippers.[161] The NEB did not discuss the basis on which it found this to be reasonable.

77 In the decision in Trans Mountain Expansion, the NEB approved Trans Mountain's proposal to reserve 20 percent of capacity for uncommitted shippers.[162] The Board noted that the proposed allocation was not opposed by any party to the proceeding and that this allocation "should provide shippers with adequate capacity on a monthly basis while allowing Trans Mountain to secure sufficient long term volumes to support the investment required for the Expansion."[163]

3. DOES THE NEB EVER DECLINE TO APPROVE THE AMOUNT OF CAPACITY RESERVED FOR UNCOMMITTED VOLUMES?

78 While the range in percentages of capacity reserved for uncommitted shippers varies greatly, it is clear based on the decision Interprovincial Pipe Line of 1997 and the Keystone XL that the NEB will exercise its discretion to require pipeline companies to change their tariffs to allocate a reasonable proportion of capacity to uncommitted shippers. It appears that the NEB may take a similar approach on Northern Gateway based on the draft conditions

proposed by the JRP.[164]

a. The Interprovincial Pipe Line Decision

79 The Interprovincial Pipe Line decision deals with the original application for the approval of facilities and a tolling methodology in order to reverse the direction of flow of crude oil in Line 9 between Montreal, Quebec, and Sarnia, Ontario.[165] Various refiners had signed firm contracts for 100 percent of available capacity. The NEB rejected the arrangement proposed by IPL, largely, it seems, because there were no transportation alternatives other than IPL available for shippers. The Board also noted that Line 9 represented "the only direct connection to bring offshore crude to the Ontario market."[166] The line had "low levels of contamination, and it was strongly preferred by the Ontario refiners."[167] The NEB held that in order for IPL to meet its common carrier obligations, IPL would be required to keep available 20 percent of the capacity on the reversed Line 9 for monthly nominations. The NEB noted that although IPL had conducted an open season, there had been "considerable uncertainty as to whether the Board would approve the reversal, what the tolls would be, the costs to be underpinned by the [firm service contracts], timing of applications to the Board and reversal of the line."[168] The NEB was not convinced by IPL's assertion that expansion facilities could be added, noting that IPL had made no attempt to provide such service.

b. The Three Keystone Decisions

The Canadian portions of the Keystone pipeline system were approved in three separate NEB proceedings as follows:

1. Keystone Base, from Hardisty, Alberta, to Haskett, Manitoba, approved by the NEB in proceeding OH 1 2007.[169]
2. The Cushing Expansion, which added capacity to Keystone Base, approved by the NEB in proceeding OH 1 2008.[170]
3. Keystone XL, from Hardisty, Alberta, to Monchy, Saskatchewan, approved by the NEB in a decision in 2010 following proceeding OH 1 2009.[171]

80 In the Keystone Base and Cushing Expansion applications, the NEB approved the reservation of 6 percent of capacity for uncommitted volumes, as proposed by Keystone. In the Keystone XL proceeding, Keystone again proposed to reserve 6 percent of capacity for uncommitted volumes. During the proceeding, the NEB invited comments from the parties on a proposal to require Keystone to reserve 20 percent of the total capacity of the combined Keystone Base and Keystone XL pipelines for uncommitted volumes. Keystone responded that a reservation of 20 percent for uncommitted volumes was unnecessary as there would be sufficient pipeline infrastructure into the US midwest. Keystone also stated that there was a risk that the Keystone pipelines would be underutilized, and that reserving 20 percent of capacity for uncommitted volumes would give Keystone less flexibility in managing the underutilization risk. Keystone proposed instead that "a 10 per cent reservation could be accommodated."[172]

81 The NEB required that 12 percent of capacity should be reserved for uncommitted volumes. The NEB stated that the amount of capacity to be set aside for uncommitted volumes "is a matter of judgment and based on the circumstances of any specific case."[173] The NEB noted that the volumes identified by Keystone to be transported on the Keystone XL Pipeline had originally been used to justify the Cushing Expansion. The NEB found, based on Keystone's evidence, that having uncommitted capacity would allow Canadian producers "added flexibility to respond to market conditions and create opportunities to develop a broader range of U.S. customers and market opportunities."[174] As a result, the NEB set the level of uncommitted capacity "at the higher end of the range,"[175] based on the Canadian public interest. Basically, the NEB overruled the proponent's proposal for uncommitted volumes even though, in this case, no party other than Enbridge, TransCanada's competitor, had challenged the

proposed allocation of 6 percent of capacity to uncommitted shippers.[176]

c. Northern Gateway Report

82 The Northern Gateway application is unusual in that it is the only current long distance oil pipeline application in which the applicant did not require shippers to sign firm contracts prior to the filing of the application.[177] Instead, the Funding Participants (shippers) had signed Funding Support Agreements by which they contributed over $10 million each towards the regulatory costs of preparing and filing the application with the NEB.[178] For each $10 million unit of financial support, a Funding Participant received certain options, including an option to secure up to 50,000 bpd of capacity on the oil pipeline at a lower toll. Shippers were reluctant to sign firm contracts in advance of the regulatory filing due to the uncertainty of obtaining a timely approval for a greenfield pipeline project in northern British Columbia. Part of that concern stemmed from anticipated opposition to the project from First Nations. Firm contracts will be signed well in advance of construction, should the project be approved.

83 In its application, Northern Gateway proposed to reserve 5 percent of the term shippers' committed volume for uncommitted shipments.[179] The JRP, in a list of draft conditions for the pipeline, invited comments from parties on a possible requirement that 10 percent of capacity be reserved for uncommitted volumes. Northern Gateway objected to the 10 percent proposal, noting that increasing the capacity for uncommitted volumes would be unfair to the Funding Participants, who, in exchange for assuming part of the risk of the pipeline application, collectively had options to pay discounted tolls on 95 percent of the capacity of the pipeline.

84 The JRP noted that the proposed pipeline

> [I]n providing access to Pacific Basin markets, would be a significant and strategic addition to the western Canadian pipeline system overall. In the Panel's view, it would provide producers with valuable flexibility in their transportation options and allow for the development of a significantly broader range of customers. From a public interest perspective, these factors would, in the Panel's view, suggest that the uncommitted reserve capacity proposed by Northern Gateway be increased.[180]

85 Despite this view, the JRP ultimately removed the 10 percent requirement from the conditions, likely because the Northern Gateway application discussed here is a facility application, and so conditions on tolling are inappropriate. The JRP concluded that it "continues to be of the view that meaningful access for uncommitted shippers to a system of the scale and strategic importance of Northern Gateway would entail reserve capacity for both the condensate import and the oil export pipelines of not less than 10 per cent."[181]

86 On 17 June 2014, the Governor in Council approved the Northern Gateway Project, subject to the 209 environmental, financial, and technical conditions set out by the JRP.[182] A number of First Nations and environmental groups have commenced court actions challenging the Northern Gateway Project.[183] In addition, the government of British Columbia has set out five conditions to be met on the Northern Gateway Project, including a condition requiring a fair share of the economic benefits of the pipeline for British Columbia.[184]

87 The next regulatory step would be for Northern Gateway to file a tolling application with the NEB which would include an application for approval of the percentage of capacity to be reserved for uncommitted volumes. The above remarks appear to be a strong hint to Northern Gateway that it will have to build its justification for the 5 percent reservation or risk the imposition of a 10 percent reservation. If the NEB were to approve the 5 percent reservation it would be the lowest percentage ever approved by the NEB.

4. THE IMPACT OF UNCERTAINTY REGARDING THE PERCENTAGE TO BE RESERVED FOR UNCOMMITTED VOLUMES

88 The lack of predictability in the NEB's findings on the percentage of capacity in oil pipelines to be reserved for spot shippers can cause issues for pipeline companies and shippers. Prior to filing a tolling application with the

NEB, a pipeline company will negotiate firm service contracts with shippers based on an assumption about how much capacity will be available for firm shippers. If the NEB decision requires that a greater percentage of capacity be reserved for spot shippers, the pipeline company may have to renegotiate contracts with firm shippers based on a smaller percentage of the volume being available for firm service. This can lead to delays in approval and construction of new pipelines that are urgently needed to provide additional take away capacity from the WCSB.

E. DO OIL PIPELINE COMPANIES TODAY HAVE MARKET POWER?

1. THE INDUSTRY PERSPECTIVE

89 In conversations with major Canadian oil shippers, several themes emerged. Shippers noted that it was important that major pipeline companies, such as Kinder Morgan and Enbridge, construct oil pipelines as these companies have the experience and the ability to obtain the financing necessary to do so. Shippers indicated that additional oil pipeline capacity is required due to the differential between the price for crude oil sold in Alberta and the world price for oil. As a result, shippers indicated that they felt obligated to support all of the major proposed export pipeline projects - the Trans Mountain Expansion, Northern Gateway, Keystone XL, and Energy East - because of the uncertainty as to whether any or all of these projects will receive regulatory approval.

90 Shippers opined that pipelines still hold a natural monopoly and therefore the general absence of objections from shippers in tolling applications by pipeline companies to the NEB ought not to be taken as active support from the shippers for the tolls proposed by the pipeline company. Rather, they indicated that shippers had no choice but to go along with whatever tolls the pipeline company proposed, due to the high demand for capacity in oil export pipelines.

2. TWO TRANS MOUNTAIN DECISIONS - THE 2011 TRANS MOUNTAIN CAPACITY REALLOCATION DECISION AND THE 2013 TRANS MOUNTAIN EXPANSION DECISION

91 In most of the NEB proceedings, shippers do not tend to describe the pipeline on which they ship their products as a monopoly or criticize the approach of the pipeline company - presumably because of the importance of pipelines to producers. Typically in NEB proceedings, shippers on a pipeline system will either intervene in support of the shipper's application or remain silent. However, shippers on the Trans Mountain pipeline have both criticized the approach taken by Trans Mountain and referred to Trans Mountain as a monopoly in two recent Trans Mountain proceedings.[185] Trans Mountain Pipeline is unusual in that it is still the only oil pipeline to the west coast of Canada and it "serves a distinct market."[186] As described earlier, other oil pipelines now face competition in their destination markets.

a. The Trans Mountain Westridge Decision (RH 2 2011)

92 The Trans Mountain Westridge decision is important for several reasons. First, it is the only case to date in which the NEB has approved the adoption of firm contracts on an existing oil pipeline as opposed to new pipelines or expansion of capacity on existing pipelines. In all other cases reviewed, NEB approval of the firm contracts was predicated on the need for firm shippers to underpin the capital costs of the capacity expansion or new facilities. Second, in this case, an approval was granted despite strenuous objections from existing shippers, which is unusual in pipeline applications.

93 The Trans Mountain pipeline has been regularly operating under apportionment since 2005.[187] Shippers on the Trans Mountain pipeline system are divided into Land Shippers and Dock Shippers. The Land Shippers ship crude oil and refined petroleum products to destinations in British Columbia. They also ship crude oil to four Washington State refineries through a US affiliate at Sumas on the British Columbia Washington State border.[188] The Dock Shippers ship crude oil all the way to the Westridge Dock at Burnaby, British Columbia, on the west coast, where it is loaded into ocean tankers and barges and shipped to overseas markets, primarily in Asia. The Dock Shippers need to be able to ship volumes in "vessel sized"[189] increments equal to the capacity of the ocean tankers. They

also need to coordinate their shipments with marine transportation schedules, and their shipments need to take place on an "all or nothing basis."[190] They needed firm service in order to meet these requirements and to enable them to develop new markets in Asia by guaranteeing the provision of certain volumes.

94 In order to accommodate the Dock Shippers' needs, Trans Mountain proposed to reallocate a portion of capacity from Land Shippers to Dock Shippers and to implement firm service for 68 percent of the Dock capacity. Firm Shippers would sign 10 year contracts and pay a premium for the privilege of receiving firm service, known as the "Firm Service Fee."[191] Trans Mountain proposed to use the Firm Service Fee "to advance incremental capital projects and conduct preliminary activities in support of a potential expansion of the [Trans Mountain] Pipeline."[192] The payment of a higher toll for firm service is unusual in the Canadian context; on most oil pipelines, firm shippers pay reduced tolls in exchange for their long term commitment to ship specified volumes. Trans Mountain held an open season in which any party could subscribe to firm service to the Westridge Dock. Overall, 18 percent of the pipeline would be subject to firm commitments and 82 percent would be available for uncommitted volumes.[193]

95 Several shippers on the Trans Mountain system objected to Trans Mountain's application. Imperial Oil argued that converting existing common carriage capacity to contract was inappropriate given the shortage in capacity and that "many shippers [had] based their investments and operations on the fundamental premise that the pipeline is a common carrier pipeline with no contract carriage."[194] Chevron argued that Trans Mountain was a monopoly as it is the only oil pipeline to the west coast of Canada and it "serves a distinct market."[195]

96 Despite these objections, the NEB approved Trans Mountain's application. It noted that Trans Mountain now faced competition from current and future pipelines serving the WCSB, including those on which the NEB had previously approved some contracted capacity. It stated that the approval of firm service would help Trans Mountain to "retain volumes and lower its long term volume risk."[196] It noted that "[u]ncertainty in acquiring pipeline capacity to the Westridge Dock could be an obstacle"[197] to developing important new offshore markets. The NEB noted again that it has a "wide discretion"[198] in determining compliance with section 71(1) of the NEBA and that it is able to "tailor the statutory obligations to fit any unique circumstances which may exist."[199] The remaining uncommitted capacity was held to be sufficient for Trans Mountain to meet its common carrier obligations.

97 The NEB noted that "shippers do not have any acquired rights to capacity on the Pipeline by virtue of past use."[200] Therefore, it was acceptable for Trans Mountain to convert existing capacity to firm service.

b. Trans Mountain Expansion Decision (RH 001 2012)

98 The Trans Mountain Expansion decision is significant because it shows the importance the NEB places on signed agreements between sophisticated shippers and pipeline companies as evidence that the market is working properly and that there is no need for intervention from the NEB. The NEB approved the Trans Mountain toll methodology even though two current shippers on Trans Mountain complained to the NEB about the negotiation process. However, the NEB will strike down a provision in an agreement requiring shippers to abstain from complaining to the NEB.

99 In this proceeding, Trans Mountain Pipeline ULC (Trans Mountain) applied for approval of the toll methodology and the terms and conditions that would apply to a proposed expansion to the Trans Mountain pipeline. After the expansion, the Trans Mountain pipeline system would have a capacity of approximately 890,000 bpd.[201]

100 In the open season process, Trans Mountain required shippers to sign confidentiality agreements, which meant that the shippers could not discuss with other shippers their negotiations with Trans Mountain.[202] In response to comments made by shippers, Trans Mountain made changes to the documents to be signed by shippers - the Facilities Support Agreement (FSA)[203] and the Transportation Service Agreement (TSA) - as well as to the Rules and Regulations of the Tariff.[204] Trans Mountain argued that the fact that they had made changes as a result of shipper comments showed that there was "give and take" in negotiations and that they had not exerted market

power over shippers.[205] Trans Mountain initially received qualifying commitments for firm service from nine shippers.

101 Suncor Energy Products Partnership (SEPP) filed a complaint with the NEB regarding a requirement in section 2.2 of the FSA for shippers to provide support and cooperation and not to oppose Trans Mountain's efforts to obtain regulatory approvals. The NEB struck down section 2.2, stating that it is key to the Board's process that shippers are able to raise concerns about tolls and tariffs.[206] After the Board's ruling, four additional shippers - Suncor Energy Marketing Inc., SEPP, Total E&P Canada Ltd. (Total), and Canadian Natural Resources Ltd. - made firm commitments to ship specified volumes on the proposed expansion. This suggests that section 2.2 may have prevented these shippers from committing to earlier volumes on the pipeline. As a result of the additional interest expressed, Trans Mountain increased the proposed capacity of the project to 890,000 bpd.

102 In the NEB proceeding, both Suncor and Total argued that given the lack of alternatives in transportation from the WCSB to the west coast of Canada and therefore in access to Asian markets, shippers were forced to accept unfair negotiating conditions and unjustly high tolls. Suncor explained that crude oil prices in Asian markets are significantly higher than in the interior of North America,[207] that there had been high levels of apportionment on the Trans Mountain Pipeline System, and that WCSB producers were facing price discounts in the range of $20 to $30 per barrel because of the lack of access to Asian markets.[208] Suncor argued that these factors meant that Trans Mountain could exert significant market power during open season negotiations. Other possible alternatives were not economically feasible given that shippers could receive substantially higher netbacks shipping on the Trans Mountain system. Due to Trans Mountain having control over the decision whether or not to proceed with the expansion, it was understandable that Western Canadian oil producers would decide to pay the excessive tolls proposed by Trans Mountain.

103 Total also objected to the application despite having signed a commitment to firm service. Total argued that the open season process was neither fair nor transparent, that the NEB had insufficient information before it to determine whether the rates proposed by Trans Mountain were just and reasonable, and that the commercial basis for the project should be improved, among other things. Total argued that the discounted oil price differential and the limited number of alternatives for transporting oil had forced shippers to agree to high fees and tariffs.[209] Possibly out of concern that Trans Mountain would decide not to proceed with the proposed capacity expansion, Total did not request a completely new negotiation process but simply an order that negotiations be extended to ensure that the negotiated settlement would be consistent with the Board's Guidelines for Negotiated Settlements of Tolls, Traffic and Tariffs.

104 George Schink, an economist testifying as an expert witness for Trans Mountain, argued that Trans Mountain faced competition from transportation of crude oil by rail and from both existing and proposed pipelines. He stated that Trans Mountain faced origin market (supply) competition from the Enbridge mainline and the Express Platte pipeline system as well as Keystone Base.[210] He also stated that Trans Mountain faced future competition from the proposed Enbridge Northern Gateway and Keystone XL pipelines, the proposed Energy East project, and potential additional rail crude oil takeaway capacity.

105 As noted above, the NEB approved Trans Mountain's proposed allocation of capacity.[211] The NEB noted that shippers were using rail and alternative pipelines as alternatives to Trans Mountain, which meant that Trans Mountain's market power was limited.[212] The NEB also stated that both Keystone XL and Northern Gateway were already "sufficiently developed as potential alternatives to the Trans Mountain pipeline to act as limiting factors on the market power of Trans Mountain."[213]

106 Surprisingly, perhaps, the NEB held that the Open Season process undertaken by the pipeline company was fair, transparent, and appropriate.[214] The NEB was not concerned about the fact that Trans Mountain had met with shippers one by one and had prevented shippers from discussing the negotiations among themselves. The NEB accepted Trans Mountain's evidence that confidentiality agreements are common in the industry and that they "do not taint the fairness of the negotiation process if the Open Season process is fair and transparent."[215]

c. Industry Perspective on the Trans Mountain Expansion Decision

107 A pipeline company representative that was interviewed noted that in negotiations with shippers, shippers alternated between wanting to have the strength in negotiations afforded by cooperation with other shippers and wanting to keep confidential their commercial information such as monthly volumes nominated and maximum capacity of receipt points (such as refineries) for competitive reasons. In the majority of NEB oil pipeline cases reviewed, the pipeline company negotiated with shippers as a group and did not require shippers to sign agreements preventing them from talking to each other about negotiations.

108 A representative of a shipper interviewed surmised that if the NEB had struck down the tolls of Trans Mountain as not being just and reasonable, or required Trans Mountain to reopen negotiations with shippers, it ran the risk of having Trans Mountain decide not to proceed with the expansion because it would not provide an adequate rate of return for its investors. Given the importance of the expansion to the Canadian economy, the NEB appears to have decided that it was appropriate to interfere as little as possible with the commercial decisions made by Trans Mountain and by shippers signing FSAs.

F. LOWER FIRM SERVICE TOLLS FOR COMMITTED SHIPPERS ARE NOT UNJUST DISCRIMINATION

109 Pursuant to section 67 of the NEBA, tolls and service must not be unjustly discriminatory.[216] In PanCanadian, the NEB stated that the question of what constituted "unjust discrimination" was a matter for the "considered judgment" of the Board.[217] Section 63 of the NEBA provides that a determination by the NEB regarding whether there is unjust discrimination in a given case is a question of fact.[218]

110 The NEB has held that lower tolls, renewal rights, and unapportioned access for committed shippers are not unjust discrimination.[219] This is because the firm shippers provide support for the financing of the pipeline and share the financial risk of the new pipeline with the pipeline company. In finding that lower tolls for firm service are not unjustly discriminatory, the NEB has taken into consideration the fact that a number of sophisticated shippers had executed firm service agreements.[220]

111 In Express Pipeline, as in Trans Mountain Expansion, the NEB noted that contract shippers are not prevented from filing complaints with the Board as a result of their contractual commitments made to the pipeline company, and that the NEB continues to be responsible to ensure that tolls are just and reasonable for both contract and uncommitted shippers.

112 In Enbridge Bakken, the Board noted that no party had raised concerns about the higher tolls to be paid by uncommitted shippers.[221] The Board found that the toll differential between uncommitted and committed shippers would not result in unjust discrimination. The Board added:

> The Board recognizes that Enbridge Bakken is operating in a very competitive environment. The Project is considered commercially at risk, with only a portion of that risk being offset through the existence of long term transportation contracts. The Board accepts that uncommitted shippers are charged a higher toll than shippers who have signed TSAs.[222]

113 In the Keystone XL decision, the NEB approved tolls for uncommitted shippers that were 20 percent higher than firm shippers with a ten year contract, with tolls for firm shippers decreasing over the length of the contract term.[223] The Board noted that these tolls were "market based rather than cost based and ... the result of negotiations between sophisticated parties."[224] The Board accepted that "this is a reflection of shippers having provided differing levels of financial support to the Keystone XL Project and accepting differing levels of risk"[225] and that this toll structure was just and reasonable.

114 In Trans Mountain, the NEB held that the additional fee for firm service complied with the requirements of section 62 of the NEBA that tolls must be just and reasonable and section 67 of the NEBA that tolls not be unjustly

discriminatory. The NEB's reasoning was based largely on the fact that the Firm Service Fee was established "following an open, transparent and fair Open Season process where all potentially interested commercial parties were invited to participate."[226]

G. UNIQUE CASES REGARDING CAPACITY IN OIL PIPELINES AND THE NEB APPROACH

115 The desire of the NEB to support functioning competitive markets is also evident in two other decisions worthy of discussion. The first, the Chevron Priority Destination Designation Application,[227] relates to the NEB interpretation of a provision in the Trans Mountain tariff regarding capacity. The second relates to an application by Trans Northern Pipelines Inc. (Trans Northern) for relief from its common carriage obligations.

1. CHEVRON PRIORITY DESTINATION DESIGNATION DECISION

116 In this proceeding, Chevron applied for a designation of its Burnaby oil refinery as a "Priority Destination" pursuant to the Tariff on the Trans Mountain Pipeline (Trans Mountain Tariff).[228] The Trans Mountain Pipeline had been under apportionment since 2010, meaning that Uncommitted Shippers (shippers that did not sign long term contracts with the Pipeline) have only been able to ship proportionally lower volumes of crude oil than the volumes they nominated.

117 "Priority Destination" is defined under section 1.58 of the Trans Mountain Tariff as a "refinery, marketing terminal or other facility connected to and capable of receiving petroleum from ... the Trans Mountain Pipeline ... and so designated by the [NEB] by reason that it is not capable of being supplied economically from alternative sources."[229] The Trans Mountain Tariff stipulates that in times of apportionment, available capacity will be allocated first to Firm Shippers (shippers that signed long term contracts with the Pipeline).[230] Of the remaining capacity, Uncommitted Shippers nominating to Priority Destinations will have priority over all other nominations.[231]

118 Chevron did not have firm service on the pipeline.[232] While Chevron had explored other alternatives to the Trans Mountain Pipeline, it stated that it would have to incur substantial capital costs and to pay transportation operating costs that would be about five times higher than the transportation costs pursuant to the Trans Mountain Tariff.

119 The NEB denied the application. It noted that other refiners served by Trans Mountain had used several different supply options in order to mitigate supply risk and that Chevron also had a responsibility to establish alternative supply options.[233]

120 In effect, the NEB's message to Chevron was that it could not rely on a regulated solution where there were market options available.

2. THE TRANS NORTHERN DECISION

121 The Trans Northern proceeding is the only oil pipeline decision that contains the NEB's views on the interpretation of section 71(3) of the NEBA under which the NEB may require a pipeline company to construct new facilities. The Trans Northern decision deals with a plan by Trans Northern to decommission the Don Valley Lateral, a pipeline to the Toronto Harbour. Trans Northern planned to decommission the line because it was costing in excess of $500,000 per year to operate while generating only $70,000 in revenues, with no potential for increased revenues.[234] Roy L was the only shipper to express concern about the suspension of service. Based on a request from Roy L, the NEB ordered Trans Northern to file an application which would establish whether it should be granted relief from its common carrier obligations pursuant to section 71(1), and whether it should be required to maintain suitable facilities pursuant to section 71(3).[235]

122 Roy L had access to truck and marine transportation alternatives, although trucking would cost more than shipping the petroleum products by pipeline, and marine delivery was "generally not an economically viable

option."[236] Roy L argued, based on the wording of section 71(3), that the test to be applied by the NEB in interpreting section 71(1) was whether the continuation of the common carrier obligation would place an undue burden on the oil pipeline company.

123 The NEB disagreed. The wording and purposes of sections 71(1) and (3) are different. Section 71(3) gave the Board the "extraordinary power to order a company to provide new facilities."[237] In applying section 71(3), the Board noted that "the burden on a [pipeline] company would be one relevant factor to be considered and balanced with any other existing public interest factors in determining what is reasonable in the circumstances."[238]

124 As in the cases cited above, the NEB asserted that compliance with the common carrier provisions of section 71(1) should be determined by "a test of reasonableness, which permits the Board to tailor the statutory obligations of an oil pipeline to fit any unique circumstances that may exist."[239] The NEB granted Trans Northern relief from section 71(1), and did not require Trans Northern to provide facilities pursuant to section 71(3), again allowing market forces to operate.

VI. CONCLUSIONS

125 The NEB's approach to allocation of capacity is consistent with economic theory and with the three economic objectives for regulation of oil pipelines described above. First, in allowing functioning oil transportation markets to work without interference, the NEB is seeking to "produce the same results as would be produced by effective competition, if it were feasible."[240] Second, the NEB "requires that pipeline companies operate according to the principle of open access.'"[241] Third, the NEB does not generally prevent entry of new pipeline companies into the oil pipeline transportation market.

126 Today, the majority of capacity in NEB regulated major oil pipelines is subject to firm long term contracts. The amount of capacity the NEB has required pipeline companies to reserve for common carriage or uncommitted volumes ranges from 6 percent to 21 percent. It is difficult to predict what percentage of capacity the NEB will require to be reserved for uncommitted volumes in new oil pipelines. Nor can it be stated that in all cases the NEB will simply approve the percentage applied for.

127 Pipeline companies negotiating firm service contracts with shippers have to guess what capacity they will be required to reserve. If their guess proves inaccurate, they may have to go back to firm shippers and renegotiate volumes after an NEB decision, which could lead to substantial delays in the approval and construction of needed export pipelines. In order to provide clarity and transparency for all parties, it is recommended that the NEB create a written policy or Memorandum of Guidance (MOG)[242] regarding access to oil pipelines.

128 No legislative amendments would be required for the NEB to adopt a Draft MOG.[243] The requirement in section 71(1) of the NEBA that all oil pipeline companies are required to transport all oil offered to them is "subject to such exemptions, conditions or regulations as the Board may prescribe."[244] Thus, the NEB has the power to adopt policy directives such as the Draft MOG to indicate how it will likely exercise its discretion.

129 It is also recommended that the NEB Filing Manual and definition of common carriers be updated.

A. RECOMMENDATIONS FOR A DRAFT MEMORANDUM OF GUIDANCE (MOG)

1. PROPOSED LANGUAGE FOR A DRAFT MOG

130 The Draft MOG could state as follows:

> An oil pipeline company may apply, pursuant to section 71(1) of the NEBA, for a partial exemption from its common carrier obligations provided that it meets the following conditions:

1. The pipeline company must demonstrate that it has held a fair and transparent open season providing all potential shippers with a fair and equal opportunity to participate.
2. The presumption will be that 5 percent of the capacity of the proposed pipeline or pipeline expansion must be reserved for uncommitted volumes, unless one of the following two conditions applies:

a. the pipeline company can demonstrate that it can readily expand capacity if there is further demand for capacity; or

b. a directly affected shipper or the proponent pipeline company can demonstrate to the satisfaction of the NEB that the circumstances of a particular case justify a higher or lower percentage of uncommitted capacity.

2. CONSULTATION

131 The NEB should consult with affected parties, including shippers, producers, oil pipeline companies, and downstream customers such as refiners and local distribution companies, on the draft MOG. The Draft MOG set out above could be used as a starting point for industry consultation. Consultation should include a discussion on the benefits and impacts of a presumption of 5 percent reservation of capacity for uncommitted volumes. It should also include a discussion of possible implementation dates for the MOG.

3. RATIONALE FOR RECOMMENDATIONS

132 Paragraph 1 of the Draft MOG codifies the NEB's current requirement for an open season. The requirement for an open season supports fairness, transparency, and competition by ensuring that interested shippers have an opportunity to obtain service. It supports the principle of open access to capacity in oil pipelines by ensuring that shippers know the terms and conditions of access before entering into contract negotiations with pipeline companies.

133 The reservation of a portion of capacity for uncommitted volumes is important to ensure that new shippers and junior producers have the potential to access pipeline capacity. New producers may not have been in existence at the time of an open season, and junior producers may not have the financial backing available to them to participate in an open season. If no capacity were reserved for new producers and junior producers, this could limit incentives for new producers to enter the crude oil supply market and hence limit competition in those markets.

134 The presumption that 5 percent be reserved for uncommitted volumes is 1 percent below 6 percent, 6 percent being the lowest reservations approved by the NEB, in the Keystone Base[245] and Cushing Expansion[246] decisions. In today's competitive crude oil transportation environment, pipeline companies that have firm contracts for the majority of capacity will be able to more easily obtain the financing necessary to construct new pipelines. The construction of additional pipelines to the west and east coasts of Canada, and to the Gulf of Mexico, would enable Canadian oil reach new overseas markets. The export of oil is important for both the Canadian and Alberta economies. The new pipelines proposed will tend to operate in competitive transportation markets, meaning that shippers will likely have a choice of transportation options. The reservation of capacity for uncommitted volumes (common carriage) is primarily necessary where there is no competition or no other option for shippers. If both Northern Gateway and the Trans Mountain Expansion are constructed, they will compete in providing access to Asian markets, providing options to shippers. If Keystone XL and Energy East are also constructed, there will be further competition for supply from the WCSB. Five percent is merely a presumption; the NEB would hear arguments from proponents and directly affected shippers in cases where a higher or lower percentage reservation may be appropriate.

B. CONCLUSIONS

135 This article has explained that it is important for the economies of Canada and Alberta to have additional

export capacity in oil pipelines. In regulating access to oil pipelines, the NEB supports well-functioning competitive markets. The NEB will generally approve the allocation of capacity in oil pipelines to firm contracts provided that a reasonable percentage of capacity is allocated to uncommitted volumes (common carriage) and that a fair and transparent open season was held. The NEB supports open access to crude oil pipelines. The NEB will exercise its discretion in regulating access to pipelines when markets are not functioning properly. As more competition develops in crude oil transportation, a lower percentage of capacity allocated to uncommitted volumes or common carriage may be appropriate. The draft MOG proposed above would be helpful to shippers, producers, and pipeline companies in providing greater certainty and transparency to the NEB approach regarding approval of firm contracts on oil pipelines, while preserving the NEB's broad discretion in this area.

* * *

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48 Transportation Report, supra note 30 at 1.

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77 Keystone XL, supra note 54 at 28.

78 Ibid at49.

79 "Keystone XL rejection leads TransCanada to sue Obama administration" CBC News (6 January 2016) online: <www.cbc.ca/news/canada/calgary/transcanada-lawsuit-keystone-xl-pipeline 1.3392446>.

80 "Barack Obama rejects Keystone XL pipeline citing national interest,'" CBC News (6 November 2015) online: <www.cbc.ca/news/business/keystone-xl-pipeline-obama-1.3307440>.

81 National Energy Board, "Energy East Project," online: <www.one-neb.gc.ca/pplctnflng/mjrpp/nrgyst/index-eng.html> [NEB, "Energy East]; National Energy Board, Media Release, "National Energy Board Receives Application for Energy East" (30 October 2014), online: <www.neb-one.gc.ca/bts/nws/nr/2014/mddvsrymvnrgst-eng.html>.

82 NEB, "Energy East," ibid.

83 TransCanada Pipelines Limited, "Energy East Pipeline Project," online: <www.transcanada.com/energy east-pipeline.html> [TransCanada, "Energy East"].

84 Ibid.

85 TransCanada Pipelines Limited, "Need for a Pipeline," online: <www.energyeastpipeline.com/home/need-for-a-pipeline/>.

86 Robert Tuttle, "NDP victory delays day of reckoning for pipelines," Calgary Herald (7 May 2015) B4.

87 Deloitte & Touche LLP, Energy East: The economic benefits of TransCanada's Canadian Mainline conversion project, online: <www.energyeastpipeline.com/wpcontent/uploads/2013/09/Energy-East- Deloitte-Economic-Benefits-Report.pdf> [Deloitte Report].

88 Shawn McCarthy, "Environmental, First Nations groups question the safety of Energy East pipeline plan," The Globe and Mail (9 August 2013), online: <www.theglobeandmail.com/news/politics/environmental-first-nations-groups-question-pipeline-plan/article13701985/>.

89 Millington & Rozhon, supra note 3 at 13. See also Deloitte Report, supra note 87.

90 See Canada West Report, supra note 7 at 2.

91 TransCanada, "Energy East," supra note 83; Canada West Report, ibid at 17.

92 Alfred E Kahn, The Economics of Regulation: Principles and Institutions, vol 1 (Cambridge, Mass: MIT Press, 1993) at 17 [Kahn, vol 1].

93 Alan J MacFadyen & G Campbell Watkins, Petropolitics: Petroleum Markets and Regulations, Alberta as an Illustrative History (Calgary: University of Calgary Press, 2014) at 31. In Trans Mountain Expansion, supra note 53, the NEB stated: "[c]rude oil pipelines like Trans Mountain tend to be natural monopolies and, as a result, highly concentrated markets are to be expected" (ibid at 18).

94 Nikol J Schultz, "Light Handed Regulation" (1999) 37:2 Alta L Rev 387 at 394. For a discussion on monopolies, see Stanislaw H Wellisz, "Regulation of Natural Gas Pipeline Companies: An Economic Analysis" (1963) 71:1 J Political Economy 30 at 36.

95 Kahn, vol 1, supra note 92 at 18.

96 Alfred E Kahn, The Economics of Regulation: Principles and Institutions, vol 2 (Cambridge, Mass: MIT Press, 1993) at 2 [Kahn, vol 2]. In a similar vein, Richard Posner defines a natural monopoly as "a market whose entire demand can be met at lowest cost by a single firm. This implies that before a firm can begin to do business it must sink large sums in a plant that is large enough or can readily be expanded to serve the entire market. Once the heavy initial fixed or overhead expenses are incurred, the cost of serving a particular customer is relatively slight": Richard A Posner, "Natural Monopoly and Its Regulation" (1969) 21 Stan L Rev 548 at 570.

97 Kahn, vol 1, supra note 92 at 123 24.

98 James C Bonbright, Albert L Danielsen & David R Kamerschen, Principles of Public Utility Rates, 2nd ed (Arlington: Public Utilities Reports, Inc, 1988) at 8.

99 Peter Duncanson Cameron, Competition in Energy Markets: Law and Regulation in the European Union, 2nd ed (Oxford: Oxford University Press, 2007) at para 1.76.

100 Kahn, vol 1, supra note 92 at 17.

101 Kahn, vol 2, supra note 96 at 28.

102 Kahn, vol 1, supra note 92 at xxxvii.

103 Peter Cameron states that "[t]he core aim of most market reform programmes is the creation of enforceable rights of access for third parties to the transmission and distribution networks": Cameron, supra note 99 at 30.

104 Bart3omiej Nowak, "Independence of the Polish Energy Regulator after the Third Energy Package: Chosen Aspects" in Robert Zajdler, ed, EU Energy Law: Constraints with the Implementation of the Third Liberalisation Package (Newcastle upon Tyne: Cambridge Scholars, 2012) 129 at 132.

105 See e.g. Bartlomiej Nowak, "Equal Access to the Energy Infrastructure as a Precondition to Promote Competition in the Energy Market: The Case of European Union" (2010) 38 Energy Policy 3691 at 3699 [Nowak, "Equal Access"]. Nowak

states that open access to electricity and natural gas transmission and distribution is essential for the development of competitive energy markets in the European Union.

106 Cameron, supra note 99 at 30.

107 Ibid at 32.

108 Kahn, vol 1, supra note 92 at 17.

109 See e.g. Nowak, "Equal Access," supra note 105 at 3699.

110 Kahn, vol 2, supra note 96 at 153. For a more general discussion see Posner, supra note 96.

111 In Trans Mountain Expansion, supra note 53, the NEB stated: "crude oil pipelines like Trans Mountain tend to be natural monopolies and, as a result, highly concentrated markets are to be expected" (ibid at 18).

112 See Mackenzie Gas Project Reasons for Decision (2010) GH 1 2004, vol 2, online: NEB <https://docs.neb-one.gc.ca/ll-eng/llisapi.dll?func=llworkspace> (regarding the Mackenzie Valley Pipeline the NEB stated that pipeline markets are "often natural monopolies" at 171).

113 See e.g. Express Pipeline, supra note 75; Keystone XL, supra note 54 at 30.

114 Trans Mountain Expansion, supra note 53.

115 Gaétan Caron, "National Energy Board Update" (Speech delivered at the Canadian Energy Summit, 8 November 2013), online: NEB <https://docs.neb-one.gc.ca/ll-eng/llisapi.dll?func=llworkspace> [emphasis in original].

116 Transportation Assessment, supra note 72 at viii.

117 Transportation Report, supra note 30 at 1. The NEB also lists factors considered in determining whether a pipeline transportation system is well functioning: ibid.

118 Ibid.

119 Keystone Base, supra note 55 at 20.

120 Ibid.

121 See NEBA, supra note 32, s 56(2).

122 Keith F Miller, "Energy Regulation and the Role of the Market" (1999) 37:2 Alta L Rev 419 at 420.

123 Alexander J Black, "Canadian Natural Gas Deregulation: Contractual Impediments and Discriminatory Consequences" (1989) 7:1 J Energy & Natural Resources L 42 at 50.

124 National Energy Board, "Regulation of Traffic, Tolls and Tariffs," online: <www.neb-one.gc.ca/bts/whwr/rspnsblt/trffctlltrff-eng.html#s1> ["NEB Responsibilities"].

125 TransCanada PipeLines Limited: Applications for Facilities and Approval of Toll Methodology and Related Tariff Matters (July 1988), GH 2 87 at 92, online: online: NEB <https://docs.neb-one.gc.ca/ll-eng/llisapi.dll?func=llworkspace> [TransCanada GH 2 87] [emphasis in original].

126 See e.g. TransCanada PipeLines Limited North Bay Junction Application Responses of the Canadian Association of Petroleum Producers (CAPP) to Information Requests from the National Energy Board (NEB) (December 2004), RH 3 2004 at 6 7, online: NEB <https://docs.neb-one.gc.ca/ll-eng/llisapi.dll?func=llworkspace> [North Bay Junction]; Keystone Base, supra note 55 at 23.

127 Keystone Base, ibid at 20.

128 Ibid.

129 Ibid. See also PanCanadian, supra note 40.

130 Considerations, supra note 65 at 353; National Energy Board, Connections: Report of the Joint Review Panel for the Enbridge Northern Gateway Project, vol 1 (Calgary: NEB, 2013) at 8. The Joint Review Panel was established by the National Energy Board and the federal Minister of the Environment to assess the environmental, social, and economic effects of the Enbridge Northern Gateway Project.

131 Considerations, ibid at 353.

132 Ibid.

133 Trans Mountain Expansion, supra note 53; Keystone Base, supra note 55; Express Pipeline, supra note 75; Enbridge Southern Lights, supra note 40; Enbridge Bakken Pipeline Company Inc, on behalf of Enbridge Bakken Pipeline Limited Partnership (December 2011), OH 01 2011, online: NEB <https://docs.neb-one.gc.ca/ll-eng/llisapi.dll?func=llworkspace> [Enbridge Bakken].

134 See e.g. Trans Mountain Pipeline ULC on behalf of Trans Mountain Pipeline, LP (1 December 2011), RH 2 2011, online: NEB <https://docs.neb-one.gc.ca/ll-eng/llisapi.dll?func=llworkspace> [Trans Mountain Westridge]; Keystone XL, supra note 54.

135 Keystone XL, ibid at 54; Keystone Base, supra note 55; Enbridge Southern Lights, supra note 40.

136 See National Energy Board, "Filing Manual Guide S Access on a Pipeline (NEB Act s.71)," online: <www.neb-one.gc.ca/bts/ctrg/gnnb/flngmnl/fmgds-eng.html> ["Filing Manual"]; National Energy Board, Appendix 1: Filing Manual Checklist at App 35, online: <www.neb-one.gc.ca/bts/ctrg/gnnb/flngmnl/fmnnx1-eng.pdf>.

137 "Filing Manual," ibid.

138 Ibid.

139 J David Brett & Nadine E Berge, "Oil and Gas Transportation: Is Contract a Viable Alternative to Traditional Regulation?" (2006) 44:1 Alta L Rev 93.

140 See e.g. Express Pipeline, supra note 75 at 44. This was also true of the Alliance Pipeline: see generally Gordon Jaremko, "Proliferating Pipelines," Oilweek (5 November 2001) 49.

141 See e.g. Trans Mountain Westridge, supra note 134, Trans Mountain said that in 2006, it had attempted to obtain shipper commitments to expand the pipeline, but it did not obtain sufficient support to proceed.

142 The guarantee of unapportioned access means that if capacity on the pipeline becomes scarce and subject to apportionment (prorationing), the firm shippers' capacity will not be cut back, only uncommitted shippers will be prorationed. In some cases, firm shippers are also given renewal rights.

143 This was a common sentiment expressed by shippers and other industry representatives. As part of the research performed for this article, representatives of major oil and gas pipeline companies and shippers, as well as industry associations and regulators, were interviewed. Parties interviewed requested that their identities be kept confidential.

144 For example, this was the case for the firm contracts for the Trans Mountain Expansion, supra note 53.

145 See e.g. Keystone Base, supra note 55; Express Pipeline, supra note 75.

146 See e.g. Trans Mountain Westridge, supra note 134.

147 Trans Mountain Expansion, supra note 53; Interprovincial Pipe Line, supra note 32.

148 See e.g. Enbridge Southern Lights, supra note 40.

149 Express Pipeline, supra note 75.

150 See e.g. Enbridge Bakken, supra note 133 at 22.

151 See e.g. Keystone Base, supra note 55 at 19; Enbridge Southern Lights, supra note 40.

152 Supra note 32 at 27.

153 See e.g. Enbridge Bakken, supra note 133.

154 See e.g. Enbridge Southern Lights, supra note 40.

155 See e.g. Trans Mountain Expansion, supra note 53.

156 Vantage Pipeline Canada ULC (1 January 2012), OH 3 2011, online: NEB <https://docs.neb-one.gc.ca/ll-eng/llisapi.dll?func=llworkspace>.

157 Enbridge Bakken, supra note 133.

158 Supra note 55 at 19.

159 Ibid at 17.

160 Ibid at 57.

161 Supra note 75.

162 Supra note 53 at 29.

163 Ibid at 32.

164 Considerations, supra note 65.

165 Supra note 32.

166 Ibid at 53.

167 Ibid.

168 Ibid

169 Keystone Base, supra note 55.

170 Keystone Pipeline GP Ltd (July 2008), OH 1 2008, online: NEB <https://docs.neb-one.gc.ca/ll-eng/llisapi.dll?func=llworkspace> [Keystone Cushing Expansion].

171 Keystone XL, supra note 54 at 44.

172 Ibid at 38.

173 Ibid at 44.

174 Ibid at 44 45.

175 Ibid at 45.

176 Ibid.

177 Considerations, supra note 65 at 348.

178 Ibid.

179 Northern Gateway proposed to reserve 25,000 bpd of capacity for uncommitted volumes, which is equal to 5 percent of the term shippers' committed volume, or approximately 4.8 percent of the total capacity of the proposed oil pipeline of 525,000 bpd: ibid at 3, 349.

180 Ibid at 352.

181 Ibid.

182 "Northern Gateway Decision Statement," supra note 65. The conditions include a requirement that Enbridge set aside $950 million in liability coverage to cover costs of a potential spill: Jeff Lewis, "Northern Gateway pipeline approved by panel with 209 conditions," Financial Post (19 December 2013),online: <business.financialpost.com/news/energy/northern-gateway- pipeline-approved-by-panel-with-209-conditions?lsa=44b9edd1>.

183 Rowland J Harrison & Gordon E Kaiser, "2014: The Energy Year in Review," Editorial (2015) 3:1 Energy Regulation Q 9 at 10; Gord Hoekstra, "First Nations challenge B.C. government in court over Northern Gateway pipeline," Vancouver Sun (14 January 2015), online: <www.vancouversun.com/technology/First+Nations+challenge+government+court+over+Northern+Gateway+pipeline/10725742/story.html>; Wendy Stueck, "B.C. First Nations challenge Northern Gateway pipeline in new court action," The Globe and Mail (14 July 2014), online: <www.theglobeandmail.com/news/british-columbia/first-nations-challenge-northern-gateway-pipeline-in-new-court-action/article19608617/>. The Federal Court of Appeal has granted leave to the Gitxaala First Nation to appeal the federal cabinet's approval of Northern Gateway: "Gitxaala First Nation granted leave to appeal Northern Gateway pipeline," CBC News (26 September 2014), online: <www.cbc.ca/news/canada/british-columbia/gitxaala-first-nation-granted-leave-to-appeal-northern-gateway-pipeline- 1.2779604>.

184 Justine Hunter & Wendy Stueck, "B.C. government to Northern Gateway pipeline proposal: No,"' The Globe and Mail (17 June 2014), online: <www.theglobeandmail.com/news/british-columbia/bc-to-northern-gateway-no/article19213866/>.

185 See e.g. Trans Mountain Westridge, supra note 134 at 11; Trans Mountain Expansion, supra note 53 at 16.

186 Trans Mountain Westridge, ibid.

187 Ibid at 1.

188 Ibid.

189 Ibid at 25.

190 Ibid at 26.

191 Ibid at 29.

192 Ibid at 38.

193 Ibid at 20.

194 Ibid at 18.

195 Ibid at 11.

196 Ibid at 28.

197 Ibid at 15.

198 Ibid at 25.

199 Ibid.

200 Ibid at 26.

201 Trans Mountain filed its facilities application for the expansion with the NEB on 16 December 2013. The NEB oral hearing on the facilities application has been postponed as of 21 August 2015: see National Energy Board, News Release, "NEB postpones Trans Mountain Expansion oral hearings" (21 August 2015), online: <news.gc.ca/web/article-en.do?nid =1015719>.

202 Trans Mountain Expansion, supra note 53.

203 By signing a FSA, a shipper commits to sign a TSA provided that certain conditions precedent are met: see ibid. Trans Mountain Pipeline ULC, Application for Approval of the Transportation Service and Toll Methodology for the Expanded Trans Mountain Pipeline System (RH 001 2012) (29 June 2012), Appendix 7 at 14, online: NEB <https://docs.neb-one.gc.ca/ll-eng/llisapi.dll?func=llworkspace> [Application] (Facility Support Agreement).

204 Application, ibid at para 19.

205 Trans Mountain Expansion, supra note 53 at 15.

206 See Suncor Energy Products Partnership (SEPP) Application Regarding Trans Mountain Pipeline ULC (Trans Mountain) Open Season National Energy Board (Board) Decision (12 August 2012), (Letter Decision), online: NEB <https://docs.neb-one.gc.ca/lleng/llisapi.dll?func=llworkspace>.

207 Trans Mountain Expansion, supra note 53 at 16.

208 Ibid at 4, 7 (Evidence of Suncor Energy Marketing Inc and Suncor Energy Products Partnership).

209 Trans Mountain Expansion, ibid (Evidence of Total E& P Canada Ltd) at para 21.

210 Ibid (Direct Evidence of George R Schink), Table IV.1 at 55.

211 Ibid at 1 2.

212 Ibid.

213 Ibid.

214 Ibid at 13.

215 Ibid.

216 NEBA, supra note 32, s 67 states: "A company shall not make any unjust discrimination in tolls, service or facilities against any person or locality.. Tolls must also be just and reasonable." Section 62 states: "All tolls shall be just and reasonable, and shall always, under substantially similar circumstances and conditions with respect to all traffic of the same description carried over the same route, be charged equally to all persons at the same rate" (ibid, s 62).

217 Supra note 40 at 12.

218 NEBA, supra note 32, s 63 states: "The Board may determine, as questions of fact, whether or not traffic is or has been carried under substantially similar circumstances and conditions referred to in section 62, whether in any case a company has or has not complied with the provisions of that section, and whether there has, in any case, been unjust discrimination within the meaning of section 67" (ibid, s 62).

219 See e.g. Federated, supra note 40 at 10; Express Pipeline, supra note 75 at 23; Enbridge Bakken, supra note 133.

220 See e.g. Trans Mountain Expansion, supra note 53.

221 Supra note 133.

222 Ibid at 17.

223 Keystone XL, supra note 54 at 46.

224 Ibid.

225 Ibid.

226 Trans Mountain Westridge, supra note 134 at 36.

227 Chevron Canada Limited (15 July 2013) MH 002 2012, online: NEB <https://docs.neb-one.gc.ca/ll-eng/llisapi.dll?func=llworkspace> [Chevron]. For additional information regarding this Application: see Jennifer Hocking, "Burnaby Refinery not a Priority Destination under Pipeline Tariff" (26 July 2013) ABlawg (blog), online: Ablawg <ablawg.ca/wp-content/uploads/2013/07/Blog_JH_Pipeline_Tariff_Chevron_Canada_Jul y2013.pdf>.

228 Trans Mountain Pipeline ULC, Petroleum Tarriff, No 92 (14 May 2013), online Kinder Morgan www.kindermorgan.com/content/docs/NEB_Tariff_No_92.pdf [Trans Mountain Tariff].

229 Ibid, s 1.58.

230 Ibid, s 14(a).

231 Ibid, s 14(b).

232 Trans Mountain Expansion, supra note 53 at 11. This may be because Chevron's view was that the pipeline ought to continue to accept all oil tendered, and that the pipeline ought to have expanded: see Trans Mountain Westridge, supra note 134 at 17.

233 Chevron, supra note 227.

234 Trans Northern, supra note 37.

235 Ibid.

236 Ibid at 11.

237 Ibid at 8.

238 Ibid.

239 Ibid.

240 Kahn, vol 1, supra note 92 at 17.

241 "NEB Responsibilities," supra note 124.

242 A "Memorandum of Guidance" (MOG) is an NEB document providing guidance to industry regarding how the NEB intends to interpret its mandate with respect to a particular issue. The NEB generally consults with affected parties prior to implementing a MOG or other policy changes.

243 It can take many years for the NEB to propose and ultimately see a legislative amendment passed in Parliament, so there are advantages to avoiding a legislative amendment.

244 NEBA, supra note 32, s 71(1).

245 Keystone Base, supra note 55 at 23.

246 Keystone Cushing Expansion, supra note 170 at 16.

End of Document

Baer, Alexander

From: Baer, Alexander
Sent: November 20, 2020 3:25 PM
To: 'Patrick Bowman'
Cc: Keen, Matthew; Melissa Davies; 'Pat Lee'
Subject: VAFFC - NEB/CER Decisions re Common Carriers, Competition and Risk

Hi Patrick,

I hope all is well. We have spent a bit more time reviewing NEB/CER decisions for content that may be relevant to your evidence, particularly regarding the relationship between common carrier regulation, competition and risk. We have flagged some excerpts from two decisions, below, which we thought you may find useful.

Also, on timing, PKMJF filed a letter with some additional documents with the Commission yesterday (here). There is no specific word yet on a new deadline for intervener evidence. That said, how are things coming on the draft? Just let us know if it would be helpful to connect next week. Many thanks, and have a great weekend!

Best regards,

Alex

* * * * * * * * * * * *

1. NEB Decision RH-003-2011: TransCanada Business and Services Restructuring Proposal and Mainline Final Tolls for 2012 and 2013

    a. The Board framed the issue facing the TransCanada Mainline as follows at pdf p. 20:

    > *The Mainline is in an unprecedented position. No major NEB regulated natural gas transmission pipeline has ever been affected by market forces to the extent that the Mainline is now affected. Throughput on the Mainline has decreased significantly, and as a result, Mainline tolls have increased substantially over a short period of time.*
    >
    > *The future of the Mainline depends on how TransCanada is able to respond to the changes to its business environment. The Mainline faces increasing competition for gas supply from intraAlberta demand, other ex-Western Canada Sedimentary Basin (WCSB) pipelines and new markets for WCSB gas. The Mainline competes with pipelines from emerging shale and tight gas basins in the United States of America (U.S.), which deliver gas to eastern markets. The Mainline must adjust to this new environment because eastern consumers may not renew contracts for long-haul service and bypass infrastructure may be built.*
    >
    > *Tolls cannot continue to increase each year in response to throughput decline. Costs associated with throughput variation have been passed to remaining Firm Transportation service (FT) shippers. Those shippers have borne all of the costs of, and the risk associated with, competition. If this were to continue, the Mainline's competitiveness could further erode and exacerbate the root cause of throughput declines.*

    b. The Board made the following comments regarding the effects of competition and the possibility of TransCanada suffering a loss at pdf p. 22:

    > *Opportunity to Recover Costs*
    >
    > *We are not disallowing any Mainline investment from being recovered in tolls. In reaching this finding, we gave the most weight to TransCanada's forecast increase in Mainline throughput. Given that forecast, we are of the view that TransCanada should be afforded the time and tools*

to adapt to its business environment, and the time to take advantage of the opportunities offered by this Decision.

We recognize that throughput, cost and revenue forecasts may not be realized. We have compensated the Mainline through a higher allowed return for the increased variability risk it will face due to its cash flows being more dependent on the accuracy of its throughput forecast than in the past. We note that the Mainline's forecast of discretionary service revenue is conservative and was based on the Mainline having less discretion to set prices for IT and STFT. As a result, Mainline revenues and profits may be higher than forecast.

If larger-than-forecast cost deferrals were to occur, they could represent a materialization of the Mainline's fundamental risk and costs could be disallowed. If costs were disallowed, it would not mean that TransCanada did not have a reasonable opportunity to recover costs, but rather that events did not turn out as forecast or that this opportunity was not seized by TransCanada. A potential outcome is that the Mainline would suffer a loss – just like any other business that faces competition.

Conclusion

The Mainline faces increased competitive risk. Accordingly, we have provided the Mainline with the tools to respond to this risk, coupled with regulatory oversight and regulatory process flexibility to effect changes as appropriate. We find this to be important regardless of what the future holds in terms of whether all or part of the facilities continue to provide gas services.

Our Decision enables TransCanada to meet market forces with market solutions. It is TransCanada's responsibility to ensure that the Mainline is economically viable and continues to be an important asset to connect the WCSB to markets in the east. The extent to which the Mainline is used as a supply option for consumers and a market option for producers can only be determined by a functioning free market. TransCanada must not look to regulation to shield the Mainline from its fundamental business risk. It must address the underlying competitive reality in which the Mainline operates.

[Underlining added]

c. The Board's views at pdf p. 56 and following are also interesting. As the Board notes:

In the paragraphs that follow, we discuss the regulatory compact, regulatory standards for cost recovery, whether the NEB Act and the GPUAR compel the Board to give TransCanada an opportunity to recover all prudently incurred costs in all circumstances, and whether a disallowance of Mainline costs would be confiscatory. We then consider fundamental risks for which TransCanada has been compensated through an allowed return on rate base and whether any costs should be disallowed…

d. See the following at pdf p. 57 regarding the regulatory compact:

Further, the regulatory compact as described by the Supreme Court of Canada in Stores Block is not directly applicable to TransCanada. The Mainline does not have a franchise area and TransCanada is not compelled by statute to provide service to customers in any area. Certificates of public convenience and necessity confer a right on TransCanada, not an obligation, to construct facilities for gas transportation service. As a result, we do not accept that the "regulatory compact" as described in Stores Block provides much assistance about how we should set tolls for the Mainline.

In adjudicating the current Application, we are mandated with establishing just and reasonable tolls, that are not unjustly discriminatory, in accordance with the provisions of the NEB Act.

e. See the following at pdf p. 59 regarding the importance of the "used and useful" standard:

In our view, a regulatory rule that compels the Board to set tolls that allow the return of and on investment, irrespective of whether assets associated with that investment are used and useful for providing service, erodes management's responsibility for its investment decisions and

management's responsibility to keep depreciation rates current. This situation, in our view, does not lend itself to creating efficient energy infrastructure and markets. It also provides no incentive for a pipeline company to find better or higher uses for its assets.

Given the foregoing, the prudency standard should not be the only standard that determines the opportunity for cost recovery for NEB-regulated pipelines in all circumstances.

f. See the following at pdf pp. 61-63 regarding the manifestation of the "fundamental risk" facing the pipeline and who should bear the consequences:

The Board previously characterized the situation where the Mainline's fundamental risk materializes as the point at which Mainline throughput has declined to a level where the resulting tolls exceed what the market could bear. If this were to happen, the Board noted that it would no longer be able to protect the Mainline and the Mainline may not be able to recover all of its costs

…

In our view, there is a limit to the level of costs related to underutilization resulting from competition that Mainline shippers can absorb for tolls to remain just and reasonable. It is not just and reasonable for all of the costs of, and the risk associated with, competition to be borne by shippers on the system who do not have access to competing sources of supply for their energy needs. Tolls cannot continue to increase each year in response to throughput decline. This approach leads to a gradual erosion of the Mainline's competitiveness and exacerbates throughput decline.

…

In our view, TransCanada downplays the extent to which the Mainline bears fundamental risk, and how close that risk is to materializing, by emphasizing past Board comments regarding the risk of underutilization and how such underutilization should be treated. This emphasis ignores that the Mainline bears fundamental risk that ultimately materializes at low or non-existent levels of utilization, and that the Mainline's awarded cost of capital has always been above the risk-free rate of return. It also fails to acknowledge that the Mainline is in an unprecedented position. No major NEB regulated natural gas transmission pipeline has been affected by market forces to the extent that the Mainline is now affected.

It is not unfair for TransCanada to bear financial consequences of fundamental risk

We are of the view that it is not unfair for TransCanada to bear negative financial consequences if the Mainline's fundamental risk materializes even if we, and previous Board decisions, define fundamental risk differently than TransCanada. Investors were aware, or ought to have been aware, that they may at some time receive lower than expected returns. Investors have financed an asset that faces risk, albeit in a regulated environment. The materialization of fundamental risk could be visited on investors through lower than expected returns, for example through a disallowance, unless TransCanada is able to develop and propose acceptable mechanisms for cost recovery. We also note that TransCanada could avoid lower returns by redeploying or repurposing assets.

We are of the view that an asymmetric risk premium is not required to compensate investors for the realization of fundamental risk because the possibility of fundamental risk materializing was known to market participants, albeit unlikely by their assessment. Our view is that the likelihood of this event happening, including the extent to which it has an asymmetric nature, has been consistently reflected in the Mainline's cost of capital and allowed return. The historical risk premiums allowed were commensurate with the risks the Mainline was facing. As the business risk facing the Mainline increases, so does the risk premium.

In our view, imposing costs of the materialization of fundamental risk on TransCanada would not amount to an inappropriate regulatory model where the Mainline can only charge tolls that are the lower of cost or market. It is possible for the Mainline to charge cost-based tolls (subject to deferrals) up to the point when fundamental risk materializes. The risks involved in this approach

have been and are reflected in the Mainline's cost of capital and allowed return. While toll competitiveness is an important consideration in determining whether the Mainline's fundamental risk has materialized, we will explain in Chapter 12 that to be considered competitive, tolls do not necessarily need to be in the money based on annual averages of basis differentials, netbacks, or delivered cost of gas on competing pipeline alternatives.

Further, we note that the concept of "expected return" indicates that the return is not a guaranteed return. It is a return to be earned if, among other things, depreciation rates correspond to the economic useful life of the regulated asset. TransCanada has been compensated for the risk that its best estimate of depreciation rates may end up being different than forecast – which is what a cost disallowance, upon a materialization of fundamental risk, could constitute. As a result, and as explained in the RH-2-2004 Phase II Decision, it is incumbent on TransCanada's management to seek changes to depreciation rates if it becomes apparent that depreciation rates do not adequately reflect current estimates of economic life.

2. CER Decision RH-001-2019: NGTL System Rate Design and Services

   a. The CER recently had the following to say regarding underutilization risk in this proceeding at pdf pp. 56-57, referencing the NEB's RH-003-2011 decision:

The Commission is of the view that fundamental risk is not materializing on the NGTL System at this time, but remains a long-term risk. It is the pipeline company, in this case NGTL, which faces fundamental risk and is ultimately responsible for managing this risk. NGTL has the flexibility and the ability to be innovative in order to adapt to changing market circumstances. It also has a variety of tools to manage its long-term risks including depreciation rates and contract terms. The Commission acknowledges the concerns raised by Centra, and notes that in accepting the Settlement, the Commission does not relieve NGTL from its long-term responsibility for managing its regulated assets beyond the terms of the Settlement.

A number of parties in this proceeding discussed how fundamental risk was framed in the NEB's RH-003-2011 decision. In line with the RH-003-2011 Decision, the Commission is of the view that the materialization of fundamental risk would occur when just and reasonable tolls could not allow for the recovery of all prudently-incurred costs. The Commission will not discuss in this decision what specific circumstances would constitute the materialization of fundamental risk on the NGTL System as the record of this proceeding is insufficient to do so.

In the near term, shippers are responsible for the costs they cause on the pipeline. Over the long term, a pipeline company is responsible to match the recovery of capital to the pipeline's use. As a part of its responsibility a pipeline company should be regularly reviewing its pipeline assets and underlying assumptions regarding depreciation. In doing this review, the pipeline company's depreciation approach and assumptions should match the economic life of the assets. Continuing the practice of regularly updating depreciation assumptions and providing revised studies reduces the future risk of undepreciated facilities…

Alexander Baer
Associate

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NORTON ROSE FULBRIGHT

KINDER MORGAN CANADA LIMITED
INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm
To the shareholders and board of directors of Kinder Morgan Canada Limited

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of Kinder Morgan Canada Limited and its subsidiaries (the "Company") as of December 31, 2018, and the related consolidated statement of income, comprehensive income, cash flows, and equity for the year then ended, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018, and the results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audit. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audit we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audit included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audit provides a reasonable basis for our opinion.

/s/PricewaterhouseCoopers LLP

Houston, Texas
February 18, 2019

We have served as the Company's auditor since 2018.

Report of Independent Registered Public Accounting Firm
To the shareholders and board of directors of Kinder Morgan Canada Limited

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of Kinder Morgan Canada Limited and its subsidiaries (together, the "Company") as of December 31, 2017, and the related consolidated statements of income, comprehensive income, cash flows and equity for each of the two years in the period ended December 31, 2017, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Canada
February 20, 2018, except for the effects of discontinued operations discussed in Note 3 and the effects of the reverse stock split discussed in Note 13 to the consolidated financial statements, as to which the date is February 18, 2019.

We served as the Company's auditor from 2016 to 2018.

KINDER MORGAN CANADA LIMITED
CONSOLIDATED STATEMENTS OF INCOME
(In millions of Canadian dollars, except per share amounts)

Year Ended December 31,	2018	2017 (Note 3)	2016 (Note 3)
Revenues			
Services	322.6	294.8	288.5
Services-affiliate	61.2	63.7	59.1
Product sales and other	—	0.4	0.2
Total Revenues	383.8	358.9	347.8
Operating Costs, Expenses and Other			
Operations and maintenance	154.5	162.5	152.8
Depreciation and amortization(Note 6)	82.6	71.7	64.2
General and administrative	39.0	30.9	25.7
Taxes, other than income taxes	6.2	6.7	7.3
Other (income) expense, net	(9.3)	3.4	0.2
Total Operating Costs, Expenses and Other	273.0	275.2	250.2
Operating Income	110.8	83.7	97.6
Other Income (Expense)			
Interest income (expense), net(Note 15)	27.2	(8.2)	(18.5)
Foreign exchange gain (loss)(Note 17)	0.1	(5.1)	14.6
Other, net	(0.3)	0.9	0.1
Total Other Income (Expense)	27.0	(12.4)	(3.8)
Income from Continuing Operations Before Income Taxes	137.8	71.3	93.8
Income Tax Expense(Note 4)	(37.8)	(20.8)	(23.4)
Income from Continuing Operations	100.0	50.5	70.4
Discontinued Operations(Note 3)			
Income from operations of the Trans Mountain Asset Group, net of tax	39.8	110.2	131.4
Gain on sale of the Trans Mountain Asset Group, net of tax	1,278.4	—	—
Income from Discontinued Operations, Net of Tax	1,318.2	110.2	131.4
Net Income	1,418.2	160.7	201.8
Preferred share dividends	(28.8)	(6.6)	—
Net Income Attributable to Kinder Morgan Interest	(973.2)	(126.2)	(201.8)
Net Income Available to Restricted Voting Stockholders	416.2	27.9	—
Restricted Voting Shares(Note 13)			
Basic and Diluted Earnings Per Restricted Voting Share from Continuing Operations	0.62	0.31	—
Basic and Diluted Earnings Per Restricted Voting Share from Discontinued Operations	11.37	0.69	—
Basic and Diluted Weighted Average Restricted Voting Shares Outstanding	34.7	27.6	—

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN CANADA LIMITED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions of Canadian dollars)

Year Ended December 31,	2018	2017	2016
Net income	1,418.2	160.7	201.8
Other comprehensive income (loss)			
Benefit plans(Note 3)	37.5	—	(4.7)
Foreign currency translation adjustments(Note 3)	(8.2)	(3.5)	(1.7)
Total other comprehensive income (loss)	29.3	(3.5)	(6.4)
Comprehensive income	1,447.5	157.2	195.4
Comprehensive income attributable to Kinder Morgan interest	(993.7)	(124.0)	(195.4)
Comprehensive income attributable to Kinder Morgan Canada Limited	453.8	33.2	—

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN CANADA LIMITED
CONSOLIDATED BALANCE SHEETS
(In millions of Canadian dollars, except share amounts)

December 31,	2018	2017 (Note 3)
ASSETS		
Current assets		
Cash and cash equivalents	4,338.1	110.7
Accounts receivable	26.2	23.3
Inventories	7.5	7.3
Current assets held for sale(Note 3)	—	192.7
Other current assets(Note 5)	5.9	6.6
Total current assets	4,377.7	340.6
Property, plant and equipment, net(Note 6)	981.3	988.4
Long-term assets held for sale(Note 3)	—	3,050.4
Deferred charges and other assets(Note 7)	10.6	73.3
Total Assets	5,369.6	4,452.7
LIABILITIES AND EQUITY		
Current liabilities		
Credit facility(Note 10)	—	—
Accounts payable(Note 8)	49.4	54.5
Distribution payable	1,195.1	—
Distribution payable-affiliates	2,782.3	—
Accrued taxes	310.6	8.7
Current liabilities held for sale(Note 3)	—	207.3
Other current liabilities(Note 9)	63.2	27.8
Total current liabilities	4,400.6	298.3
Long-term liabilities and deferred credits		
Deferred income taxes(Note 4)	0.1	348.9
Contract liabilities	67.5	53.5
Long-term liabilities held for sale(Note 3)	—	113.6
Other deferred credits(Note 12)	8.9	0.8
Total long-term liabilities and deferred credits	76.5	516.8
Total Liabilities	4,477.1	815.1
Commitments and contingencies(Notes 10 and 20)		
Equity		
Preferred share capital, 12,000,000 shares of Series 1 and 10,000,000 shares of Series 3, issued and outstanding(Note 13)	537.2	537.2
Restricted Voting Share capital, 34,944,993 and 34,455,635 Restricted Voting Shares, respectively, issued and outstanding(Note 13)	278.1	1,707.5
Retained deficit	(165.8)	(770.0)
Accumulated other comprehensive loss	—	(8.8)
Total Kinder Morgan Canada Limited equity	649.5	1,465.9
Kinder Morgan interest, 81,353,820 and 80,960,966 Special Voting Shares, respectively, issued and outstanding(Note 13)	243.0	2,171.7
Total Equity	892.5	3,637.6
Total Liabilities and Equity	5,369.6	4,452.7

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN CANADA LIMITED
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions of Canadian dollars)

Year Ended December 31,	2018	2017	2016
Operating Activities			
Net income	1,418.2	160.7	201.8
Non-cash items:			
Depreciation and amortization	129.4	142.4	137.2
Deferred income taxes	(339.9)	57.2	55.1
Capitalized equity financing costs	(34.8)	(29.1)	(17.9)
Unrealized foreign exchange (gain) loss	(0.8)	5.6	(32.6)
Write-off of unamortized debt issuance costs	60.5	—	—
Gain on sale of the Trans Mountain Asset Group(Note 3)	(1,197.0)	—	—
Other non-cash items	9.4	8.1	(6.2)
Change in operating assets and liabilities(Note 16)	337.0	(94.4)	(27.5)
Cash provided by operating activities(Note 3)	382.0	250.5	309.9
Investing Activities			
Capital expenditures	(528.4)	(618.5)	(269.1)
Contributions to trusts	(9.9)	(16.4)	(13.7)
Sales of property, plant and equipment, net of removal costs	16.0	(0.2)	(0.4)
Proceeds from the sale of the Trans Mountain Asset Group, net of cash disposed(Note 3)	3,913.4	—	—
Other, net	0.6	—	—
Cash provided by (used in) investing activities(Note 3)	3,391.7	(635.1)	(283.2)
Financing Activities			
Issuances of debt	792.6	337.3	—
Repayments of debt	(232.7)	(337.3)	—
Proceeds received from IPO, net	—	1,671.0	—
Issuances of preferred shares, net	(0.5)	536.8	—
Proceeds from debt with affiliates	—	—	70.2
Repayments of debt with affiliates	—	(1,606.3)	—
Cash dividends - restricted shares	(50.0)	(16.1)	—
Dividends - preferred shares	(27.7)	(4.0)	—
Distributions - Kinder Morgan interest	(142.0)	(41.8)	—
Debt issuance costs	(9.3)	(74.7)	—
Contributions from Kinder Morgan - pre-IPO	—	—	10.7
Distributions to Kinder Morgan - pre-IPO	—	—	(21.1)
Other, net	(6.0)	—	—
Cash provided by financing activities	324.4	464.9	59.8
Change in Cash, Cash Equivalents and Restricted Deposits held by the Trans Mountain Asset Group	128.3	(78.3)	(28.9)
Effect of exchange rate changes on cash, cash equivalents and restricted deposits	1.0	(1.1)	0.1
Net increase in Cash, Cash Equivalents and Restricted Deposits	4,227.4	0.9	57.7
Cash, Cash Equivalents and Restricted Deposits, beginning of period	111.2	110.3	52.6
Cash, Cash Equivalents and Restricted Deposits, end of period	4,338.6	111.2	110.3
Cash and Cash Equivalents, beginning of period	110.7	109.8	52.2
Restricted Deposits, beginning of period	0.5	0.5	0.4
Cash, Cash Equivalents, and Restricted Deposits, beginning of period	111.2	110.3	52.6
Cash and Cash Equivalents, end of period	4,338.1	110.7	109.8
Restricted Deposits, end of period	0.5	0.5	0.5
Cash, Cash Equivalents, and Restricted Deposits, end of period	4,338.6	111.2	110.3
Net increase in Cash, Cash Equivalents and Restricted Deposits	4,227.4	0.9	57.7
Supplemental Disclosures of Cash Flow Information			
Cash paid including to affiliates during the period for interest (net of capitalized interest)	—	59.2	31.2
Cash paid during the period for income taxes	9.4	2.3	1.1
Non-cash Investing and Financing Activities			
Increase in property, plant and equipment from both accruals and contractor retainage		38.1	26.0
Increase (decrease) in property, plant and equipment due to foreign currency translation adjustments	1.5	(2.8)	(4.0)
Distribution accruals	3,977.4	—	—

The accompanying notes are an integral part of these consolidated financial statements.

	Canadian dollars (in millions)			
	Equity attributable to Kinder Morgan pre-IPO	Retained deficit	Accumulated other comprehensive loss	Total
Balance at December 31, 2015	1,464.3	(193.8)	(19.5)	1,251.0
Net income		201.8		201.8
Contributions	10.7			10.7
Distributions		(21.1)		(21.1)
Other comprehensive income			(6.4)	(6.4)
Balance at December 31, 2016	1,475.0	(13.1)	(25.9)	1,436.0

	Issued shares (in millions)			Canadian dollars (in millions)						
	Preferred Shares	Restricted Voting Shares	Kinder Morgan Interest - Special Voting Shares	Equity attributable to Kinder Morgan pre-IPO	Preferred Share Capital	Restricted Voting Share capital	Retained deficit	Accumulated other comprehensive loss	Kinder Morgan interest	Total
Balance at December 31, 2016	—	—	—	1,475.0	—	—	(13.1)	(25.9)	—	1,436.0
Activity attributable to Kinder Morgan prior to IPO:										
Equity interests issued				126.9						126.9
Distribution				(261.7)						(261.7)
Issuance of restricted voting shares		34.3				1,750.0				1,750.0
Issuance of special voting shares and reallocation of Kinder Morgan pre-IPO carrying basis			80.7	(1,340.2)			13.1	25.9	1,301.2	—
Reallocation of equity on common control transaction							(777.7)	(7.5)	785.2	—
Equity issuance fees					(13.9)	(69.9)				(83.8)
Issuance of preferred shares	22.0				550.0					550.0
Net income							34.5		126.2	160.7
Preferred share dividend							(4.0)			(4.0)
Restricted voting share dividends							(22.8)			(22.8)
Special voting share distributions									(55.1)	(55.1)
Dividend/Distribution reinvestment plan		0.2	0.3			6.7			13.3	20.0
Stock-based compensation						2.2				2.2
Deferred tax liability adjustment					1.1	18.8			2.8	22.7
Other						(0.3)			0.3	—
Other comprehensive loss								(1.3)	(2.2)	(3.5)
Balance at December 31, 2017	22.0	34.5	81.0	—	537.2	1,707.5	(770.0)	(8.8)	2,171.7	3,637.6

	Issued shares (in millions)			Canadian dollars (in millions)					
	Preferred shares	Restricted Voting Shares	Kinder Morgan Interest - Special Voting Shares	Preferred share capital	Restricted Voting Share capital	Retained deficit	Accumulated other comprehensive loss	Kinder Morgan interest	Total
Balance at December 31, 2017	22.0	34.5	81.0	537.2	1,707.5	(770.0)	(8.8)	2,171.7	3,637.6
Net income						445.0		973.2	1,418.2
Preferred share dividend						(27.7)			(27.7)
Restricted voting share dividends						(68.0)			(68.0)
Special voting share distributions								(161.8)	(161.8)
Return of Capital(Note 3)						(1,195.1)		(2,782.3)	(3,977.4)
Dividend/Distribution reinvestment plan		0.4	0.4		18.0			19.8	37.8
Stock-based compensation					4.5				4.5
Stated Capital Reduction(Note 3)					(1,450.0)	1,450.0			—
Other					(1.9)			1.9	—
Other comprehensive income							8.8	20.5	29.3
Balance at December 31, 2018	22.0	34.9	81.4	537.2	278.1	(165.8)	—	243.0	892.5

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN CANADA LIMITED

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. General

The Company was incorporated under the Business Corporations Act (Alberta) on April 7, 2017. On May 30, 2017, we completed an IPO of our Restricted Voting Shares and used the net proceeds of $1,671.0 million to acquire an approximate 30% indirect equity interest in the Limited Partnership from certain affiliates of Kinder Morgan, who retained an approximate 70% equity ownership of the limited partnership units in the Limited Partnership. When we refer to "us," "we," "our," "ours," "the Company," or "KML," we are describing Kinder Morgan Canada Limited.

The Limited Partnership and Kinder Morgan Canada GP Inc. (the "General Partner"), were formed under the laws of the Province of Alberta in conjunction with the IPO. After the sale of the Trans Mountain Asset Group further discussed in Note 3 , the Limited Partnership, through its ownership of KMCU, indirectly consolidates KMCSI and all or its proportion of the following operating entities (collectively the "Operating Entities"):

- KMCU
- KM Canada Marine Terminal Limited Partnership
- KM Canada North 40 Limited Partnership
- KM Canada Rail Holdings GP Limited
- KM Canada (Jet Fuel) Inc.
- KM Canada Terminals GP ULC
- KM Canada Edmonton South Rail Terminal Limited Partnership[(a)]
- KM Canada Edmonton North Rail Terminal Limited Partnership[(a)]
- Base Line Terminal East Limited Partnership[(a)]

a. Through these wholly owned partnerships we own a 50% undivided interest in joint venture operations with unaffiliated entities that are proportionality consolidated.

The Limited Partnership is a variable interest entity because a simple majority or lower threshold of the limited partnership interests do not possess substantive "kick-out" rights (i.e., the right to remove the general partner or to dissolve (liquidate) the entity without cause) or substantive participation rights. The General Partner is the primary beneficiary because it has the power to direct the activities that most significantly impact the Limited Partnership's performance and the right to receive benefits, and obligation to absorb losses, that could be significant to the Limited Partnership. As a result, the General Partner consolidates the Limited Partnership. The General Partner is a wholly owned subsidiary of the Company. Consequently, we indirectly consolidate the Limited Partnership and the Operating Entities in our consolidated financial statements.

Business Description

We have two business segments: (i) the Terminals segment which includes the ownership and operation of liquid product merchant storage and rail terminals in the Edmonton, Alberta market as well as a predominantly dry cargo import/ export facility in Vancouver, B.C. and (ii) the Pipelines segment which owns and operates Cochin and Jet Fuel.

Our Reorganization and IPO

On May 30, 2017, we completed an IPO of 102,942,000 Restricted Voting Shares (number of shares is before our January 4, 2019 Share Consolidation, see Note 3) on the TSX at a price of $17.00 per Restricted Voting Share for total gross proceeds of approximately $1.75 billion. We used our IPO proceeds to indirectly acquire from Kinder Morgan an approximate 30% equity interest in the Limited Partnership, with Kinder Morgan retaining the remaining approximate 70% equity interest.

Concurrent with closing of our IPO, the Limited Partnership acquired an interest in the Operating Entities from KMCC and KMTU, each wholly owned subsidiaries of Kinder Morgan, in exchange for the issuance to KMCC and KMCT of Class B Units of the Limited Partnership. In addition, KMCC and KMCT were issued Special Voting Shares in the Company for nominal consideration.

Immediately following the closing of our IPO, we used the proceeds from our IPO to indirectly subscribe for Class A Units representing an approximate 30% economic interest in the Limited Partnership while the Class B Units held by KMCC and KMCT represent, in the aggregate, an approximate 70% economic interest in the Limited Partnership. Following the issuance of the Series 1 Preferred Shares and Series 3 Preferred Shares, the Company's and Kinder Morgan's respective interests in the Limited Partnership are subject to the preferred shareholders' priority on distributions and upon liquidation.

After the completion of our IPO and the reorganization transaction described above and as of December 31, 2017, the issued and outstanding Restricted Voting Shares comprises approximately 30% of the votes attached to all outstanding Company voting shares, and the Kinder Morgan interest, which represents its indirect ownership of 100% of the Special Voting Shares, comprises approximately 70% of the votes attached to all outstanding Company voting shares.

Subsequent to our IPO, Kinder Morgan retained control of us and the Limited Partnership, and as a result we accounted for our acquisition of an approximate 30% equity interest in the Limited Partnership as a transfer of net assets among entities under common control. Therefore, our consolidated financial statements presented herein were derived from the consolidated financial statements and accounting records of Kinder Morgan. The assets and liabilities in these consolidated financial statements have been reflected at historical carrying value of the immediate parents within the Kinder Morgan organizational structure including goodwill and purchase price assigned amounts, as applicable. Prior to May 30, 2017, our historical financial statements were presented as combined consolidated financial statements derived from information included within the consolidated financial statements and accounting records of Kinder Morgan. All significant intercompany balances between the companies included in our accompanying consolidated financial statements have been eliminated.

In addition, as of and for the reporting periods after May 30, 2017, Kinder Morgan's economic interest in the Limited Partnership is reflected within "Kinder Morgan interest" in our consolidated statements of equity and consolidated balance sheets and earnings attributable to Kinder Morgan's economic ownership interest in the Limited Partnership is presented in "Net Income Attributable to Kinder Morgan Interest" in our consolidated statements of income.

Kinder Morgan retained control of us, therefore, the amounts recorded to "Restricted Voting Share capital," "Retained deficit," "Accumulated other comprehensive loss" and "Kinder Morgan interest" presented in the consolidated statement of equity for the year ended December 31, 2017 include (i) the "Issuance of special voting shares and reallocation of Kinder Morgan pre-IPO carrying basis" which represents Kinder Morgan's pre-IPO 100% ownership interest in us including net income for the period January 1 through May 29, 2017 and (ii) the "Reallocation of equity on common control transaction" which represents the difference between our book value prior to our IPO and the proportionate ownership percentages in the book value in our net assets after our IPO.

2. Summary of Significant Accounting Policies

Basis of Presentation

In January 2018, we completed the registration of our Restricted Voting Shares pursuant to Section 12(g) of the United States Securities Exchange Act of 1934 (the "Exchange Act") and are subject to the reporting requirements of Section 13(a) of the Exchange Act.

We have prepared the accompanying consolidated financial statements in accordance with the accounting principles contained in the FASB Accounting Standards Codification, the single source of U.S. GAAP and referred to in this report as the Codification. U.S. GAAP means generally accepted accounting principles that the SEC has identified as having substantial authoritative support, as supplemented by Regulation S-X under the U.S. Securities Exchange Commission Act of 1934, as amended from time to time. Under such rules and regulations, all significant intercompany items have been eliminated in consolidation.

Amounts are stated in Canadian dollars unless otherwise noted which is the functional currency of most of our operations. Additionally, certain amounts from prior years have been reclassified to conform to the current presentation.

Adoption of New Accounting Pronouncements

On January 1, 2018, we adopted Accounting Standards Updates (ASU) No. 2014-09, "Revenue from Contracts with Customers" and a series of related accounting standard updates designed to create improved revenue recognition and disclosure comparability in financial statements. For more information, see "—*Revenue Recognition*" below and Note 18.

On January 1, 2018, we retroactively adopted ASU No. 2016-18, “Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force).” This ASU requires the statements of cash flows to present the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents are now included with cash and cash equivalents when reconciling the beginning of period and end of period amounts presented on the statements of cash flows. The retrospective application of this new accounting guidance resulted in a net increase of $0.6 million and a net decrease of $0.3 million in the total consolidated cash, cash equivalents and restricted deposits, which is the included both at “Cash, Cash Equivalents and Restricted Deposits, beginning (end) of period” and at “Change in Cash and Cash Equivalents, and Restricted Deposits held by the Trans Mountain Asset Group” within our consolidated statements of cash flows, and a decrease of $0.6 million and an increase of $0.3 million in “Cash used in investing activities,” for the years ended December 2017 and 2016, respectively, from what was previously presented in our consolidated statements of cash flows in our Annual Report on Form 10-K for the year ended December 31, 2017.

Use of Estimates

Certain amounts included in or affecting our financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions which cannot be known with certainty at the time our financial statements are prepared. These estimates and assumptions affect the amounts we report for assets and liabilities, our revenues and expenses during the reporting period, and our disclosures, including as it relates to contingent assets and liabilities at the date of our financial statements. We evaluate these estimates on an ongoing basis, utilizing historical experience, consultation with experts and other methods considered reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Certain accounting policies are of more significance in our financial statement preparation process than others, and set out below are the principal accounting policies we apply in the preparation of our consolidated financial statements.

Cash Equivalents and Restricted Cash

We define cash equivalents as all highly liquid short-term investments with original maturities of three months or less. Restricted cash of approximately $0.5 million as of both December 31, 2018 and 2017, is included in “Other current assets” on our accompanying consolidated balance sheets.

Accounts Receivable

We establish provisions for losses on accounts receivable due from customers if it is determined that all or part of the outstanding balance is probable of not being collected. We review collectability regularly and establish an allowance or record adjustments as necessary using the specific identification method. We had no allowance for doubtful accounts as of December 31, 2018 and 2017.

Inventories

Our inventories, which consist of materials and supplies, are valued at weighted-average cost, and we periodically review for physical deterioration and obsolescence.

Property, Plant and Equipment, net

We record property, plant and equipment at historical cost. We capitalize expenditures for construction, expansion, major renewals and betterments. We expense maintenance and repair costs as incurred. We capitalize expenditures for project development if they are expected to have future benefit. We capitalize Interest Incurred During Construction (“IDC”) for our assets.

Our assets require the use of management estimates of the useful lives of assets. Our Terminal business segment assets are depreciated on a straight-line basis over their estimated useful lives. For Cochin we apply a composite depreciation rate to the total cost of the composite group until the net book value equals the salvage value. In applying the composite method, we generally charge the original cost of property sold or retired to accumulated depreciation and amortization, plus cost of removal and less salvage value.

Asset Retirement Obligations ("ARO")

We record liabilities for obligations related to the retirement and removal of long-lived assets used in our businesses. We record, as liabilities, the fair value of asset retirement obligations on a discounted basis when they are incurred and can be reasonably estimated, which is typically at the time the assets are installed or acquired. Amounts recorded for the related assets are increased by the amount of these obligations. Over time, the liabilities increase due to the change in their present value, and the initial capitalized costs are depreciated over the useful lives of the related assets. The liabilities are eventually extinguished when the asset is taken out of service.

Due to the lack of information that can be derived from past experience or industry practice, the timing and fair value of future removal and site restoration costs for our assets is not currently determinable. We have not recognized an ARO in these consolidated financial statements. Also, see Note 7 regarding the Cochin Pipeline Reclamation Trust Securities.

Long-lived Asset Impairments

We evaluate long-lived assets and investments for impairment whenever events or changes in circumstances indicate that our carrying amount of an asset or investment may not be recoverable. We recognize impairment losses when estimated future cash flows expected to result from our use of the asset and its eventual disposition is less than its carrying amount.

To the extent triggering events exist, we complete a review of the carrying value of our long-lived assets, including property, plant and equipment as well as other intangibles, and record, as applicable, the appropriate impairments. Because the impairment test for long-lived assets held in use is based on undiscounted cash flows, there may be instances where an asset or asset group is not considered impaired, even when its fair value may be less than its carrying value, because the asset or asset group is recoverable based on the cash flows to be generated over the estimated life of the asset or asset group. Our fair value estimates are generally based on assumptions market participants would use, including market data obtained through the sale process or an analysis of expected discounted future cash flows. We did not record any impairments to long-lived assets in the years ended December 31, 2018, 2017 and 2016.

Jointly controlled operations

Jointly controlled operations are assets over which we have joint ownership with unaffiliated entities and are not held in a partnership, corporation or other legal entity. We have three joint ventures that undertake terminaling activities through jointly controlled operations. We account for jointly controlled operations using the proportionate consolidation method for which (i) our consolidated balance sheets include our share of the assets that we control jointly with third parties and the liabilities for which we are jointly responsible and (ii) our consolidated statements of income include our share of the income and expenses generated by the jointly controlled operations.

Revenue Recognition

Adoption of Topic 606

Effective January 1, 2018, we adopted ASU No. 2014-09, "*Revenue from Contracts with Customers*" and the series of related accounting standard updates that followed (collectively referred to as "Topic 606"). We utilized the modified retrospective method to adopt Topic 606, which required us to apply the new revenue standard to (i) all new revenue contracts entered into after January 1, 2018, and (ii) revenue contracts that were not completed as of January 1, 2018. In accordance with this approach, our consolidated revenues for periods prior to January 1, 2018 were not revised. The cumulative effect of the adoption of Topic 606 as of January 1, 2018 and the impact to the financial statement line items for the current year was not material.

Revenue from Contracts with Customers

Beginning in 2018, we account for revenue from contracts with customers in accordance with Topic 606. The unit of account in Topic 606 is a performance obligation, which is a promise in a contract to transfer to a customer either a distinct good or service (or bundle of goods or services) or a series of distinct goods or services provided over a period of time. Topic 606 requires that a contract's transaction price, which is the amount of consideration to which an entity expects to be entitled in exchange for transferring promised goods or services to a customer, is to be allocated to each performance obligation in the contract based on relative standalone selling prices and recognized as revenue when (point in time) or as (over time) control of the goods or services transfers to the customer and the performance obligation is satisfied.

Our customer service contracts primarily include terminaling service and transportation service contracts, as described below. Generally, for the majority of these contracts: (i) our promise is to transfer (or stand ready to transfer) a series of distinct integrated services over a period of time, which is a single performance obligation; (ii) the transaction price includes fixed and/or variable consideration, which amount is determinable at contract inception and/or at each month end based on our right to invoice at month end for the value of services provided to the customer that month; and (iii) the transaction price is recognized as revenue over the service period specified in the contract (which can be a day, including each day in a series of promised daily services, a month, a year, or other time increment, including a deficiency makeup period) as the services are rendered using a time-based (passage of time) or units-based (units of service transferred) output method for measuring the transfer of control of the services and satisfaction of our performance obligation over the service period, based on the nature of the promised service (e.g., firm or non-firm) and the terms and conditions of the contract (e.g., contracts with or without makeup rights).

Firm Services

Firm services (also called uninterruptible services) are services that are promised to be available to the customer at all times during the period(s) covered by the contract, with limited exceptions. Our firm service contracts are typically structured with take-or-pay or minimum volume provisions, which specify minimum service quantities a customer will pay for even if it chooses not to receive or use them in the specified service period (referred to as "deficiency quantities"). We typically recognize the portion of the transaction price associated with such provisions, including any deficiency quantities, as revenue depending on whether the contract prohibits the customer from making up deficiency quantities in subsequent periods, or the contract permits this practice, as follows:

- Contracts without Makeup Rights: If contractually the customer cannot make up deficiency quantities in future periods, our performance obligation is satisfied, and revenue associated with any deficiency quantities is generally recognized as each service period expires. Because a service period may exceed a reporting period, we determine at inception of the contract and at the beginning of each subsequent reporting period if we expect the customer to take the minimum volume associated with the service period. If we expect the customer to make up all deficiencies in the specified service period (i.e., we expect the customer to take the minimum service quantities), the minimum volume provision is deemed not substantive and we will recognize the transaction price as revenue in the specified service period as the promised units of services are transferred to the customer. Alternatively, if we expect that there will be any deficiency quantities that the customer cannot or will not make up in the specified service period (referred to as "breakage"), we will recognize the estimated breakage amount (subject to the constraint on variable consideration) as revenue ratably over such service period in proportion to the revenue that we will recognize for actual units of service transferred to the customer in the service period. For certain take-or-pay contracts where we make the service, or a part of the service, continuously available over the service period, we typically recognize the take-or-pay amount as revenue ratably over such period based on the passage of time.

- Contracts with Makeup Rights: If contractually the customer can acquire the promised service in a future period and make up the deficiency quantities in such future period (the "deficiency makeup period"), we have a performance obligation to deliver those services at the customer's request (subject to contractual and/or capacity constraints) in the deficiency makeup period. At inception of the contract, and at the beginning of each subsequent reporting period, we estimate if we expect that there will be deficiency quantities that the customer will or will not make up. If we expect the customer will make up all deficiencies it is contractually entitled to, any non-refundable consideration received relating to temporary deficiencies that will be made up in the deficiency makeup period will be deferred as a contract liability, and we will recognize that amount as revenue in the deficiency makeup period when either of the following occurs: (i) the customer makes up the volumes; or (ii) the likelihood that the customer will exercise its right for deficiency volumes then becomes remote (e.g., there is insufficient capacity to make up the volumes, the deficiency makeup period expires). Alternatively, if we expect at inception of the contract, or at the beginning of any subsequent reporting period, that there will be any deficiency quantities that the customer cannot or will not make up (i.e., breakage), we will recognize the estimated breakage amount (subject to the constraint on variable consideration) as revenue ratably over the specified service periods in proportion to the revenue that we will recognize for actual units of service transferred to the customer in those service periods.

Non-Firm Services

Non-firm services (also called interruptible services) are the opposite of firm services in that such services are provided to a customer on an "as available" basis. Generally, we do not have an obligation to perform these services until we accept a customer's periodic request for service. For the majority of our non-firm service contracts, the customer will pay only for the actual quantities of services it chooses to receive or use, and we typically recognize the transaction price as revenue as those units of service are transferred to the customer in the specified service period (typically a daily or monthly period).

Revenue Recognition Policy prior to January 1, 2018

We recognized revenue as services were rendered or goods were delivered and, if applicable, risk of loss had passed.

We recognized transportation revenues when our customers' products were delivered and services had been provided and adjusted according to terms prescribed by the relevant toll settlements with shippers as approved by the regulator. To the extent a customer did not meet its minimum volume commitment, we generally recognized revenue when we had no further performance obligation at the contractual rate applicable to such committed volumes. If such minimum volume commitments contained make up rights, we deferred revenue until the expiration of the make-up right or when our obligation to the customer had otherwise ceased. We recognized differences between transportation revenue and actual toll receipts as regulatory assets or liabilities which were settled through future tolls.

We generally recognized bulk terminal transfer service revenues based on volumes handled. Liquids terminal warehousing revenue was generally recognized ratably over the contract period. We generally recognized liquids terminal throughput revenue based on volumes received and volumes delivered. We generally deferred revenue within the Terminals business segment related to capital improvements paid for in advance by certain customers, which we then amortized over the initial term of the related customer contracts.

Environmental Matters

We capitalize or expense, as appropriate, environmental expenditures. We capitalize certain environmental expenditures required in obtaining rights-of-way, regulatory approvals or permitting as part of construction. We accrue and expense environmental costs that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation. We generally do not discount environmental liabilities to a net present value, and we record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, our recording of these accruals coincides with completion of a feasibility study or our commitment to a formal plan of action. We recognize receivables for anticipated associated insurance recoveries when such recoveries are deemed to be probable. We record at estimated fair value, where appropriate, environmental liabilities assumed in a business combination.

We routinely conduct reviews of potential environmental issues and claims that could impact our assets or operations. These reviews assist us in identifying environmental issues and estimating the costs and timing of remediation efforts. We also routinely adjust our environmental liabilities to reflect changes in previous estimates. In making environmental liability estimations, we consider the material effect of environmental compliance, pending legal actions against us, and potential third-party liability claims. Often, as the remediation evaluation and effort progresses, additional information is

obtained, requiring revisions to estimated costs. These revisions are reflected in income in the period in which they are reasonably determinable. As of December 31, 2018, we had $0.1 million accrued for our outstanding environmental matters and no accrual at December 31, 2017.

Pension and Other Postretirement Benefits

We recognize the differences between the fair value of each of our pension and other postretirement benefit plans' assets and the benefit obligations as either assets or liabilities on our consolidated balance sheet. We record deferred plan costs and income—unrecognized losses and gains, unrecognized prior service costs and credits, and any remaining unamortized transition obligations—in "Accumulated other comprehensive loss," with the proportionate share associated with less than wholly owned subsidiaries allocated and included within "Kinder Morgan interest" or as a regulatory asset or liability for certain of our regulated operations, until they are amortized as a component of benefit expense. See Note 11 for additional information regarding our other postretirement benefit plans.

Kinder Morgan Interest

Kinder Morgan Interest represents the interest in our consolidated subsidiaries that are not owned by us. In our accompanying consolidated income statements, the Kinder Morgan Interest in the net income of our consolidated subsidiaries is shown as an allocation of our consolidated net income and is presented separately as "Net Income Attributable to Kinder Morgan Interest." In our accompanying consolidated balance sheets, the Kinder Morgan interest is presented separately as "Kinder Morgan interest" within "Equity."

Income Taxes

We record income tax expense based on an estimate of the effective tax rate in effect or to be in effect during the relevant periods. We include changes in tax legislation in the relevant computations in the period in which such changes are enacted. We do business in a number of provinces with differing laws concerning how income subject to each province's tax regime is measured and at what effective rate such income is taxed, requiring us to estimate how our income will be apportioned among the various provinces in order to arrive at an overall effective tax rate. Changes in our effective rate, including any effect on previously recorded deferred taxes, are recorded in the period in which the need for such change is identified.

Deferred income tax assets and liabilities are recognized for temporary differences between the basis of assets and liabilities for financial reporting and tax purposes. Deferred tax assets are reduced by a valuation allowance for the amount that is, more likely than not, to not be realized. While we have considered estimated future taxable income and prudent and feasible tax planning strategies in determining the amount of our valuation allowance, any change in the amount that we expect to ultimately realize will be included in income in the period in which such a determination is reached.

Foreign Currency

Transactions in foreign currencies are initially recorded at the exchange rate in effect at the time of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars using the closing exchange rate at the balance sheet date. The resulting exchange rate differences are included in the consolidated statements of income.

3. Trans Mountain Transaction

On August 31, 2018, we closed on the sale of the Trans Mountain Asset Group, which were indirectly acquired by the Government of Canada, through Trans Mountain Corporation (a subsidiary of the Canada Development Investment Corporation) for cash consideration of approximately $4.43 billion, which is the contractual purchase price of $4.5 billion net of a preliminary working capital adjustment (the "Trans Mountain Transaction"). As of December 31, 2018, we accrued for an additional $37.0 million for a final working capital adjustment that was subsequently settled in cash. The August 31, 2018 Trans Mountain Asset Group balance sheet included $502.4 million of cash and cash equivalents, along with $559.8 million of debt and $26.2 million of accumulated other comprehensive loss (which was realized as other comprehensive income, net, in our consolidated statement of comprehensive income for the year ended December 31, 2018).

Pursuant to our voting shareholders' approval on November 29, 2018, a distribution of approximately $1.2 billion were made as a return of capital to holders of our Restricted Voting Shares ($11.40 per Restricted Voting Share) and approximately $2.8 billion to KMI as the indirect holder of our Special Voting Shares on January 3, 2019 (the "Return of Capital"). To facilitate the Return of Capital and provide flexibility for dividends going forward, our voting shareholders also

approved (i) the reduction of the stated capital of our Restricted Voting Shares by $1.45 billion (the "Stated Capital Reduction") (ii) a "reverse stock split" of our Restricted Voting Shares and Special Voting Shares on a one-for-three basis (three shares consolidating to one share) (the "Share Consolidation"), which was effected on January 4, 2019. In accordance with U.S. GAAP, the Restricted Voting Shares and Special Voting Shares outstanding and earnings per share information in this report reflect the Share Consolidation for all periods presented unless otherwise noted.

We have recorded a Gain on sale of the Trans Mountain Asset Group, net of tax of $1,278.4 million as presented in the accompanying consolidated statement of income for year ended December 31, 2018. The gain included a tax benefit of approximately $81.4 million comprised of the release of deferred income taxes of approximately $389.0 million, which was partially offset by an adjustment to accrued taxes of approximately $307.6 million on the accompanying consolidated balance sheet as of December 31, 2018.

The underlying assets in the Trans Mountain Asset Group were primarily within our Pipelines business segment and the operating results for the Trans Mountain Asset Group are included in Income from operations of the Trans Mountain Asset Group, net of tax in the accompanying consolidated statements of income for the years ended December 31, 2018, 2017 and 2016. Major income and expense line items associated with the Trans Mountain Asset Group that have been presented within the caption Discontinued Operations in the accompanying consolidated statements of income were as follows:

Year Ended December 31,	**2018(a)**	**2017**	**2016**
(In millions of Canadian dollars)			
Revenues	214.3	324.9	328.3
Depreciation and amortization	(46.8)	(70.7)	(73.0)
Operating expenses, including general and administrative	(89.8)	(122.0)	(115.5)
Interest and other income (expense)(b)	(22.4)	21.4	24.5
Income from operations of the Trans Mountain Asset Group before income taxes	55.3	153.6	164.3
Gain on sale of the Trans Mountain Asset Group before income taxes	1,197.0	—	—
Income from Discontinued Operations before income taxes	1,252.3	153.6	164.3
Income tax benefit (expense)	65.9	(43.4)	(32.9)
Income from Discontinued Operations, Net of Tax	1,318.2	110.2	131.4

The Trans Mountain Asset Group's carrying value of assets and liabilities have been presented as held for sale in the accompanying consolidated balance sheet as of December 31, 2017 and include:

December 31,	**2017**
(In millions of Canadian dollars)	
Cash and cash equivalents	128.1
Accounts receivable	46.0
Other current assets	18.6
Property, plant and equipment, net	2,719.6
Goodwill(c)	248.0
Non-current regulatory assets	29.1
Other non-current assets	53.7
Total assets of the Trans Mountain Asset Group	3,243.1
Credit Facility	—
Accounts payable	97.6
Current regulatory liabilities	103.1
Other current liabilities	6.6
Pension and postretirement benefits	75.4
Other non-current liabilities	38.1
Total liabilities of the Trans Mountain Asset Group	320.8

Our net cash flows from operating and investing activities from the Trans Mountain Asset Group included in the accompanying consolidated statements of cash flows were as follows:

Year Ended December 31,	2018(a)	2017	2016
(Net cash provided by (used in) in millions of Canadian dollars)			
Operating activities	182.3	58.1	25.5
Investing activities	(507.3)	(462.6)	(190.3)

a. Amounts are for the period January 1, 2018 to August 31, 2018, the closing of the Trans Mountain Transaction.
b. 2018 includes approximately $60.5 million pre-tax write off of deferred financing costs, see Note 10. 2017 and 2016 amounts also include interest expenses from our credit facilities and KMI Loans that were allocated to discontinued operations for borrowings that were directly related to the Trans Mountain Asset Group.
c. Goodwill was evaluated for impairment on May 31 of each year and no impairments were recorded in 2018, 2017 and 2016.

Also, see Note 10 for information on our 4-year, $500.0 million unsecured revolving credit facility.

4. Income Taxes

Income from continuing operations before income taxes for years ended December 31, 2018, 2017, and 2016 were $137.8 million, $71.3 million, and $93.8 million, respectively.

Components of our income tax provision are as follows:

Year Ended December 31,	2018	2017	2016
(In millions of Canadian dollars)			
Current tax expense (benefit)	43.1	6.8	0.4
Deferred tax expense	(5.3)	14.0	23.0
Total tax provision	37.8	20.8	23.4

The difference between the statutory income tax rate and our effective income tax rate is summarized as follows:

Year Ended December 31,	2018		2017		2016	
(In millions of Canadian dollars, except percentages)						
Statutory income tax	37.2	27.0 %	19.2	27.0 %	25.3	27.0 %
Increase (decrease) as a result of:						
Capital gains deduction	—	— %	—	— %	(2.0)	(2.1)%
Valuation allowance	(0.2)	(0.1)%	—	— %	(2.0)	(2.1)%
Tax impact on the future tax rate change	—	— %	0.8	1.1 %	1.9	2.0 %
Inter-corporate charges not tax deducted	2.4	1.7 %	2.2	3.1 %	(0.3)	(0.3)%
Other	(1.6)	(1.2)%	(1.4)	(2.0)%	0.5	0.5 %
Total	37.8	27.4 %	20.8	29.2 %	23.4	25.0 %

Deferred tax assets and liabilities result from the following:

December 31,	2018	2017
(In millions of Canadian dollars)		
Deferred tax assets		
Non capital losses	0.1	—
Reserves	35.8	43.0
Capital losses	0.2	27.2
Investment in partnerships	144.4	117.4
Valuation allowances	(144.6)	(144.5)
Total deferred tax assets	35.9	43.1
Deferred tax liabilities		
Property, plant and equipment	(36.0)	(392.0)
Total deferred tax liabilities	(36.0)	(392.0)
Net non-current deferred tax liability	(0.1)	(348.9)

Deferred Tax Assets and Valuation Allowances: We have deferred tax assets of $0.1 million related to non-capital loss carryovers, $0.2 million capital loss carryovers and $0.2 million of valuation allowances related to these deferred tax assets as of December 31, 2018. As of December 31, 2017, we had deferred tax assets of $27.2 million for capital loss carryovers and $27.1 million of valuation allowances related to these deferred tax assets.

Expiration Periods for Deferred Tax Assets: As of December 31, 2018, we have non-capital loss carryforwards of $0.3 million which will expire in 2038 and capital loss carryforwards of $1.8 million which can be carried forward indefinitely.

Unrecognized Tax Benefits: We had no unrecognized tax benefits as of December 31, 2018 and 2017.

As a result of our IPO and subsequent revaluation (or rebalancing) of our investment in the Limited Partnership, our tax basis exceeds our accounting basis in our investment in the Limited Partnership by approximately $1.1 billion. This excess tax basis results in a deferred tax asset of approximately $144.4 million. A full valuation allowance was recorded against this deferred tax asset as we determined it was more likely than not to not be realized.

Income Tax Expense on Discontinued Operations: Income tax expense in respect of our Discontinued Operations, includes income tax expense on the Trans Mountain Asset Group earnings for the periods presented until August 31, 2018, and the Trans Mountain Transaction gain. As of December 31, 2018 and 2017, our effective tax rate on income from Discontinued Operations was (5.2)%, and 28.3%, respectively. The 2018 effective tax rate on our income from Discontinued Operations is lower than the statutory federal and provincial rate due to the taxable gain being eligible for a 50.0% capital gains deduction along with the release of the non-cash deferred tax liabilities attributable to the Trans Mountain Asset Group.

5. Other Current Assets

December 31,	2018	2017
(In millions of Canadian dollars)		
Prepaid expenses and deposits	3.5	3.9
Contract Asset(Note 18)	1.6	2.1
Restricted cash(a)	0.5	0.5
Other current deferred assets	0.3	0.1
	5.9	6.6

a. Represents restricted cash in the Trusts that is to be used solely for the purposes of satisfying NEB's Land Matters Consultation Initiative ("LMCI") liabilities. Also, see Note 7.

6. Property, Plant and Equipment, net

Classes and Depreciation

As of December 31, 2018 and 2017, our property, plant and equipment, net consisted of the following:

December 31,	2018	2017	Useful Life in Years(a)
(In millions of Canadian dollars, except years)			
Tanks and Station equipment (primarily storage of crude oil and other refined products)	1,040.9	703.4	5-40
Pipelines (primarily transportation of crude oil and other refined products)	143.7	151.9	30-64
Other(b)	195.4	173.5	5-35
Accumulated depreciation and amortization	(413.1)	(330.7)	
	966.9	698.1	
Land	0.3	0.1	
Construction work in process	14.1	290.2	
Property, plant and equipment, net	981.3	988.4	

a. For Cochin, the composite depreciation rate is included in the equivalent number of years for Pipelines.
b. Includes vehicles, docks, shiploaders, rail and other.

Depreciation and amortization expense charged against property, plant and equipment was $82.6 million, $71.7 million, and $64.2 million for the years ended December 31, 2018, 2017, and 2016, respectively.

7. Deferred Charges and Other Assets

December 31,	2018	2017
(In millions of Canadian dollars)		
Cochin Pipeline Reclamation Trust Securities(a)	6.1	4.3
Unamortized debt issue costs	0.6	67.2
Other	3.9	1.8
	10.6	73.3

a. Represents restricted investments in Canadian government bonds. Restricted long-term investments by the Cochin Pipeline Reclamation Trust (the "Trust") are to be used solely for the purposes of satisfying LMCI liabilities as further described in Note 20. We have related LMCI short-term and long-term obligations of an amount approximately equal to our restricted cash and restricted investments recorded in Other current liabilities and Other deferred credits, respectively, on our accompanying consolidated balance sheets. The restricted assets are measured at fair value with offsetting adjustments recorded to the LMCI liabilities. Fair values for the restricted asset investments were determined based on observable prices and inputs for similar instruments available in the market, utilizing widely accepted cash flow models to value such instruments. Such techniques represent a Level 2 fair value measurement, see Note 17.

8. Accounts Payable

December 31,	2018	2017
(In millions of Canadian dollars)		
Accounts payable-trade	25.0	19.7
Property, plant and equipment accrued liabilities	24.4	34.8
	49.4	54.5

9. Other Current Liabilities

December 31,	2018	2017
(In millions of Canadian dollars)		
Contract liabilities(Note 18)	12.8	14.7
Trust liability(Note 7)	0.4	4.8
Environmental capital recovery surcharge	4.1	3.8
Employee compensation	4.8	1.1
Final working capital adjustment for Trans Mountain Transaction	37.0	—
Other	4.1	3.4
	63.2	27.8

10. Debt

Credit Facilities

In conjunction with the announcement of the Trans Mountain Transaction described in Note 3, on May 30, 2018 and concurrently with the termination of our June 16, 2017 revolving credit facility ("2017 Credit Facility"), we established a $500.0 million revolving credit facility (the "Temporary Credit Facility"), for general corporate purposes, including working capital during the period from June 1, 2018 through the closing of the Trans Mountain Transaction. The approximate $100.0 million of borrowings outstanding under the terminated 2017 Credit Facility were repaid pursuant to an initial drawdown under the Temporary Credit Facility and approximately $60.5 million of deferred costs associated with the 2017 Credit Facility that were being amortized as interest expense over its term were written off.

On June 14, 2018, our former subsidiary, Trans Mountain, as the borrower, entered into a non-revolving, unsecured construction credit agreement (the "Trans Mountain Non-recourse Credit Agreement") in an aggregate principal amount of up to approximately $1.0 billion to facilitate the resumption of the TMEP planning and construction work until the close of the Transaction. The $559.8 million of outstanding borrowings under the Trans Mountain Non-recourse Credit Agreement were included in the Trans Mountain Asset Group's assets and liabilities as part of the Trans Mountain Transaction.

Upon the closing of the Trans Mountain Transaction on August 31, 2018, the Temporary Credit Facility was replaced with a new 4-year, $500.0 million unsecured revolving credit facility ("2018 Credit Facility") for working capital purposes under a credit agreement with the Royal Bank of Canada, as agent (the "Credit Agreement"). In addition, the $132.6 million of outstanding borrowings under the Temporary Credit Facility were paid off prior to its termination with a portion of the proceeds from the Trans Mountain Transaction.

Depending on the type of loan requested, interest on loans outstanding will be calculated based on: (i) a Canadian prime rate of interest; (ii) a U.S. base rate; (iii) LIBOR; or (iv) bankers' acceptance fees, plus (A) in the case of Canadian prime rate or U.S. base rate loans, an applicable margin of up to 1.25% per annum; or (B) in the case of LIBOR loans or banker's acceptances, an applicable margin ranging from 1.00% to 2.25% per annum, with such margin determined by our then applicable debt credit rating. Standby fees for the unused portion of the 2018 Credit Facility will be calculated at a rate ranging from 0.20% to 0.45% per annum based upon our then applicable debt credit rating.

The Credit Agreement contains various financial and other covenants that apply to KMCU and its subsidiaries and that are common in such agreements, including a maximum ratio of consolidated total funded debt to consolidated earnings before interest, income taxes, D&A, and non-cash adjustments as defined in the Credit Agreement, of 5.00:1.00 and restrictions on KMCU's ability to incur debt, grant liens, make dispositions, engage in transactions with affiliates, make restricted payments(including distributions), amend our organizational documents and engage in corporate reorganization transactions.

In addition, the Credit Agreement contains customary events of default, including non-payment; non-compliance with covenants (in some cases, subject to grace periods); payment default under, or acceleration events affecting, certain other indebtedness; bankruptcy or insolvency events involving KMCU or certain of its subsidiaries; and changes of control. If an event of default under the Credit Agreement exists and is continuing, the lenders could terminate their commitments and accelerate the maturity of our outstanding obligations under the Credit Agreement.

As of December 31, 2018, we had no outstanding borrowings under our 2018 Credit Facility, and had $489.0 million available under the 2018 Credit Facility, after reducing the $500.0 million capacity for $11.0 million in letters of credit. Of the

total $11.0 million of letters of credit issued, approximately $7.9 million are issued on behalf of Trans Mountain for which it has issued a backstop letter of credit to us. As of December 31, 2018, we were in compliance with all required covenants. As of December 31, 2017, we had no borrowings outstanding under our 2017 Credit Facility. For the years ended December 31, 2018 and 2017, we incurred $1.1 million and $0.7 million, respectively, in standby fees.

11. Share-based Compensation and Benefit Plans

Share-based Compensation

Restricted Share Unit Plan for Non-Employee Directors

We have adopted the Restricted Share Unit Plan for Non-Employee Directors, in which our eligible non-employee directors participate. The plan recognizes that the compensation paid to each eligible non-employee director is fixed by our board of directors, generally annually, and that the compensation is payable in cash. Pursuant to the plan, in lieu of receiving some or all of the cash compensation, each eligible non-employee director may elect to receive RSUs. Each election will be generally at or around the first board of directors meeting in January of each calendar year and will be effective for the entire calendar year. An eligible director may make a new election each calendar year. The total number of Restricted Voting Shares authorized under the plan is 156,140, after giving effect to the Return of Capital and Share Consolidation in accordance with board of directors approval and guidelines within the RSU plan.

During 2018 and 2017, we issued RSUs to our non-employee directors of 20,000 and 11,580, respectively (number of shares issued is before our January 4, 2019 Share Consolidation). These RSUs were valued at the time of issuance at $0.4 million and $0.2 million, respectively.

Restricted Share Unit Plan for Employees

We have adopted the Restricted Share Unit Plan for Employees (the "RSU Plan") for our eligible employees. The RSU Plan provides that the number of Restricted Voting Shares that may be issued or issuable by the Company pursuant to RSU awards shall not exceed 1,345,093, after giving effect to the Return of Capital and Share Consolidation in accordance with board of directors approval and guidelines within the RSU plan. The purpose of the RSU Plan is to provide incentive to our employees for our future endeavors, to advance our and our shareholders' interests and to enable us to compete effectively for the services of employees. The RSU Plan is administered by our board of directors, which will have authority to construe and interpret the RSU Plan, including any questions in respect of any RSU awards granted thereunder.

The following table sets forth a summary of activity and related balances of our RSU awards, excluding those issued to our non-employee directors:

(Per share amount in Canadian dollars)	Year Ended December 31, 2018		May 30, 2017 to December 31, 2017	
	Shares	Weighted Average Grant Date Fair Value per share	Shares	Weighted Average Grant Date Fair Value per share
Outstanding at beginning of period	781,307	15.99	—	—
Granted	85,104	16.63	784,621	15.99
Vested(a)	(703,505)	15.99	—	—
Forfeited	(8,771)	16.19	(3,314)	15.99
Outstanding prior to Return of Capital and Share Consolidation	154,135	16.33	781,307	15.99
Effect of Return of Capital and Share Consolidation	25,167	16.33	—	—
Outstanding at end of period	179,302	16.33	781,307	15.99

a. RSU awards vested upon August 31, 2018 closing of the Trans Mountain Transaction.

RSU awards under the RSU Plan have vesting periods that may range from one-year with variable to three years. Following is a summary of the future vesting of our outstanding RSUs under the RSU Plan:

For the Year Ended December 31, 2018	
2019	—
2020	83,444
2021	95,858
Total Outstanding	179,302

The compensation costs related to our RSU awards is generally recognized ratably over the vesting period of the RSU awards. Upon vesting, the grants will be paid in our split-adjusted Restricted Voting Shares.

During the year ended December 31, 2018 and 2017, we recognized $7.9 million, which included $6.5 million of expense related to the Trans Mountain Transaction, and $0.7 million, respectively, of expense related to the RSU Plan, and we capitalized $2.1 million and $1.4 million, respectively, related to the RSU Plan. At December 31, 2018, unrecognized compensation costs associated with the RSU awards was approximately $3.5 million with a weighted average remaining amortization period of 2.1 years.

Benefit Plans

The benefit plans that were provided to our employees prior to the closing of the Trans Mountain Transaction were included in the assets and liabilities held for sale, and we no longer have any obligations for those benefit plans. For our remaining employees, new pension and other postretirement benefit ("OPEB") plans became effective after the closing of the Trans Mountain Transaction that provide value similar to the prior benefit plans. Our pension benefits provided prior to the close of the Trans Mountain Transaction were under a defined benefit pension formula and are now provided under a registered defined contribution pension plan ("DCPP") and a supplemental unfunded arrangement ("SPP") which provides pension benefits in excess of Income Tax Act limits. Our new OPEB plan benefits are relatively consistent with the prior OPEB plan. As a result of the Trans Mountain Transaction, we released $36.3 million of benefit plan losses.

Pension benefits

Our pension benefits cover eligible employees and are provided under the DCPP and SPP. We contribute a percentage of eligible compensation based on a combination of age and years of service. The total cost for our DCPP was approximately $0.5 million for the period from September 1, 2018 to December 31, 2018.

The SPP benefits are unfunded and annual expense is recorded on an accrual basis based on an independent actuarial determination. No employees have accrued a benefit under the SPP as of December 31, 2018; therefore, no information on the SPP is provided in the tables below.

Other postretirement benefits

Our OPEB plan benefits are provided to eligible current and future retirees and their spouses in the form of a healthcare spending account. Postretirement benefits are unfunded and annual expense is recorded on an accrual basis based on independent actuarial determination. The most recent actuarial valuation for accounting purposes was completed as of December 31, 2018.

Benefit Obligation, Plan Assets and Funded Status

The following table provides information about our OPEB plan.

For the Periods Ended December 31, 2018	
(In millions of Canadian dollars)	
Change in benefit obligation	
Benefit obligation at September 1, 2018	1.8
Service cost	0.1
Interest cost	—
Actuarial loss (gain)	(0.1)
Benefits paid	—
Benefit obligation at December 31, 2018	1.8
Presented as follows:	
Current benefit liability(a)	—
Non-current benefit liability(b)	(1.8)
	(1.8)

a. Amount included in Other current liabilities on our consolidated balance sheets.
b. Amount included in Other deferred credits on our consolidated balance sheets as of December 31, 2018.

Components of Accumulated Other Comprehensive Loss

We include the amounts of pre-tax accumulated other comprehensive loss related to the OPEB plans on our accompanying balance sheets. These balances exclude amounts recoverable through tolls and are immaterial.

Actuarial gains and losses deferred in accumulated other comprehensive loss are amortized into income over the period of expected future service of active participants.

Expected Payment of Future Benefits and Employer Contributions

Following are the expected future benefit payments as of December 31, 2018:

For the Year Ended December 31,	
(In millions of Canadian dollars)	
2019	—
2020	—
2021	—
2022	—
2023	0.1
2024-2028	0.4

In 2019, we expect the contribution to our OPEB plan to be inconsequential.

Actuarial Assumptions and Sensitivity Analysis

Benefit obligations and net benefit cost are based on actuarial estimates and assumptions. The following table details the weighted-average actuarial assumptions used in determining the benefit obligation and net benefit costs of our OPEB plan:

For the Year Ended December 31,	2018
Assumptions related to benefit obligations:	
Discount rate	3.91%
Assumptions related to benefit costs:	
Discount rate for benefit obligations	3.76%
Discount rate for interest on benefit obligations	3.67%
Discount rate for service cost	3.78%
Discount rate for interest on service cost	3.74%

12. Other Deferred Credits

December 31,	2018	2017
(In millions of Canadian dollars)		
Trust liability(Note 7)	6.1	
Postretirement benefit liability	1.8	—
Environmental liabilities	0.1	—
Other	0.9	0.8
	8.9	0.8

13. Equity

We are authorized to issue an unlimited number of Restricted Voting Shares, an unlimited number of Special Voting Shares and an unlimited number of preferred shares issuable in series. As of December 31, 2018, we had (i) 34.9 million and 81.4 million of split-adjusted Restricted Voting Shares and Special Voting Shares outstanding, respectively, with no par value, for an aggregate of 116.3 million voting shares outstanding, (ii) 12.0 million and 10.0 million of Series 1 Preferred Shares and Series 3 Preferred Shares outstanding, respectively, and (iii) 0.2 million of restricted stock awards outstanding.

Return of Capital, Stated Capital Reduction and Share Consolidation

Pursuant to our Voting Shareholders' approval on November 29, 2018, Return of Capital disbursements of approximately $1.2 billion were made to holders of our Restricted Voting Shares ($11.40 per Restricted Voting Share) and approximately $2.8 billion to KMI as the indirect holder of our Special Voting Shares on January 3, 2019. To facilitate the Return of Capital distributions and provide flexibility for dividends going forward, our Voting Shareholders also approved (i) a Stated Capital Reduction to our stated Restricted Voting Share capital by $1.45 billion and (ii) a Share Consolidation, a "reverse stock split" of our Restricted Voting Shares and Special Voting Shares on a one-for-three basis (one-for-three basis, three shares consolidating to one), which was effected on January 4, 2019.

Preferred Share Dividends

On August 15, 2017, we completed an offering of 12.0 million Series 1 Preferred Shares on the TSX at a price to the public of $25.00 per Series 1 Preferred Share for total gross proceeds of $300.0 million. The net proceeds of $292.9 million from the offering were used to indirectly subscribe for preferred units in the Limited Partnership, which in turn were used by the Limited Partnership to repay indebtedness outstanding under our revolving credit facility and for general corporate purposes. We have the option to redeem the Series 1 Preferred Shares on November 15, 2022 and on November 15 in every fifth year thereafter by payment of $25.00 per Series 1 Preferred Share plus all accrued and unpaid dividends. The holders of the Series 1 Preferred Shares will have the right to convert all or any of their Series 1 Preferred Shares into cumulative redeemable floating rate Preferred Shares, Series 2 (Series 2 Preferred Shares), subject to certain conditions, on November 15, 2022 and on November 15 in every fifth year thereafter. The Series 1 Preferred Shares and the Series 2 Preferred Shares are series of shares in the same class. The conversion right entitles holders to elect periodically which of the two series they wish to hold and does not entitle holders to receive a different class or type of security.

In the event of our liquidation, the holders of Series 1 Preferred Shares shall be entitled to receive $25.00 per Series 1 Preferred Share plus all accrued and unpaid dividends thereon before any amount shall be paid or any property or assets of the Company shall be distributed to the holders of the Restricted Voting Shares, Special Voting Shares and holders of any other shares ranking junior to the Series 1 Preferred Shares.

Dividends on the Series 1 Preferred Shares are fixed, cumulative, preferential and $1.3125 per share annually, payable quarterly on the 15th day of February, May, August and November, as and when declared by our board of directors, for the initial fixed rate period to but excluding November 15, 2022.

On December 15, 2017, we completed an offering of 10.0 million Series 3 Preferred Shares on the TSX at a price to the public of $25.00 per Series 3 Preferred Share for total gross proceeds of $250.0 million. The net proceeds of $243.2 million (net of fees paid and accrued) from the offering were used to indirectly subscribe for preferred units in the Limited Partnership, which in turn were used by the Limited Partnership to repay indebtedness outstanding under our revolving credit facility and for general corporate purposes. We have the option to redeem the Series 3 Preferred Shares on February 15, 2023 and on February 15 in every fifth year thereafter by payment of $25.00 per Series 3 Preferred Share plus all accrued and unpaid dividends. The holders of the Series 3 Preferred Shares will have the right to convert all or any of their Series 3 Preferred Shares into cumulative redeemable floating rate Preferred Shares, Series 4 (Series 4 Preferred Shares), subject to certain conditions, on February 15, 2023 and on February 15 in every fifth year thereafter. The Series 3 Preferred Shares and the Series 4 Preferred Shares are series of shares in the same class. The conversion right entitles holders to elect periodically which of the two series they wish to hold and does not entitle holders to receive a different class or type of security.

In the event of our liquidation, the holders of Series 3 Preferred Shares shall be entitled to receive $25.00 per Series 3 Preferred Share plus all accrued and unpaid dividends thereon before any amount shall be paid or any property or assets shall be distributed to the holders of the Restricted Voting Shares, Special Voting Shares and holders of any other shares ranking junior to the Series 3 Preferred Shares.

Dividends on the Series 3 Preferred Shares are fixed, cumulative, preferential and $1.3000 per share annually, payable quarterly on the 15th day of February, May, August and November, as and when declared by our board of directors, for the initial fixed rate period to but excluding February 15, 2023.

The following table provides information regarding dividends declared, or paid, as applicable, on our Preferred Shares during the year ended December 31, 2018:

Period	Total Series 1 quarterly dividend per share for the period	Total Series 3 quarterly dividend per share for the period	Date of declaration	Date of record	Date of dividend	Total amount of dividends paid in cash
(In millions of Canadian dollars, except per share amounts)						
November 15, 2017 to February 14, 2018 (a)	0.328125	0.22082	January 17, 2018	January 31, 2018	February 15, 2018	6.1
February 15, 2018 to May 14, 2018	0.328125	0.325	April 18, 2018	April 30, 2018	May 15, 2018	7.2
May 15, 2018 to August 14, 2018	0.328125	0.325	July 18, 2018	July 31, 2018	August 15, 2018	7.2
August 15, 2018 to November 14, 2018	0.328125	0.325	October 10, 2018	October 31, 2018	November 15, 2018	7.2
November 15, 2018 to February 14, 2019	0.328125	0.325	January 16, 2019	January 31, 2019	February 15, 2019	7.2

(a) Series 3 per share amount reflects that the shares were outstanding for 62 days during the period ended February 14, 2018.

Suspension of Dividend Reinvestment Plan (DRIP)

Effective January 16, 2019, our board of directors suspended our DRIP until further notice. Shareholders who were enrolled in the program will receive dividend payments in the form of cash, including dividends paid on February 15, 2019. We elected to suspend our DRIP in light of KML's reduced need for capital following the Trans Mountain Transaction. If KML elects to reinstate the DRIP in the future, shareholders who were enrolled in the DRIP at suspension and remained enrolled at reinstatement will automatically resume participation in the DRIP. Kinder Morgan’s participation in the distribution reinvestment in Class B Units of the Limited Partnership has been suspended since July 18, 2018.

Shortly after our IPO, we had implemented a DRIP pursuant to which holders (excluding holders not resident in Canada) of Restricted Voting Shares could elect to have all cash dividends of the Company payable to any such shareholder automatically reinvested in additional Restricted Voting Shares at a price per share calculated by reference to the weighted average trading price of the Restricted Voting Shares on the stock exchange on which the Restricted Voting Shares then listed for the five trading days preceding the relevant dividend payment date, less a discount of between 0% and 5% (as determined from time to time by the board of directors, in its sole discretion). Kinder Morgan had participated in a DRIP under the same general terms as described for the Restricted Voting Stockholders. In addition, KML's suspension of its DRIP on January 16, 2019 also suspended the Limited Partnership's distribution reinvestment plan under the terms of the Limited Partnership Agreement.

Restricted Voting Share Dividends

Restricted Voting Shares were issued to the public pursuant to our IPO. Holders of Restricted Voting Shares are entitled to one vote for each Restricted Voting Share held at all our meetings of shareholders, except meetings at which or in respect of matters on which only holders of another class of shares are entitled to vote separately as a class. Except as otherwise provided by our articles or required by law, the holders of Restricted Voting Shares will vote together with the holders of Special Voting Shares as a single class.

The holders of Restricted Voting Shares are entitled to receive, subject to the rights of the holders of another class of shares, any dividend we declare and the remaining property of the Company on the liquidation, dissolution or winding up of the Company, whether voluntary or involuntary. Notwithstanding the foregoing, we may not issue or distribute to all or to substantially all of the holders of the Restricted Voting Shares either (i) Restricted Voting Shares, or (ii) rights or securities of the Company exchangeable for or convertible into or exercisable to acquire Restricted Voting Shares, unless contemporaneously therewith, we issue or distribute Special Voting Shares or rights or securities of the Company exchangeable for or convertible into or exercisable to acquire Special Voting Shares on substantially similar terms (having regard to the specific attributes of the Special Voting Shares) and in the same proportion.

The following table provides information regarding dividends declared, or paid, as applicable, on our Restricted Voting Shares during the year ended December 31, 2018.

For the three month period ended	Dividend rate per share	Date of declaration	Date of record	Date of dividend	Total amount of dividends paid in cash(a)	Total amount of dividends paid in form of additional shares
(In millions of Canadian dollars, except per share amounts)						
December 31, 2017	0.1625	January 17, 2018	January 31, 2018	February 15, 2018	11.8	5.1
March 31, 2018	0.1625	April 18, 2018	April 30, 2018	May 15, 2018	11.1	5.9
June 30, 2018	0.1625	July 18, 2018	July 31, 2018	August 15, 2018	13.9	3.1
September 30, 2018	0.1625	October 17, 2018	October 31, 2018	November 15, 2018	13.2	3.9
December 31, 2018	0.1625	January 16, 2019	January 31, 2019	February 15, 2019	5.7	—

a. Amount includes notional dividends on outstanding restricted stock awards of $0.4 million during 2018.

Kinder Morgan Interest Distributions

The Kinder Morgan interest consists of Class B Units in the Limited Partnership which are owned by indirect wholly owned subsidiaries of Kinder Morgan. Each Class B Unit is accompanied by a Special Voting Share, which entitles the holder of such Special Voting Share to one vote for each Special Voting Share held at all our meetings of shareholders, except meetings at which or in respect of matters on which only holders of another class of shares are entitled to vote separately as a class. The holders of Special Voting Shares are entitled to receive, subject to the rights of the holders of preferred shares and in priority to the holders of Restricted Voting Shares, an amount per Special Voting Share equal to $.000001 on the liquidation, dissolution or winding-up of the Company, whether voluntary or involuntary. The Special Voting Shares are subject to anti-dilution

provisions, which provide that adjustments will be made to the Special Voting Shares in the event of a change to the Restricted Voting Shares in order to preserve the voting equivalency of such shares.

The Limited Partnership makes quarterly distributions, when and if declared by the board of directors, to holders of Class A Units (being the Company, through the General Partner) and Class B Units (being Kinder Morgan) on a pro rata basis subject to limitations described above for the Restricted Voting Shares. Kinder Morgan then receives its pro rata share of declared distributions from the Limited Partnership through its ownership interest in the Limited Partnership Class B Units.

The following table provides information regarding distributions declared, or paid, as applicable, to Kinder Morgan during the year ended December 31, 2018.

For the three month period ended	Dividend rate per share	Date of declaration	Date of distribution	Total amount of distribution paid in cash(a)	Total amount of distribution paid in form of additional shares
(In millions of Canadian dollars, except per share amounts)					
December 31, 2017	0.1625	January 17, 2018	February 15, 2018	31.0	9.9
March 31, 2018	0.1625	April 18, 2018	May 15, 2018	31.0	9.9
June 30, 2018	0.1625	July 18, 2018	August 15, 2018	40.3	—
September 30, 2018	0.1625	October 17, 2018	November 15, 2018	39.7	—
December 31, 2018	0.1625	January 16, 2019	February 15, 2019	13.2	—

a. Distributions paid in cash include U.S. income tax reimbursements related to Puget Sound earnings of $3.4 million during 2018.

Earnings per Restricted Voting Share

We calculate earnings per share from continuing and discontinued operations using the two-class method. Earnings were allocated to Restricted Voting Shares and participating securities based on the amount of dividends paid in the current period plus an allocation of the undistributed earnings or excess distributions over earnings to the extent that each security participates in earnings or excess distributions over earnings. Our unvested restricted stock awards, which may be settled in Restricted Voting Shares issued to employees and non-employee directors and include dividend equivalent payments, do not participate in excess distributions over earnings.

The following table sets forth the allocation of income from continuing operations and net income available to shareholders of Restricted Voting Shares and participating securities:

Year ended December 31,	2018	2017
(In millions of Canadian dollars, except per share amounts)		
Income from Continuing Operations Available to Restricted Voting Stockholders	21.8	8.9
Participating securities:		
Less: Income from Continuing Operations allocated to restricted stock awards(a)	(0.4)	(0.2)
Income from Continuing Operations Allocated to Restricted Voting Stockholders	21.4	8.7
Basic Weighted Average Restricted Voting Shares Outstanding	34.7	27.6
Basic Earnings from Continuing Operations Per Restricted Voting Share	0.62	0.31

The following table sets forth the allocation of income from discontinued operations and net income available to shareholders of Restricted Voting Shares and participating securities:

Year ended December 31,	2018	2017
(In millions of Canadian dollars, except per share amounts)		
Income from Discontinued Operations Available to Restricted Voting Stockholders	394.4	19.0
Participating securities:		
Less: Income from Discontinued Operations allocated to restricted stock awards(a)	(0.4)	(0.2)
Income from Discontinued Operations Allocated to Restricted Voting Stockholders	394.0	18.8
Basic Weighted Average Restricted Voting Shares Outstanding	34.7	27.6
Basic Earnings from Discontinued Operations Per Restricted Voting Share	11.37	0.69

a. As of December 31, 2018 and 2017, there were approximately 0.2 million and 0.3 million, respectively, unvested restricted stock awards.

For the both years ended December 31, 2018 and 2017, the weighted average maximum number of potential Restricted Voting Share equivalents of 0.2 million unvested restricted stock awards are antidilutive and, accordingly, are excluded from the determination of diluted earnings per Restricted Voting Share.

14. Transactions with Related Parties

Affiliate Activities

The following table summarizes our related party income statement activity. Revenues, operating costs and capitalized costs are under normal trade terms.

Year ended December 31,	2018	2017	2016
(In millions of Canadian dollars)			
Income Statement location			
Revenues-Services(a)	61.2	63.7	59.1
Operations and maintenance and general and administrative expenses	6.8	0.5	1.0
Interest expense(b)	—	10.0	21.3
Other			
Capitalized costs from affiliates in property, plant and equipment	0.1	6.5	19.1

a. Amounts represent sales to a customer who is a related party through joint ownership of a joint venture.
b. 2017 and 2016 amounts primarily represent interest on long-term debt with affiliates (“KMI Loans”) that was repaid with proceeds from our IPO.

Accounts receivable and payable

Accounts receivable-affiliate and accounts payable-affiliate are non-interest bearing and are settled on demand and, since our IPO, primarily settled monthly. The following table summarizes our affiliate balances:

December 31,	2018	2017
(In millions of Canadian dollars)		
Accounts receivable(a)	0.2	9.0
Contract accounts receivable(b)	0.7	1.2
Accounts payable(c)	4.7	0.7

a. Included in "Accounts receivable" on our accompanying consolidated balance sheets.
b. Included in "Other current assets" on our accompanying consolidated balance sheets.
c. Included in "Accounts payable" on our accompanying consolidated balance sheets.

15. Interest (Income) Expense, net

Year ended December 31,	2018	2017	2016
(In millions of Canadian dollars)			
Interest expense on KMI Loans	—	10.0	21.3
Interest expense on credit facilities(a)	2.1	0.9	—
Amortization expense of debt issuance costs	0.6	0.5	—
Interest expense, other	0.4	0.4	—
Interest income	(29.7)	—	—
Capitalized debt financing costs	(0.6)	(3.6)	(2.8)
	(27.2)	8.2	18.5

a. 2018 and 2017 amounts include $1.1 million and $0.7 million, respectively, of standby fees.

16. Change in Operating Assets and Liabilities

The following amounts represent consolidated changes in operating assets and liabilities, which include changes for the Trans Mountain Asset Group. See Note 3 for a summary of operating and investing cash flows related to the Trans Mountain Asset Group.

Year ended December 31,	2018	2017	2016
(In millions of Canadian dollars)	**Cash inflow (outflow)**		
Accounts receivable	25.0	(3.8)	25.9
Inventories	(0.2)	(0.7)	(1.5)
Other current assets	(4.0)	4.1	(3.2)
Deferred charges and other assets	(5.6)	(12.4)	(4.2)
Accounts payable	(48.0)	(21.3)	35.3
Accrued taxes	303.8	10.2	(0.5)
Other current liabilities	3.6	(55.5)	3.5
Other deferred credits	62.4	(15.0)	(82.8)
	337.0	(94.4)	(27.5)

17. Risk Management and Financial Instruments

Credit risk

We are exposed to credit risk, which is the risk that a customer or other counterparty will fail to perform an obligation or settle a liability, resulting in a financial loss to our business, which is primarily concentrated in the crude oil and refined products transportation industry and is dependent upon the ability of our customers to pay for these services. A majority of our customers operate in the oil and gas exploration and development, or energy marketing or transportation industries. Our customers may be exposed to long-term downturns in energy commodity prices, including the price for crude oil, or other credit events impacting these industries. We limit our exposure to credit risk by requiring shippers who fail to maintain specified credit ratings or a suitable financial position to provide acceptable security, generally in the form of guarantees from credit worthy parties or letters of credit from well rated financial institutions. Our cash and cash equivalents are held with major financial institutions, minimizing the risk of non-performance by counter parties.

Interest Rate Risk

We are exposed to interest rate risk attributed to floating rate debt, which is used to finance capital expansion projects, and general corporate operations. The changes in interest rates may impact future cash flows and the fair value of our financial instruments.

Foreign Currency Transactions and Translation

Foreign currency transaction gains or losses result from a change in exchange rates between the functional currency of an entity and the currency in which a transaction is denominated. Unrealized and realized gains and losses generated from these transactions are recorded in foreign exchange loss in the accompanying consolidated statements of income and include:

- As a result of the Trans Mountain Transaction, we released foreign currency translation gains previously held within Accumulated other comprehensive loss to the Gain on sale of the Trans Mountain Asset Group, net of tax in the accompanying consolidated statement of income of $10.1 million for the year ended December 31, 2018.

- Prior to repayment of the KMI Loans utilizing proceeds from our IPO, we were exposed to foreign currency risk related to the U.S. dollar denominated KMI Loans. For the years ended December 31, 2017 and 2016, our continuing operations had unrealized foreign exchange gain of $0.2 million and $13.2 million, respectively, and our discontinued operations had unrealized foreign exchange (loss) and gain of $(2.6) million and $16.5 million, respectively, related to the KMI Loans.

- Our continuing operations unrealized foreign exchange (loss) and gain for the years ended December 31, 2018, 2017 and 2016 were $1.0 million, $(5.6) million and $1.4 million, respectively, due to changes in exchange rates between the Canadian dollar and the U.S. dollar on U.S. dollar denominated balances. These currency exchange rate fluctuations affect the expected Canadian dollar cash flows on unsettled U.S. dollar denominated transactions, primarily related to cash bank accounts that are denominated in U.S. dollars and affiliate receivables or payables that are denominated in U.S. dollars. Prior to the closing of the Trans Mountain Transaction, we translated the assets and liabilities of Puget Sound that has the U.S. dollar as its functional currency to Canadian dollars at period-end exchange rates.

- Cochin earns its revenues in U.S. dollars. Therefore, fluctuations in the U.S. dollar to Canadian dollar exchange rate can affect the earnings contributed by Cochin to our overall results. Our continuing operations had realized foreign exchange (loss) and gain of $(0.9) million and $0.3 million for the years ended December 31, 2018 and 2017. The net realized foreign exchange gains and losses were nominal in 2016.

Liquidity risk

Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments, as they become due. We manage our liquidity risk by ensuring access to sufficient funds to meet our obligations. We forecast cash requirements to ensure funding is available to settle financial liabilities when they become due. Our primary sources of liquidity and capital resources are funds generated from operations and our 2018 Credit Facility.

Fair value measurements

We do not carry any financial assets or liabilities measured at fair value on a recurring basis, other than the Trusts described in Note 7. We disclose the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects our best estimate of market value based on generally accepted valuation techniques or models and are supported by observable market prices and rates. When such values are not available, we use discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

Fair value of financial instruments

Fair value represents the price at which a financial instrument could be exchanged in an orderly market, in an arm's length transaction between knowledgeable and willing parties who are under no compulsion to act. We classify the fair value of the financial instruments according to the following hierarchy based on the observable inputs used to value the instrument:

- Level 1— inputs to the valuation methodology are quoted prices unadjusted for identical assets or liabilities in active markets;

- Level 2— inputs other than quoted prices included in Level 1 that are observable for the asset or liability either directly (as prices) or indirectly (i.e. derived from prices); and
- Level 3 — inputs to the valuation model are not based on observable market data.

Fair value measurements are classified in the fair value hierarchy based on the lowest level input that is significant to that fair value measurement. This assessment requires judgment considering factors specific to an asset or liability and may affect placement within the fair value hierarchy. Level 1 and Level 2 are used for the fair value of cash and cash equivalents and restricted investments, respectively.

Due to the short-term or on demand nature of cash and cash equivalents, restricted cash, accounts receivable, accounts receivable from affiliates, accounts payable, accounts payable to affiliates and accrued interest, we have determined that the carrying amounts for these balances approximate fair value.

18. Revenue Recognition

Nature of Revenue by Segment

Terminals Segment

We provide various types of liquid tank and bulk terminal services. These services are generally comprised of inbound, storage and outbound handling of customer products.

Our liquid tank storage and handling service contracts generally include a promised tank storage capacity provision and prepaid volume throughput of the stored product. In these contracts, we have a stand-ready obligation to perform this contracted service each day over the life of the contract. The customer pays a transaction price typically in the form of a fixed monthly charge and is obligated to pay whether or not it uses the storage capacity and throughput service (i.e., a take-or-pay payment obligation). These contracts generally include a per-unit rate for any quantities we handle at the request of the customer in excess of the prepaid volume throughput amount and also typically include per-unit rates for additional, ancillary services that may be periodically requested by the customer.

Our bulk storage and handling contracts generally include inbound handling of our customers' dry bulk material product into our storage facility and outbound handling of these products from our storage facility. These services are provided on both a firm and non-firm basis. In our firm bulk storage and handling contracts, we are committed to handle and store on a stand-ready basis the minimum throughput quantity of bulk materials contracted by the customer. The customer is obligated to pay for its minimum volume commitment amount, regardless of whether or not it uses the storage and handling service. The customer pays a transaction price typically based on a per-unit rate for quantities handled, including amounts attributable to deficiency quantities. For non-firm storage and handling services, the customer pays a transaction price typically based on a per-unit rate for quantities handled on an as requested, non-guaranteed basis.

Pipelines Segment

We transport light hydrocarbon liquids (primarily to be used as diluent to facilitate bitumen transportation) on a firm or non-firm contractual basis, and jet fuel on a non-firm contractual basis. The regulated tariff for Cochin is designed to provide revenues sufficient to recover the costs of providing transportation to shippers, including a return on invested capital. The majority of Cochin's transportation service is provided on a firm basis under its current contracts.

We typically promise to transport on a stand-ready basis the shipper's minimum volume commitment amount. The shipper is obligated to pay for its volume commitment amount, regardless of whether or not it flows quantities in Cochin's pipeline. The shipper pays a transaction price typically based on a per-unit rate for quantities transported, including amounts attributable to deficiency quantities.

Our non-firm, interruptible transportation services are provided on Cochin's pipeline when and to the extent we determine capacity is available in this pipeline system. The shippers typically pay a per-unit rate for actual quantities of product transported.

Disaggregation of Revenues

The following table presents our revenues disaggregated by revenue source and type of revenue for each revenue source:

	Year Ended December 31, 2018		
	Pipelines	**Terminals**	**Total**
(In millions of Canadian dollars)			
Revenue from contracts with customers			
Services			
Firm services(a)	54.0	229.4	283.4
Fee-based services	1.3	79.2	80.5
Total services revenues	55.3	308.6	363.9
Other revenues(b)	6.9	13.0	19.9
Total revenues	62.2	321.6	383.8

a. Includes non-cancellable firm service customer contracts with take-or-pay or minimum volume commitment elements, including those contracts where both the price and quantity amount are fixed. In these arrangements, the customer is obligated to pay for the rendered service whether or not the customer chooses to utilize the service. Excludes service contracts with indexed-based pricing, which along with revenues from other contracts are reported as Fee-based services.

b. Amounts recognized as revenue under guidance prescribed in Topics of the Accounting Standards Codification other than in Topic 606 and primarily include regulatory-based adjustments and leases.

Contract Balances

Contract assets and contract liabilities are the result of timing differences between revenue recognition, billings and cash collections. We recognize contract assets in those instances where billing occurs subsequent to revenue recognition and our right to invoice the customer is conditioned on something other than the passage of time. Our contract liabilities are substantially related to (i) capital improvements paid for in advance by certain customers generally in our non-regulated businesses, which we subsequently recognize as revenue on a straight-line basis over the initial term of the related customer contracts, and (ii) consideration received from customers for temporary deficiency quantities under minimum volume contracts that we expect will be made up in a future period, which we subsequently recognize as revenue when the customer makes up the volumes or the likelihood that the customer will exercise its right for deficiency volumes becomes remote (e.g., there is insufficient capacity to make up the volumes, the deficiency makeup period expires).

The following table presents the activity in our contract assets and liabilities:

(In millions of Canadian dollars)	
Contract Assets	
Balance at January 1, 2018	2.1
Additions	17.9
Transfer to Accounts receivable	(18.4)
Balance at December 31, 2018(a)	1.6
Contract Liabilities	
Balance at January 1, 2018	68.2
Additions	154.5
Transfer to Revenues	(143.1)
Other (b)	0.7
Balance at December 31, 2018(c)	80.3

a. Includes current balances reported within “Other current assets” in our accompanying consolidated balance sheets at December 31, 2018.

b. Includes 2018 foreign currency translation adjustments associated with the balances at December 31, 2017.

c. Includes current balances and non-current balances of $12.8 million and $67.5 million reported within "Other current liabilities" and "Contract liabilities," respectively, in our accompanying consolidated balance sheets at December 31, 2018.

Revenue Allocated to Remaining Performance Obligations

The following table presents our estimated revenue allocated to remaining performance obligations for contracted revenue that has not yet been recognized, representing our "contractually committed" revenue as of December 31, 2018 that we will invoice or transfer from contract liabilities and recognize in future periods:

Year	Estimated Revenue
(In millions of Canadian dollars)	
2019	313.4
2020	250.0
2021	193.3
2022	183.9
2023	171.3
Thereafter	533.1
Total	1,645.0

Our contractually committed revenue for purposes of the tabular presentation above is generally limited to service customer contracts which have fixed pricing and fixed volume terms and conditions, generally including contracts with take-or-pay or minimum volume commitment payment obligations. Our contractually committed revenue amounts generally exclude, based on the following practical expedients that we elected to apply, remaining performance obligations for: (i) contracts with index-based pricing or variable volume attributes in which such variable consideration is allocated entirely to a wholly unsatisfied performance obligation or to a wholly unsatisfied promise to transfer a distinct service that forms part of a series of distinct services; (ii) contracts with an original expected duration of one year or less; and (iii) contracts for which we recognize revenue at the amount for which we have the right to invoice for services performed.

Major Customer

For the years ended December 31, 2018 and 2017, revenues from Imperial Oil represented 31% of our total revenue from continuing operations for each year. For the year ended December 31, 2016, revenues from Imperial Oil represented 23% of our total revenue.

19. Reportable Segments

Our reportable business segments are based on the way management organizes the enterprise. Each of our reportable business segments represent a component of the enterprise that engages in a separate business activity and for which discrete financial information is available.

Our reportable business segments are:

- Terminals - the ownership and operation of liquid product merchant storage and rail terminals in the Edmonton, Alberta market as well as a predominantly dry cargo import/export facility in North Vancouver, B.C. Certain Edmonton South Terminal tanks that are owned by TMPL were included in the Trans Mountain Asset Group and continue to be leased to Terminals segment; and

- Pipelines - the ownership and operation of Cochin, a 12-inch diameter multi-product pipeline which spans approximately 1,000 kilometers in Saskatchewan and Alberta and Jet Fuel serving Vancouver International Airport.

We evaluate the performance of our reportable business segments by evaluating our Segment earnings before depreciation and amortization expenses ("Segment EBDA"). We believe that Segment EBDA is a useful measure of our operating performance because it measures segment operating results before D&A and certain expenses that are generally not controllable by the operating managers of our respective business segments, such as general and administrative expense, interest expense, income tax expense and prior to May 2017, the foreign exchange losses (or gains) on the KMI Loans. Our

general and administrative expenses include such items as employee benefits, insurance, rentals, certain litigation and shared corporate services including accounting, information technology, human resources and legal services.

We consider each period's earnings before all non-cash D&A expenses to be an important measure of business segment performance for our reporting segments. We account for intersegment sales at market prices, while we account for asset transfers at either market value or, in some instances, book value. Intercompany transactions are eliminated in consolidation.

Financial information by segment for continuing operations is as follows:

Year Ended December 31,	**2018**	**2017**	**2016**
(In millions of Canadian dollars)			
Revenues			
Terminals	321.6	298.6	287.5
Pipelines	62.2	60.3	60.3
Total consolidated revenues	383.8	358.9	347.8

Year Ended December 31,	**2018**	**2017**	**2016**
(In millions of Canadian dollars)			
Operating expenses(a)			
Terminals	137.6	136.9	129.6
Pipelines	23.1	32.3	30.5
Total consolidated operating expenses	160.7	169.2	160.1

Year Ended December 31,	**2018**	**2017**	**2016**
(In millions of Canadian dollars)			
Other operating expense (income)			
Terminals	(9.3)	3.1	0.2
Pipelines	—	0.3	—
Total consolidated other expense (income)	(9.3)	3.4	0.2

Year Ended December 31,	**2018**	**2017**	**2016**
(In millions of Canadian dollars)			
D&A			
Terminals	78.5	65.7	60.2
Pipelines	4.1	6.0	4.0
Total consolidated D&A	82.6	71.7	64.2

Year Ended December 31,	**2018**	**2017**	**2016**
(In millions of Canadian dollars)			
Other expense (income) net of foreign exchange loss, net(b)			
Terminals	0.1	(4.2)	(1.5)
Pipelines	0.1	8.6	—
Total consolidated other expense (income) net of foreign exchange loss	0.2	4.4	(1.5)

Year Ended December 31,	2018	2017	2016
(In millions of Canadian dollars)			
Segment EBDA(a)(b)			
Terminals	193.2	162.8	159.2
Pipelines	39.0	19.1	29.8
Total Segment EBDA	232.2	181.9	189.0
D&A	(82.6)	(71.7)	(64.2)
Foreign exchange gain on KMI Loans(c)	—	0.2	13.2
General and administrative	(39.0)	(30.9)	(25.7)
Interest income (expense), net	27.2	(8.2)	(18.5)
Income tax expense	(37.8)	(20.8)	(23.4)
Income from Continuing Operations	100.0	50.5	70.4
Income from Discontinued Operations, Net of Tax	1,318.2	110.2	131.4
Net Income	1,418.2	160.7	201.8

Year Ended December 31,	2018	2017	2016
(In millions of Canadian dollars)			
Capital expenditures			
Terminals	100.4	172.9	97.4
Pipelines	1.4	7.1	6.3
Discontinued Operations	426.6	438.5	165.4
Total consolidated capital expenditures	528.4	618.5	269.1

December 31,	2018	2017
(In millions of Canadian dollars)		
Assets		
Terminals	974.2	863.0
Pipelines	4,395.4	346.6
Assets Held for Sale	—	3,243.1
Total consolidated assets	5,369.6	4,452.7

a. Includes revenues less operations and maintenance expense, and taxes, other than income taxes and other, net.
b. Segment EBDA for the years ended December 31, 2018, 2017 and 2016 includes $0.1 million, $(5.3) million and $1.4 million, respectively, of foreign exchange gain (losses) due to changes in exchange rates between our Canadian dollar and the U.S. dollar on U.S. dollar denominated balances.
c. The KMI Loans, which represented U.S. dollar denominated long-term notes payable to Kinder Morgan, were settled with proceeds from our IPO.

We do not allocate interest, net, general and administrative, income taxes and foreign currency exchange losses and gains associated with short and long-term debt-affiliates to any of our reportable business segments.

20. Litigation, Commitments and Contingencies

Litigation

We and our subsidiaries are parties to various legal, regulatory and other matters arising from the day-to-day operations of our businesses or certain predecessor operations that may result in claims against the Company. Although no assurance can be given, we believe, based on our experiences to date and taking into account established reserves and insurance, that the ultimate resolution of such items will not have a material adverse impact on our business, financial position, results of operations, cash flows, or dividends to our shareholders. We believe we have meritorious defenses to the matters to which we are a party and intend to vigorously defend the Company. When we determine a loss is probable of occurring and is reasonably estimable, we accrue an undiscounted liability for such contingencies based on our best estimate using information available at that time. If the estimated loss is a range of potential outcomes and there is no better estimate within the range, we accrue the amount at the low end of the range. We disclose contingencies where an adverse outcome may be material, or in the

judgment of management, we conclude the matter should otherwise be disclosed. We had no accruals for any outstanding legal proceedings as of December 31, 2018 and 2017.

Base Line Terminal Project Litigation

On March 2, 2018, Arnett & Burgess Oilfield Construction Limited ("A&B") filed a statement of claim and certificate of lis pendens, in the Court of Queen's Bench of Alberta, against Alberta Envirofuels Inc. ("AEF") and Base Line Terminal East Limited Partnership, by its general partner, KM Canada Rail Holdings GP Limited ("BLTELP"). A&B was a contractor on the Base Line Terminal Project (the "BTT Project") and has claimed it is owed $21.2 million, inclusive of goods and services tax, asserting that BLTELP failed to pay A&B for work performed on the BTT Project under a construction services agreement.

On March 26, 2018, A&B filed a separate statement of claim, in the Court of Queen's Bench of Alberta, against BLTELP solely, asserting that BLTELP failed to pay for work performed under a separate construction services agreement also related to the BTT Project. With respect to the second claim, A&B has claimed it is owed approximately $1.0 million, inclusive of goods and services tax. We dispute both claims and intend to defend against them vigorously.

On June 5, 2018, Barrier Coating Inc. ("Barrier") filed a statement of claim and certificate of lis pendens in the Court of Queen's Bench of Alberta against Enbridge Pipelines Inc., AEF, Strathcona County, BLTELP, KM Canada Rail Holdings GP Limited, Keyera Energy Ltd., Trans Mountain Pipeline ULC and Fabricom Inc. ("Fabricom"). Barrier is a subcontractor on the BTT Project and has a construction agreement with Fabricom (the "Fabricom Agreement"). In its claim, Barrier asserts that Fabricom has breached its obligations under the Fabricom Agreement and, as such, Fabricom owes damages to Barrier. The remaining defendants, including BLTELP, KM Canada Rail Holdings GP Limited and Trans Mountain Pipeline ULC, have been named in the claim as parties with registered interests on lands affected by the work performed by Barrier under the Fabricom Agreement. Barrier asserts that these parties were, collectively, unjustly enriched in the amount of $2.5 million. This matter has been resolved and dismissed without any payment from any Kinder Morgan affiliate.

On September 6, 2018, Fabricom Inc. ("Fabricom") filed a statement of claim and certificate of lis pendens in the Court of Queen's Bench of Alberta, against KM Canada Terminals ULC, BLTELP, Trans Mountain Pipeline ULC, AEF, Doran Stewart Oilfield Services (1990) Ltd., Alberta Envirofuels Inc., Enbridge Pipelines Inc., and Strathcona County. Fabricom was a contractor on the BTT Project, and claims that it is owed $30.4 million by BLTELP above the contract value for work performed on the BTT Project under a construction services agreement. Fabricom subsequently sent a notice of arbitration incorporating its claim. Pursuant to a provision in the construction services agreement, the dispute will be resolved by arbitration and the Court of Queen's Bench matter will be stayed. We dispute this claim and intend to defend against it vigorously.

Commitments

Capital Commitments

As of December 31, 2018, we have commitments for purchases of property, plant, and equipment of $20.2 million which includes approximately $13.8 million of our proportional share of commitments through joint ownership of a joint venture.

Leases and Rights-of-Way Obligations

The table below depicts future gross minimum rental commitments under our operating leases and rights-of-way obligations as of December 31, 2018:

	Commitment
(In millions of Canadian dollars)	
2019	61.8
2020	59.9
2021	59.0
2022	59.0
2023	43.2
Thereafter	9.4
Total minimum payments	292.3

The remaining terms on our operating leases range from one to twenty-five years. Total lease and rental expenses were $66.2 million, $69.8 million and $66.5 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Contingencies

We and our subsidiaries are subject to various legal and regulatory actions and proceedings which arise in the normal course of business. While the final outcome of such actions and proceedings cannot be predicted with certainty, we believe that the resolution of such actions and proceedings will not have a material impact on our financial position or results of operations.

We and our subsidiaries are also subject to environmental cleanup and enforcement actions from time to time. Although we believe our operations are in substantial compliance with applicable environmental law and regulations, risks of additional costs and liabilities are inherent in pipeline and terminal operations, and there can be no assurance that we will not incur significant costs and liabilities. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies under the terms of authority of those laws, and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities to us.

Although it is not possible to predict the ultimate outcomes, we believe that the resolution of the environmental matters to which we and our subsidiaries are a party will not have a material adverse effect on our business, financial position, results of operations or cash flows. As of December 31, 2018, we had $0.1 million accrued for our outstanding environment matters and no accrual as of December 31, 2017.

Land Matters Consultation Initiative Trust

On January 30, 2015 Kinder Morgan established the Trust, a required regulatory liability in relation to the NEB's LMCI. The Trust was created to set aside funds collected through abandonment surcharges over a collection period established by the NEB. The NEB approved the amounts to be collected by the company in respect of future pipeline abandonment. Funds are transferred to the Trust account each billing cycle. As of December 31, 2018 and 2017, our Trust liability balance was $6.5 million and $4.8 million, respectively and we had Trust assets of $6.1 million and $4.3 million. The Trust liability amounts are included within Other Current Liabilities and Other Deferred Credits, and the Trust asset amount is recorded in Deferred Charges and Other Assets, on our accompanying consolidated balance sheet.

21. Recent Accounting Pronouncements

Topic 842

On February 25, 2016, the FASB issued ASU No. 2016-02, *"Leases"* followed by a series of related accounting standard updates (collectively referred to as "Topic 842"). Topic 842 establishes a new lease accounting model for leases. The most significant changes include the clarification of the definition of a lease, the requirement for lessees to recognize for all leases a right-of-use asset and a lease liability in the consolidated balance sheet, and additional quantitative and qualitative disclosures that are designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. Expenses are recognized in the consolidated statement of income in a manner similar to current accounting guidance. Lessor accounting under the new standard is substantially unchanged. The new standard will become effective for us beginning with the first quarter 2019. We will adopt the accounting standard using a prospective transition approach, which applies the provisions of the new guidance at the effective date without adjusting the comparative periods presented. We have elected the package of practical expedients permitted under the transition guidance within the new standard, which among other things, allows us to carry forward the historical accounting relating to lease identification and as well as no reassessment of lease identification and classification for existing leases upon adoption. We have also elected the optional practical expedient permitted under the transition guidance within the new standard related to land easements that allows us to carry forward our historical accounting treatment for land easements on existing agreements upon adoption. We have made an accounting policy election to keep leases with an initial term of 12 months or less off of the consolidated balance sheet. We are finalizing our evaluation of the impacts that the adoption of this accounting guidance will have on the consolidated financial statements, and estimate approximately $300 million of additional right-of-use assets and liabilities will be recognized in our consolidated balance sheet upon adoption.

ASU No. 2016-13

On June 16, 2016, the FASB issued ASU No. 2016-13, "*Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments.*" This ASU modifies the impairment model to utilize an expected loss

methodology in place of the currently used incurred loss methodology, which will result in the more timely recognition of losses. ASU No. 2016-13 will be effective for us as of January 1, 2020, and earlier adoption is permitted. We are currently reviewing the effect of this ASU to our financial statements.

ASU No. 2018-14

On August 28, 2018, the FASB issued ASU No. 2018-14, "Compensation - Retirement Benefits - Defined Benefit Plans - General (Subtopic 715-20): Disclosure Framework - Changes to the Disclosure Requirements for Defined Benefit Plans." This ASU amends existing annual disclosure requirements applicable to all employers that sponsor defined benefit pension and other postretirement plans by adding, removing, and clarifying certain disclosures. ASU No. 2018-14 will be effective for us for the fiscal year ending December 31, 2020, and earlier adoption is permitted. We are currently reviewing the effect of this ASU to our financial statements.

Supplemental Selected Quarterly Financial Data (Unaudited)

	2018				2017			
	Q4(a)	Q3(a)	Q2	Q1	Q4	Q3	Q2	Q1
(In millions of Canadian dollars, except for per share amounts)								
Revenues	105.2	94.3	95.7	88.6	95.0	85.9	89.0	89.0
Operating Income	31.4	26.4	32.4	20.6	28.8	17.5	20.0	17.4
Foreign exchange gain (loss)	0.5	(0.6)	0.5	(0.3)	0.2	(2.0)	(18.3)	15.0
Income from Continuing Operations	40.3	22.2	23.5	14.0	22.5	9.8	5.9	12.3
Income (loss) from Discontinued Operations, net of tax	—	19.2	(9.8)	30.4	23.9	32.6	19.2	34.5
(Loss) gain on sale of the Trans Mountain Asset Group, net of tax	(29.6)	1,308.0	—	—	—	—	—	—
Net Income	10.7	1,349.4	13.7	44.4	46.4	42.4	25.1	46.8
Net Income Available to Restricted Voting Stockholders	2.1	401.5	1.8	10.8	12.0	11.7	4.2	
Basic and Diluted Earnings Per Restricted Voting Share from Continuing Operations	0.30	0.14	0.13	0.05	0.14	0.06	0.11	
Basic and Diluted (Loss) Earnings Per Restricted Voting Share from Discontinued Operations	(0.23)	11.42	(0.08)	0.26	0.20	0.28	0.21	

a. The three months ended December 31, 2018 (Q4) include an approximately $6.3 million out of period adjustment that decreased the loss on sale of the Trans Mountain Asset Group, net of tax, and increased net income in Q4. The adjustment relates to a correction on the amount released for deferred income taxes that resulted in a tax benefit from the sale of the Trans Mountain Asset Group for the three months ended September 30, 2018 (Q3), see Note 3. The impact of recognizing the adjustment in Q4 and not in Q3 was not significant to either individual period and did not impact the accompanying consolidated financial statements for the year ended and as of December 31, 2018. Management believes this adjustment between Q4 and Q3 is immaterial to the unaudited supplemental selected quarterly financial data presented above and to the previously issued unaudited consolidated financial statements for Q3.

Item 16. ***Form 10-K Summary.***

Not Applicable.

EXPLANATORY NOTE

Capitalized terms used throughout this document are defined in the "*Glossary*" below. References to "we," "us," "our" and the "Company" are to Kinder Morgan Canada Limited and its majority-owned and/or controlled subsidiaries. We state our financial statements in Canadian dollars. References in this document to "dollars," "$" or "CAD$" are to the currency of Canada, and references to "U.S.$" or "U.S. dollar" are to the currency of the U.S.

GLOSSARY

Company Abbreviations

Class A Units	=	the Class A limited partnership units of the Limited Partnership
Class B Units	=	the Class B limited partnership units of the Limited Partnership
Cochin	=	U.S. and Canadian Cochin pipeline system
Cooperation Agreement	=	the cooperation agreement, between the Company, the General Partner, the Limited Partnership, KMCC, KMCT and Kinder Morgan (in respect to certain provisions only) entered into in connection with the IPO
General Partner	=	Kinder Morgan Canada GP Inc.
IPO	=	Initial Public Offering of KML's Restricted Voting Shares in May 2017
Jet Fuel	=	Jet Fuel pipeline system
KMCC	=	Kinder Morgan Canada Company
KMCI	=	Kinder Morgan Canada Inc.
KMCSI	=	Kinder Morgan Canada Services Inc.
KMCT	=	Kinder Morgan Canada Terminals ULC
KMCU	=	Kinder Morgan Cochin ULC
KML	=	Kinder Morgan Canada Limited and its majority-owned and/or controlled subsidiaries
Kinder Morgan or KMI	=	Kinder Morgan, Inc.
Kinder Morgan Canada Group	=	collectively, the Company, the General Partner, the Limited Partnership, and each person that any of the Company, the General Partner or the Limited Partnership controls from time to time
Kinder Morgan Group	=	Kinder Morgan and each person that Kinder Morgan directly or indirectly controls from time to time, other than any member of the Kinder Morgan Canada Group
Limited Partnership	=	Kinder Morgan Canada Limited Partnership
Limited Partnership Agreement	=	the limited partnership agreement of the Limited Partnership, as amended from time to time
LP Units	=	collectively, the Class A Units and the Class B Units
Preferred LP Units	=	the preferred limited partnership units in the Limited Partnership
Preferred Shares	=	collectively all outstanding preferred shares in the capital of KML
Puget Sound	=	Puget Sound pipeline system
Restricted Voting Shares	=	the restricted voting shares in the capital of KML
Series 1 Preferred Shares	=	the 12,000,000 cumulative redeemable minimum rate reset Preferred Shares, Series 1 in the capital of KML
Series 3 Preferred Shares	=	the 10,000,000 cumulative redeemable minimum rate reset Preferred Shares, Series 3 in the capital of KML
Special Voting Shares	=	the special voting shares in the capital of KML
TMEP	=	Trans Mountain Expansion Project
TMPL	=	Trans Mountain pipeline system
Trans Mountain Asset Group	=	the assets sold; collectively, TMPL, along with its associated Puget Sound, the TMEP, and KMCI (the Canadian employer of the staff that operates those businesses sold)
Trans Mountain	=	Trans Mountain Pipeline ULC

Common Industry and Other Terms

/d	=	per day
Adjusted EBITDA	=	adjusted earnings before interest expense, taxes, depreciation and amortization
B.C.	=	the Province of British Columbia
BCUC	=	British Columbia Utilities Commission
bpd	=	barrels per day

BC OGC	=	British Columbia Oil and Gas Commission
DCF	=	distributable cash flow
D&A	=	depreciation and amortization
EBDA	=	earnings before depreciation and amortization expenses
FASB	=	Financial Accounting Standards Board
FERC	=	Federal Energy Regulatory Commission
GAAP or U.S. GAAP	=	United States Generally Accepted Accounting Principles
MBbl	=	thousand barrels
MMBbl	=	million barrels
MMtonnes	=	million metric tonnes
NEB	=	National Energy Board
SEC	=	United States Securities and Exchange Commission
TSX	=	Toronto Stock Exchange
U.S.	=	United States of America

Information Regarding Forward-Looking Statements

This report includes forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "intend," "plan," "projection," "forecast," "strategy," "position," "continue," "estimate," "expect," "may," or the negative of those terms or other variations of them or comparable terminology. In particular, expressed or implied statements concerning future actions, conditions or events, future operating results or the ability to generate sales, income or cash flow or to pay dividends are forward-looking statements. In particular, but without limitation, this document contains forward-looking statements pertaining to the following:

- expectations regarding our ability to generate certain targeted Adjusted EBITDA and DCF and to declare and pay dividends, including amounts thereof;
- the future commercial viability of our business;
- expectations regarding expansion projects, including our ability to complete such projects, anticipated costs, scheduling and in-service dates, future benefits and utilization, anticipated project returns and the impacts of such projects;
- the realization of benefits deriving from future growth projects;
- the potential growth opportunities and anticipated competitive position of our business segments;
- the anticipated results of our pipeline tolls and toll structure and our ability to recover certain costs and earn returns as a result of such tolls;
- performance by our counterparties of their obligations to us;
- expectations respecting our ability to generate predictable and growing cash available for distribution;
- expectations and intentions respecting distributions from the Limited Partnership, the payout of DCF and our payment of quarterly dividends to our shareholders, as well as the amounts of those dividends;
- the impact of commodity pricing;
- anticipated future capital and operating expenditures;
- expectations respecting the ongoing financing of our business and operations;
- anticipated decommissioning and abandonment costs;
- operational (including marine) safety levels and standards;
- future pipeline capacity and tolls; and
- future supply of and demand for the products we handle and demand for the services we provide.

The foregoing list should not be construed to be exhaustive. We believe the forward-looking statements in this document are reasonable. However, there is no assurance that any of the actions, events or results of the forward-looking statements will occur, or if any of them do, of their timing or what impact they will have on our results of operations or financial condition. Because of these uncertainties, investors should not put undue reliance on any forward-looking statements.

Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict. Any "financial outlook" set out in this document has been included for the purpose of providing information relating to management's current expectations and plans for the future, is based on a number of significant assumptions and may not be appropriate, and should not be used, for purposes other than those for which such forward-looking statements are disclosed herein.

Our business, financial condition and results of operations, including our ability to pay cash dividends, are substantially dependent on our financial condition and results of operations. As a result, factors or events that impact our business are likely to have a commensurate impact on us, the market price and value of the Restricted Voting Shares, the Preferred Shares, and our ability to pay dividends.

See Item 1A "*Risk Factors*" and Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook"* included in this report for a more detailed description of factors that may affect the forward-looking statements. You should keep these risk factors in mind when considering forward-looking statements. These risk factors could cause our actual results to differ materially from those contained in any forward-looking statement. Because of these risks and uncertainties, you should not place undue reliance on any forward-looking statement. Any financial outlook *or* other forward-looking statements included in this report are included for the purpose of providing information relating to

management's current expectations and plans for the future, are based on a number of significant assumptions and may not be appropriate, and should not be used, for any purpose other than those for which such forward-looking statements are disclosed herein.

Forward-looking statements in this report are given only as of the date of this report and we disclaim any obligation to update or revise any forward-looking statements included in this report, except as required by law.

NORTON ROSE FULBRIGHT

Internal Memorandum

To: Alex Baer
Matthew D. Keen
Emily Chan

April 9, 2020

Client-Matter #: 1000385944

From: Natasha John

Re: Regulation of "Common Carrier" Pipelines

You have asked that I address the following:

1. Reproduce the relevant provisions of the federal and British Columbia legislation concerning the regulation of "common carrier" pipelines by the National Energy Board ("NEB") and Canadian Energy Regulator ("CER"), and British Columbia Utilities Commission ("BCUC"), respectively;

2. Compare the common law principles regarding common carriers to the statutory provisions above;

3. Provide a bullet point list of quotes from NEB or CER regarding the codification of common law common carrier principles; and

4. Provide a bullet point list of quotes from NEB or CER regarding policy objectives and overarching principles it applies or considers when setting tolls for pipeline operators.

1. RELEVANT STATUTORY PROVISIONS

Federal

The following are the statutory provisions relevant to pipeline regulation at the federal level:

1959 to 2019 (as it was in 2019)	2019 to Present (as it presently is)
All provisions are from the NEB Act[1]: **Definitions** 2 The following definitions apply in this Act. … ***company*** includes (a) a person having authority under a Special Act to construct or operate a pipeline; and (b) a body corporate incorporated or continued under the *Canada Business Corporations Act* or an Act of the legislature of a province and not discontinued under the Act in question. …	All provisions are from the CER Act[2]: **Definitions** 2 The following definitions apply in this Act. … ***company*** includes (a) a person having authority under a Special Act to construct or operate a pipeline; and (b) a body corporate incorporated or continued under the *Canada Business Corporations Act* or an Act of the legislature of a province and not discontinued under the Act in question. …

[1] *National Energy Board Act*, R.S.C., 1985, c. N-7 [NEB Act].
[2] *Canadian Energy Regulator Act*, S.C. 2019, c. 28 [CER Act]

[NOTE: there are also definitions of “oil” and “gas”] … ***pipeline*** means a line that is used or to be used for the transmission of oil, gas or any other commodity and that connects a province with any other province or provinces or extends beyond the limits of a province or the offshore area as defined in section 123, and includes all branches, extensions, tanks, reservoirs, storage facilities, pumps, racks, compressors, loading facilities, interstation systems of communication by telephone, telegraph or radio and real and personal property, or immovable and movable, and works connected to them, but does not include a sewer or water pipeline that is used or proposed to be used solely for municipal purposes;	[NOTE: there are also definitions of “oil” and “gas”] … ***pipeline*** means a line — including all branches, extensions, tanks, reservoirs, storage or loading facilities, pumps, racks, compressors, interstation communication systems, real or personal property, or immovable or movable, and any connected works — that connects at least two provinces or extends beyond the limits of a province, Sable Island or an area referred to in paragraph (c) of the definition *designated area* in section 368 and that is used or is to be used for the transmission of oil, gas or any other commodity. It does not however include a sewer or water pipeline that is used or is to be used solely for municipal purposes.
Tolls to be just and reasonable 62 All tolls shall be just and reasonable, and shall always, under substantially similar circumstances and conditions with respect to all traffic of the same description carried over the same route, be charged equally to all persons at the same rate.	**Tolls** 230 All tolls must be just and reasonable, and must always, under substantially similar circumstances and conditions with respect to all traffic of the same description carried over the same route, be charged equally to all persons at the same rate.
No unjust discrimination 67 A company shall not make any unjust discrimination in tolls, service or facilities against any person or locality.	**No unjust discrimination** 235 A company must not make any unjust discrimination in tolls, service or facilities against any person or locality.
Transmission, etc., of Oil or Gas **Duty of pipeline company** 71 (1) Subject to such exemptions, conditions or regulations as the Board may prescribe, a company operating a pipeline for the transmission of oil shall, according to its powers, without delay and with due care and diligence, receive, transport and deliver all oil offered for transmission by means of its pipeline.	**Transmission by Pipeline** **Duty — company** 239 (1) Subject to any regulations that the Commission may prescribe and any exemptions or conditions it may impose, a company operating a pipeline for the transmission of oil must, according to its powers, without delay and with due care and diligence, receive, transport and deliver all oil offered for transmission by means of its pipeline.
Orders for transmission of commodities (2) The Board may, by order, on such terms and conditions as it may specify in the order, require the following companies to receive, transport and deliver, according to their powers, a commodity offered for transmission by means of a pipeline: (a) a company operating a pipeline for the transmission of gas; and (b) a company that has been issued a certificate under Part III authorizing the transmission of a commodity other than oil.	**Commission’s orders** (2) The Commission may, by order, on any conditions that it specifies in the order, require a company operating a pipeline for the transmission of gas or a commodity other than oil to, according to its powers, receive, transport and deliver such a commodity offered for transmission by means of its pipeline.

Extension of facilities (3) The Board may, if it considers it necessary or desirable to do so in the public interest, require a company operating a pipeline for the transmission of hydrocarbons, or for the transmission of any other commodity authorized by a certificate issued under Part III, to provide adequate and suitable facilities for (a) the receiving, transmission and delivering of the hydrocarbons or other commodity offered for transmission by means of its pipeline, (b) the storage of the hydrocarbons or other commodity, and (c) the junction of its pipeline with other facilities for the transmission of the hydrocarbons or other commodity, if the Board finds that no undue burden will be placed on the company by requiring the company to do so.	**Extension of facilities** (3) If the Commission considers it necessary or in the public interest and it finds that no undue burden will be placed on the company, it may require a company operating a pipeline for the transmission of oil, gas or any other commodity to provide adequate and suitable facilities for (a) receiving, transmitting and delivering the oil, gas or other commodity offered for transmission by means of its pipeline; (b) storing the oil, gas or other commodity; and (c) joining its pipeline with other facilities for the transmission of oil, gas or any other commodity.

British Columbia

The statutory provisions that have granted the BCUC jurisdiction to regulate common carriers are as follows:

1980 to 2010 (as it was in 2010)	**2010 to Present (as it presently is)**
Relevant provisions appear in the *Pipeline Act*[3] and *Utilities Commission Act*.[4] <u>*Utilities Commission Act:*</u> **Common carrier** 65 (1) In this section, **"common carrier"** means a person declared to be a common carrier by the commission under subsection (2) (a). (2) On application by an interested person and after a hearing, sufficient notice of which has been given to all persons the commission believes may be affected, the commission may (a) issue an order, to be effective on a date determined by it, declaring a person who owns or operates a pipeline for the transportation of (i) one or more of crude oil, natural gas and natural gas liquids, or (ii) any other type of energy resource prescribed by the Lieutenant Governor in Council, to be a common carrier with respect to the operation of the pipeline, and (b) in the order establish the conditions under which the common carrier must accept and carry energy resources. (3) On application by a person that uses or seeks to use facilities operated by a common carrier, the commission, by order and after a hearing, sufficient notice of which has been given to all persons the	Relevant provisions only in the *Utilities Commission Act*.[5] **Common carrier** 65 (1) In this section, **"common carrier"** means a person declared to be a common carrier by the commission under subsection (2) (a). (2) On application by an interested person and after a hearing, sufficient notice of which has been given to all persons the commission believes may be affected, the commission may (a) issue an order, to be effective on a date determined by it, declaring a person who owns or operates a pipeline for the transportation of (i) one or more of crude oil, natural gas and natural gas liquids, or (ii) any other type of energy resource prescribed by the Lieutenant Governor in Council, to be a common carrier with respect to the operation of the pipeline, and (b) in the order establish the conditions under which the common carrier must accept and carry energy resources. (3) On application by a person that uses or seeks to use facilities operated by a common carrier, the commission, by order and after a hearing, sufficient notice of which has been given to all persons the commission believes may be affected, may establish

[3] *Pipeline Act*, R.S.B.C. 1996, c. 364.
[4] Link to 2010 version before consequential amendments following repeal of *Pipeline Act*.
[5] *Utilities Commission Act*, R.S.B.C. 1996, c. 473.

commission believes may be affected, may establish the conditions under which the common carrier must accept and carry crude oil, natural gas, natural gas liquids or prescribed energy resources referred to in subsection (2) (a).	the conditions under which the common carrier must accept and carry crude oil, natural gas, natural gas liquids or prescribed energy resources referred to in subsection (2) (a).
	(3.1) Without limiting subsection (2) (b) or (3), the commission may establish conditions with respect to a common carrier in relation to any of the following matters: (a) a toll that may be charged by the common carrier; (b) extensions, improvements or abandonment of service.
	(3.2) The commission may order that section 43 applies with respect to a common carrier as though the common carrier were a public utility referred to in that section.
(4) A common carrier must not unreasonably discriminate (a) between itself and persons who apply to the common carrier to transport, in its pipeline, crude oil, natural gas, natural gas liquids or prescribed energy resources referred to in subsection (2) (a) (ii), or (b) among the persons who so apply.	(4) A common carrier must not unreasonably discriminate (a) between itself and persons who apply to the common carrier to transport, in its pipeline, crude oil, natural gas, natural gas liquids or prescribed energy resources referred to in subsection (2) (a) (ii), or (b) among the persons who so apply.
(5) A common carrier must comply with the conditions in any order applicable to the common carrier that is made under this section.	(5) A common carrier must comply with the conditions in any order applicable to the common carrier that is made under this section.
(6) The commission may, by order and after a hearing, sufficient notice of which has been given to all persons the commission believes may be affected, vary an order made under this section.	(6) The commission may, by order and after a hearing, sufficient notice of which has been given to all persons the commission believes may be affected, vary an order made under this section.
(7) If an agreement between a common carrier and another person (a) is made before an order is made under this section, and (b) is inconsistent with the conditions established by the commission in an order made under this section, the commission may, in the order or in a subsequent order, after a hearing, sufficient notice of which has been given to all persons the commission believes may be affected, vary the agreement between the parties to eliminate the inconsistency.	(7) If an agreement between a common carrier and another person (a) is made before an order is made under this section, and (b) is inconsistent with the conditions established by the commission in an order made under this section, the commission may, in the order or in a subsequent order, after a hearing, sufficient notice of which has been given to all persons the commission believes may be affected, vary the agreement between the parties to eliminate the inconsistency.
(8) Subject to subsection (9), if an agreement is varied under subsection (7), the common carrier and the commission are not liable for damages suffered as a result of that variation by the other party to the agreement.	(8) Subject to subsection (9), if an agreement is varied under subsection (7), the common carrier and the commission are not liable for damages suffered as a result of that variation by the other party to the agreement.
(9) Subsection (8) does not apply to a common carrier referred to in that subsection in relation to anything done or omitted by that person in bad faith.	(9) Subsection (8) does not apply to a common carrier referred to in that subsection in relation to anything done or omitted by that person in bad faith.
Pipeline Act **Part 7 — Oil Lines** **Application to oil lines** 40 This Part applies to company pipelines for the transportation of oil and to companies operating them.	

Traffic, tolls, tariffs

41 The minister may make regulations with respect to all matters relating to traffic, tolls or tariffs.

Duty of common carrier

42 Subject to exceptions or conditions the British Columbia Utilities Commission approves, a common carrier must, according to its powers, without delay and with due care and diligence, receive, transport and deliver all oil offered for transportation by means of its company pipeline.

B.C. Utilities Commission power

43 The British Columbia Utilities Commission may require a common carrier to provide adequate and suitable facilities for receiving, transporting and delivering all oil offered for transportation by means of its company pipeline, and adequate and suitable facilities for storage of oil at the junction of its line with other pipelines.

Tolls must be approved

44 A common carrier must not charge a toll unless it is specified in a tariff that has been filed with the British Columbia Utilities Commission and is in effect.

Equal tolls to be charged

45 All tolls must be just and reasonable, and must always, under substantially similar circumstances and conditions with respect to all traffic of the same description carried over the same route, be charged equally to all persons at the same rate.

Disallowance and substitution

46 The British Columbia Utilities Commission may

(a) disallow a tariff or a portion of the tariff that it considers to be contrary to this Act or to a regulation and may

(b) require a company, within a specified time, to substitute for a disallowed tariff or a portion of it a tariff satisfactory to the British Columbia Utilities Commission, or

(c) specify other tolls in place of the tolls disallowed.

B.C. Utilities Commission may suspend

47 The British Columbia Utilities Commission may suspend a tariff or a portion of it before or after it goes into effect.

No discrimination in rates, service or facilities

48 A common carrier must not unjustly discriminate in rates, service or facilities against any person or locality.

Burden of proof

49 If it is shown that a common carrier discriminates in rates, service or facilities against a person or locality, the burden of proving the discrimination is not unjust lies on the common carrier.

Offence and penalty

50 A common carrier or an officer, employee or agent of it who

(a) offers, grants, gives, solicits, accepts or receives a rebate, concession or discrimination, or

(b) knowingly is party or privy to a false billing, false classification, false report or other device,

by which a person obtains transportation of oil by a common

carrier at a rate less than that named in the tariffs then in force, commits an offence and is liable on conviction to a fine not exceeding $10 000. **Terms of carriage** 51 (1) Except as provided in this section, a contract, condition or notice made or given by a common carrier impairing, restricting or limiting its liability in respect of the transportation of oil does not relieve the common carrier from its liability, unless the class of contract, condition or notice has been first authorized or approved by regulation of the minister. (2) The minister may, by regulation, determine the extent to which the liability of a common carrier may be impaired, restricted or limited. (3) The minister may prescribe the terms under which oil may be carried by a common carrier. **B.C. Utilities Commission investigations** 52 (1) The British Columbia Utilities Commission may investigate a matter arising under this Part. (2) Despite anything to the contrary in the Utilities Commission Act (a) the British Columbia Utilities Commission is authorized to exercise its powers under section 43 of the Utilities Commission Act, and (b) where "public utility", "utility's" and "utility" are used in section 43 of the Utilities Commission Act, for the purposes of this Act, they mean "oil pipeline common carrier", "carrier's" and "carrier" respectively.	

2. COMPARISON BETWEEN STATUTORY SCHEMES AND COMMON CARRIER PRINCIPLES

Definition of Common Carrier

At common law, a common carrier of goods is any carrier which holds itself out to the public as being available to carry the goods of any persons for hire, without retaining any right with respect to for whom it carries.

The federal legislation provides no definition of common carrier; in fact the legislation does not use that expression at all.

The BC regulatory scheme includes a definition, but it is one that does not assist in defining the concept. Rather, it is a definition that defers to the BCUC's ability to declare a person who owns or operates a pipeline to be a common carrier.

Obligations of Common Carriers

The two main restrictions imposed on common carriers of goods at common law is that 1) they must not discriminate in providing their services; and 2) they are liable as an insurer of the goods they transport.

The former restriction appears to have been codified in respect of the regulation of pipelines both federally and in BC. At the federal level, see s. 67 and 235 of the NEB Act and CER Act, respectively for non-discrimination in fees and s. 71(1) and 239(1) for non-discrimination in access, both of which can be seen as elements of providing service. At the BC level, see s. 65(4) of the *Utilities Commission Act*.

The insurer-like liability of common carriers, which is arguably the crux of the common carrier status at common law,[6] does not appear to have been expressly codified in respect of federal or BC regulation of pipelines.

The common law rules governing carriers, in respect of liability and their powers or authority, can be altered by legislation. The validity and effect of this type of additional statutory regulation or abrogation has been confirmed by the courts on many occasions.

An example is the requirement in the federal statutory scheme that tolls be "just and reasonable". This was an express requirement in BC's regulation of common carrier pipelines until 2010 when the *Pipeline Act* was repealed.

At common law, there is no such restriction. A common carrier can stipulate the rates at which it provides its services, as long as it enforces that rate without discrimination.[7] In other words, the common law effectively requires that a common carrier operate in accordance with a "public tariff". Where a specific rate or sum for the transport of goods is not agreed upon, there is an implied undertaking on the part of the common carrier that remuneration shall be reasonable.[8] Otherwise, there is no requirement at common law for reasonableness of fees charged by common carriers.

3. NEB/CER STATEMENTS ON CODIFICATION OF COMMON CARRIER PRINCIPLES

The following are quotes from NEB decisions regarding the codification of common carrier principles in the legislative schemes regulating pipelines federally:

- … the approach does not raise concerns regarding [the pipeline operator's] obligation under subsection 71(1) of the NEB Act, the statutory embodiment of the common law "common carriage" principle…[9]
- Subsection 71(1) of the NEB Act sets out the concept that oil pipelines under the Board's jurisdiction are common carriage pipelines.[10]

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[6] *Canadian National Railway Co. v. Harris*, [1946] S.C.R. 352 at 369-370; *Canadian Forest Products Ltd. v. B.C. Rail Ltd.*, 2005 BCCA 369 at para. 35.

[7] *Law of Carriers* at 137.

[8] *Law of Carriers* at 67-68.

Some discussions concerning the duties of common carriers at common law suggest that common carriers have an obligation to charge reasonable rates. This does not appear consistent with the historical case law and each time I have tried to trace the authority for that proposition it is apparent that it is not an accurate restatement of the authority. The requirement that rates be reasonable cannot be so generally construed. "Reasonableness" is sometimes used as a stand in for equal or indiscriminate charging. Discussions of reasonable rates also often flow from the discussions of a common carrier's entitlement to payment or *quantum meruit* remedy, which recognizes an implied right to reasonable payment in the absence of express terms concerning payment.

See for example *British Columbia Electric Railway v. British Columbia Public Utilities Commission,* [1960] S.C.R. 837, 1960 CarswellBC 94 at paras. 20-22. I note that at para. 20 the Supreme Court of Canada very generally stated that a common carrier has on it "imposed as a matter of law the duty of transporting goods tendered to him for transport at fair and reasonable rates." However, the Court goes on to cite cases and secondary sources that confirm that the fair and reasonable or *quantum meruit* rate is only charged in absence of a particular agreement as to the amount to be paid.

See also *London & North Western Ry. Co. v. Evershed* (1878), L.R. 3 App. Cas. 1029 (H.L.), which has been cited for the proposition that if a customer is forced to pay a larger sum than what is reasonable in the circumstances in order to have the carrier to carry the goods concerned, the customer may recover the excess payment. Reading those reasons at 1035, it is clear that such "excess payment" is recoverable only if the customer is charged a rate that it is not comparable or equal to other customers of the same kind, doing the same business and supplying the same traffic.

In that sense, in terms of pricing, restrictions on common carriers are concerned with the fairness of relative rates as a means to prevent price discrimination, whereas restrictions on public utilities are concerned with the fairness of absolute rates as a means of ensuring access.

[99] NEB Decision RHW-001-2013 (January 2015) [*TransMountain Pipeline 2015 Tolls Decision*] at 29.
[10] NEB Decision RH-001-2012 (May 2013) [*TransMountain Pipeline 2013 Tolls Decision*] at 29.

- While section 71 does not specifically refer to common carriage, the Board has repeatedly noted that this section most closely relates to the common law duties of a common carrier pipeline[11]
- Although it is common practice to refer to oil pipelines under the Board's jurisdiction as "common carriage pipelines", the National Energy Board Act does not define or use this term. However, the statutory embodiment of this common law concept and the duty of pipeline companies for the transmission of oil or gas are set out in section 71 of the Act.[12]
- Subsection 71(1) generally reflects the common law interpretation of common carrier obligations in respect of oil pipelines. An oil pipeline must receive and transmit all oil offered for transmission by means of its pipeline, if the Board finds that no undue burden will be placed on the company by requiring the company to do so. Taken together, subsections 71(1) and section 67 require an oil pipeline to offer service under the same terms and conditions to any party wishing to ship oil on its pipeline.[13]
- Subsection 71(1) of the NEB Act embodies the common law concept that oil pipelines under the Board's jurisdiction are "common carriage" pipelines.[14]
- Subsection 71(1) grants the Board broad authority, and, in contrast to some other provisions in the Act, does not specify criteria that the Board must take into consideration. The Act does not define or use the term common carrier; nor does it establish whether, and if so under what circumstances, priority access may be granted on an oil pipeline. The Board has a wide discretion in determining compliance with this section and could, if it found it necessary and appropriate, grant an exemption from the requirements of subsection 71(1). The Board has, in the past, held that compliance with the common carrier provision is determined by a test of reasonableness, which is a relative concept. It follows that statutory service obligations which are imposed by law on regulated undertakings are relative, rather than absolute, obligations. Subsection 71(1) permits the Board to tailor the statutory obligations to fit any unique circumstances which may exist; therefore, the provision imposing common carrier obligations must be considered within the circumstances of each case.[15]
- "Common Carrier Pipeline" is defined as follows: "Pursuant to the NEB Act, a company operating a pipeline under the Board's jurisdiction for the transmission of oil '... shall, according to its powers, without delay and with due care and diligence, receive, transport and deliver all oil offered for transmission by means of its pipeline.' (subsection 71(1) of the NEB Act)."[16]
- Regulatory statutes such as the NEB Act must be applied along with the common law where there is no apparent conflict between the statute and the common law. It is clear from the common law that a common carrier may be created by the actions of the undertaking itself, in holding out to the public through public tariffs, or otherwise, that it will carry all traffic of a particular description offered to it for transportation. … The importance of the approach articulated in the case law is that compliance with the common carrier provisions is determined by a test of reasonableness, which is a relative concept. Section 71 of the NEB Act is consistent with this common law approach because it permits the Board to tailor the statutory obligations of both oil and gas pipelines to fit any unique circumstances which may exist.[17]
- Together, these provisions [ss. 71(1) and 67] require that an oil pipeline offer service under the same terms and conditions to any party wishing to ship oil on its line. …[the pipeline operator] has not contravened its common carrier obligations under subsection 71(1) of the NEBA.[18]

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[11] NEB Decision OH-2-97 (December 1997) [*Interprovincial Pipe Line Decision*] at 49.
[12] *TransMountain Pipeline Capacity Allocation Procedure Decision* (March 2006 - August 2007) at 13.
[13] NEB Decision OH-2-96 (May 1997) [*Novagas Clearinghouse Pipelines Decision*] at 12-14; see also NEB Decision OH-3-96 (April 1997) [*Federated Pipe Lines Decision*] at 12-14. Both are quoted also in NEB Decision MH-3-2000 (November 2000) [*Trans-Northern Pipelines Suspension of Service Decision*] at 7.
[14] NEB Decision RH-2-2011 (December 2011) [*TransMountain Access Decision*] at 16.
[15] *TransMountain Access Decision* at 25.
[16] NEB Decision MH-4-96 (February 1997) [*PanCanadian NGL Access Decision*] at (iii); see also 10-12 for application of common carrier principles.
[17] *PanCanadian NGL Access Decision* at 10-12.
[18] NEB Decision OH-1-95 (June 1996) [*Express Pipeline Decision*] at 25 and 27.

- With respect to the duties and obligations of IPL as a "common carrier" the Board would draw the attention of parties to subsection 59(1) of the Act [predecessor to s. 71(1)] … Thus, the obligation on the pipeline is only imposed according to its powers and therefore the pipeline must have available both the capacity and the necessary facilities in order to be able to transport a particular product tendered to it. Of course, if the company does not presently have the required facilities it is clearly open to it to apply to the Board for approval to construct the necessary facilities.[19]

4. NEB/CER STATEMENTS ON POLICY OBJECTIVES AND OVERARCHING PRINCIPLES GOVERNING TOLL SETTING

The NEB helpfully summarized the tolling principles that assist in the interpretation and application of s. 62 of the NEB Act (the provision that requires tolls to be just and reasonable) in a 2007 decision as follows. I note that nowhere in the decision does the NEB refer to common carrier principles.

> The Board finds it beneficial to review those guiding principles and considerations [with respect to tolling] in this section as they provide an effective framework for deciding on the issues before the Board in this application.
>
> …
>
> **Cost Based and User Pay**
>
> A principle referred to in many Board decisions is that tolls should be, to the greatest extent possible, cost based and that the users of a pipeline system should bear the financial responsibility for the costs caused by the transportation of their product through the pipeline. This is often referred to as the cost-based/user-pay principle, which the Board views as a single toll-making principle. At other times, this principle is referred to as the cost causation principle.
>
> …
>
> **No Acquired Rights**
>
> … payment of tolls in the past conferred no benefit on tollpayers beyond the provision of services at that time. In other words, previous tollpayers have no acquired rights. The Board stated that it does not equate those who paid for a service with those who paid for the facilities. Accordingly, the Board rejected the notion that shippers who have used the pipeline in the past are somehow entitled to continue using the existing facilities without being affected by new circumstances. They cannot be exempted from a toll increase simply because they paid tolls in the past.
>
> …
>
> **Economic Efficiency**
>
> The concept of economic efficiency has been a part of the Board's strategic goals for many years. In the context of regulated tolls, economic efficiency generally means that tolls should promote proper price signals in order to maximize the utilization of the pipeline system and thus lower costs.
>
> …
>
> **Degree of Integration and Nature of Service**
>
> While not principles, the Board, in past hearings, has treated the following two factors as key considerations when deciding whether rolled-in or stand-alone tolls would best adhere to the principle of cost-based/user-pay tolls. Those factors are: (1) the degree to which the proposed facilities would be integrated with the rest of the pipeline system; and (2) the nature of the service to be provided by the proposed facilities in relation to the service provided by the rest of the pipeline system.
>
> …
>
> **Other Considerations**
>
> Other toll methodology considerations raised by parties in past Board hearings are practicality, toll stability and administrative simplicity. While the Board found these to be useful considerations, it did not find them to be the primary ones in arriving at just and reasonable tolls. [Citations omitted.] [20]

[19] NEB Decision RH-2-88 (July 1987) [*Interprovincial Pipe Line Tolls Decision*] at 49-50.
[20] NEB Decision RH-1-2007 (July 2007) at 21-23.

The following are quotes from other CER or NEB decisions regarding the principles and policy it applies when setting tolls (which considers both ss. 62 and 67). Citations to other decisions have been omitted from all quotes included below.

- …the NEB [has] articulated a number of tolling principles that assist in the interpretation and application of this statutory provision. These fundamental tolling principles include cost-based/user-pay, economic efficiency, and no acquired rights.
  The cost-based/user-pay principle means that tolls should be, to the greatest extent possible, cost based and that users of a pipeline system should bear the financial responsibility for the costs caused by the transportation of their product through the pipeline without unjustified cross subsidization by other rate payers. The NEB has stated that adherence to the principle of cost causation lays the foundation for fair competition among regulated pipelines.
  The NEB has also stated that in the context of regulated tolls, economic efficiency generally means that tolls should promote proper price signals, which will protect against over investment and promote the efficient development and use of pipeline systems.
  The no acquired rights principle has been articulated as meaning that payment of tolls in the past confers no benefit on toll payers beyond the provision of service at that time.[21]

- …the Board has been guided by a number of tolling principles and key considerations in determining whether tolls are just and reasonable and not unjustly discriminatory. These fundamental tolling principles are no unjust discrimination, costbased/user-pay, no acquired rights and economic efficiency. The Board has also referenced fairness and equity in past decisions as important factors to be considered under Part IV of the NEB Act. … The Board remains guided by these principles, which are inherent in the Board's exercise of its mandate to set just and reasonable tolls and to establish non-discriminatory access to transportation. The Board reaffirms that these fundamental tolling principles and key considerations remain of utmost importance.[22]

- …in accordance with the principles of cost causation and 'user pay', the shippers using and benefiting from this service should be required to bear the incremental costs in order to ensure that undue cross-subsidization by other tollpayers does not occur.[23]

- In the Board's view, the costs of any portion of an integrated pipeline system, which is jointly used by many shippers and which provides a standard service, should be shared by all system users through rolled-in tolls. Rolled-in tolls reflect the facts that all shippers cause costs on the system and that all shippers also share the benefits of the integrated system. In such instances, rolled-in tolls send the correct market signals to shippers with respect to the cost of providing the service.[24]

- In the Board's view, economic regulation is designed to prevent the potential abuse of market power by a pipeline company operating in a monopolistic environment or in one with limited competition. In this regard, regulation ensures that a pipeline company charges rates that are fair to shippers while simultaneously providing the company with a reasonable opportunity to earn a fair return on its capital investment. Different environments require different levels of regulatory input. The Board considers that certain circumstances may require little regulatory input, such as when competitive forces are sufficient to justify allowing the market to work. In other cases, the existence of market power, or more specifically the potential to abuse market power, may require more active regulatory intervention.[25]

- While cost of service has been widely used and accepted in toll design, there is no requirement that tolls be derived in this manner in order to be found just and reasonable. The methodology that the Board employs in setting just and reasonable tolls is not prescribed by law, and the Board has broad discretion to determine what is just and reasonable.[26]

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[21] CER Decision RH-001-2019 (March 2020) at 2-3. NOTE: This decision was made under the NEB Act, as the transition provisions of the CER Act provided that applications which commenced prior to the CER Act coming into force would be decided by the CER under the provisions of the NEB Act.
[22] NEB Decision RH-001-2016 (November 2016) at 32-33.
[23] NEB Decision GH-2-87 (July 1988) at 78.
[24] NEB Decision GH-R-1-92 (June 1992) at 67.
[25] NEB Decision RH-002-2014 (July 2015) at 7.
[26] *Ibid* at 42.

- The Board is ever mindful of its obligation to set just, reasonable, and not unjustly discriminatory tolls, and reiterates its finding… that there is a limit to the level of costs related to underutilization resulting from competition that Mainline shippers can absorb for tolls to remain just and reasonable. This limit has not been exceeded, and the proposal results in just and reasonable tolls.[27]
- The Board recognizes business risk from a variety of sources and allows a regulated pipeline the opportunity to earn higher returns where there is higher risk. Just and reasonable tolls provide the opportunity for debt and equity investors to earn a fair return in a cost of service regime.[28]
- In determining just and reasonable tolls, one of the approaches the Board has taken is to allocate costs to various services on the basis of cost causation ; tolls are then designed to recover the costs of these services from the customers using them. … Although the Board has a wide discretion in choosing a toll methodology which results in just and reasonable tolls, this discretion is fettered by the requirement … that tolls shall not be unjustly discriminatory.[29]
- …the Board believes that in order to set just and reasonable tolls for [the pipeline operator], the principles of cost-based/user-pay tolls and no unjust discrimination should be respected. If possible, the objectives of simplicity, stability and predictability' should be met, but not at the expense of the principles. Further, tolls should ideally be set in order to promote economic efficiency. However, when there is a conflict between adherence to the principles of cost-based/user-pay tolls and setting tolls to promote economic efficiency, there would need to be strong reasons before the Board would depart from adherence to cost-based/user-pay tolls. Finally, consideration should be given to fairness for all of the parties affected by the decision.[30]
- …there is an important distinction to be made between facilities which are dedicated to one shipper or one commodity group and facilities which serve, or which can reasonably be expected to serve, many shippers or commodity groups. … In view of the foregoing, the Board does not believe that a cost-allocation methodology, such as the light-crude equivalency approach proposed here by [the pipeline operator], is appropriate. The costs associated with the proposed NGL facilities can clearly be attributed to their users and the principle of user-pay can best be applied by a stand-alone approach.[31]
- When using the cost of service approach to determine tolls, the cost of capital is determined using the Board's sound judgment. Often the largest and therefore most important portion of cost of capital is the overall return on equity. While customers and consumers have an interest in ensuring that the cost of equity is not overstated, in the Board's view, this is factored in by having intervenors test and challenge the position the company has put forward. It does not mean that in determining the cost of capital that investor and consumer interests are balanced. In the Board's view, the Federal Court of Appeal was clear that the overall return on equity must be determined solely on the basis of a company's cost of equity capital, and that the impact of any resulting toll increase is an irrelevant consideration in that determination.[32]

[27] NEB Decision RH-001-2014 (December 2014) at 86.
[28] NEB Decision RH-4-2010 (June 2011) at 15.
[29] NEB Decision GH-2-87 (July 1988) at 71-72.
[30] NEB Decision RH-2-91 (June 1992) at 62.
[31] NEB Decision GHW-5-90 and RH-3-90 (February 1991) at 38-39.
[32] NEB Decision RH-1-2008 (March 2009) at 6.

Baer, Alexander

From: Keen, Matthew
Sent: October 2, 2019 6:04 AM
To: pattyslee@comcast.net; pbowman@intergroup.ca; Melissa@intergroup.ca
Cc: Bond, Niles; Chan, Emily; Tomm, Jonathan
Subject: Fwd: Shipper Notification: Trans Mountain 2019 Depreciation Study and Revised Depreciation Rates

Anything useful here?

Matthew D. Keen*
Partner

Norton Rose Fulbright Canada LLP / S.E.N.C.R.L., s.r.l.
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T: +1 604.641.4913 | F: +1 604.646.2551
matthew.keen@nortonrosefulbright.com
*Law Corporation

NORTON ROSE FULBRIGHT

Begin forwarded message:

From: <NoReply-SPF@transmountain.com>
Date: October 2, 2019 at 4:33:06 AM PDT
To: <mdk@bht.com>
Subject: Shipper Notification: Trans Mountain 2019 Depreciation Study and Revised Depreciation Rates

To: Trans Mountain Shippers and Interested Parties

Trans Mountain 2019 Depreciation Study and Revised Depreciation Rates

Please be advised that Trans Mountain has filed its Application to the Canada Energy Regulator for approval of the revised depreciation rates to be effective January 1, 2020 in accordance with the results of the 2019 Depreciation Study.

https://apps.cer-rec.gc.ca/REGDOCS/Item/Filing/C02007

Should you have any questions please contact the undersigned.

Dorothy Golosinski

Director Regulatory/

Directrice, Réglementation

W: 587.956.7061

dorothy_golosinski@transmountain.com

Toll Free: 1.866.514.6700 | E: info@transmountain.com|W: transmountain.com

Follow: @TransMtn

Baer, Alexander

From: Bond, Niles
Sent: May 30, 2019 12:32 PM
To: Keen, Matthew; 'Patricia Lee'; 'Patrick Bowman'; 'Melissa Davies'
Cc: Manhas, Michael
Subject: Item #2: Reporting from Kinder Morgan Canada (KMC) and Kinder Morgan (KM)
Attachments: KMC 2018 10K - Final.pdf; KM-2018-10K_final.pdf

Hello all,

To follow up for item #2, I had looked at KMC and KM's reporting back in January, when Matt had asked me to investigate revenues for KMJF's revenues prior to the 10 year settlement. KMJF itself does not publish annual reports that I could find. KMJF's parent company is KMC, while a further parent of KMC is KM. The information online for the KMJF system published by KM and KMC is rather sparse as well. I looked at KMC and KM's reports to see whether they would contain financial information on KMJF, and found that neither have KMJF specific information (other than a general summary description of the pipeline and its history, i.e. no financial information). I attach the 2018 report for both as examples.

- The KMC reports only provide financial information with regard to two "reportable segments" — terminals and pipelines. The KMJF pipeline is one of two pipelines under the pipeline segment, along with Cochin, a 12-inch diameter pipeline which spans approximately 1,000 kilometers in Saskatchewan and Alberta. Because only information for the segment in the aggregate is presented and the two are intermingled, there is not independent reporting with regard to the KMJF pipeline.
- The most relevant information that I could find in the KM reports was with regard to Jet fuel throughput volumes, at page 48 of the attached report. It was not clear to me that KM does not carry jet fuel on its other pipelines as well however, so I was reluctant to rely on this information. The report also did not contain other financial information that was jet fuel or KMJF specific, so the reports would be of limited usefulness in any event.

I note that KMC addressed abandonment costs in its report at page 22 in the following way:

> ***We may be subject to abandonment costs.***
>
> We are responsible for compliance with all applicable laws and regulations regarding the abandonment of our pipeline systems and other assets at the end of their economic life, and these abandonment costs may be substantial. The proceeds of the disposition of certain assets, including in respect of certain pipeline systems and line fill, may be available to offset abandonment costs. <u>While we estimate future abandonment costs and receive (through tolls) future abandonment costs based on such estimates, actual abandonment costs may be higher than the amounts received through tolls. We may, in the future, determine it to be prudent or required by applicable laws or regulations to establish and fund additional reclamation trusts to provide for payment of our future abandonment costs.</u> Such reserves could decrease cash flow available for dividends to shareholders and to service our obligations under any applicable debt obligations.
>
> To date, we have complied with the NEB's requirements on Cochin, our NEB-regulated pipeline, for the creation of abandonment trusts and have completed the compliance-based filings that are required under the applicable NEB rules and regulations regarding its abandonment. While we collect abandonment surcharges from our shippers and deposit such amounts in our abandonment trust for our NEB-regulated pipelines, there is a risk that abandonment costs and post-abandonment liabilities could exceed the amounts held in trust. Further, and unlike our approach to Cochin, we do not maintain dedicated abandonment trusts for our Jet Fuel or terminals assets. Additional or unexpected expenditures incurred in respect of abandonment costs could have a material adverse effect on our business, results of operations and financial condition.
>
> [Emphasis added.]

Please let me know if you have any questions or would like me to do further research, I would be happy to do so.

Best,
Niles

Niles Bond
Associate

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NORTON ROSE FULBRIGHT

From: Bond, Niles
Sent: May 30, 2019 11:48 AM
To: Keen, Matthew; Patricia Lee; 'Patrick Bowman'; 'Melissa Davies'
Cc: Manhas, Michael
Subject: NEB submissions summary

Hello all,

As discussed, here is a summary that I prepared at Matt's request of relevant portions from the TransCanada and Enbridge submissions, with regard to collection of abandonment costs and liability, in the NEB proceeding: Land Matters Consultation Initiative (LMCI) Stream 3. The relevant documents these excerpts are taken from are attached, with the excerpted portions highlighted. I also attach a copy of the NEB's decision on stream 3.

Enbridge Responses to NEB IR No. 1, IR 1.8:

> Collecting abandonment costs over a longer period can mitigate some of the risk of intergenerational equity because earlier generations of shippers are required to pay a share of the abandonment costs. This factor militates in favour of a longer time horizon of foreseeability and thus a longer collection period.
>
> Conversely, it must be recognized that over-collection from early shippers would also be inequitable. For example, commencing collection before abandonment is reasonably foreseeable is more likely to make the estimates of abandonment timing and abandonment costs even more speculative and thus less reliable as a basis for tolls. This creates a risk of over-collection from shippers and militates against requiring the collection of abandonment costs to commence in the shorter term.
>
> An unnecessarily long collection period also imposes a higher administrative burden both in absolute terms and relative to the amount of the funds collected – particularly in early years. The practical result can be greater costs with little or no corresponding economic benefit.
>
> Finally, the collection and setting aside of abandonment funds creates an opportunity cost vis-à-vis other, potentially more productive, uses for the capital. An unnecessarily long collection period exacerbates that opportunity cost.
> Deferral of fund collection in appropriate circumstances can mitigate these risks and, conversely, should not increase the risk of under-collection (or of a "death spiral") due to the expected length of the period of reasonable foreseeability.
>
> Deferral of fund collection is unlikely to impact competitiveness since the expected economic lives of competing pipelines (i.e., those that are providing capacity from the same producing regions to similar markets) can be expected to be of a similar length (such that their abandonment fund collection would begin more or less contemporaneously).

Reply Written Evidence of Enbridge Pipelines Inc.:

> Includes, as Appendix A, a report from Wright Mansell Research Limited that provides analysis regarding the appropriate time horizon for accumulating funds to cover the costs of facility abandonment. While this report may be interesting and relevant to consider generally, it specifically addresses issues of rate stability, and fairness and

equity amongst intergenerational shippers. For example, "As noted in Section 4.3 above, there are numerous dimensions to [the criterion of fairness and equity]. The principle of 'no acquired rights' would suggest that any surcharge for abandonment should be applied to all users of a particular component of a system rather than being 'vintaged' (that is, differentially applied to shippers based on whether they used the system on a particular date, over a particular period or for a particular market). Put differently, if this principle was not applied and abandonment costs were differentially applied across shippers it is more likely that other regulatory objectives (such as rate stability) would not be met."

TransCanada written evidence:

A8. Intergenerational inequity arises if pipeline companies are not required to begin setting aside funds to cover abandonment costs. Funds to cover the costs associated with the eventual terminal abandonment of a pipeline should be collected sufficiently in advance of abandonment so as not to unfairly burden those shippers who contract for service on the pipeline towards the end of its economic life. In recovering costs through utility rates, a basic regulatory and financial principle is that the customers who benefit from a required service should bear the cost of providing the service, including terminal abandonment costs. There should be a fair allocation of costs among customer generations.

TransCanada Responses to NEB IR No. 1:

1.2. (b) The circumstances will vary from pipeline to pipeline, but "sufficiently in advance" should in principle be a point for all pipelines whereby:

- the collection of abandonment costs will minimize intergenerational inequity among rate payers; and
- there can be a material accumulation of compounded interest on invested funds.

1.6 With regard to how to address toll settlements that do not contemplate collection for abandonment, TransCanada responded as follows:

Possible options to address this issue are:

- The terms of the settlement are maintained and collection is deferred until after the settlement has expired;
  - o The settlement has been negotiated to provide shippers with a greater degree of certainty of costs in the revenue requirement. Deferring the collection of abandonment funds maintains this certainty. Commencing collection of abandonment costs would start after the settlement has expired and could become part of the revenue requirement in a new negotiated settlement.
- The Board mandates the collection of funds for abandonment during the Settlement in the form of an order;
  - o If deferring the collection of abandonment funds is deemed to be inappropriate, the Board could order the funds to be collected during the term of any existing settlement and treated as a flow through cost item in the existing settlement. A Board order would preclude the pipeline from having to open an existing settlement and change the terms under which it was negotiated. It would also limit the issue to collection of abandonment funds only and not open other aspects of the settlement that parties might wish to change.

1.7 With regard to questions about the risks of, and caused by, orphaned pipelines:

There will always exist some element of risk that insufficient funds will be collected before a pipeline is abandoned. However, pipelines are tightly regulated and a properly designed framework would allow the Board to review the appropriateness of the amount of funds collected by a pipeline. This should minimize the risk of an orphan pipeline situation.

Any risk faced by landowners, governments and other stakeholders with respect to orphan pipelines must be balanced against the appropriateness of collecting costs from shippers and users of other systems who have received no benefit associated with the orphaned pipeline. Further, this would be a departure from cost causality that is fundamental to rate-making principles. The cost of abandonment is a cost of service that each pipeline incurs. As such, each pipeline is responsible through its collection of tolls to ensure that sufficient funds are collected to cover these costs.

Submissions made in the proceeding's transcripts:

Vol 1, Witnesses for Enbridge:

- P. 47: Insufficient collection for abandonment should be a risk born by the company, not landowners or otherwise. This point is elaborated on at pp. 52-60, 76-79, and 89-90. Enbridge's primary position is that orphan pipelines are more of a theoretical and practical concern, if proper regulatory procedures are in place.

Vol 4, Witnesses for TransCanada:

- A similar position to Enbridge's is by TransCanada expressed at pp. 30-33, 47, 58 and 60.
- At pp. 38-40 TransCanada also spoke to the issues that could be associated with toll settlement agreements, including potential intergenerational risk and inter-pipeline competition issues.

Vol 6, final submissions:

- TransCanada and Enbridge's final submissions, including with regard to the issues of intergenerational equity and risk of under-collection for abandonment at pp. 15-19 and 65.

Best,
Niles

Niles Bond
Lawyer

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niles.bond@nortonrosefulbright.com

NORTON ROSE FULBRIGHT

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2018

or

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____to_____

Commission file number: 001-35081

Kinder Morgan, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**80-0682103**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

1001 Louisiana Street, Suite 1000, Houston, Texas 77002

(Address of principal executive offices) (zip code)

Registrant's telephone number, including area code: 713-369-9000

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Class P Common Stock	New York Stock Exchange
1.500% Senior Notes due 2022	New York Stock Exchange
2.250% Senior Notes due 2027	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934. Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K(§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934).
Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐ Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes ☐ No ☑

Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant, based on closing prices in the daily composite list for transactions on the New York Stock Exchange on June 29, 2018 was approximately $33,499,494,320. As of February 7, 2019, the registrant had 2,263,656,419 Class P shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2019 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2019, are incorporated into PART III, as specifically set forth in PART III.

KINDER MORGAN, INC. AND SUBSIDIARIES
TABLE OF CONTENTS

KINDER MORGAN, INC. AND SUBSIDIARIES
TABLE OF CONTENTS (continued)

KINDER MORGAN, INC. AND SUBSIDIARIES
GLOSSARY
Company Abbreviations

Calnev	=	Calnev Pipe Line LLC
CIG	=	Colorado Interstate Gas Company, L.L.C.
CPGPL	=	Cheyenne Plains Gas Pipeline Company, L.L.C.
EagleHawk	=	EagleHawk Field Services LLC
Elba Express	=	Elba Express Company, L.L.C.
ELC	=	Elba Liquefaction Company, L.L.C.
EPB	=	El Paso Pipeline Partners, L.P. and its majority-owned and controlled subsidiaries
EPNG	=	El Paso Natural Gas Company, L.L.C.
FEP	=	Fayetteville Express Pipeline LLC
Hiland	=	Hiland Partners, LP
KinderHawk	=	KinderHawk Field Services LLC
KMEP	=	Kinder Morgan Energy Partners, L.P.
KMGP	=	Kinder Morgan G.P., Inc.
KMI	=	Kinder Morgan, Inc. and its majority-owned and/or controlled subsidiaries
KML	=	Kinder Morgan Canada Limited and its majority-owned and/or controlled subsidiaries
KMLP	=	Kinder Morgan Louisiana Pipeline LLC
KMP	=	Kinder Morgan Energy Partners, L.P. and its majority-owned and controlled subsidiaries
KMTP	=	Kinder Morgan Texas Pipeline LLC
MEP	=	Midcontinent Express Pipeline LLC
NGPL	=	Natural Gas Pipeline Company of America LLC
Ruby	=	Ruby Pipeline Holding Company, L.L.C.
SFPP	=	SFPP, L.P.
SLNG	=	Southern LNG Company, L.L.C.
SNG	=	Southern Natural Gas Company, L.L.C.
TGP	=	Tennessee Gas Pipeline Company, L.L.C.
TMEP	=	Trans Mountain Expansion Project
TMPL	=	Trans Mountain Pipeline System
Trans Mountain	=	Trans Mountain Pipeline ULC
WIC	=	Wyoming Interstate Company, L.L.C.
WYCO	=	WYCO Development L.L.C.

Unless the context otherwise requires, references to “we,” “us,” “our,” or “the Company” are intended to mean Kinder Morgan, Inc. and its majority-owned and/or controlled subsidiaries.

Common Industry and Other Terms

2017 Tax Reform	=	The Tax Cuts & Jobs Act of 2017
/d	=	per day
AFUDC	=	allowance for funds used during construction
BBtu	=	billion British Thermal Units
Bcf	=	billion cubic feet
CERCLA	=	Comprehensive Environmental Response, Compensation and Liability Act
C$	=	Canadian dollars
CO_2	=	carbon dioxide or our CO_2 business segment
CPUC	=	California Public Utilities Commission
DCF	=	distributable cash flow
DD&A	=	depreciation, depletion and amortization
Dth	=	dekatherms
EBDA	=	earnings before depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments
EPA	=	United States Environmental Protection Agency
FASB	=	Financial Accounting Standards Board
FERC	=	Federal Energy Regulatory Commission
GAAP	=	United States Generally Accepted Accounting Principles
IPO	=	Initial Public Offering
LIBOR	=	London Interbank Offered Rate
LLC	=	limited liability company
LNG	=	liquefied natural gas
MBbl	=	thousand barrels
MDth	=	thousand dekatherms
MLP	=	master limited partnership
MMBbl	=	million barrels
MMcf	=	million cubic feet
NEB	=	Canadian National Energy Board
NGL	=	natural gas liquids
NYMEX	=	New York Mercantile Exchange
NYSE	=	New York Stock Exchange
OTC	=	over-the-counter
PHMSA	=	United States Department of Transportation Pipeline and Hazardous Materials Safety Administration
U.S.	=	United States of America
SEC	=	United States Securities and Exchange Commission
TBtu	=	trillion British Thermal Units
WTI	=	West Texas Intermediate

When we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

Information Regarding Forward-Looking Statements

This report includes forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "intend," "plan," "projection," "forecast," "strategy," "outlook," "continue," "estimate," "expect," "may," or the negative of those terms or other variations of them or comparable terminology. In particular, expressed or implied statements concerning future actions, conditions or events, future operating results or the ability to generate sales, income or cash flow, service debt or pay dividends, are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results may differ materially from those expressed in our forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or accurately predict. Specific factors that could cause actual results to differ from those in our forward-looking statements include:

- changes in supply of and demand for NGL, refined petroleum products, oil, CO_2, natural gas, electricity, coal, steel and other bulk materials and chemicals and certain agricultural products in North America;
- economic activity, weather, alternative energy sources, conservation and technological advances that may affect price trends and demand;
- changes in our tariff rates required by the FERC, the CPUC, Canada's NEB or another regulatory agency;
- our ability to acquire new businesses and assets and integrate those operations into our existing operations, and make cost-saving changes in operations, particularly if we undertake multiple acquisitions in a relatively short period of time, as well as our ability to expand our facilities;
- our ability to safely operate and maintain our existing assets and to access or construct new assets including pipelines, terminals, gas processing, gas storage and NGL fractionation capacity;
- our ability to attract and retain key management and operations personnel;
- difficulties or delays experienced by railroads, barges, trucks, ships or pipelines in delivering products to or from our terminals or pipelines;
- shut-downs or cutbacks at major refineries, petrochemical or chemical plants, natural gas processing plants, ports, utilities, military bases or other businesses that use our services or provide services or products to us;
- changes in crude oil and natural gas production (and the NGL content of natural gas production) from exploration and production areas that we serve, such as the Permian Basin area of West Texas, the shale plays in North Dakota, Oklahoma, Ohio, Pennsylvania and Texas, and the U.S. Rocky Mountains;
- changes in laws or regulations, third-party relations and approvals, and decisions of courts, regulators and governmental bodies that may increase our compliance costs, restrict our ability to provide or reduce demand for our services, or otherwise adversely affect our business;
- interruptions of operations at our facilities due to natural disasters, damage by third parties, power shortages, strikes, riots, terrorism (including cyber attacks), war or other causes;
- the uncertainty inherent in estimating future oil, natural gas, and CO_2 production or reserves;
- issues, delays or stoppage associated with new construction or expansion projects;
- regulatory, environmental, political, grass roots opposition, legal, operational and geological uncertainties that could affect our ability to complete our expansion projects on time and on budget or at all;
- the timing and success of our business development efforts, including our ability to renew long-term customer contracts at economically attractive rates;
- the ability of our customers and other counterparties to perform under their contracts with us;

- competition from other pipelines, terminals or other forms of transportation;
- changes in accounting pronouncements that impact the measurement of our results of operations, the timing of when such measurements are to be made and recorded, and the disclosures surrounding these activities;
- changes in tax laws;
- our ability to access external sources of financing in sufficient amounts and on acceptable terms to the extent needed to fund acquisitions of operating businesses and assets and expansions of our facilities;
- our indebtedness, which could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, place us at a competitive disadvantage compared to our competitors that have less debt, or have other adverse consequences;
- our ability to obtain insurance coverage without significant levels of self-retention of risk;
- natural disasters, sabotage, terrorism (including cyber attacks) or other similar acts or accidents causing damage to our properties greater than our insurance coverage limits;
- possible changes in our and our subsidiaries' credit ratings;
- conditions in the capital and credit markets, inflation and fluctuations in interest rates;
- political and economic instability of the oil producing nations of the world;
- national, international, regional and local economic, competitive and regulatory conditions and developments, including the effects of any enactment of import or export duties, tariffs or similar measures;
- our ability to achieve cost savings and revenue growth;
- foreign exchange fluctuations;
- the extent of our success in developing and producing CO_2 and oil and gas reserves, including the risks inherent in development drilling, well completion and other development activities;
- engineering and mechanical or technological difficulties that we may experience with operational equipment, in well completions and work-overs, and in drilling new wells; and
- unfavorable results of litigation and the outcome of contingencies referred to in Note 18 "*Litigation, Environmental and Other Contingencies*" to our consolidated financial statements.

The foregoing list should not be construed to be exhaustive. We believe the forward-looking statements in this report are reasonable. However, there is no assurance that any of the actions, events or results expressed in forward-looking statements will occur, or if any of them do, of their timing or what impact they will have on our results of operations or financial condition. Because of these uncertainties, you should not put undue reliance on any forward-looking statements.

Additional discussion of factors that may affect our forward-looking statements appears elsewhere in this report, including in Item 1A "*Risk Factors,*" Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations,*" and Item 7A "*Quantitative and Qualitative Disclosures About Market Risk—Energy Commodity Market Risk.*" In addition, there is a general level of uncertainty regarding the extent to which potential positive or negative changes to fiscal, tax and trade policies may impact us and those with whom we do business. It is not possible at this time to predict the extent of any such impact. When considering forward-looking statements, you should keep in mind the factors described in this section and the other sections referenced above. These factors could cause our actual results to differ materially from those contained in any forward-looking statement. We disclaim any obligation, other than as required by applicable law, and described below under Items 1 and 2 "*Business and Properties—(a) General Development of Business—2019 Outlook,*" to update the above list or to announce publicly the result of any revisions to any of our forward-looking statements to reflect future events or developments.

PART I

Items 1 and 2. ***Business and Properties.***

We are one of the largest energy infrastructure companies in North America. We own an interest in or operate approximately 84,000 miles of pipelines and 153 terminals. Our pipelines transport natural gas, refined petroleum products, crude oil, condensate, CO_2 and other products, and our terminals transload and store liquid commodities including petroleum products, ethanol and chemicals, and bulk products, including petroleum coke, metals and ores. Our common stock trades on the NYSE under the symbol "KMI."

(a) General Development of Business

Organizational Structure

We are a Delaware corporation and our common stock has been publicly traded since February 2011.

You should read the following in conjunction with our audited consolidated financial statements and the notes thereto. We have prepared our accompanying consolidated financial statements under GAAP and the rules and regulations of the SEC. Our accounting records are maintained in U.S. dollars and all references to dollars in this report are to U.S. dollars, except where stated otherwise. Our consolidated financial statements include our accounts and those of our majority-owned and/or controlled subsidiaries, and all significant intercompany items have been eliminated in consolidation. The address of our principal executive offices is 1001 Louisiana Street, Suite 1000, Houston, Texas 77002, and our telephone number at this address is (713) 369-9000.

Recent Developments

The following is a brief listing of significant developments and updates related to our major projects and other transactions. Additional information regarding most of these items may be found elsewhere in this report. "Capital Scope" is estimated for our share of the described project which may include portions not yet completed.

Asset or project	Description	Activity	Approx. Capital Scope
Divestitures			
TMPL(a)	Sold interests in TMPL, TMEP, Puget Sound system and Kinder Morgan Canada Inc. to the Government of Canada.	Completed in August 2018.	n/a
Placed in service or acquisitions			
TGP Broad Run Expansion	Second of two projects to create a total of 790,000 Dth/d of incremental firm transportation capacity from the southwest Marcellus and Utica supply basins to delivery points in Mississippi and Louisiana. Subscribed under long-term firm transportation contracts.	Broad Run Expansion (200,000 Dth/d) was placed in service October 2018. Broad Run Flexibility facilities (590,000 Dth/d) were placed in service November 2015.	$463 million
KM Base Line Terminal Development(b)	A 12 tank, 4.8 MMBbl, new-build merchant crude oil storage facility in Edmonton, Alberta. Developed as part of a 50-50 joint venture with Keyera Corp. Capital figure includes costs associated with the construction of a pipeline segment funded solely by Kinder Morgan. Subscribed under long-term contracts with an average initial term of 7.5 years.	First 6 tanks placed in service in first quarter 2018 with balance placed in service in the third and fourth quarters of 2018.	C$357 million
Elba Express and SNG Expansion	Expansion project that provides 854,000 Dth/d of incremental natural gas transportation service supporting the needs of customers in Georgia, South Carolina and northern Florida, and also serving ELC. Supported by long-term firm transportation contracts.	Initial service began in December 2016 and as of December 31, 2017, more than 70% of capacity had been placed in service. The final portion was placed in service November 2018.	$284 million

Asset or project	Description	Activity	Approx. Capital Scope
Utopia Pipeline	New 270 mile pipeline, supported by long-term transportation contracts, to transport ethane and ethane-propane mixtures from the prolific Utica Shale, with a design capacity of 50 MBbl/d, expandable to more than 75 MBbl/d. We own a 50% interest in and operate Utopia Holding L.L.C. Riverstone Investment Group LLC owns the remaining 50% interest.	Placed in service January 2018.	$275 million
TGP Southwest Louisiana Supply	Expansion project to provide 900,000 Dth/d of incremental firm transportation capacity from multiple supply basins to the Cameron LNG export facility in Cameron Parish, Louisiana. Subscribed under long-term firm transportation contracts.	Placed in service March 2018.	$175 million
KMLP Sabine Pass Expansion	Expansion project to provide 600,000 Dth/d of incremental firm transportation capacity from various receipt points to Cheniere's Sabine Pass Liquefaction Terminal in Cameron Parish, Louisiana. Subscribed under long-term firm transportation contracts.	Placed in service December 2018.	$133 million
SNG Fairburn Expansion	Expansion project in Georgia to provide 370,000 Dth/d of incremental long-term firm transportation capacity into the Southeast market, and includes the construction of a new compressor station, 6.5 miles of new pipeline and new meter stations.	Placed in service December 2018.	$122 million
TGP Lone Star	Expansion project to provide 300,000 Dth/d of incremental firm transportation capacity from Mississippi receipt points to Cheniere's Corpus Christi LNG export facility in Jackson County, Texas. Subscribed under long-term firm transportation contracts.	Placed in service December 2018.	$106 million
NGPL Gulf Coast Southbound Expansion	Expansion project to provide 460,000 Dth/d of incremental firm transportation capacity from various interstate pipeline interconnects in Illinois, Arkansas and Texas, to points south on NGPL's pipeline system to serve growing demand in the Gulf Coast area. Subscribed under long-term firm transportation contracts.	Partially in service April 2017 (75,000 Dth/d). Remaining (385,000 Dth/d) placed in service October 2018.	$88 million
Other Announcements			
Natural Gas Pipelines			
ELC and SLNG Expansion	Building of new natural gas liquefaction and export facilities at our SLNG natural gas terminal on Elba Island, near Savannah, Georgia, with a total capacity of 2.5 million tonnes per year of LNG, equivalent to approximately 357,000 Dth/d of natural gas. Supported by a long-term firm contract with Shell.	First of 10 liquefaction units expected to be placed in service at the end of first quarter 2019 with the remaining 9 units to come online throughout 2019.	$1.2 billion
Permian Highway Pipeline Project (PHP Project)(c)	Joint venture pipeline project (KMTP 50% and BCP PHP, LLC (BCP) 50% ownership interest) is designed to transport up to 2.1 Bcf/d of natural gas through approximately 430 miles of 42-inch pipeline from the Waha, Texas area to the U.S. Gulf Coast and Mexico markets. Subscribed under long-term firm transportation contracts.	Expected in-service date fourth quarter 2020, pending regulatory approvals.	$572 million
Gulf Coast Express Pipeline Project (GCX Project)	Joint venture pipeline project (KMTP 35%, DCP Midstream, LP 25%, an affiliate of Targa Resources Corp. 25% and Altus Midstream Company 15% ownership interest) to provide up to 1.98 Bcf/d of transportation capacity from the Permian Basin to the Agua Dulce, Texas area. Subscribed under long-term firm transportation contracts.	The first 9 miles of the Midland Lateral were placed in service in August 2018 with the remaining 40 miles to be placed in-service in April 2019. Expected full in-service date of the project is October 2019.	$637 million
Texas Intrastate Crossover Expansion	Expansion project that provides over 1,000,000 Dth/d of transportation capacity from the Katy Hub, the Company's Houston Central processing plant, and other third-party receipt points to serve customers in Texas and Mexico. Phase I is supported by long-term firm transportation contracts of nearly 700,000 Dth/d, including a contract with Comisión Federal de Electricidad. Phase 2, which is supported by long-term firm transportation contracts with Cheniere Energy, Inc. at its Corpus Christi LNG facility and SK E&S LNG, LLC, that will provide service to the Freeport LNG export facility and other domestic markets.	Phase 1 was placed in service in September 2016. Phase 2 is expected to be placed in service by second quarter 2020.	$298 million

Asset or project	Description	Activity	Approx. Capital Scope
EPNG South Mainline Expansion	Expansion project that provides 471,000 Dth/d of firm transportation capacity with a first phase of system improvements to deliver volumes to the Sierrita pipeline and the second phase for incremental deliveries of natural gas to Arizona and California. Subscribed under long-term firm transportation contracts.	Phase 1 placed in service October 2014, phase 2 expected to be in service third quarter 2020.	$138 million
NGPL Gulf Coast Southbound Expansion (second phase)	Expansion project to increase southbound capacity on NGPL's Gulf Coast System to serve Corpus Christi Liquefaction. Subscribed under a long-term firm transportaton contract.	Expected in-service date June 2021, pending regulatory approvals.	$114 million

n/a - not applicable

(a) These assets were included in KML and were partially owned by KML's Restricted Voting Stockholders.

(b) These assets are included in KML and are partially owned by KML's Restricted Voting Stockholders.

(c) An affiliate of an anchor shipper exercised its option in January 2019 to acquire 20% equity interest in the project, bringing KMTP's and BCP's ownership interest to 40% each. Altus Midstream Company (Altus Midstream) (a gas gathering, processing and transportation company formed by shipper Apache Corporation) has an option to acquire an equity interest in the project from the initial partners by September 2019. If Altus Midstream exercises its option, KMTP, BCP and Altus Midstream will each hold a 26.67% ownership interest in the project. Our share of capital scope is adjusted to reflect the potential exercise of Altus Midstream's option.

Financings

On January 3, 2019, KML distributed to us our approximately 70% portion of the proceeds from the TMPL Sale of approximately $1.9 billion (after Canadian tax) which we used to repay our outstanding balance of commercial paper borrowings, and then in February 2019, to repay $500 million of maturing 9.00% senior notes and $800 million of maturing 2.65% senior notes.

In December 2018 and January 2019, we repurchased approximately 1.5 million and 0.1 million, respectively, of our Class P shares for approximately $23 million and $2 million, respectively, at an average price of $15.54 per share, as part of our $2 billion common share buy-back program approved by our board of directors in December 2017.

On November 16, 2018, we entered into (i) a new five-year $4.0 billion revolving credit agreement and (ii) a new 364-day $500 million revolving credit agreement with a syndicate of lenders and replaced the prior KMI credit agreement.

2019 Outlook

We expect to declare dividends of $1.00 per share for 2019, a 25% increase from the 2018 declared dividends of $0.80 per share, and generate approximately $5.0 billion of DCF in 2019. We also expect to invest $3.1 billion in expansion projects and contributions to joint ventures during 2019. Our discretionary spending will be primarily funded with excess, internally generated cash flow, with no need to access equity markets during 2019.

We are unable to provide budgeted net income attributable to common stockholders (the GAAP financial measure most directly comparable to DCF) due to the impracticality of predicting certain amounts required by GAAP, such as unrealized gains and losses on derivatives marked to market, and potential changes in estimates for certain contingent liabilities. See Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations—Non-GAAP Financial Measures.*"

Our expectations for 2019 assume average annual prices for WTI crude oil and Henry Hub natural gas of $60.00 per barrel and $3.15 per MMBtu, respectively, consistent with forward pricing during our 2019 budget process. The vast majority of revenue we generate is supported by multi-year fee-based customer arrangements and therefore is not directly exposed to commodity prices. The primary area where we have direct commodity price sensitivity is in our CO_2 segment, in which we hedge the majority of the next 12 months of oil and NGL production to minimize this sensitivity. For 2019, we estimate that every $1 change in the average WTI crude oil price per barrel from our budget of $60.00 per barrel would impact our budgeted DCF by approximately $8 million and each $0.10 per MMBtu change in the average price of natural gas from our budget of $3.15 per MMBtu would impact budgeted DCF by approximately $1 million.

In addition, our expectations for 2019 discussed above involve risks, uncertainties and assumptions, and are not guarantees of performance. Many of the factors that will determine these expectations are beyond our ability to control or predict, and

because of these uncertainties, it is advisable not to put undue reliance on any forward-looking statement. Please read our Item 1A "*Risk Factors*" below for more information. Furthermore, we plan to provide updates to our 2019 expectations when we believe previously disclosed expectations no longer have a reasonable basis.

(b) Financial Information about Segments

For financial information on our reportable business segments, see Note 17 "*Reportable Segments*" to our consolidated financial statements.

(c) Narrative Description of Business

Business Strategy

Our business strategy is to:

- focus on stable, fee-based energy transportation and storage assets that are central to the energy infrastructure of growing markets within North America;
- increase utilization of our existing assets while controlling costs, operating safely, and employing environmentally sound operating practices;
- leverage economies of scale from incremental acquisitions and expansions of assets that fit within our strategy and are accretive to cash flow; and
- maintain a strong balance sheet and return value to our stockholders.

It is our intention to carry out the above business strategy, modified as necessary to reflect changing economic conditions and other circumstances. However, as discussed under Item 1A. *"Risk Factors"* below, there are factors that could affect our ability to carry out our strategy or affect its level of success even if carried out.

We regularly consider and enter into discussions regarding potential acquisitions, and full and partial divestitures, and we are currently contemplating potential transactions. Any such transaction would be subject to negotiation of mutually agreeable terms and conditions, and, as applicable, receipt of fairness opinions, and approval of our board of directors. While there are currently no unannounced purchase or sale agreements for the acquisition or sale of any material business or assets, such transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets or operations.

Business Segments

Our business segments and their primary activities and sources of revenues are as follows:

- Natural Gas Pipelines—the ownership and operation of (i) major interstate and intrastate natural gas pipeline and storage systems; (ii) natural gas and crude oil gathering systems and natural gas processing and treating facilities; (iii) NGL fractionation facilities and transportation systems; and (iv) LNG facilities;
- Products Pipelines—the ownership and operation of refined petroleum products, NGL and crude oil and condensate pipelines that primarily deliver, among other products, gasoline, diesel and jet fuel, propane, ethane, crude oil and condensate to various markets, plus the ownership and/or operation of associated product terminals and petroleum pipeline transmix facilities;
- Terminals—the ownership and/or operation of (i) liquids and bulk terminal facilities located throughout the U.S. and portions of Canada that transload and store refined petroleum products, crude oil, ethanol and chemicals, and bulk products, including petroleum coke, metals and ores; and (ii) Jones Act tankers;
- CO_2—(i) the production, transportation and marketing of CO_2 to oil fields that use CO_2 as a flooding medium to increase recovery and production of crude oil from mature oil fields; (ii) ownership interests in and/or operation of oil fields and gas processing plants in West Texas; and (iii) the ownership and operation of a crude oil pipeline system in West Texas; and
- Kinder Morgan Canada (prior to August 31, 2018)—the ownership and operation of the Trans Mountain pipeline system that transports crude oil and refined petroleum products from Edmonton, Alberta, Canada to marketing terminals and refineries in British Columbia, Canada and the state of Washington. As a result of the TMPL Sale, this segment does not have results of operations on a prospective basis.

Natural Gas Pipelines

Our Natural Gas Pipelines business segment includes interstate and intrastate pipelines and our LNG terminals, and includes both FERC regulated and non-FERC regulated assets.

Our primary businesses in this segment consist of natural gas transportation, storage, sales, gathering, processing and treating, and various LNG services. Within this segment are: (i) approximately 46,000 miles of wholly owned natural gas pipelines and (ii) our equity interests in entities that have approximately 26,000 miles of natural gas pipelines, along with associated storage and supply lines for these transportation networks, which are strategically located throughout the North American natural gas pipeline grid. Our transportation network provides access to the major natural gas supply areas and consumers in the western U.S., Louisiana, Texas, the Midwest, Northeast, Rocky Mountain, Midwest and Southeastern regions. Our LNG terminals also serve natural gas market areas in the southeast. The following tables summarize our significant Natural Gas Pipelines business segment assets, as of December 31, 2018. The Design Capacity represents transmission, gathering or liquefaction capacity, depending on the nature of the asset.

Asset (KMI ownership shown if not 100%)	Miles of Pipeline	Design (Bcf/d) Capacity	Storage (Bcf) [Processing (Bcf/d)] Capacity	Supply and Market Region
Natural Gas Pipelines				
TGP	11,775	12.10	76	Marcellus, Utica, Gulf Coast, Haynesville, and Eagle Ford shale supply basins; Northeast, Southeast U.S., Gulf Coast and U.S.-Mexico border
EPNG/Mojave pipeline system	10,660	5.65	44	Northern New Mexico, Texas, Oklahoma, to California, connects to San Juan, Permian and Anadarko basins
NGPL (50%)	9,100	7.60	288	Chicago and other Midwest markets and all central U.S. supply basins; north to south for LNG and to U.S.-Mexico border
SNG (50%)	6,950	4.32	66	Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina and Tennessee; basins in Texas, Louisiana, Mississippi and Alabama
Florida Gas Transmission (Citrus) (50%)	5,350	3.90	—	Texas to Florida; basins along Louisiana and Texas Gulf Coast, Mobile Bay and offshore Gulf of Mexico
CIG	4,280	5.15	38	Colorado and Wyoming; Rocky Mountains and the Anadarko Basin
WIC	850	3.83	—	Wyoming, Colorado and Utah; Overthrust, Piceance, Uinta, Powder River and Green River Basins
Ruby (50%)(a)	680	1.53	—	Wyoming to Oregon with interconnects supplying California and the Pacific Northwest; Rocky Mountain basins
MEP (50%)	510	1.80	—	Oklahoma and north Texas supply basins to interconnects with deliveries to interconnects with Transco, Columbia Gulf and various other pipelines
CPGPL	410	1.20	—	Colorado and Kansas, natural gas basins in the Central Rocky Mountain area
TransColorado Gas	310	0.80	—	Colorado and New Mexico; connects to San Juan, Paradox and Piceance basins
WYCO (50%)	224	1.20	7	Northeast Colorado; interconnects with CIG, WIC, Rockies Express Pipeline, Young Gas Storage and PSCo's pipeline system
Elba Express	200	1.06	—	Georgia; connects to SNG (Georgia), Transco (Georgia/South Carolina), SLNG (Georgia) and Dominion Energy Carolina Gas Transmission (Georgia)
FEP (50%)	185	2.00	—	Arkansas to Mississippi; connects to NGPL, Trunkline Gas Company, Texas Gas Transmission and ANR Pipeline Company
KMLP	135	2.95	—	Columbia Gulf, ANR Pipeline Company and various other pipeline interconnects; Cheniere Sabine Pass LNG and industrial markets
Sierrita Gas Pipeline LLC (35%)	60	0.20	—	Near Tucson, Arizona, to the U.S.-Mexico border near Sasabe, Arizona; connects to EPNG and via an international border crossing with a third-party natural gas pipeline in Mexico
Young Gas Storage (48%)	17	—	5.8	Morgan County, Colorado, capacity is committed to CIG and Colorado Springs Utilities
Keystone Gas Storage	15	—	6.4	Located in the Permian Basin and near the WAHA natural gas trading hub in West Texas

Asset (KMI ownership shown if not 100%)	Miles of Pipeline	Design (Bcf/d) Capacity	Storage (Bcf) [Processing (Bcf/d)] Capacity	Supply and Market Region
Gulf LNG Holdings (50%)	5	1.50	6.6	Near Pascagoula, Mississippi; connects to four interstate pipelines and a natural gas processing plant
Bear Creek Storage (75%)	—	—	59.2	Located in Louisiana; provides storage capacity to SNG and TGP
SLNG	—	1.76	11.5	Georgia; connects to Elba Express, SNG and Dominion Energy Carolina Gas Transmission
ELC (51%)	—	0.35	—	Georgia; expect phased in-service Q1 2019 through Q4 2019
Midstream Natural Gas Assets				
KM Texas and Tejas pipelines	5,640	7.00	134 [0.51]	Texas Gulf Coast
Mier-Monterrey pipeline	90	0.65	—	Starr County, Texas to Monterrey, Mexico; connect to CENEGAS national system and multiple power plants in Monterrey
KM North Texas pipeline	80	0.33	—	Interconnect from NGPL; connects to 1,750-megawatt Forney, Texas, power plant and a 1,000-megawatt Paris, Texas, power plant
Oklahoma				
Oklahoma System	4,075	0.75	[0.14]	Hunton Dewatering, Woodford Shale, Anadarko Basin and Mississippi Lime, Arkoma Basin
Cedar Cove (70%)	115	0.03	—	Oklahoma STACK, capacity excludes third-party offloads
South Texas				
South Texas System	1,300	1.93	[1.02]	Eagle Ford shale, Woodbine and Eaglebine formations
Webb/Duval gas gathering system (63%)	145	0.15	—	South Texas
EagleHawk (25%)	530	1.20	—	South Texas, Eagle Ford shale formation
KM Altamont	1,370	0.08	[0.08]	Utah, Uinta Basin
Red Cedar (49%)	900	0.55	—	La Plata County, Colorado, Ignacio Blanco Field
Rocky Mountain				
Fort Union (37%)	310	1.25	—	Powder River Basin (Wyoming)
Bighorn (51%)	290	0.60	—	Powder River Basin (Wyoming)
KinderHawk	520	2.35	—	Northwest Louisiana, Haynesville and Bossier shale formations
North Texas	550	0.14	[0.10]	North Barnett Shale Combo
Camino Real	70	0.15	—	South Texas, Eagle Ford shale formation
KM Treating	—	—	—	Odessa, Texas, other locations in Tyler and Victoria, Texas
Hiland - Williston	2,030	0.37	[0.20]	Bakken/Three Forks shale formations (North Dakota/Montana)
Midstream Liquids/Oil/Condensate Pipelines				
		(MBbl/d)	(MBbl)	
Liberty Pipeline (50%)	87	140	—	Y-grade pipeline from Houston Central complex to the Texas Gulf Coast
South Texas NGL Pipelines	340	115	—	Ethane and propane pipelines from Houston Central complex to the Texas Gulf Coast
Camino Real - Condensate(b)	70	110	60	South Texas, Eagle Ford shale formation
Hiland - Williston - Oil(b)	1,587	282	—	Bakken/Three Forks shale formations (North Dakota/Montana)
EagleHawk - Condensate (25%)	400	220	60	South Texas, Eagle Ford shale formation

(a) We operate Ruby and own the common interest in Ruby. Pembina Pipeline Corporation (Pembina) owns the remaining interest in Ruby in the form of a convertible preferred interest and has 50% voting rights. If Pembina converted its preferred interest into common interest, we and Pembina would each own a 50% common interest in Ruby.

(b) Effective January 1, 2019, these assets were transferred from the Natural Gas Pipelines business segment to the Products Pipelines business segment.

Competition

The market for supply of natural gas is highly competitive, and new pipelines, storage facilities, treating facilities, and facilities for related services are currently being built to serve the growing demand for natural gas in each of the markets served by the pipelines in our Natural Gas Pipelines business segment. Our operations compete with interstate and intrastate pipelines, and their shippers, for connections to new markets and supplies and for transportation, processing and treating services. We believe the principal elements of competition in our various markets are location, rates, terms of service and flexibility and reliability of service. From time to time, other projects are proposed that would compete with us. We do not know whether or when any such projects would be built, or the extent of their impact on our operations or profitability.

Shippers on our natural gas pipelines compete with other forms of energy available to their natural gas customers and end users, including electricity, coal, propane, fuel oils and renewables such as wind and solar. Several factors influence the demand for natural gas, including price changes, the availability of natural gas and other forms of energy, the level of business activity, conservation, legislation and governmental regulations, the ability to convert to alternative fuels and weather.

Products Pipelines

Our Products Pipelines business segment consists of our refined petroleum products, crude oil and condensate, and NGL pipelines and associated terminals, Southeast terminals, our condensate processing facility and our transmix processing facilities. The following summarizes our significant Products Pipelines business segment assets we own and operate as of December 31, 2018:

Asset (KMI ownership shown if not 100%)	Miles of Pipeline	Number of Terminals (a) or locations	Terminal Capacity (MMBbl)	Supply and Market Region
Plantation pipeline (51%)	3,182	—	—	Louisiana to Washington D.C.
West Coast Products Pipelines(b)				
Pacific (SFPP)	2,845	13	15.1	Six western states
Calnev	566	2	2.0	Colton, CA to Las Vegas, NV; Mojave region
West Coast Terminals	64	7	10.0	Seattle, Portland, San Francisco and Los Angeles areas, Vancouver Jet Fuel pipeline
Cochin pipeline(c)	1,525	4	1.1	Three provinces in Canada and seven states in the U.S.
Utopia pipeline (50%)(c)	270	—	—	Harrison County, Ohio extending to Windsor, Ontario
KM Crude & Condensate pipeline	264	5	2.6	Eagle Ford shale field in South Texas (Dewitt, Karnes, and Gonzales Counties) to the Houston ship channel refining complex
Double H Pipeline	512	—	—	Bakken shale in Montana and North Dakota to Guernsey, Wyoming
Central Florida pipeline	206	2	2.5	Tampa to Orlando
Double Eagle pipeline (50%)	204	2	0.6	Live Oak County, Texas; Corpus Christi, Texas; Karnes County, Texas; and LaSalle County
Cypress pipeline (50%)(c)	104	—	—	Mont Belvieu, Texas to Lake Charles, Louisiana
Southeast Terminals(d)	—	32	10.8	From Mississippi through Virginia, including Tennessee
KM Condensate Processing Facility	—	1	2.0	Houston Ship Channel, Galena Park, Texas
Transmix Operations	—	5	0.6	Colton, California; Richmond, Virginia; Dorsey Junction, Maryland; St. Louis, Missouri; and Greensboro, North Carolina

(a) The terminals provide services including short-term product storage, truck loading, vapor handling, additive injection, dye injection and ethanol blending.

(b) Our West Coast Products Pipelines assets include interstate common carrier pipelines rate-regulated by the FERC, intrastate pipelines in the state of California rate-regulated by the CPUC, and certain non rate-regulated operations and terminal facilities.

(c) Effective January 1, 2019, these assets were transferred from the Products Pipelines business segment to the Natural Gas Pipelines business segment.
(d) Effective January 1, 2019, a small number of terminals were transferred between the Products Pipelines and Terminals business segments.

Competition

Our Products Pipelines' pipeline operations compete against proprietary pipelines owned and operated by major oil companies, other independent products pipelines, trucking and marine transportation firms (for short-haul movements of products) and railcars. Our Products Pipelines' terminal operations compete with proprietary terminals owned and operated by major oil companies and other independent terminal operators, and our transmix operations compete with refineries owned by major oil companies and independent transmix facilities.

Terminals

Our Terminals business segment includes the operations of our refined petroleum product, crude oil, chemical, ethanol and other liquid terminal facilities (other than those included in the Products Pipelines business segment) and all of our petroleum coke, metal and ores facilities. Our terminals are located throughout the U.S. and in portions of Canada. We believe the location of our facilities and our ability to provide flexibility to customers help attract new and retain existing customers at our terminals and provide expansion opportunities. We often classify our terminal operations based on the handling of either liquids or dry-bulk material products. In addition, Terminals' marine operations include Jones Act-qualified product tankers that provide marine transportation of crude oil, condensate and refined petroleum products between U.S. ports. The following summarizes our Terminals business segment assets, as of December 31, 2018:

	Number	Capacity (MMBbl)
Liquids terminals(a)	52	89.6
Bulk terminals	34	—
Jones Act tankers	16	5.3

(a) Effective January 1, 2019, a small number of terminals were transferred between the Terminals and Products Pipelines business segments.

Competition

We are one of the largest independent operators of liquids terminals in North America, based on barrels of liquids terminaling capacity. Our liquids terminals compete with other publicly or privately held independent liquids terminals, and terminals owned by oil, chemical, pipeline, and refining companies. Our bulk terminals compete with numerous independent terminal operators, terminals owned by producers and distributors of bulk commodities, stevedoring companies and other industrial companies opting not to outsource terminaling services. In some locations, competitors are smaller, independent operators with lower cost structures. Our Jones Act-qualified product tankers compete with other Jones Act qualified vessel fleets.

CO_2

Our CO_2 business segment produces, transports, and markets CO_2 for use in enhanced oil recovery projects as a flooding medium for recovering crude oil from mature oil fields. Our CO_2 pipelines and related assets allow us to market a complete package of CO_2 supply and transportation services to our customers. We also hold ownership interests in several oil-producing fields and own a crude oil pipeline, all located in the Permian Basin region of West Texas.

Sales and Transportation Activities

Our principal market for CO_2 is for injection into mature oil fields in the Permian Basin. Our ownership of CO_2 resources as of December 31, 2018 includes:

	Ownership Interest %	Compression Capacity (Bcf/d)	Location
McElmo Dome unit	45	1.5	Colorado
Doe Canyon Deep unit	87	0.2	Colorado
Bravo Dome unit(a)	11	0.3	New Mexico

(a) We do not operate this unit.

CO_2 Business Segment Pipelines

The principal market for transportation on our CO_2 pipelines is to customers, including ourselves, using CO_2 for enhanced recovery operations in mature oil fields in the Permian Basin, where industry demand is expected to remain stable for the next several years. The tariffs charged on (i) the Wink crude oil pipeline system are regulated by both the FERC and the Texas Railroad Commission; (ii) the Pecos Carbon Dioxide Pipeline are regulated by the Texas Railroad Commission; and (iii) the Cortez pipeline are based on a consent decree. Our other CO_2 pipelines are not regulated.

Our ownership of CO_2 and crude oil pipelines as of December 31, 2018 includes:

Asset (KMI ownership shown if not 100%)	Miles of Pipeline	Transport Capacity (Bcf/d)	Supply and Market Region
CO_2 pipelines			
Cortez pipeline (53%)	569	1.5	McElmo Dome and Doe Canyon source fields to the Denver City, Texas hub
Central Basin pipeline	334	0.7	Cortez, Bravo, Sheep Mountain, Canyon Reef Carriers, and Pecos pipelines
Bravo pipeline (13%)(a)	218	0.4	Bravo Dome to the Denver City, Texas hub
Canyon Reef Carriers pipeline (98%)	163	0.3	McCamey, Texas, to the SACROC, Sharon Ridge, Cogdell and Reinecke units
Centerline CO_2 pipeline	113	0.3	between Denver City, Texas and Snyder, Texas
Eastern Shelf CO_2 pipeline	98	0.1	between Snyder, Texas and Knox City, Texas
Pecos pipeline (95%)	25	0.1	McCamey, Texas, to Iraan, Texas, delivers to the Yates unit
		(Bbls/d)	
Crude oil pipeline			
Wink pipeline	457	145,000	West Texas to Western Refining's refinery in El Paso, Texas

(a) We do not operate Bravo pipeline.

Oil and Gas Producing Activities

Oil Producing Interests

Our ownership interests in oil-producing fields located in the Permian Basin of West Texas include the following:

	Working Interest %	KMI Gross Developed Acres
SACROC	97	49,156
Yates	50	9,576
Goldsmith Landreth San Andres	99	6,166
Katz Strawn	99	7,194
Sharon Ridge	14	2,619
Tall Cotton	100	641
MidCross	13	320
Reinecke	70	3,793

Our oil and gas producing activities are not significant, and therefore, we do not include the supplemental information on oil and gas producing activities under Accounting Standards Codification Topic 932, Extractive Activities - Oil and Gas.

Gas and Gasoline Plant Interests

Operated gas plants in the Permian Basin of West Texas:

	Ownership Interest %	Source
Snyder gasoline plant(a)	22	The SACROC unit and neighboring CO_2 projects, specifically the Sharon Ridge and Cogdell units
Diamond M gas plant	51	Snyder gasoline plant
North Snyder plant	100	Snyder gasoline plant

(a) This is a working interest, in addition, we have a 28% net profits interest.

Competition

Our primary competitors for the sale of CO_2 include suppliers that have an ownership interest in McElmo Dome, Bravo Dome and Sheep Mountain CO_2 resources. Our ownership interests in the Central Basin, Cortez and Bravo pipelines are in direct competition with other CO_2 pipelines. We also compete with other interest owners in the McElmo Dome unit and the Bravo Dome unit for transportation of CO_2 to the Denver City, Texas market area.

Major Customers

Our revenue is derived from a wide customer base. For each of the years ended December 31, 2018, 2017 and 2016, no revenues from transactions with a single external customer accounted for 10% or more of our total consolidated revenues. We do not believe that a loss of revenues from any single customer would have a material adverse effect on our business, financial position, results of operations or cash flows.

Our Texas Intrastate Natural Gas Pipeline operations (includes the operations of Kinder Morgan Tejas Pipeline LLC, Kinder Morgan Border Pipeline LLC, Kinder Morgan Texas Pipeline LLC, Kinder Morgan North Texas Pipeline LLC and the Mier-Monterrey Mexico pipeline system) buys and sells significant volumes of natural gas within the state of Texas, and, to a far lesser extent, the CO_2 business segment also sells natural gas. Combined, total revenues from the sales of natural gas from the Natural Gas Pipelines and CO_2 business segments in 2018, 2017 and 2016 accounted for 23%, 22% and 19%, respectively, of our total consolidated revenues. To the extent possible, we attempt to balance the pricing and timing of our natural gas purchases to our natural gas sales, and these contracts are often settled in terms of an index price for both purchases and sales.

Regulation

Interstate Common Carrier Refined Petroleum Products and Oil Pipeline Rate Regulation - U.S. Operations

Some of our U.S. refined petroleum products and crude oil gathering and transmission pipelines are interstate common carrier pipelines, subject to regulation by the FERC under the Interstate Commerce Act, or ICA. The ICA requires that we maintain our tariffs on file with the FERC. Those tariffs set forth the rates we charge for providing gathering or transportation services on our interstate common carrier pipelines as well as the rules and regulations governing these services. The ICA requires, among other things, that such rates on interstate common carrier pipelines be "just and reasonable" and nondiscriminatory. The ICA permits interested persons to challenge newly proposed or changed rates and authorizes the FERC to suspend the effectiveness of such rates for a period of up to seven months and to investigate such rates. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it is authorized to require the carrier to refund the revenues in excess of the prior tariff collected during the pendency of the investigation. The FERC also may investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained during the two years prior to the filing of a complaint.

The Energy Policy Act of 1992 deemed petroleum products pipeline tariff rates that were in effect for the 365-day period ending on the date of enactment or that were in effect on the 365th day preceding enactment and had not been subject to complaint, protest or investigation during the 365-day period to be just and reasonable or "grandfathered" under the ICA. The Energy Policy Act also limited the circumstances under which a complaint can be made against such grandfathered rates. Certain rates on our Pacific operations' pipeline system were subject to protest during the 365-day period established by the Energy Policy Act. Accordingly, certain of the Pacific pipelines' rates have been, and continue to be, the subject of complaints with the FERC, as is more fully described in Note 18 *"Litigation, Environmental and Other Contingencies"* to our consolidated financial statements.

Petroleum products and crude oil pipelines may change their rates within prescribed ceiling levels that are tied to an inflation index. Shippers may protest rate increases made within the ceiling levels, but such protests must show that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs from the previous year. A petroleum products or crude oil pipeline must, as a general rule, utilize the indexing methodology to change its rates. Cost-of-service ratemaking, market-based rates and settlement rates are alternatives to the indexing approach and may be used in certain specified circumstances to change rates.

Common Carrier Pipeline Rate Regulation - Canadian Operations

The Canadian portion of our condensate Cochin pipeline system is under the regulatory jurisdiction of the NEB. The National Energy Board Act gives the NEB power to authorize pipeline construction and to establish tolls and conditions of service.

Interstate Natural Gas Transportation and Storage Regulation

As an owner and operator of natural gas companies subject to the Natural Gas Act of 1938, we are required to provide service to shippers on our interstate natural gas pipelines and storage facilities at regulated rates that have been determined by the FERC to be just and reasonable. Recourse rates and general terms and conditions for service are set forth in posted tariffs approved by the FERC for each pipeline (including storage facilities or companies as used herein). Generally, recourse rates are based on our cost of service, including recovery of and a return on our investment. Posted tariff rates are deemed just and reasonable and cannot be changed without FERC authorization following an evidentiary hearing or settlement. The FERC can initiate proceedings, on its own initiative or in response to a shipper complaint, that could result in a rate change or confirm existing rates.

Posted tariff rates set the general range of maximum and minimum rates we charge shippers on our interstate natural gas pipelines. Within that range, each pipeline is permitted to charge discounted rates, so long as such discounts are offered to all similarly situated shippers and granted without undue discrimination. Apart from discounted rates, upon mutual agreement, the pipeline is permitted to charge negotiated rates that are not bound by and are irrespective of changes that may occur to the range of tariff-based maximum and minimum rate levels. Negotiated rates provide certainty to the pipeline and the shipper of agreed-upon rates during the term of the transportation agreement, regardless of changes to the posted tariff rates. The actual negotiated rate agreement or a summary of such agreement must be posted as part of the pipelines' tariffs. While pipelines and their shippers may agree to a variety of negotiated rate structures depending on the shipper and circumstance, pipelines

generally must use for all shippers the form of service agreement that is contained within their FERC-approved tariff. Any deviation from the *pro forma* service agreements must be filed with the FERC and only certain types of deviations in the terms and conditions of service are acceptable to the FERC.

The FERC regulates the rates, terms and conditions of service, construction and abandonment of facilities by companies performing interstate natural gas transportation services, including storage services, under the Natural Gas Act of 1938. To a lesser extent, the FERC regulates interstate transportation rates, terms and conditions of service under the Natural Gas Policy Act of 1978. Beginning in the mid-1980's, the FERC initiated a number of regulatory changes intended to ensure that interstate natural gas pipelines operated on a not unduly discriminatory basis and to create a more competitive and transparent environment in the natural gas marketplace. Among the most important of these changes were:

- Order No. 436 (1985) which required open-access, nondiscriminatory transportation of natural gas;
- Order No. 497 (1988) which set forth new standards and guidelines imposing certain constraints on the interaction between interstate natural gas pipelines and their marketing affiliates and imposing certain disclosure requirements regarding that interaction;
- Order Nos. 587, et seq., Order No. 809 (1996-2015) which adopt regulations to standardize the business practices and communication methodologies of interstate natural gas pipelines to create a more integrated and efficient pipeline grid and wherein the FERC has incorporated by reference in its regulations standards for interstate natural gas pipeline business practices and electronic communications that were developed and adopted by the North American Energy Standards Board (NAESB). Interstate natural gas pipelines are required to incorporate by reference or verbatim in their respective tariffs the applicable version of the NAESB standards;
- Order No. 636 (1992) which required interstate natural gas pipelines that perform open-access transportation under blanket certificates to "unbundle" or separate their traditional merchant sales services from their transportation and storage services and to provide comparable transportation and storage services with respect to all natural gas supplies. Natural gas pipelines must now separately state the applicable rates for each unbundled service they provide (i.e., for transportation services and storage services for natural gas);
- Order No. 637 (2000) which revised, among other things, FERC regulations relating to scheduling procedures, capacity segmentation, and pipeline penalties in order to improve the competitiveness and efficiency of the interstate pipeline grid; and
- Order No. 717 (2008) amending the Standards of Conduct for Transmission Providers (the Standards of Conduct or the Standards) to make them clearer and to refocus the marketing affiliate rules on the areas where there is the greatest potential for abuse.

In addition to regulatory changes initiated by the FERC, the U.S. Congress passed the Energy Policy Act of 2005. Among other things, the Energy Policy Act amended the Natural Gas Act to: (i) prohibit market manipulation by any entity; (ii) direct the FERC to facilitate market transparency in the market for sale or transportation of physical natural gas in interstate commerce; and (iii) significantly increase the penalties for violations of the Natural Gas Act, the Natural Gas Policy Act of 1978, or FERC rules, regulations or orders thereunder.

CPUC Rate Regulation

The intrastate common carrier operations of our Pacific operations' pipelines in California are subject to regulation by the CPUC under a "depreciated book plant" methodology, which is based on an original cost measure of investment. Intrastate tariffs filed by us with the CPUC have been established on the basis of revenues, expenses and investments allocated as applicable to the California intrastate portion of the Pacific operations' business. Tariff rates with respect to intrastate pipeline service in California are subject to challenge by complaint by interested parties or by independent action of the CPUC. A variety of factors can affect the rates of return permitted by the CPUC, and certain other issues similar to those which have arisen with respect to our FERC regulated rates also could arise with respect to its intrastate rates. The intrastate rates for movements in California on our SFPP and Calnev systems have been, and may in the future be, subject to complaints before the CPUC, as is more fully described in Note 18 "*Litigation, Environmental and Other Contingencies*" to our consolidated financial statements.

Railroad Commission of Texas (RCT) Rate Regulation

The intrastate operations of our crude oil and liquids pipelines and natural gas pipelines and storage facilities in Texas are subject to regulation with respect to such intrastate transportation by the RCT. The RCT has the authority to regulate our rates, though it generally has not investigated the rates or practices of our intrastate pipelines in the absence of shipper complaints.

Mexico - Energy Regulatory Commission

The Mier-Monterrey Pipeline has a natural gas transportation permit granted by the Energy Regulatory Commission of Mexico (the Commission) that defines the conditions for the pipeline to carry out activity and provide natural gas transportation service. This permit expires in 2026.

This permit establishes certain restrictive conditions, including without limitation: (i) compliance with the general conditions for the provision of natural gas transportation service; (ii) compliance with certain safety measures, contingency plans, maintenance plans and the official standards of Mexico regarding safety; (iii) compliance with the technical and economic specifications of the natural gas transportation system authorized by the Commission; (iv) compliance with certain technical studies established by the Commission; and (v) compliance with a minimum contributed capital not entitled to withdrawal of at least the equivalent of 10% of the investment proposed in the project.

Mexico - National Agency for Industrial Safety and Environmental Protection (ASEA)

ASEA regulates environmental compliance and industrial and operational safety. The Mier-Monterrey Pipeline must satisfy and maintain ASEA's requirements, including compliance with certain safety measures, contingency plans, maintenance plans and the official standards of Mexico regarding safety, including a Safety Administration Program.

Safety Regulation

We are also subject to safety regulations issued by PHMSA, including those requiring us to develop and maintain pipeline Integrity Management programs to evaluate areas along our pipelines and take additional measures to protect pipeline segments located in what are referred to as High Consequence Areas, or HCAs, where a leak or rupture could potentially do the most harm.

The ultimate costs of compliance with pipeline Integrity Management rules are difficult to predict. Changes such as advances of in-line inspection tools, identification of additional integrity threats and changes to the amount of pipe determined to be located in HCAs can have a significant impact on costs to perform integrity testing and repairs. We will continue our pipeline integrity testing programs to assess and maintain the integrity of our existing and future pipelines as required by PHMSA regulations. These tests could result in significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to continue the safe and reliable operation of our pipelines.

The Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 or "PIPES Act of 2016" requires PHMSA, among other regulators, to set minimum safety standards for underground natural gas storage facilities and allows states to set more stringent standards for intrastate pipelines. In compliance with the PIPES Act of 2016, we have implemented procedures for underground natural gas storage facilities.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which was signed into law in 2012, increased penalties for violations of safety laws and rules and may result in the imposition of more stringent regulations in the future. In 2012, PHMSA issued an Advisory Bulletin which, among other things, advises pipeline operators that if they are relying on design, construction, inspection, testing, or other data to determine maximum pressures at which their pipelines should operate, the records of that data must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing or modifying or replacing facilities to meet the Advisory Bulletin requirements, could significantly increase our costs. Additionally, failure to locate such records to verify maximum pressures could result in reductions of allowable operating pressures, which would reduce available capacity on our pipelines. There can be no assurance as to the amount or timing of future expenditures for pipeline Integrity Management regulation, and actual expenditures may be different from the amounts we currently anticipate. Regulations, changes to regulations or an increase in public expectations for pipeline safety may require additional reporting, the replacement of some of our pipeline segments, addition of monitoring equipment and more frequent inspection or testing of our pipeline facilities. Repair, remediation, and preventative or mitigating actions may require significant capital and operating expenditures.

From time to time, our pipelines or facilities may experience leaks and ruptures. These leaks and ruptures may cause explosions, fire, damage to the environment, damage to property and/or personal injury or death. In connection with these incidents, we may be sued for damages. Depending upon the facts and circumstances of a particular incident, state and federal regulatory authorities may seek civil and/or criminal fines and penalties.

We are also subject to the requirements of the Occupational Safety and Health Administration (OSHA) and other federal and state agencies that address employee health and safety. In general, we believe current expenditures are fulfilling the OSHA

requirements and protecting the health and safety of our employees. Based on new regulatory developments, we may increase expenditures in the future to comply with higher industry and regulatory safety standards. However, such increases in our expenditures, and the extent to which they might be offset, cannot be estimated at this time.

State, Provincial and Local Regulation

Certain of our activities are subject to various state or provincial and local laws and regulations, as well as orders of regulatory bodies, governing a wide variety of matters, including marketing, production, pricing, pollution, protection of the environment, and human health and safety.

Marine Operations

The operation of tankers and marine equipment create maritime obligations involving property, personnel and cargo under General Maritime Law. These obligations create a variety of risks including, among other things, the risk of collision, which may result in claims for personal injury, cargo, contract, pollution, third-party claims and property damages to vessels and facilities.

We are subject to the Jones Act and other federal laws that restrict maritime transportation (between U.S. departure and destination points) to vessels built and registered in the U.S. and owned and crewed by U.S. citizens. As a result, we monitor the foreign ownership of our common stock and under certain circumstances consistent with our certificate of incorporation, we have the right to redeem shares of our common stock owned by non-U.S. citizens. If we do not comply with such requirements, we would be prohibited from operating our vessels in U.S. coastwise trade, and under certain circumstances we would be deemed to have undertaken an unapproved foreign transfer, resulting in severe penalties, including permanent loss of U.S. coastwise trading rights for our vessels, fines or forfeiture of the vessels. Furthermore, from time to time, legislation has been introduced unsuccessfully in Congress to amend the Jones Act to ease or remove the requirement that vessels operating between U.S. ports be built and registered in the U.S. and owned and crewed by U.S. citizens. If the Jones Act were amended in such fashion, we could face competition from foreign-flagged vessels.

In addition, the U.S. Coast Guard and the American Bureau of Shipping maintain the most stringent regime of vessel inspection in the world, which tends to result in higher regulatory compliance costs for U.S.-flag operators than for owners of vessels registered under foreign flags of convenience. The Jones Act and General Maritime Law also provide damage remedies for crew members injured in the service of the vessel arising from employer negligence or vessel unseaworthiness.

The Merchant Marine Act of 1936 is a federal law that provides the U.S. Secretary of Transportation, upon proclamation by the U.S. President of a national emergency or a threat to the national security, the authority to requisition or purchase any vessel or other watercraft owned by U.S. citizens (including us, provided that we are considered a U.S. citizen for this purpose). If one of our vessels were purchased or requisitioned by the U.S. government under this law, we would be entitled to be paid the fair market value of the vessel in the case of a purchase or, in the case of a requisition, the fair market value of charter hire. However, we would not be entitled to compensation for any consequential damages suffered as a result of such purchase or requisition.

Environmental Matters

Our business operations are subject to federal, state, provincial and local laws and regulations relating to environmental protection, pollution and human health and safety in the U.S. and Canada. For example, if an accidental leak, release or spill of liquid petroleum products, chemicals or other hazardous substances occurs at or from our pipelines, or at or from our storage or other facilities, we may experience significant operational disruptions, and we may have to pay a significant amount to clean up the leak, release or spill, pay for government penalties, address natural resource damages, compensate for human exposure or property damage, install costly pollution control equipment or a combination of these and other measures. Furthermore, new projects may require approvals and environmental analysis under federal and state or provincial laws, including the National Environmental Policy Act and the Endangered Species Act. The resulting costs and liabilities could materially and negatively affect our business, financial condition, results of operations and cash flows. In addition, emission controls required under federal, state and provincial environmental laws could require significant capital expenditures at our facilities.

Environmental and human health and safety laws and regulations are subject to change. The clear trend in environmental regulation is to place more restrictions and limitations on activities that may be perceived to affect the environment, wildlife, natural resources and human health. There can be no assurance as to the amount or timing of future expenditures for environmental regulation compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating

restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and cash flows.

In accordance with GAAP, we accrue liabilities for environmental matters when it is probable that obligations have been incurred and the amounts can be reasonably estimated. This policy applies to assets or businesses currently owned or previously disposed. We have accrued liabilities for estimable and probable environmental remediation obligations at various sites, including multi-party sites where the EPA, or similar state or Canadian agency has identified us as one of the potentially responsible parties. The involvement of other financially responsible companies at these multi-party sites could increase or mitigate our actual joint and several liability exposures.

We believe that the ultimate resolution of these environmental matters will not have a material adverse effect on our business, financial position, results of operations or cash flows. However, it is possible that our ultimate liability with respect to these environmental matters could exceed the amounts accrued in an amount that could be material to our business, financial position, results of operations or cash flows in any particular reporting period. We have accrued an environmental reserve in the amount of $271 million as of December 31, 2018. Our aggregate reserve estimate ranges in value from approximately $271 million to approximately $448 million, and we recorded our liability equal to the low end of the range, as we did not identify any amounts within the range as a better estimate of the liability. For additional information related to environmental matters, see Note 18 "*Litigation, Environmental and Other Contingencies*" to our consolidated financial statements.

Hazardous and Non-Hazardous Waste

We generate both hazardous and non-hazardous wastes that are subject to the requirements of the Federal Resource Conservation and Recovery Act and comparable state and Canadian federal and provincial statutes. From time to time, the EPA, as well as other U.S. federal and state regulators and Canadian federal and provincial regulators, consider the adoption of stricter disposal standards for non-hazardous waste. Furthermore, it is possible that some wastes that are currently classified as non-hazardous, which could include wastes currently generated during our pipeline or liquids or bulk terminal operations or wastes from oil and gas facilities that are currently exempt as exploration and production waste, may in the future be designated as hazardous wastes. Hazardous wastes are subject to more rigorous and costly handling and disposal requirements than non-hazardous wastes. Such changes in the regulations may result in additional capital expenditures or operating expenses for us.

Superfund

The CERCLA or the Superfund law, and analogous state laws, impose joint and several liability, without regard to fault or the legality of the original conduct, on certain classes of potentially responsible persons for releases of hazardous substances into the environment. These persons include the owner or operator of a site and companies that disposed or arranged for the disposal of the hazardous substances found at the site. CERCLA authorizes the EPA and, in some cases, third parties to take actions in response to threats to public health or the environment and to seek to recover from the responsible classes of persons the costs they incur, in addition to compensation for natural resource damages, if any. Although petroleum is excluded from CERCLA's definition of a hazardous substance, in the course of our ordinary operations, we have and will generate materials that may fall within the definition of "hazardous substance." By operation of law, if we are determined to be a potentially responsible person, we may be responsible under CERCLA for all or part of the costs required to clean up sites at which such materials are present, in addition to compensation for natural resource damages, if any.

Clean Air Act

Our operations are subject to the Clean Air Act, its implementing regulations, and analogous state and Canadian statutes and regulations. The EPA regulations under the Clean Air Act contain requirements for the monitoring, reporting, and control of GHG emissions from stationary sources. For further information, see *"—Climate Change"* below.

Clean Water Act

Our operations can result in the discharge of pollutants. The Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, and analogous state laws impose restrictions and controls regarding the discharge of pollutants into waters of the U.S. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by applicable federal, state or Canadian authorities. The Oil Pollution Act was enacted in 1990 and amends provisions of the Clean Water Act pertaining to prevention of and response to oil spills. Spill prevention, control and countermeasure requirements of the Clean Water Act and some state and Canadian laws require containment and similar structures to help prevent contamination of navigable waters in the event of an overflow or release of oil.

EPA Revisions to Ozone National Ambient Air Quality Standard (NAAQS)

As required by the Clean Air Act, the EPA establishes National Ambient Air Quality Standards (NAAQS) for how much pollution is permissible, and the states then have to adopt rules so their air quality meets the NAAQS. In October 2015, the EPA published a rule lowering the ground level ozone NAAQS from 75 ppb to a more stringent 70 ppb standard. This change triggered a process under which the EPA designated the areas of the country in or out of compliance with the new NAAQS standard. Now, certain states will have to adopt more stringent air quality regulations to meet the new NAAQS standard. These new state rules, which are expected in 2020 or 2021, will likely require the installation of more stringent air pollution controls on newly-installed equipment and possibly require the retrofitting of existing KMI facilities with air pollution controls. Given the nationwide implications of the new rule, it is expected that it will have financial impacts for each of our business units.

Climate Change

Studies have suggested that emissions of certain gases, commonly referred to as GHGs, may be contributing to warming of the Earth's atmosphere. Methane, a primary component of natural gas, and CO_2, which is naturally occurring and also a byproduct of the burning of natural gas, are examples of GHGs. Various laws and regulations exist or are under development to regulate the emission of such GHGs, including the EPA programs to report GHG emissions and state actions to develop statewide or regional programs. The U.S. Congress has in the past considered legislation to reduce emissions of GHGs.

Beginning in December 2009, EPA published several findings and rulemakings under the Clean Air Act requiring the permitting and reporting of certain GHGs including CO_2 and methane. Our facilities are subject to these requirements. Operational and/or regulatory changes could require additional facilities to comply with GHG emissions reporting and permitting requirements.

On October 23, 2015, the EPA published as a final rule the Clean Power Plan, which sets interim and final CO_2 emission performance rates for power generating units that are fueled by coal, oil or natural gas. The final rule is the focus of legislative discussion in the U.S. Congress and litigation in federal court. On February 10, 2016, the U.S. Supreme Court stayed the final rule, effectively suspending the duty to comply with the rule until certain legal challenges are resolved. In October 2017, the EPA proposed to repeal the Clean Power Plan. In August 2018, the EPA proposed to replace the Clean Power Plan and Affordable Clean Energy rule. The ultimate determination of the Clean Power Plan and Affordable Clean Energy rule remains uncertain. While we do not operate power plants that would be subject to the Clean Power Plan or the Affordable Clean Energy rule, it remains unclear what effect a final rule, if it comes into force, might have on the anticipated demand for natural gas, including natural gas that we gather, process, store and transport.

At the state level, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of GHGs, primarily through the planned development of emission inventories or regional GHG "cap and trade" programs. Although many of the state-level initiatives have to date been focused on large sources of GHG emissions, such as electric power plants, it is possible that sources such as our gas-fueled compressors and processing plants could become subject to related state regulations. Various states are also proposing or have implemented more strict regulations for GHGs that go beyond the requirements of the EPA. Some of the states have implemented regulations that require additional monitoring and reporting of methane emissions. Depending on the state programs pending implementation, we could be required to conduct additional monitoring, do additional emissions reporting and/or purchase and surrender emission allowances.

Because our operations, including the compressor stations and processing plants, emit various types of GHGs, primarily methane and CO_2, such new legislation or regulation could increase the costs related to operating and maintaining the facilities. Depending on the particular law, regulation or program, we or our subsidiaries could be required to incur capital expenditures for installing new monitoring equipment of emission controls on the facilities, acquire and surrender allowances for the GHG emissions, pay taxes related to the GHG emissions and administer and manage a GHG emissions program. We are not able at this time to estimate such increased costs; however, as is the case with similarly situated entities in the industry, they could be significant to us. While we may be able to include some or all of such increased costs in the rates charged by our or our subsidiaries' pipelines, recovery of costs in all cases is uncertain and may depend on events beyond their control, including the outcome of future rate proceedings before the FERC or other regulatory bodies, and the provisions of any final legislation or other regulations. Any of the foregoing could have an adverse effect on our business, financial position, results of operations and prospects.

Many climate models indicate that global warming is likely to result in rising sea levels, increased intensity of hurricanes and tropical storms, and increased frequency of extreme precipitation and flooding. We may experience increased insurance premiums and deductibles, or a decrease in available coverage, for our assets in areas subject to severe weather. These climate-related changes could damage our physical assets, especially operations located in low-lying areas near coasts and river banks, and facilities situated in hurricane-prone and rain-susceptible regions. However, the timing, severity and location of these climate change impacts are not known with certainty and, these impacts are expected to manifest themselves over varying time horizons.

Because natural gas produces less GHG emissions per unit of energy than competing fossil fuels, cap-and-trade legislation or EPA regulatory initiatives such as the Clean Power Plan or Affordable Clean Energy rule could stimulate demand for natural gas by increasing the relative cost of competing fuels such as coal and oil. In addition, we anticipate that GHG regulations will increase demand for carbon sequestration technologies, such as the techniques we have successfully demonstrated in our enhanced oil recovery operations within our CO_2 business segment. However, these potential positive effects on our markets may be offset if these same regulations also cause the cost of natural gas to increase relative to competing non-fossil fuels. Although we currently cannot predict the magnitude and direction of these impacts, GHG regulations could have material adverse effects on our business, financial position, results of operations or cash flows.

Department of Homeland Security

The Department of Homeland Security, referred to in this report as the DHS, has regulatory authority over security at certain high-risk chemical facilities. The DHS has promulgated the Chemical Facility Anti-Terrorism Standards and required all high-risk chemical and industrial facilities, including oil and gas facilities, to comply with the regulatory requirements of these standards. This process includes completing security vulnerability assessments, developing site security plans, and implementing protective measures necessary to meet DHS-defined, risk-based performance standards. The DHS has not provided final notice to all facilities that it determines to be high risk and subject to the rule; therefore, neither the extent to which our facilities may be subject to coverage by the rules nor the associated costs to comply can currently be determined, but it is possible that such costs could be substantial.

Other

Employees

We employed 11,012 full-time personnel at December 31, 2018, including approximately 936 full-time hourly personnel at certain terminals and pipelines covered by collective bargaining agreements that expire between 2019 and 2022. We consider relations with our employees to be good.

Most of our employees are employed by us and a limited number of our subsidiaries and provide services to one or more of our business units. The direct costs of compensation, benefits expenses, employer taxes and other employer expenses for these employees are allocated to our subsidiaries. Our human resources department provides the administrative support necessary to implement these payroll and benefits services, and the related administrative costs are allocated to our subsidiaries pursuant to our board-approved expense allocation policy. The effect of these arrangements is that each business unit bears the direct compensation and employee benefits costs of its assigned or partially assigned employees, as the case may be, while also bearing its allocable share of administrative costs.

Properties

We believe that we generally have satisfactory title to the properties we own and use in our businesses, subject to liens for current taxes, liens incident to minor encumbrances, and easements and restrictions, which do not materially detract from the value of such property, the interests in those properties or the use of such properties in our businesses. Our terminals, storage facilities, treating and processing plants, regulator and compressor stations, oil and gas wells, offices and related facilities are located on real property owned or leased by us. In some cases, the real property we lease is on federal, state, provincial or local government land.

We generally do not own the land on which our pipelines are constructed. Instead, we obtain and maintain rights to construct and operate the pipelines on other people's land generally under agreements that are perpetual or provide for renewal rights. Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of such property. In many instances, lands over which rights-of-way have been obtained are subject to prior liens that have not been subordinated to the right-of-way grants. In some cases, not all of the apparent record owners have joined in the right-of-way grants, but in substantially all such cases, signatures of the owners of a majority of the interests have been obtained. Permits

have been obtained from public authorities to cross over or under, or to lay facilities in or along, water courses, county roads, municipal streets and state highways, and in some instances, such permits are revocable at the election of the grantor, or, the pipeline may be required to move its facilities at its own expense. Permits also have been obtained from railroad companies to run along or cross over or under lands or rights-of-way, many of which are also revocable at the grantor's election. Some such permits require annual or other periodic payments. In a few minor cases, property for pipeline purposes was purchased by the Company.

(d) Financial Information about Geographic Areas

For geographic information concerning our assets and operations, see Note 17 "*Reportable Segments*" to our consolidated financial statements.

(e) Available Information

We make available free of charge on or through our internet website, at www.kindermorgan.com, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The information contained on or connected to our internet website is not incorporated by reference into this Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

Item 1A. *Risk Factors.*

You should carefully consider the risks described below, in addition to the other information contained in this document. Realization of any of the following risks could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Risks Related to Operating our Business

Our businesses are dependent on the supply of and demand for the products that we handle.

Our pipelines, terminals and other assets and facilities depend in part on continued production of natural gas, oil and other products in the geographic areas that they serve. Our business also depends in part on the levels of demand for natural gas, oil, NGL, refined petroleum products, CO_2, coal, steel, chemicals and other products in the geographic areas to which our pipelines, terminals, shipping vessels and other facilities deliver or provide service, and the ability and willingness of our shippers and other customers to supply such demand. For example, without additions to oil and gas reserves, production will decline over time as reserves are depleted, and production costs may rise. Producers may reduce or shut down production during times of lower product prices or higher production costs to the extent they become uneconomic. Producers in areas served by us may not be successful in exploring for and developing additional reserves, and our pipelines and related facilities may not be able to maintain existing volumes of throughput. Commodity prices and tax incentives may not remain at levels that encourage producers to explore for and develop additional reserves, produce existing marginal reserves or renew transportation contracts as they expire.

Changes in the business environment, such as declining or sustained low commodity prices, supply disruptions, or higher development or production costs, could result in a slowing of supply to our pipelines, terminals and other assets. In addition, changes in the overall demand for hydrocarbons, the regulatory environment or applicable governmental policies, including in relation to climate change or other environmental concerns, may have a negative impact on the supply of crude oil and other products. In recent years, a number of initiatives and regulatory changes relating to reducing GHG emissions have been undertaken by federal, provincial, state and municipal governments and oil and gas industry participants. In addition, emerging technologies and public opinion have resulted in increasing demand for energy efficiency, including energy provided from renewable energy sources rather than fossil fuels and fuel-efficient alternatives such as hybrid and electric vehicles. These factors could result in not only increased costs for producers of hydrocarbons but also an overall decrease in the demand for hydrocarbons. Each of the foregoing could negatively impact our business directly as well as our shippers and other customers, which in turn could negatively impact our prospects for new contracts for transportation, terminaling or other midstream services, or renewals of existing contracts or the ability of our customers and shippers to honor their contractual commitments. See "*—Financial distress experienced by our customers or other counterparties could have an adverse impact on us in the event they are unable to pay us for the products or services we provide or otherwise fulfill their obligations to us"* below.

We cannot predict the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation or technological advances in fuel economy and energy generation devices, all of which could reduce the production of and/or demand for the products we handle. In addition, irrespective of supply of or demand for products we handle, implementation of new regulations or changes to existing regulations affecting the energy industry could have a material adverse effect on us. See "*—The FERC, the CPUC, or the NEB may establish pipeline tariff rates that have a negative impact on us. In addition, the FERC, the CPUC, the NEB, or our customers could initiate proceedings or file complaints challenging the tariff rates charged by our pipelines, which could have an adverse impact on us.*"

Expanding our existing assets and constructing new assets is part of our growth strategy. Our ability to begin and complete construction on expansion and new-build projects may be inhibited by difficulties in obtaining, or our inability to obtain, permits and rights-of-way, as well as public opposition, increases in costs of construction materials, cost overruns, inclement weather and other delays. Should we pursue expansion of or construction of new projects through joint ventures with others, we will share control and benefits from those projects.

We regularly undertake major construction projects to expand our existing assets and to construct new assets. New growth projects generally will be subject to, among other things, the receipt of regulatory approvals, feasibility and cost analyses, funding availability and industry, market and demand conditions. If we pursue joint ventures with third parties, those parties may share approval rights over major decisions, and may act in their own interests. Their views may differ from our own or our views of the interests of the venture which could result in operational delays or impasses, which in turn could affect the financial expectations of and our benefits from the venture. A variety of factors outside of our control, such as difficulties in obtaining permits and rights-of-way or other regulatory approvals, have caused, and may continue to cause, delays in or cancellations of our construction projects. Regulatory authorities may modify their permitting policies in ways that disadvantage our construction projects, such as the FERC's consideration of changes to its Certificate Policy Statement. Such factors can be exacerbated by public opposition to our projects. See "*—We are subject to reputational risks and risks related to public opinion.*" For example, changing public attitudes toward pipelines bearing fossil fuels may impede our ability to secure rights of way or governmental reviews and authorizations on a timely basis or at all. Inclement weather, natural disasters and delays in performance by third-party contractors have also resulted in, and may continue to result in, increased costs or delays in construction. Significant increases in costs of construction materials, cost overruns or delays, or our inability to obtain a required permit or right-of-way, could have a material adverse effect on our return on investment, results of operations and cash flows, and could result in project cancellations or limit our ability to pursue other growth opportunities.

We face competition from other pipelines and terminals, as well as other forms of transportation and storage.

Any current or future pipeline system or other form of transportation (such as barge, rail or truck) that delivers the products we handle into the areas that our pipelines serve could offer transportation services that are more desirable to shippers than those we provide because of price, location, facilities or other factors. Likewise, competing terminals or other storage options may become more attractive to our customers. To the extent that competitors offer the markets we serve more desirable transportation or storage options, this could result in unused capacity on our pipelines and in our terminals. We also could experience competition for the supply of the products we handle from both existing and proposed pipeline systems; for example, several pipelines access many of the same areas of supply as our pipeline systems and transport to destinations not served by us. If capacity on our assets remains unused, our ability to re-contract for expiring capacity at favorable rates or otherwise retain existing customers could be impaired.

The volatility of oil, NGL and natural gas prices could adversely affect our CO_2 business segment and businesses within our Natural Gas Pipelines and Products Pipelines business segments.

The revenues, cash flows, profitability and future growth of some of our businesses depend to a large degree on prevailing oil, NGL and natural gas prices. Our CO_2 business segment (and the carrying value of its oil, NGL and natural gas producing properties) and certain midstream businesses within our Natural Gas Pipelines business segment depend to a large degree, and certain businesses within our Product Pipelines business segment depend to a lesser degree, on prevailing oil, NGL and natural gas prices. For 2019, we estimate that every $1 change in the average WTI crude oil price per barrel would impact our DCF by approximately $8 million, each $0.10 per MMBtu change in the average price of natural gas would impact DCF by approximately $1 million, and each 1% change in the ratio of the weighted-average NGL price per barrel to the WTI crude oil price per barrel would impact DCF by approximately $3 million.

Prices for oil, NGL and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil, NGL and natural gas, uncertainties within the market and a variety of other factors beyond our control. These factors include, among other things (i) weather conditions and events such as hurricanes in the U.S.; (ii) domestic and global economic conditions; (iii) the activities of the Organization of Petroleum Exporting Countries; (iv) governmental

regulation; (v) political instability in oil producing countries; (vi) the foreign supply of and demand for oil and natural gas; (vii) the price of foreign imports; (viii) the proximity and availability of storage and transportation infrastructure and processing and treating facilities; and (ix) the availability and prices of alternative fuel sources. We use hedging arrangements to partially mitigate our exposure to commodity prices, but these arrangements also are subject to inherent risks. Please read *"—Our use of hedging arrangements does not eliminate our exposure to commodity price risks and could result in financial losses or volatility in our income.*"

A sharp decline in the prices of oil, NGL or natural gas, or a prolonged unfavorable price environment, would result in a commensurate reduction in our revenues, income and cash flows from our businesses that produce, process, or purchase and sell oil, NGL, or natural gas, and could have a material adverse effect on the carrying value of our CO_2 business segment's proved reserves. If prices fall substantially or remain low for a sustained period and we are not sufficiently protected through hedging arrangements, we may be unable to realize a profit from these businesses and would operate at a loss.

In recent decades, there have been periods worldwide of both overproduction and underproduction of hydrocarbons, and periods of both increased and relaxed energy conservation efforts. Such conditions have resulted in periods of excess supply of, and reduced demand for, crude oil on a worldwide basis and for natural gas on a domestic basis. These periods have been followed by periods of short supply of, and increased demand for, crude oil and natural gas. The cycles of excess or short supply of crude oil or natural gas have placed pressures on prices and resulted in dramatic price fluctuations even during relatively short periods of seasonal market demand. These fluctuations impact the accuracy of assumptions used in our budgeting process. For more information about our energy and commodity market risk, see Item 7A "*Quantitative and Qualitative Disclosures About Market Risk-Energy Commodity Market Risk*."

Commodity transportation and storage activities involve numerous risks that may result in accidents or otherwise adversely affect our operations.

There are a variety of hazards and operating risks inherent to the transportation and storage of the products we handle, such as leaks; releases; the breakdown, underperformance or failure of equipment, facilities, information systems or processes; damage to our pipelines caused by third-party construction; the compromise of information and control systems; spills at terminals and hubs; spills associated with the loading and unloading of harmful substances at rail facilities; adverse sea conditions (including storms and rising sea levels) and releases or spills from our shipping vessels or vessels loaded at our marine terminals; operator error; labor disputes/work stoppages; disputes with interconnected facilities and carriers; operational disruptions or apportionment on third-party systems or refineries on which our assets depend; and catastrophic events such as natural disasters, fires, floods, explosions, earthquakes, acts of terrorists and saboteurs, cyber security breaches, and other similar events, many of which are beyond our control. Additional risks to our vessels include capsizing, grounding and navigation errors.

The occurrence of any of these risks could result in serious injury and loss of human life, significant damage to property and natural resources, environmental pollution, significant reputational damage, impairment or suspension of operations, fines or other regulatory penalties, and revocation of regulatory approvals or imposition of new requirements, any of which also could result in substantial financial losses, including lost revenue and cash flow to the extent that an incident causes an interruption of service. For pipeline and storage assets located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of damage resulting from these risks may be greater. In addition, the consequences of any operational incident (including as a result of adverse sea conditions) at one of our marine terminals may be even more significant as a result of the complexities involved in addressing leaks and releases occurring in the ocean or along coastlines and/or the repair of marine terminals.

Our operating results may be adversely affected by unfavorable economic and market conditions.

Unfavorable economic conditions worldwide have from time to time contributed to slowdowns in several industries, including the oil and gas industry, the steel industry, the coal industry and in specific segments and markets in which we operate, resulting in reduced demand and increased price competition for our products and services. In addition, uncertain or changing economic conditions within one or more geographic regions may affect our operating results within the affected regions. Volatility in commodity prices or changes in markets for a given commodity might also have a negative impact on many of our customers, which could impair their ability to meet their obligations to us. See *"—Financial distress experienced by our customers or other counterparties could have an adverse impact on us in the event they are unable to pay us for the products or services we provide or otherwise fulfill their obligations to us."* In addition, decreases in the prices of crude oil, NGL and natural gas will have a negative impact on our operating results and cash flow. See *"—The volatility of oil, NGL and natural gas prices could adversely affect our CO_2 business segment and businesses within our Natural Gas Pipelines and Products Pipelines business segments."*

If economic and market conditions (including volatility in commodity markets) globally, in the U.S. or in other key markets become more volatile or deteriorate, we may experience material impacts on our business, financial condition and results of operations.

Financial distress experienced by our customers or other counterparties could have an adverse impact on us in the event they are unable to pay us for the products or services we provide or otherwise fulfill their obligations to us.

We are exposed to the risk of loss in the event of nonperformance by our customers or other counterparties, such as hedging counterparties, joint venture partners and suppliers. Many of our counterparties finance their activities through cash flow from operations or debt or equity financing, and some of them may be highly leveraged. Our counterparties are subject to their own operating, market, financial and regulatory risks, and some are experiencing, or may experience in the future, severe financial problems that have had or may have a significant impact on their creditworthiness. For example, PG&E, a customer of Ruby, filed for Chapter 11 bankruptcy protection in January 2019. See Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations—General—Investment in Ruby.*" Further, the security that is permitted to be obtained from such customers may be limited by FERC regulation. While certain of our customers are subsidiaries of an entity that has an investment grade credit rating, in many cases the parent entity has not guaranteed the obligations of the subsidiary and, therefore, the parent's credit ratings may have no bearing on such customers' ability to pay us for the services we provide or otherwise fulfill their obligations to us. Furthermore, financially distressed customers might be forced to reduce or curtail their future use of our products and services, which also could have a material adverse effect on our results of operations, financial condition, and cash flows.

We cannot provide any assurance that such customers and key counterparties will not become financially distressed or that such financially distressed customers or counterparties will not default on their obligations to us or file for bankruptcy protection. If one of such customers or counterparties files for bankruptcy protection, we likely would be unable to collect all, or even a significant portion, of amounts owed to us. Significant customer and other counterparty defaults and bankruptcy filings could have a material adverse effect on our business, financial position, results of operations or cash flows.

The acquisition of additional businesses and assets is part of our growth strategy. We may experience difficulties completing acquisitions or integrating new businesses and properties, and we may be unable to achieve the benefits we expect from any future acquisitions.

Part of our business strategy includes acquiring additional businesses and assets. We evaluate and pursue assets and businesses that we believe will complement or expand our operations in accordance with our growth strategy. We cannot provide any assurance that we will be able to complete acquisitions in the future or achieve the desired results from any acquisitions we do complete. Any acquired business or assets will be subject to many of the same risks as our existing businesses and may not achieve the levels of performance that we anticipate.

If we do not successfully integrate acquisitions, we may not realize anticipated operating advantages and cost savings. Integration of acquired companies or assets involves a number of risks, including (i) the loss of key customers of the acquired business; (ii) demands on management related to the increase in our size; (iii) the diversion of management's attention from the management of daily operations; (iv) difficulties in implementing or unanticipated costs of accounting, budgeting, reporting, internal controls and other systems; and (v) difficulties in the retention and assimilation of necessary employees.

We may not be able to maintain the levels of operating efficiency that acquired companies have achieved or might achieve separately. Successful integration of each acquisition will depend upon our ability to manage those operations and to eliminate redundant and excess costs. Difficulties in integration may be magnified if we make multiple acquisitions over a relatively short period of time. Because of difficulties in combining and expanding operations, we may not be able to achieve the cost savings and other size-related benefits that we hoped to achieve after these acquisitions, which would harm our financial condition and results of operations.

We are subject to reputational risks and risks relating to public opinion.

Our business, operations or financial condition generally may be negatively impacted as a result of negative public opinion. Public opinion may be influenced by negative portrayals of the industry in which we operate as well as opposition to development projects. In addition, market events specific to us could result in the deterioration of our reputation with key stakeholders. Potential impacts of negative public opinion or reputational issues may include delays or stoppages in expansion projects, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support from regulatory

authorities, challenges to regulatory approvals, difficulty securing financing for and cost overruns affecting expansion projects and the degradation of our business generally.

Reputational risk cannot be managed in isolation from other forms of risk. Credit, market, operational, insurance, regulatory and legal risks, among others, must all be managed effectively to safeguard our reputation. Our reputation and public opinion could also be impacted by the actions and activities of other companies operating in the energy industry, particularly other energy infrastructure providers, over which we have no control. In particular, our reputation could be impacted by negative publicity related to pipeline incidents or unpopular expansion projects and due to opposition to development of hydrocarbons and energy infrastructure, particularly projects involving resources that are considered to increase GHG emissions and contribute to climate change. Negative impacts from a compromised reputation or changes in public opinion (including with respect to the production, transportation and use of hydrocarbons generally) could include revenue loss, reduction in customer base, delays in obtaining, or challenges to, regulatory approvals with respect to growth projects and decreased value of our securities and our business.

The future success of our oil and gas development and production operations depends in part upon our ability to develop additional oil and gas reserves that are economically recoverable.

The rate of production from oil and natural gas properties declines as reserves are depleted. Without successful development activities, the reserves, revenues and cash flows of the oil and gas producing assets within our CO_2 business segment will decline. We may not be able to develop or acquire additional reserves at an acceptable cost or have necessary financing for these activities in the future. Additionally, if we do not realize production volumes greater than, or equal to, our hedged volumes, we may suffer financial losses not offset by physical transactions.

The development of crude oil and gas properties involves risks that may result in a total loss of investment.

The business of developing and operating oil and gas properties involves a high degree of business and financial risk that even a combination of experience, knowledge and careful evaluation may not be able to overcome. Acquisition and development decisions generally are based on subjective judgments and assumptions that, while they may be reasonable, are by their nature speculative. It is impossible to predict with certainty the production potential of a particular property or well. Furthermore, the successful completion of a well does not ensure a profitable return on the investment. A variety of geological, operational and market-related factors, including, but not limited to, unusual or unexpected geological formations, pressures, equipment failures or accidents, fires, explosions, blowouts, cratering, pollution and other environmental risks, shortages or delays in the availability of drilling rigs and the delivery of equipment, loss of circulation of drilling fluids or other conditions, may substantially delay or prevent completion of any well or otherwise prevent a property or well from being profitable. A productive well may become uneconomic in the event water or other deleterious substances are encountered, which impair or prevent the production of oil and/or gas from the well. In addition, production from any well may be unmarketable if it is contaminated with water or other deleterious substances.

Our use of hedging arrangements does not eliminate our exposure to commodity price risks and could result in financial losses or volatility in our income.

We engage in hedging arrangements to reduce our exposure to fluctuations in the prices of crude oil, natural gas and NGL. These hedging arrangements expose us to risk of financial loss in some circumstances, including when production is less than expected, when the counterparty to the hedging contract defaults on its contract obligations, or when there is a change in the expected differential between the underlying price in the hedging agreement and the actual price received. In addition, these hedging arrangements may limit the benefit we would otherwise receive from increases in prices for crude oil and natural gas.

The markets for instruments we use to hedge our commodity price exposure generally reflect then-prevailing conditions in the underlying commodity markets. As our existing hedges expire, we will seek to replace them with new hedging arrangements. To the extent underlying market conditions are unfavorable, new hedging arrangements available to us will reflect such unfavorable conditions.

The accounting standards regarding hedge accounting are very complex, and even when we engage in hedging transactions (for example, to mitigate our exposure to fluctuations in commodity price or currency exchange rates or to balance our exposure to fixed and variable interest rates) that are effective economically, these transactions may not be considered effective for accounting purposes. Accordingly, our consolidated financial statements may reflect some volatility due to these hedges, even when there is no underlying economic impact at the dates of those statements. In addition, it may not be possible for us to engage in hedging transactions that completely eliminate our exposure to commodity prices; therefore, our consolidated financial statements may reflect a gain or loss arising from an exposure to commodity prices for which we are unable to enter

into a completely effective hedge. For more information about our hedging activities, see Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates—Hedging Activities*" and Note 14 "*Risk Management*" to our consolidated financial statements.

A breach of information security or failure of one or more key information technology or operational (IT) systems, or those of third parties, may adversely affect our business, results of operations or business reputation.

Our business is dependent upon our operational systems to process a large amount of data and complex transactions. The various uses of these IT systems, networks and services include, but are not limited to, controlling our pipelines and terminals with industrial control systems, collecting and storing information and data, processing transactions, and handling other processing necessary to manage our business.

If any of our systems are damaged, fail to function properly or otherwise become unavailable, we may incur substantial costs to repair or replace them and may experience loss or corruption of critical data and interruptions or delays in our ability to perform critical functions, which could adversely affect our business and results of operations. A significant failure, compromise, breach or interruption in our systems could result in a disruption of our operations, customer dissatisfaction, damage to our reputation and a loss of customers or revenues. Efforts by us and our vendors to develop, implement and maintain security measures may not be successful in preventing these events from occurring, and any network and information systems-related events could require us to expend significant resources to remedy such event. In the future, we may be required to expend additional resources to continue to enhance our information security measures and/or to investigate and remediate information security vulnerabilities.

Attacks, including acts of terrorism or cyber sabotage, or the threat of such attacks, may adversely affect our business or reputation.

The U.S. government has issued public warnings that indicate that pipelines and other infrastructure assets might be specific targets of terrorist organizations or "cyber sabotage" events. For example, in 2018, a cyberattack on a shared data network forced four U.S. natural gas pipeline operators to temporarily shut down computer communications with their customers. Potential targets include our pipeline systems, terminals, processing plants or operating systems. The occurrence of an attack could cause a substantial decrease in revenues and cash flows, increased costs to respond or other financial loss, damage to our reputation, increased regulation or litigation or inaccurate information reported from our operations. There is no assurance that adequate cyber sabotage and terrorism insurance will be available at rates we believe are reasonable in the near future. These developments may subject our operations to increased risks, as well as increased costs, and, depending on their ultimate magnitude, could have a material adverse effect on our business, results of operations and financial condition or could harm our business reputation.

Hurricanes, earthquakes, flooding and other natural disasters, as well as subsidence and coastal erosion, could have an adverse effect on our business, financial condition and results of operations.

Some of our pipelines, terminals and other assets are located in, and our shipping vessels operate in, areas that are susceptible to hurricanes, earthquakes, flooding and other natural disasters or could be impacted by subsidence and coastal erosion. These natural disasters and phenomena could potentially damage or destroy our assets and disrupt the supply of the products we transport. In the third quarter of 2017, Hurricane Harvey caused disruptions in our operations and damage to our assets near the Texas Gulf Coast requiring approximately $45 million in repair costs, approximately $10 million of which was not recoverable through insurance. For more information regarding the impact of Hurricane Harvey on our assets and operating results, see Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations*." Many climate models indicate that global warming is likely to result in rising sea levels, increased intensity of weather, and increased frequency of extreme precipitation and flooding. These climate-related changes could damage physical assets, especially operations located in low-lying areas near coasts and river banks, and facilities situated in hurricane-prone and rain-susceptible regions. In addition, we may experience increased insurance premiums and deductibles, or a decrease in available coverage, for our assets in areas subject to severe weather. Natural disasters and phenomena can similarly affect the facilities of our customers. In either case, losses could exceed our insurance coverage and our business, financial condition and results of operations could be adversely affected, perhaps materially. See Items 1 and 2 "*Business and Properties—(c) Narrative Description of Business—Environmental Matters*."

Substantially all of the land on which our pipelines are located is owned by third parties. If we are unable to procure and maintain access to land owned by third parties, our revenue and operating costs, and our ability to complete construction projects, could be adversely affected.

We must obtain and maintain the rights to construct and operate pipelines on other owners' land, including private landowners, railroads, public utilities and others. While our interstate natural gas pipelines in the U.S. have federal eminent domain authority, the availability of eminent domain authority for our other pipelines varies from state to state depending upon the type of pipeline—petroleum liquids, natural gas, CO_2, or crude oil—and the laws of the particular state. In any case, we must compensate landowners for the use of their property, and in eminent domain actions, such compensation may be determined by a court. If we are unable to obtain rights-of-way on acceptable terms, our ability to complete construction projects on time, on budget, or at all, could be adversely affected. In addition, we are subject to the possibility of increased costs under our right-of-way or rental agreements with landowners, primarily through renewals of expiring agreements and rental increases. If we were to lose these rights, our operations could be disrupted or we could be required to relocate the affected pipelines, which could cause a substantial decrease in our revenues and cash flows and a substantial increase in our costs.

Our business requires the retention and recruitment of a skilled workforce, and difficulties recruiting and retaining our workforce could result in a failure to implement our business plans.

Our operations and management require the retention and recruitment of a skilled workforce, including engineers, technical personnel and other professionals. We and our affiliates compete with other companies in the energy industry for this skilled workforce. In addition, many of our current employees are retirement eligible and have significant institutional knowledge that must be transferred to other employees. If we are unable to (i) retain current employees; (ii) successfully complete the knowledge transfer; and/or (iii) recruit new employees of comparable knowledge and experience, our business could be negatively impacted. In addition, we could experience increased costs to retain and recruit these professionals.

The increased financial reporting and other obligations of management resulting from KML's obligations as a public company may divert management's attention away from other business operations.

KML, in which we own an approximate 70% interest, completed its IPO in Canada in May of 2017 and in 2018, completed the sale of its interest in the TMPL as described under Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations—General—KML—Sale of Trans Mountain Pipeline System and Its Expansion Project.*" Certain of our officers and directors also serve as officers and directors of KML, and we provide financial reporting support and other services as requested by KML and its controlled affiliates pursuant to a Services Agreement. The increased obligations associated with providing support to KML as a public company may divert our management's attention from other business concerns and may adversely affect our business, financial condition and results of operations. We are subject to financial reporting and other obligations that place significant demands on our management, administrative, operational, legal, internal audit and accounting resources. The demands on our personnel related to KML's obligations as a public company will be intensified as a result of the management and personnel departures and related transition following the sale of our interest in the TMPL.

If we are unable to retain our executive officers, our ability to execute our business strategy, including our growth strategy, may be hindered.

Our success depends in part on the performance of and our ability to retain our executive officers, particularly Richard D. Kinder, our Executive Chairman and one of our founders, Steve Kean, our Chief Executive Officer, and Kim Dang, our President. Along with the other members of our senior management, Mssrs. Kinder and Kean and Ms. Dang have been responsible for developing and executing our growth strategy. If we are not successful in retaining Mr. Kinder, Mr. Kean, Ms. Dang or our other executive officers, or replacing them, our business, financial condition or results of operations could be adversely affected. We do not maintain key personnel insurance.

Our Terminals business segment is subject to U.S. dollar/Canadian dollar exchange rate fluctuations as a result of operations in Canada.

We are a U.S. dollar reporting company. As a result of the operations of our Terminals business segment in Canada, a portion of our consolidated assets, liabilities, revenues, cash flows and expenses are denominated in Canadian dollars. Fluctuations in the exchange rate between U.S. and Canadian dollars could expose us to reductions in the U.S. dollar value of our earnings and cash flows and a reduction in our stockholders' equity under applicable accounting rules.

Our insurance policies do not cover all losses, costs or liabilities that we may experience, and insurance companies that currently insure companies in the energy industry may cease to do so or substantially increase premiums.

Our insurance program may not cover all operational risks and costs and may not provide sufficient coverage in the event of a claim. We do not maintain insurance coverage against all potential losses and could suffer losses for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Losses in excess of our insurance coverage could have a material adverse effect on our business, financial condition and results of operations.

Changes in the insurance markets subsequent to certain hurricanes and natural disasters have made it more difficult and more expensive to obtain certain types of coverage. The occurrence of an event that is not fully covered by insurance, or failure by one or more of our insurers to honor its coverage commitments for an insured event, could have a material adverse effect on our business, financial condition and results of operations. Insurance companies may reduce the insurance capacity they are willing to offer or may demand significantly higher premiums or deductibles to cover our assets. If significant changes in the number or financial solvency of insurance underwriters for the energy industry occur, we may be unable to obtain and maintain adequate insurance at a reasonable cost. There is no assurance that our insurers will renew their insurance coverage on acceptable terms, if at all, or that we will be able to arrange for adequate alternative coverage in the event of non-renewal. The unavailability of full insurance coverage to cover events in which we suffer significant losses could have a material adverse effect on our business, financial condition and results of operations.

Risks Related to Financing Our Business

Our substantial debt could adversely affect our financial health and make us more vulnerable to adverse economic conditions.

As of December 31, 2018, we had approximately $36.6 billion of consolidated debt (excluding debt fair value adjustments). Additionally, we and substantially all of our wholly owned U.S. subsidiaries are parties to a cross guarantee agreement under which each party to the agreement unconditionally guarantees the indebtedness of each other party, which means that we are liable for the debt of each of such subsidiaries. This level of consolidated debt and the cross guarantee agreement could have important consequences, such as (i) limiting our ability to obtain additional financing to fund our working capital, capital expenditures, debt service requirements or potential growth, or for other purposes; (ii) increasing the cost of our future borrowings; (iii) limiting our ability to use operating cash flow in other areas of our business or to pay dividends because we must dedicate a substantial portion of these funds to make payments on our debt; (iv) placing us at a competitive disadvantage compared to competitors with less debt; and (v) increasing our vulnerability to adverse economic and industry conditions.

Our ability to service our consolidated debt, and our ability to meet our consolidated leverage targets, will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, many of which are beyond our control. If our consolidated cash flow is not sufficient to service our consolidated debt, and any future indebtedness that we incur, we will be forced to take actions such as reducing dividends, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We may also take such actions to reduce our indebtedness if we determine that our earnings (or consolidated earnings before interest, taxes, depreciation and amortization, or EBITDA, as calculated in accordance with our revolving credit facility) may not be sufficient to meet our consolidated leverage targets, or to comply with consolidated leverage ratios required under certain of our debt agreements. We may not be able to effect any of these actions on satisfactory terms or at all. For more information about our debt, see Note 9 "*Debt*" to our consolidated financial statements.

Our business, financial condition and operating results may be affected adversely by increased costs of capital or a reduction in the availability of credit.

Adverse changes to the availability, terms and cost of capital, interest rates or our credit ratings (which would have a corresponding impact on the credit ratings of our subsidiaries that are party to the cross guarantee agreement) could cause our cost of doing business to increase by limiting our access to capital, including our ability to refinance maturities of existing indebtedness on similar terms, which could in turn reduce our cash flows and limit our ability to pursue acquisition or expansion opportunities. Our credit ratings may be impacted by our leverage, liquidity, credit profile and potential transactions. Although the ratings from credit agencies are not recommendations to buy, sell or hold our securities, our credit ratings will generally affect the market value of our and our subsidiaries' debt securities and the terms available to us for future issuances of debt securities.

Also, disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability, impacting our ability to finance our operations on favorable terms. A significant reduction in the availability of credit could materially and adversely affect our business, financial condition and results of operations.

Our large amount of variable rate debt makes us vulnerable to increases in interest rates.

As of December 31, 2018, approximately $11.4 billion of our approximately $36.6 billion of consolidated debt (excluding debt fair value adjustments) was subject to variable interest rates, either as short-term or long-term variable-rate debt obligations, or as long-term fixed-rate debt effectively converted to variable rates through the use of interest rate swaps. Should interest rates increase, the amount of cash required to service variable-rate debt would increase, as would our costs to refinance maturities of existing indebtedness, and our earnings and cash flows could be adversely affected. For more information about our interest rate risk, see Item 7A "*Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Risk.*"

Acquisitions and growth capital expenditures may require access to external capital. Limitations on our access to external financing sources could impair our ability to grow.

We have limited amounts of internally generated cash flows to fund acquisitions and growth capital expenditures. If our internally generated cash flows are not sufficient to fund one or more capital projects or acquisitions, we may have to rely on external financing sources, including commercial borrowings and issuances of debt and equity securities, to fund our acquisitions and growth capital expenditures. Limitations on our access to external financing sources, whether due to tightened capital markets, more expensive capital or otherwise, could impair our ability to execute our growth strategy.

Our debt instruments may limit our financial flexibility and increase our financing costs.

The instruments governing our debt contain restrictive covenants that may prevent us from engaging in certain transactions that may be beneficial to us. Some of the agreements governing our debt generally require us to comply with various affirmative and negative covenants, including the maintenance of certain financial ratios and restrictions on (i) incurring additional debt; (ii) entering into mergers, consolidations and sales of assets; (iii) granting liens; and (iv) entering into sale-leaseback transactions. The instruments governing any future debt may contain similar or more limiting restrictions. Our ability to respond to changes in business and economic conditions and to obtain additional financing, if needed, may be restricted.

Our and our customer's access to capital could be affected by evolving financial institutions' policies concerning businesses linked to fossil fuels.

Our and our customer's access to capital could be affected by evolving financial institutions' policies concerning businesses linked to fossil fuels. Public opinion toward industries linked to fossil fuels continues to evolve. Concerns about the potential effects of climate change have caused some to direct their attention towards sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in energy-related activities. Ultimately, this could make it more difficult for our customers to secure funding for exploration and production activities, and consequently could both indirectly affect demand for our services and directly affect our ability to fund construction or other capital projects.

Risks Related to Ownership of Our Capital Stock

The guidance we provide for our anticipated dividends is based on estimates. Circumstances may arise that lead to conflicts between using funds to pay anticipated dividends or to invest in our business.

We disclose in this report and elsewhere the expected cash dividends on our common stock. These reflect our current judgment, but as with any estimate, they may be affected by inaccurate assumptions and other risks and uncertainties, many of which are beyond our control. See "*Information Regarding Forward-Looking Statements*" at the beginning of this report. If our board of directors elects to pay dividends at the anticipated level and that action would leave us with insufficient cash to take timely advantage of growth opportunities (including through acquisitions), to meet any large unanticipated liquidity requirements, to fund our operations, to maintain our leverage metrics or otherwise to address properly our business prospects, our business could be harmed.

Conversely, a decision to address such needs might lead to the payment of dividends below the anticipated levels. As events present themselves or become reasonably foreseeable, our board of directors, which determines our business strategy and our dividends, may decide to address those matters by reducing our anticipated dividends. Alternatively, because nothing in our governing documents or credit agreements prohibits us from borrowing to pay dividends, we could choose to incur debt to enable us to pay our anticipated dividends. This would add to our substantial debt discussed above under "*—Risks Related to Financing Our Business—Our substantial debt could adversely affect our financial health and make us more vulnerable to adverse economic conditions*."

Our certificate of incorporation restricts the ownership of our common stock by non-U.S. citizens within the meaning of the Jones Act. These restrictions may affect the liquidity of our common stock and may result in non-U.S. citizens being required to sell their shares at a loss.

The Jones Act requires, among other things, that at least 75% of our common stock be owned at all times by U.S. citizens, as defined under the Jones Act, in order for us to own and operate vessels in the U.S. coastwise trade. As a safeguard to help us maintain our status as a U.S. citizen, our certificate of incorporation provides that, if the number of shares of our common stock owned by non-U.S. citizens exceeds 22%, we have the ability to redeem shares owned by non-U.S. citizens to reduce the percentage of shares owned by non-U.S. citizens to 22%. These redemption provisions may adversely impact the marketability of our common stock, particularly in markets outside of the U.S. Further, those stockholders would not have control over the timing of such redemption, and may be subject to redemption at a time when the market price or timing of the redemption is disadvantageous. In addition, the redemption provisions might have the effect of impeding or discouraging a merger, tender offer or proxy contest by a non-U.S. citizen, even if it were favorable to the interests of some or all of our stockholders.

Risks Related to Regulation

The FERC, the CPUC, or the NEB may establish pipeline tariff rates that have a negative impact on us. In addition, the FERC, the CPUC, the NEB, or our customers could initiate proceedings or file complaints challenging the tariff rates charged by our pipelines, which could have an adverse impact on us.

The profitability of our regulated pipelines is influenced by fluctuations in costs and our ability to recover any increases in our costs in the rates charged to our shippers. To the extent that our costs increase in an amount greater than what we are permitted by the FERC, the CPUC, or the NEB to recover in our rates, or to the extent that there is a lag before we can file for and obtain rate increases, such events can have a negative impact on our operating results.

Our existing rates may also be challenged by complaint. Regulators and shippers on our pipelines have rights to challenge, and have challenged, the rates we charge under certain circumstances prescribed by applicable regulations. Some shippers on our pipelines have filed complaints with the regulators that seek substantial refunds for alleged overcharges during the years in question and prospective reductions in the tariff rates. Further, the FERC may continue to initiate investigations to determine whether interstate natural gas pipelines have over-collected on rates charged to shippers. We may face challenges, similar to those described in Note 18 "*Litigation, Environmental and Other Contingencies*" to our consolidated financial statements, to the rates we charge on our pipelines. In addition, following the 2017 Tax Reform, which reduced the corporate tax rate from 35% to 21%, the FERC initiated the Form 501-G process to review the estimated impact of the 2017 Tax Reform on interstate pipelines with respect to tax recovery in existing jurisdictional rates. See Note 18 "*Litigation, Environmental and Other Contingencies—FERC Proceedings*" to our consolidated financial statements. Any successful challenge to our rates could materially adversely affect our future earnings, cash flows and financial condition.

New laws, policies, regulations, rulemaking and oversight, as well as changes to those currently in effect, could adversely impact our earnings, cash flows and operations.

Our assets and operations are subject to regulation and oversight by federal, state, provincial and local regulatory authorities. Legislative changes, as well as regulatory actions taken by these agencies, have the potential to adversely affect our profitability. In addition, a certain degree of regulatory uncertainty is created by the current U.S. presidential administration because it remains unclear specifically what the current administration may do with respect to future policies and regulations that may affect us. Regulation affects almost every part of our business and extends to such matters as (i) federal, state, provincial and local taxation; (ii) rates (which include tax, reservation, commodity, surcharges, fuel and gas lost and unaccounted for), operating terms and conditions of service; (iii) the types of services we may offer to our customers; (iv) the contracts for service entered into with our customers; (v) the certification and construction of new facilities; (vi) the costs of raw materials, such as steel, which may be affected by tariffs or otherwise; (vii) the integrity, safety and security of facilities and operations; (viii) the acquisition of other businesses; (ix) the acquisition, extension, disposition or abandonment of services

or facilities; (x) reporting and information posting requirements; (xi) the maintenance of accounts and records; and (xii) relationships with affiliated companies involved in various aspects of the energy businesses.

Should we fail to comply with any applicable statutes, rules, regulations, and orders of regulatory authorities, we could be subject to substantial penalties and fines and potential loss of government contracts. Furthermore, new laws, regulations or policy changes sometimes arise from unexpected sources. New laws or regulations, unexpected policy changes or interpretations of existing laws or regulations, such as the 2017 Tax Reform and the resulting Form 501-G process initiated by FERC, applicable to our income, operations, assets or another aspect of our business, could have a material adverse impact on our earnings, cash flow, financial condition and results of operations. For more information, see Items 1 and 2 "*Business and Properties—(c) Narrative Description of Business—Regulation*."

Environmental, health and safety laws and regulations could expose us to significant costs and liabilities.

Our operations are subject to federal, state, provincial and local laws, regulations and potential liabilities arising under or relating to the protection or preservation of the environment, natural resources and human health and safety. Such laws and regulations affect many aspects of our present and future operations, and generally require us to obtain and comply with various environmental registrations, licenses, permits, inspections and other approvals. Liability under such laws and regulations may be incurred without regard to fault under CERCLA, the Resource Conservation and Recovery Act, the Federal Clean Water Act, the Oil Pollution Act or analogous state or provincial laws as a result of the presence or release of hydrocarbons and other hazardous substances into or through the environment, and these laws may require response actions and remediation and may impose liability for natural resource and other damages. Private parties, including the owners of properties through which our pipelines pass, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with such laws and regulations or for personal injury or property damage. Our insurance may not cover all environmental risks and costs and/or may not provide sufficient coverage in the event an environmental claim is made against us.

Failure to comply with these laws and regulations including required permits and other approvals also may expose us to civil, criminal and administrative fines, penalties and/or interruptions in our operations that could harm our business, financial position, results of operations and prospects. For example, if an accidental leak, release or spill of liquid petroleum products, chemicals or other hazardous substances occurs at or from our pipelines, shipping vessels or storage or other facilities, we may experience significant operational disruptions and we may have to pay a significant amount to clean up or otherwise respond to the leak, release or spill, pay government penalties, address natural resource damage, compensate for human exposure or property damage, install costly pollution control equipment or undertake a combination of these and other measures. The resulting costs and liabilities could materially and negatively affect our earnings and cash flows.

We own and/or operate numerous properties that have been used for many years in connection with our business activities. While we believe we have utilized operating, handling, and disposal practices that were consistent with industry practices at the time, hydrocarbons or other hazardous substances may have been released at or from properties owned, operated or used by us or our predecessors, or at or from properties where our or our predecessors' wastes have been taken for disposal. In addition, many of these properties have been owned and/or operated by third parties whose management, handling and disposal of hydrocarbons or other hazardous substances were not under our control. These properties and the hazardous substances released and wastes disposed on them may be subject to laws in the U.S. such as CERCLA, which impose joint and several liability without regard to fault or the legality of the original conduct. Under the regulatory schemes of the various Canadian provinces, such as British Columbia's Environmental Management Act, Canada has similar laws with respect to properties owned, operated or used by us or our predecessors. Under such laws and implementing regulations, we could be required to remove or remediate previously disposed wastes or property contamination, including contamination caused by prior owners or operators. Imposition of such liability schemes could have a material adverse impact on our operations and financial position.

Further, we cannot ensure that such existing laws and regulations will not be revised or that new laws or regulations will not be adopted or become applicable to us. For example, the Federal Clean Air Act and other similar federal, state and provincial laws are subject to periodic review and amendment, which could result in more stringent emission control requirements obligating us to make significant capital expenditures at our facilities. There can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and prospects. For more information, see Items 1 and 2 "*Business and Properties—(c) Narrative Description of Business—Environmental Matters.*"

Increased regulatory requirements relating to the integrity of our pipelines may require us to incur significant capital and operating expense outlays to comply.

We are subject to extensive laws and regulations related to pipeline integrity at the federal, state and provincial level. There are, for example, federal guidelines issued by the U.S. Department of Transportation (DOT) for pipeline companies in the areas of testing, education, training and communication. The ultimate costs of compliance with the integrity management rules are difficult to predict. The majority of compliance costs relate to pipeline integrity testing and repairs. Technological advances in in-line inspection tools, identification of additional threats to a pipeline's integrity and changes to the amount of pipeline determined to be located in "High Consequence Areas" can have a significant impact on integrity testing and repair costs. We plan to continue our integrity testing programs to assess and maintain the integrity of our existing and future pipelines as required by the DOT rules. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

Further, additional laws and regulations that may be enacted in the future or a new interpretation of existing laws and regulations could significantly increase the amount of these expenditures. There can be no assurance as to the amount or timing of future expenditures for pipeline integrity regulation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not deemed by regulators to be fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and prospects.

Climate change and related regulation could result in significantly increased operating and capital costs for us and could reduce demand for our products and services.

Various laws and regulations exist or are under development that seek to regulate the emission of GHGs such as methane and CO_2, including the EPA programs to control GHG emissions and state actions to develop statewide or regional programs. Existing EPA regulations require us to report GHG emissions in the U.S. from sources such as our larger natural gas compressor stations, fractionated NGL, and production of naturally occurring CO_2 (for example, from our McElmo Dome CO_2 field), even when such production is not emitted to the atmosphere. Proposed approaches to further regulate GHG emissions include establishing GHG "cap and trade" programs, increased efficiency standards, and incentives or mandates for pollution reduction, use of renewable energy sources, or use of alternative fuels with lower carbon content. For more information about climate change regulation, see Items 1 and 2 "*Business and Properties—(c) Narrative Description of Business—Environmental Matters—Climate Change.*"

Adoption of any such laws or regulations could increase our costs to operate and maintain our facilities and could require us to install new emission controls on our facilities, acquire allowances for our GHG emissions, pay taxes related to our GHG emissions and administer and manage a GHG emissions program, and such increased costs could be significant. Recovery of such increased costs from our customers is uncertain in all cases and may depend on events beyond our control, including the outcome of future rate proceedings before the FERC. Such laws or regulations could also lead to reduced demand for hydrocarbon products that are deemed to contribute to GHGs, or restrictions on their use, which in turn could adversely affect demand for our products and services.

Finally, many climate models indicate that global warming is likely to result in rising sea levels and increased frequency and severity of weather events, which may lead to higher insurance costs, or a decrease in available coverage, for our assets in areas subject to severe weather. These climate-related changes could damage our physical assets, especially operations located in low-lying areas near coasts and river banks, and facilities situated in hurricane-prone and rain-susceptible regions.

Any of the foregoing could have adverse effects on our business, financial position, results of operations or cash flows.

Increased regulation of exploration and production activities, including hydraulic fracturing, could result in reductions or delays in drilling and completing new oil and natural gas wells, as well as reductions in production from existing wells, which could adversely impact the volumes of natural gas transported on our natural gas pipelines and our own oil and gas development and production activities.

We gather, process or transport crude oil, natural gas or NGL from several areas in which the use of hydraulic fracturing is prevalent. Oil and gas development and production activities are subject to numerous federal, state, provincial and local laws and regulations relating to environmental quality and pollution control. The oil and gas industry is increasingly relying on supplies of hydrocarbons from unconventional sources, such as shale, tight sands and coal bed methane. The extraction of hydrocarbons from these sources frequently requires hydraulic fracturing. Hydraulic fracturing involves the pressurized

injection of water, sand, and chemicals into the geologic formation to stimulate gas production and is a commonly used stimulation process employed by oil and gas exploration and production operators in the completion of certain oil and gas wells. There have been initiatives at the federal and state levels to regulate or otherwise restrict the use of hydraulic fracturing. Adoption of legislation or regulations placing restrictions on hydraulic fracturing activities could impose operational delays, increased operating costs and additional regulatory burdens on exploration and production operators, which could reduce their production of crude oil, natural gas or NGL and, in turn, adversely affect our revenues, cash flows and results of operations by decreasing the volumes of these commodities that we handle.

In addition, many states are promulgating stricter requirements not only for wells but also compressor stations and other facilities in the oil and gas industry sector. These laws and regulations increase the costs of these activities and may prevent or delay the commencement or continuance of a given operation. Specifically, these activities are subject to laws and regulations regarding the acquisition of permits before drilling, restrictions on drilling activities and location, emissions into the environment, water discharges, transportation of hazardous materials, and storage and disposition of wastes. In addition, legislation has been enacted that requires well and facility sites to be abandoned and reclaimed to the satisfaction of state authorities. These laws and regulations may adversely affect our oil and gas development and production activities.

Derivatives regulation could have an adverse effect on our ability to hedge risks associated with our business.

The Dodd-Frank Act requires the U.S. Commodity Futures Trading Commission (CFTC) and the SEC to promulgate rules and regulations establishing federal oversight and regulation of the OTC derivatives market and entities that participate in that market. Those rules and regulations are largely complete; although in December 2016, the CFTC re-proposed new rules pursuant to the Dodd-Frank Act that would institute broad new aggregate position limits for OTC swaps and futures and options traded on regulated exchanges. Thus, we cannot predict how further rules and regulations will affect us.

If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Increased volatility may make us less attractive to certain types of investors. Any of these consequences could have a material adverse effect on our financial condition and results of operations.

The Jones Act includes restrictions on ownership by non-U.S. citizens of our U.S. point to point maritime shipping vessels, and failure to comply with the Jones Act, or changes to or a repeal of the Jones Act, could limit our ability to operate our vessels in the U.S. coastwise trade, result in the forfeiture of our vessels or otherwise adversely impact our earnings, cash flows and operations.

We are subject to the Jones Act, which generally restricts U.S. point-to-point maritime shipping to vessels operating under the U.S. flag, built in the U.S., owned and operated by U.S.-organized companies that are controlled and at least 75% owned by U.S. citizens and crewed by predominately U.S. citizens. Our business would be adversely affected if we fail to comply with the Jones Act provisions on coastwise trade. If we do not comply with any of these requirements, we would be prohibited from operating our vessels in the U.S. coastwise trade and, under certain circumstances, we could be deemed to have undertaken an unapproved transfer to non-U.S. citizens that could result in severe penalties, including permanent loss of U.S. coastwise trading rights for our vessels, fines or forfeiture of vessels. Our business could be adversely affected if the Jones Act were to be modified or repealed so as to permit foreign competition that is not subject to the same U.S. government imposed burdens.

Item 1B. ***Unresolved Staff Comments.***

None.

Item 3. ***Legal Proceedings.***

See Note 18 "*Litigation, Environmental and Other Contingencies*" to our consolidated financial statements.

Item 4. ***Mine Safety Disclosures.***

We no longer own or operate mines for which reporting requirements apply under the mine safety disclosure requirements of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank), except for one terminal that is in temporary idle status with the Mine Safety and Health Administration. We have not received any specified health and safety violations, orders or citations, related assessments or legal actions, mining-related fatalities, or similar events requiring disclosure pursuant to the mine safety disclosure requirements of Dodd-Frank for the year ended December 31, 2018.

PART II

Item 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.***

Our Class P common stock is listed for trading on the NYSE under the symbol "KMI."

As of February 7, 2019, we had 11,434 holders of our Class P common stock, which does not include beneficial owners whose shares are held by a nominee, such as a broker or bank.

For information on our equity compensation plans, see Note 10 "*Share-based Compensation and Employee Benefits—Share-based Compensation*" to our consolidated financial statements.

Our Purchases of Our Class P Shares

Period	Total number of securities purchased(a)	Average price paid per security	Total number of securities purchased as part of publicly announced plans(a)	Maximum number (or approximate dollar value) of securities that may yet be purchased under the plans or programs
October 1 to October 31, 2018	—	$ —	—	$ 1,500,000,715
November 1 to November 30, 2018	—	$ —	—	$ 1,500,000,715
December 1 to December 31, 2018(b)	1,473,120	$ 15.56	1,473,120	$ 1,477,062,687
Total	1,473,120	$ 15.56	1,473,120	$ 1,477,062,687

(a) On July 19, 2017, our board of directors approved a $2 billion common share buy-back program that began in December 2017. After repurchase, the shares are cancelled and no longer outstanding.
(b) Excludes repurchases made in December 2018 of 0.1 million shares for approximately $2 million which settled on January 2, 2019.

Item 6. ***Selected Financial Data.***

The following table sets forth, for the periods and at the dates indicated, our summary historical financial data. The table is derived from our consolidated financial statements and notes thereto, and should be read in conjunction with those audited financial statements. See also Item 7 *"Management's Discussion and Analysis of Financial Condition and Results of Operations"* in this report for more information.

Five-Year Review
Kinder Morgan, Inc. and Subsidiaries

	As of or for the Year Ended December 31,				
	2018	2017	2016	2015	2014
	(In millions, except per share amounts)				
Income and Cash Flow Data:					
Revenues	$ 14,144	$ 13,705	$ 13,058	$ 14,403	$ 16,226
Operating income	3,794	3,529	3,538	2,378	4,387
Earnings from equity investments	887	578	497	414	406
Net income	1,919	223	721	208	2,443
Net income attributable to Kinder Morgan, Inc.	1,609	183	708	253	1,026
Net income available to common stockholders	1,481	27	552	227	1,026
Class P Shares					
Basic and Diluted Earnings Per Common Share From Continuing Operations	$ 0.66	$ 0.01	$ 0.25	$ 0.10	$ 0.89
Basic Weighted Average Common Shares Outstanding	2,216	2,230	2,230	2,187	1,137
Dividends per common share declared for the period(a)	$ 0.80	$ 0.50	$ 0.50	$ 1.61	$ 1.74
Dividends per common share paid in the period(a)	0.725	0.50	0.50	1.93	1.70
Balance Sheet Data (at end of period):					
Property, plant and equipment, net	$ 37,897	$ 40,155	$ 38,705	$ 40,547	$ 38,564
Total assets	78,866	79,055	80,305	84,104	83,049
Current portion of debt(b)	3,388	2,828	2,696	821	2,717
Long-term debt(c)	33,205	34,088	36,205	40,732	38,312

(a) Dividends for the fourth quarter of each year are declared and paid during the first quarter of the following year.
(b) Using part of our portion of proceeds from the TMPL Sale that KML distributed to us in January 2019, we immediately repaid our outstanding balance of commercial paper of $409 million and then repaid $500 million of maturing 9.00% senior notes and $800 million of maturing 2.65% senior notes in February 2019.
(c) Excludes debt fair value adjustments.

Item 7. ***Management's Discussion and Analysis of Financial Condition and Results of Operations.***

The following discussion and analysis should be read in conjunction with our consolidated financial statements and the notes thereto. We prepared our consolidated financial statements in accordance with GAAP. Additional sections in this report which should be helpful to the reading of our discussion and analysis include the following: (i) a description of our business strategy found in Items 1 and 2 "*Business and Properties—(c) Narrative Description of Business—Business Strategy;*" (ii) a description of developments during 2018, found in Items 1 and 2 "*Business and Properties—(a) General Development of Business—Recent Developments;*" and (iii) a description of risk factors affecting us and our business, found in Item 1A "*Risk Factors.*"

Inasmuch as the discussion below and the other sections to which we have referred you pertain to management's comments on financial resources, capital spending, our business strategy and the outlook for our business, such discussions contain forward-looking statements. These forward-looking statements reflect the expectations, beliefs, plans and objectives of management about future financial performance and assumptions underlying management's judgment concerning the matters discussed, and accordingly, involve estimates, assumptions, judgments and uncertainties. Our actual results could differ materially from those discussed in the forward-looking statements. Factors that could cause or contribute to any differences

include, but are not limited to, those discussed below and elsewhere in this report, particularly in Item 1A "*Risk Factors*" and at the beginning of this report in "*Information Regarding Forward-Looking Statements.*"

General

Our reportable business segments are:

- Natural Gas Pipelines—the ownership and operation of (i) major interstate and intrastate natural gas pipeline and storage systems; (ii) natural gas and crude oil gathering systems and natural gas processing and treating facilities; (iii) NGL fractionation facilities and transportation systems; and (iv) LNG facilities;

- Products Pipelines—the ownership and operation of refined petroleum products, NGL and crude oil and condensate pipelines that primarily deliver, among other products, gasoline, diesel and jet fuel, propane, ethane, crude oil and condensate to various markets, plus the ownership and/or operation of associated product terminals and petroleum pipeline transmix facilities;

- Terminals—the ownership and/or operation of (i) liquids and bulk terminal facilities located throughout the U.S. and portions of Canada that transload and store refined petroleum products, crude oil, ethanol and chemicals, and bulk products, including petroleum coke, metals and ores; and (ii) Jones Act tankers;

- CO_2—(i) the production, transportation and marketing of CO_2 to oil fields that use CO_2 as a flooding medium to increase recovery and production of crude oil from mature oil fields; (ii) ownership interests in and/or operation of oil fields and gasoline processing plants in West Texas; and (iii) the ownership and operation of a crude oil pipeline system in West Texas; and

- Kinder Morgan Canada (prior to August 31, 2018)—the ownership and operation of the Trans Mountain pipeline system that transports crude oil and refined petroleum products from Edmonton, Alberta, Canada to marketing terminals and refineries in British Columbia, Canada and the state of Washington. As a result of the TMPL Sale, this segment does not have results of operations on a prospective basis.

As an energy infrastructure owner and operator in multiple facets of the various U.S. and Canadian energy industries and markets, we examine a number of variables and factors on a routine basis to evaluate our current performance and our prospects for the future.

With respect to our interstate natural gas pipelines, related storage facilities and LNG terminals, the revenues from these assets are primarily received under contracts with terms that are fixed for various and extended periods of time. To the extent practicable and economically feasible in light of our strategic plans and other factors, we generally attempt to mitigate risk of reduced volumes and prices by negotiating contracts with longer terms, with higher per-unit pricing and for a greater percentage of our available capacity. These long-term contracts are typically structured with a fixed fee reserving the right to transport or store natural gas and specify that we receive the majority of our fee for making the capacity available, whether or not the customer actually chooses to utilize the capacity. Similarly, the Texas Intrastate Natural Gas Pipeline operations, currently derives approximately 76% of its sales and transport margins from long-term transport and sales contracts. As contracts expire, we have additional exposure to the longer term trends in supply and demand for natural gas. As of December 31, 2018, the remaining weighted average contract life of our natural gas transportation contracts (including intrastate pipelines' sales portfolio) was approximately six years.

Our midstream assets provide gathering and processing services for natural gas and gathering services for crude oil. These assets are mostly fee-based and the revenues and earnings we realize from gathering natural gas, processing natural gas in order to remove NGL from the natural gas stream, and fractionating NGL into their base components, are affected by the volumes of natural gas made available to our systems. Such volumes are impacted by producer rig count and drilling activity. In addition to fee based arrangements, some of which may include minimum volume commitments, we also provide some services based on percent-of-proceeds, percent-of-index and keep-whole contracts. Our service contracts may rely solely on a single type of arrangement, but more often they combine elements of two or more of the above, which helps us and our counterparties manage the extent to which each shares in the potential risks and benefits of changing commodity prices.

The profitability of our refined petroleum products pipeline transportation and storage business generally is driven by the volume of refined petroleum products that we transport and the prices we receive for our services. We also have approximately 55 liquids terminals in this business segment that store fuels and offer blending services for ethanol and biofuels.
The transportation and storage volume levels are primarily driven by the demand for the refined petroleum products being

shipped or stored. Demand for refined petroleum products tends to track in large measure demographic and economic growth, and, with the exception of periods of time with very high product prices or recessionary conditions, demand tends to be relatively stable. Because of that, we seek to own refined petroleum products pipelines located in, or that transport to, stable or growing markets and population centers. The prices for shipping are generally based on regulated tariffs that are adjusted annually based on changes in the U.S. Producer Price Index.

Our crude and condensate transportation services are primarily provided either pursuant to (i) long-term contracts that normally contain minimum volume commitments or (ii) through terms prescribed by the toll settlements with shippers and approved by regulatory authorities. As a result of these contracts, our settlement volumes are generally not sensitive to changing market conditions in the shorter term; however, in the longer term the revenues and earnings we realize from our crude oil and condensate pipelines are affected by the volumes of crude oil and condensate available to our pipeline systems, which are impacted by the level of oil and gas drilling activity in the respective producing regions that we serve. Our petroleum condensate processing facility splits condensate into its various components, such as light and heavy naphtha, under a long-term fee-based agreement with a major integrated oil company.

The factors impacting our Terminals business segment generally differ between liquid and bulk terminals, and in the case of a bulk terminal, the type of product being handled or stored. Our liquids terminals business generally has long-term contracts that require the customer to pay regardless of whether they use the capacity. Thus, similar to our natural gas pipelines business, our liquids terminals business is less sensitive to short-term changes in supply and demand. Therefore, the extent to which changes in these variables affect our terminals business in the near term is a function of the length of the underlying service contracts (which on average is approximately four years), the extent to which revenues under the contracts are a function of the amount of product stored or transported, and the extent to which such contracts expire during any given period of time. As with our refined petroleum products pipelines transportation business, the revenues from our bulk terminals business are generally driven by the volumes we handle and/or store, as well as the prices we receive for our services, which in turn are driven by the demand for the products being shipped or stored. While we handle and store a large variety of products in our bulk terminals, the primary products are petroleum coke, metals and ores. For the most part, we have contracts for this business that contain minimum volume guarantees and/or service exclusivity arrangements under which customers are required to utilize our terminals for all or a specified percentage of their handling and storage needs. The profitability of our minimum volume contracts is generally unaffected by short-term variation in economic conditions; however, to the extent we expect volumes above the minimum and/or have contracts which are volume-based, we can be sensitive to changing market conditions. To the extent practicable and economically feasible in light of our strategic plans and other factors, we generally attempt to mitigate the risk of reduced volumes and pricing by negotiating contracts with longer terms, with higher per-unit pricing and for a greater percentage of our available capacity. In addition, weather-related factors such as hurricanes and other weather related events may impact our facilities and access to them and, thus, the profitability of certain terminals for limited periods of time or, in relatively rare cases of severe damage to facilities, for longer periods. In addition to liquid and bulk terminals, we also own Jones Act tankers in our Terminals business segment. As of December 31, 2018, we have sixteen Jones Act qualified tankers that operate in the marine transportation of crude oil, condensate and refined products in the U.S. and are currently operating pursuant to multi-year fixed price charters with major integrated oil companies, major refiners and the U.S. Military Sealift Command.

The CO_2 source and transportation business primarily has third-party contracts with minimum volume requirements, which as of December 31, 2018, had a remaining average contract life of approximately nine years. CO_2 sales contracts vary from customer to customer and have evolved over time as supply and demand conditions have changed. Our recent contracts have generally provided for a delivered price tied to the price of crude oil, but with a floor price. On a volume-weighted basis, for third-party contracts making deliveries in 2019, and utilizing the average oil price per barrel contained in our 2019 budget, approximately 97% of our revenue is based on a fixed fee or floor price, and 3% fluctuates with the price of oil. In the long-term, our success in this portion of the CO_2 business segment is driven by the demand for CO_2. However, short-term changes in the demand for CO_2 typically do not have a significant impact on us due to the required minimum sales volumes under many of our contracts. In the CO_2 business segment's oil and gas producing activities, we monitor the amount of capital we expend in relation to the amount of production that we expect to add. In that regard, our production during any period is an important measure. In addition, the revenues we receive from our crude oil and NGL sales are affected by the prices we realize from the sale of these products. Over the long-term, we will tend to receive prices that are dictated by the demand and overall market price for these products. In the shorter term, however, market prices are likely not indicative of the revenues we will receive due to our risk management, or hedging, program, in which the prices to be realized for certain of our future sales quantities are fixed, capped or bracketed through the use of financial derivative contracts, particularly for crude oil. The realized weighted average crude oil price per barrel, with the hedges allocated to oil, was $57.83 per barrel in 2018, $58.40 per barrel in 2017 and $61.52 per barrel in 2016. Had we not used energy derivative contracts to transfer commodity price risk, our crude oil sales prices would have averaged $58.63 per barrel in 2018, $49.61 per barrel in 2017 and $41.36 per barrel in 2016.

Also, see Note 16 "*Revenue Recognition*" to our consolidated financial statements for more information about the types of contracts and revenues recognized for each of our segments.

Investment in Ruby

In January 2019, Pacific Gas and Electric (PG&E) filed for Chapter 11 bankruptcy protection. Our exposure to PG&E is limited to our $750 million equity investment in Ruby and an approximate $55 million note receivable from Ruby, where PG&E is Ruby's largest customer. PG&E represents approximately $93 million of annual revenues on Ruby, and our partner's preferred equity interest in Ruby is senior to our interest. Despite the bankruptcy filing, Ruby continues to perform under its existing service contracts with PG&E, and PG&E has provided credit support on its trade payables to Ruby through a prepayment arrangement. While the ultimate outcome of the bankruptcy proceedings remains uncertain, there is the potential for Ruby's existing contracts with PG&E to be canceled in the bankruptcy process. Any cancellation of these contracts could negatively impact Ruby's future revenues and require us to evaluate our investment in Ruby for an other than temporary impairment. This could result in a material impairment of our investment in Ruby at the time such events become known.

KML

Sale of Trans Mountain Pipeline System and Its Expansion Project

On August 31, 2018, KML completed the sale of the TMPL, the TMEP, the Puget Sound pipeline system and Kinder Morgan Canada Inc., the Canadian employer of our staff that operate the business, which were indirectly acquired by the Government of Canada through Trans Mountain Corporation (a subsidiary of the Canada Development Investment Corporation) for cash consideration of C$4.43 billion (U.S.$3.4 billion), which is the contractual purchase price of C$4.5 billion net of a preliminary working capital adjustment (the "TMPL Sale"). These assets comprised our Kinder Morgan Canada business segment. We recognized a pre-tax gain from the TMPL Sale of $596 million within "Loss on impairments and divestitures, net" in our accompanying consolidated statement of income during the year ended December 31, 2018, including an incremental working capital adjustment of $26 million accrued as of December 31, 2018.

On January 3, 2019, pursuant to KML's shareholders' approval on November 29, 2018, KML distributed to its shareholders as a return of capital, the net proceeds from the TMPL Sale, after capital gains taxes, customary purchase price adjustments and the repayment of debt outstanding under a temporary KML credit facility (see Note 9 "*Debt—Credit Facilities and Restrictive Covenants—KML*"). KML's public owners of its restricted voting shares, reflected as noncontrolling interests by us, received approximately $0.9 billion (C$1.2 billion), and part of our approximate 70% portion of the net proceeds of $1.9 billion (C$2.5 billion) (after Canadian tax) were used to immediately repay our outstanding commercial paper borrowings of $0.4 billion, and in February 2019, to pay down approximately $1.3 billion of maturing long-term debt. To facilitate the return of capital and provide flexibility for KML's dividends going forward, KML's shareholders also approved a reduction in the stated capital of its restricted voting shares by C$1.45 billion, which was recorded in the fourth quarter of 2018, along with a "reverse stock split" of KML's restricted voting shares, and KML's special voting shares that we own, on a one-for-three basis (three shares consolidating to one share) which occurred on January 4, 2019.

KML continues to manage a portfolio of strategic infrastructure assets across Western Canada, including (i) the crude terminal facilities, which constitute the largest merchant terminal storage position in the Edmonton market and the largest origination crude by rail loading facility in North America; (ii) the Vancouver Wharves Terminal, the largest mineral concentrate export/import facility on the west coast of North America; (iii) the Jet Fuel pipeline system; and (iv) the Canadian portion of the U.S. and Canadian Cochin pipeline system. These KML assets are part of our Products Pipelines and Terminals business segments.

KML IPO

The interest in the Canadian business operations that we sold to the public on May 30, 2017 in KML's IPO represented an interest in all our operating assets in our Kinder Morgan Canada business segment and our operating Canadian assets in our Terminals and Products Pipelines business segments. These Canadian assets included the TMPL, TMEP and the Puget Sound pipeline system, all of which have been sold in the TMPL Sale, the Jet Fuel pipeline system, the Canadian portion of the Cochin pipeline system, the Vancouver Wharves Terminal and the North 40 Terminal; as well as three jointly controlled investments: the Edmonton Rail Terminal, the Alberta Crude Terminal and the Base Line Terminal.

Subsequent to the IPO, we retained control of KML, and as a result, it remains consolidated in our consolidated financial statements. The public ownership of the KML restricted voting shares is reflected within "Noncontrolling interests" in our

consolidated statements of stockholders' equity and consolidated balance sheets. Earnings attributable to the public ownership of KML are presented in "Net income attributable to noncontrolling interests" in our consolidated statements of income for the periods presented after May 30, 2017. KML transacts in and/or uses the Canadian dollar as the functional currency, which affects our segment results due to the variability in U.S. - Canadian dollar exchange rates.

Subsequent to its IPO, KML has obtained a credit facility and completed two preferred share offerings. KML continues to be a self-funding entity and we do not anticipate making contributions to fund its growth or operations.

2017 Tax Reform

While the 2017 Tax Reform will ultimately be moderately positive for us, the reduced corporate income tax rate caused certain of our deferred-tax assets to be revalued at 21% versus 35% at the end of 2017. Although there is no impact to the underlying related deductions, which can continue to be used to offset future taxable income, we took an estimated approximately $1.4 billion non-cash accounting charge in 2017. The positive impacts of the law include the reduced corporate income tax rate and the fact that several of our U.S. business units (essentially all but our interstate natural gas pipelines) will be able to deduct 100% of their capital expenditures through 2022. See Note 5 "*Income Taxes*" to our consolidated financial statements.

Critical Accounting Policies and Estimates

Accounting standards require information in financial statements about the risks and uncertainties inherent in significant estimates, and the application of GAAP involves the exercise of varying degrees of judgment. Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time our financial statements are prepared. These estimates and assumptions affect the amounts we report for our assets and liabilities, our revenues and expenses during the reporting period, and our disclosure of contingent assets and liabilities at the date of our financial statements. We routinely evaluate these estimates, utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates, and any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

In preparing our consolidated financial statements and related disclosures, examples of certain areas that require more judgment relative to others include our use of estimates in determining: (i) revenue recognition; (ii) income taxes; (iii) the economic useful lives of our assets and related depletion rates; (iv) the fair values used to (a) assign purchase price from business combinations, (b) determine possible asset and equity investment impairment charges, and (c) calculate the annual goodwill impairment test; (v) reserves for environmental claims, legal fees, transportation rate cases and other litigation liabilities; (vi) provisions for uncollectible accounts receivables; (vii) computing the gain or loss, if any, on assets sold in whole or in part; and (viii) exposures under contractual indemnifications.

For a summary of our significant accounting policies, see Note 2 "*Summary of Significant Accounting Policies*" to our consolidated financial statements. We believe that certain accounting policies are of more significance in our consolidated financial statement preparation process than others, which policies are discussed as follows.

Environmental Matters

With respect to our environmental exposure, we utilize both internal staff and external experts to assist us in identifying environmental issues and in estimating the costs and timing of remediation efforts. We expense or capitalize, as appropriate, environmental expenditures that relate to current operations, and we record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, we do not discount environmental liabilities to a net present value, and we recognize receivables for anticipated associated insurance recoveries when such recoveries are deemed to be probable. We record at fair value, where appropriate, environmental liabilities assumed in a business combination.

Our recording of our environmental accruals often coincides with our completion of a feasibility study or our commitment to a formal plan of action, but generally, we recognize and/or adjust our environmental liabilities following routine reviews of potential environmental issues and claims that could impact our assets or operations. These adjustments may result in increases in environmental expenses and are primarily related to quarterly reviews of potential environmental issues and resulting environmental liability estimates. In making these liability estimations, we consider the effect of environmental compliance, pending legal actions against us, and potential third party liability claims. For more information on environmental matters, see

Part I, Items 1 and 2 "*Business and Properties—(c) Narrative Description of Business—Environmental Matters.*" For more information on our environmental disclosures, see Note 18 "*Litigation, Environmental and Other Contingencies*" to our consolidated financial statements.

Legal and Regulatory Matters

Many of our operations are regulated by various U.S. and Canadian regulatory bodies and we are subject to legal and regulatory matters as a result of our business operations and transactions. We utilize both internal and external counsel in evaluating our potential exposure to adverse outcomes from orders, judgments or settlements. In general, we expense legal costs as incurred. When we identify contingent liabilities, we identify a range of possible costs expected to be required to resolve the matter. Generally, if no amount within this range is a better estimate than any other amount, we record a liability equal to the low end of the range. Any such liability recorded is revised as better information becomes available. Accordingly, to the extent that actual outcomes differ from our estimates, or additional facts and circumstances cause us to revise our estimates, our earnings will be affected. For more information on legal proceedings, see Note 18 "*Litigation, Environmental and Other Contingencies*" to our consolidated financial statements.

Intangible Assets

Intangible assets are those assets which provide future economic benefit but have no physical substance. Identifiable intangible assets having indefinite useful economic lives, including goodwill, are not subject to regular periodic amortization, and such assets are not to be amortized until their lives are determined to be finite. Instead, the carrying amount of a recognized intangible asset with an indefinite useful life must be tested for impairment annually or on an interim basis if events or circumstances indicate that the fair value of the asset has decreased below its carrying value. We evaluate goodwill for impairment on May 31 of each year. At year end and during other interim periods we evaluate our reporting units for events and changes that could indicate that it is more likely than not that the fair value of a reporting unit could be less than its carrying amount.

Excluding goodwill, our other intangible assets include customer contracts, relationships and agreements, and technology-based assets. These intangible assets have definite lives, are being amortized in a systematic and rational manner over their estimated useful lives, and are reported separately as "Other intangibles, net" in our accompanying consolidated balance sheets.

Hedging Activities

We engage in a hedging program that utilizes derivative contracts to mitigate (offset) our exposure to fluctuations in energy commodity prices, foreign currency exposure on Euro denominated debt and net investments in foreign operations, and to balance our exposure to fixed and variable interest rates, and we believe that these hedges are generally effective in realizing these objectives. According to the provisions of GAAP, to be considered effective, changes in the value of a derivative contract or its resulting cash flows must substantially offset changes in the value or cash flows of the item being hedged, and any ineffective portion of the hedge gain or loss and any component excluded from the computation of the effectiveness of the derivative contract must be reported in earnings immediately.

All of our derivative contracts are recorded at estimated fair value. We utilize published prices, broker quotes, and estimates of market prices to estimate the fair value of these contracts; however, actual amounts could vary materially from estimated fair values as a result of changes in market prices. In addition, changes in the methods used to determine the fair value of these contracts could have a material effect on our results of operations. We do not anticipate future changes in the methods used to determine the fair value of these derivative contracts. For more information on our hedging activities, see Note 14 "*Risk Management*" to our consolidated financial statements.

Employee Benefit Plans

We reflect an asset or liability for our pension and other postretirement benefit plans based on their overfunded or underfunded status. As of December 31, 2018, our pension plans were underfunded by $702 million, and our other postretirement benefits plans were underfunded by $33 million. Our pension and other postretirement benefit obligations and net benefit costs are primarily based on actuarial calculations. We use various assumptions in performing these calculations, including those related to the return that we expect to earn on our plan assets, the rate at which we expect the compensation of our employees to increase over the plan term, the estimated cost of health care when benefits are provided under our plan and other factors. A significant assumption we utilize is the discount rate used in calculating our benefit obligations. We utilize a full yield curve approach in the estimation of the service and interest cost components of net periodic benefit cost (credit) for our pension and other postretirement benefit plans which applies the specific spot rates along the yield curve used in the

determination of the benefit obligation to their underlying projected cash flows. The selection of these assumptions is further discussed in Note 10 *"Share-based Compensation and Employee Benefits"* to our consolidated financial statements.

Actual results may differ from the assumptions included in these calculations, and as a result, our estimates associated with our pension and other postretirement benefits can be, and often are, revised in the future. The income statement impact of the changes in the assumptions on our related benefit obligations are deferred and amortized into income over either the period of expected future service of active participants, or over the expected future lives of inactive plan participants. As of December 31, 2018, we had deferred net losses of approximately $536 million in pre-tax accumulated other comprehensive loss related to our pension and other postretirement benefits.

The following table shows the impact of a 1% change in the primary assumptions used in our actuarial calculations associated with our pension and other postretirement benefits for the year ended December 31, 2018:

	Pension Benefits		Other Postretirement Benefits	
	Net benefit cost (income)	Change in funded status(a)	Net benefit cost (income)	Change in funded status(a)
	(In millions)			
One percent increase in:				
Discount rates	$ (11)	$ 183	$ (1)	$ 25
Expected return on plan assets	(21)	—	(3)	—
Rate of compensation increase	2	(7)	—	—
Health care cost trends	—	—	3	(16)
One percent decrease in:				
Discount rates	13	(214)	1	(29)
Expected return on plan assets	21	—	3	—
Rate of compensation increase	(2)	7	—	—
Health care cost trends	—	—	(3)	14

(a) Includes amounts deferred as either accumulated other comprehensive income (loss) or as a regulatory asset or liability for certain of our regulated operations.

Income Taxes

Income tax expense is recorded based on an estimate of the effective tax rate in effect or to be in effect during the relevant periods. Changes in tax legislation are included in the relevant computations in the period in which such changes are enacted. We do business in a number of states with differing laws concerning how income subject to each state's tax structure is measured and at what effective rate such income is taxed. Therefore, we must make estimates of how our income will be apportioned among the various states in order to arrive at an overall effective tax rate. Changes in our effective rate, including any effect on previously recorded deferred taxes, are recorded in the period in which the need for such change is identified.

Deferred income tax assets and liabilities are recognized for temporary differences between the basis of assets and liabilities for financial reporting and tax purposes. Deferred tax assets are reduced by a valuation allowance for the amount that is more likely than not to not be realized. While we have considered estimated future taxable income and prudent and feasible tax planning strategies in determining the amount of our valuation allowance, any change in the amount that we expect to ultimately realize will be included in income in the period in which such a determination is reached.

In determining the deferred income tax asset and liability balances attributable to our investments, we apply an accounting policy that looks through our investments. The application of this policy resulted in no deferred income taxes being provided on the difference between the book and tax basis on the non-tax-deductible goodwill portion of our investments, including KMI's investment in its wholly-owned subsidiary, KMP.

Results of Operations

Overview

Our management evaluates our performance primarily using the measures of Segment EBDA and, as discussed below under *"—Non-GAAP Financial Measures,"* DCF, and Segment EBDA before certain items. Segment EBDA is a useful measure of our operating performance because it measures the operating results of our segments before DD&A and certain expenses that are generally not controllable by our business segment operating managers, such as general and administrative expenses, interest expense, net, and income taxes. Our general and administrative expenses include such items as unallocated employee benefits, insurance, rentals, unallocated litigation and environmental expenses, and shared corporate services including accounting, information technology, human resources and legal services.

In our discussions of the operating results of individual businesses that follow, we generally identify the important fluctuations between periods that are attributable to dispositions and acquisitions separately from those that are attributable to businesses owned in both periods.

Effective January 1, 2019, certain assets were transferred between Natural Gas Pipelines, Products Pipelines and Terminals business segments, which are not reflected in the following business segment Management Discussion and Analysis tables below.

Consolidated Earnings Results

	Year Ended December 31,		
	2018	2017	2016
		(In millions)	
Segment EBDA(a)			
Natural Gas Pipelines	$ 3,580	$ 3,487	$ 3,211
Products Pipelines	1,173	1,231	1,067
Terminals	1,171	1,224	1,078
CO_2	759	847	827
Kinder Morgan Canada(b)	720	186	181
Total segment EBDA(c)	7,403	6,975	6,364
DD&A	(2,297)	(2,261)	(2,209)
Amortization of excess cost of equity investments	(95)	(61)	(59)
General and administrative and corporate charges(d)	(588)	(660)	(652)
Interest, net(e)	(1,917)	(1,832)	(1,806)
Income before income taxes	2,506	2,161	1,638
Income tax expense(f)	(587)	(1,938)	(917)
Net income	1,919	223	721
Net income attributable to noncontrolling interests	(310)	(40)	(13)
Net income attributable to Kinder Morgan, Inc.	1,609	183	708
Preferred stock dividends	(128)	(156)	(156)
Net income available to common stockholders	$ 1,481	$ 27	$ 552

(a) Includes revenues, earnings from equity investments, and other, net, less operating expenses, loss on impairments and divestitures, net, loss on impairments and divestitures of equity investments, net and other income, net. Operating expenses include costs of sales, operations and maintenance expenses, and taxes, other than income taxes.

(b) As a result of the TMPL Sale on August 31, 2018, this segment does not have results of operations on a prospective basis.

Certain items affecting Total Segment EBDA (see "*—Non-GAAP Measures*" below)

(c) 2018, 2017 and 2016 amounts include net decreases in earnings of $269 million, $384 million and $1,121 million, respectively, related to the combined net effect of the certain items impacting Total Segment EBDA. The extent to which these items affect each of our business segments is discussed below in the footnotes to the tables within "*—Segment Earnings Results.*"

(d) 2018, 2017 and 2016 amounts include net increases in expense of $24 million and $15 million and a net decrease in expense of $13 million, respectively, related to the combined net effect of the certain items related to general and administrative and corporate charges disclosed below in "—*General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests.*"

(e) 2018, 2017 and 2016 amounts include a net increase in expense of $26 million and net decreases in expense of $39 million and $193 million, respectively, related to the combined net effect of the certain items related to interest expense, net disclosed below in "—*General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests.*"

(f) 2018, 2017 and 2016 amounts include a net decrease of $58 million and net increases in expense of $1,085 million and $18 million, respectively, related to the combined net effect of the certain items related to income tax expense representing the income tax provision on certain items plus discrete income tax items.

Year Ended December 31, 2018 vs. 2017

The certain item totals reflected in footnotes (c) through (e) to the table above accounted for $41 million of the increase in income before income taxes in 2018 as compared to 2017 (representing the difference between decreases of $319 million and $360 million from certain items in income before income taxes for 2018 and 2017, respectively). After giving effect to these certain items, which are discussed in more detail in the discussion that follows, the remaining increase of $304 million (12%) from the prior year in income before income taxes is primarily attributable to increased performance from our Natural Gas Pipelines, Products Pipelines, and CO_2 business segments and decreased general and administrative expense partially offset by increased DD&A expense, interest expense, net and lower earnings from our Kinder Morgan Canada business segment as a result of the TMPL Sale and our Terminals business segment.

Year Ended December 31, 2017 vs. 2016

The certain item totals reflected in footnotes (c) through (e) to the table above accounted for $555 million of the increase in income before income taxes in 2017 as compared to 2016 (representing the difference between decreases of $360 million and $915 million from certain items in income before income taxes for 2017 and 2016, respectively). After giving effect to these certain items, which are discussed in more detail in the discussion that follows, the remaining decrease of $32 million (1%) from the prior year in income before income taxes is primarily attributable to decreased performance from our Natural Gas Pipelines business segment, largely associated with our sale of a 50% interest in SNG to The Southern Company (Southern Company) on September 1, 2016, and increased DD&A expense partially offset by decreased general and administrative expense and decreased interest expense.

Non-GAAP Financial Measures

Our non-GAAP performance measures are DCF, both in the aggregate and per share, and Segment EBDA before certain items. Certain items, as used to calculate our non-GAAP measures, are items that are required by GAAP to be reflected in net income, but typically either (i) do not have a cash impact (for example, asset impairments), or (ii) by their nature are separately identifiable from our normal business operations and in our view are likely to occur only sporadically (for example, certain legal settlements, enactment of new tax legislation and casualty losses).

Our non-GAAP performance measures described below should not be considered alternatives to GAAP net income or other GAAP measures and have important limitations as analytical tools. Our computations of DCF and Segment EBDA before certain items may differ from similarly titled measures used by others. You should not consider these non-GAAP performance measures in isolation or as substitutes for an analysis of our results as reported under GAAP. DCF should not be used as an alternative to net cash provided by operating activities computed under GAAP. Management compensates for the limitations of these non-GAAP performance measures by reviewing our comparable GAAP measures, understanding the differences between the measures and taking this information into account in its analysis and its decision making processes.

DCF

DCF is calculated by adjusting net income available to common stockholders before certain items for DD&A, total book and cash taxes, sustaining capital expenditures and other items. DCF is a significant performance measure useful to management and external users of our financial statements in evaluating our performance and in measuring and estimating the ability of our assets to generate cash earnings after servicing our debt and preferred stock dividends, paying cash taxes and expending sustaining capital that could be used for discretionary purposes such as common stock dividends, stock repurchases, retirement of debt, or expansion capital expenditures. We believe the GAAP measure most directly comparable to DCF is net income available to common stockholders. A reconciliation of DCF to net income available to common stockholders is provided in the table below. DCF per common share is DCF divided by average outstanding common shares, including restricted stock awards that participate in dividends.

Reconciliation of Net Income Available to Common Stockholders to DCF

	Year Ended December 31,		
	2018	2017	2016
		(In millions)	
Net Income Available to Common Stockholders	$ 1,481	$ 27	$ 552
Add/(Subtract):			
Certain items before book tax(a)	355	141	915
Noncontrolling interest certain items(b)	240	—	(8)
Book tax certain items(c)	(58)	(77)	18
Impact of 2017 Tax Reform(d)	(36)	1,381	—
Total certain items	501	1,445	925
Net income available to common stockholders before certain items	1,982	1,472	1,477
Add/(Subtract):			
DD&A expense(e)	2,752	2,684	2,617
Total book taxes(f)	710	957	993
Cash taxes(g)	(77)	(72)	(79)
Other items(h)	15	29	43
Sustaining capital expenditures(i)	(652)	(588)	(540)
DCF	$ 4,730	$ 4,482	$ 4,511
Weighted average common shares outstanding for dividends(j)	2,228	2,240	2,238
DCF per common share	$ 2.12	$ 2.00	$ 2.02
Declared dividend per common share	0.80	0.50	0.50

(a) Consists of certain items summarized in footnotes (c) through (e) to the "*—Results of Operations—Consolidated Earnings Results*" table included above, and described in more detail below in the footnotes to tables included in "*—Segment Earnings Results*" and "*—General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests.*"
(b) Represents noncontrolling interests share of certain items. 2018 includes KML shareholders' approximately 30% share of the gain on the TMPL Sale.
(c) Represents income tax provision on certain items plus discrete income tax items.
(d) 2018 amount represents 2017 Tax Reform provisional adjustments including our share of certain equity investees' 2017 Tax Reform provisional adjustments related to our FERC regulated business. 2017 amount includes book tax certain items and $219 million pre-tax certain items related to our FERC regulated business. See Note 5 "*Income Taxes*" to our consolidated financial statements.
(e) Includes DD&A and amortization of excess cost of equity investments. Also includes our share of certain equity investee's DD&A, net of the noncontrolling interests' portion of KML DD&A and consolidating joint venture partners' share of DD&A of $360 million, $362 million and $349 million in 2018, 2017 and 2016, respectively.
(f) Excludes book tax certain items of $58 million, $(1,085) million and $(18) million for 2018, 2017 and 2016, respectively. 2018, 2017 and 2016 amounts also include $65 million, $104 million and $94 million, respectively, of our share of taxable equity investees' book taxes, net of the noncontrolling interests' portion of KML book taxes.
(g) Includes our share of taxable equity investees' cash taxes of $(68) million, $(69) million and $(76) million in 2018, 2017 and 2016, respectively.
(h) Includes pension contributions and non-cash compensation associated with our restricted stock program.
(i) Includes our share of (i) certain equity investees'; (ii) KML's; and (iii) certain consolidating joint venture subsidiaries' sustaining capital expenditures of $(105) million, $(107) million and $(90) million in 2018, 2017 and 2016, respectively.
(j) Includes restricted stock awards that participate in common share dividends.

Segment EBDA Before Certain Items

Segment EBDA before certain items is used by management in its analysis of segment performance and management of our business. General and administrative expenses generally are not under the control of our segment operating managers, and therefore, are not included when we measure business segment operating performance. We believe Segment EBDA before certain items is a significant performance metric because it provides us and external users of our financial statements additional

insight into the ability of our business segments to generate segment cash earnings on an ongoing basis. We believe it is useful to investors because it is a performance measure that management uses to allocate resources to our segments and assess each segment's performance. We believe the GAAP measure most directly comparable to Segment EBDA before certain items is Segment EBDA.

In the tables for each of our business segments under *"— Segment Earnings Results"* below, Segment EBDA before certain items and Revenues before certain items are calculated by adjusting the Segment EBDA and Revenues for the applicable certain item amounts, which are totaled in the tables and described in the footnotes to those tables. Revenues before certain items is provided to further enhance our analysis of Segment EBDA before certain items and is not a performance measure.

Segment Earnings Results

Natural Gas Pipelines

	Year Ended December 31,		
	2018	**2017**	**2016**
	(In millions, except operating statistics)		
Revenues(a)	$ 9,015	$ 8,618	$ 8,005
Operating expenses(b)	(5,353)	(5,457)	(4,393)
Loss on impairments and divestitures, net(c)	(594)	(27)	(200)
Other income	1	1	1
Earnings (losses) from equity investments(d)	474	303	(221)
Other, net(e)	37	49	19
Segment EBDA(a)(b)(c)(d)(e)	3,580	3,487	3,211
Certain items(a)(b)(c)(d)(e)	622	392	825
Segment EBDA before certain items	$ 4,202	$ 3,879	$ 4,036
Change from prior period	**Increase/(Decrease)**		
Revenues before certain items	$ 363	$ 594	
Segment EBDA before certain items	$ 323	$ (157)	
Natural gas transport volumes (BBtu/d)(f)	32,821	29,108	28,095
Natural gas sales volumes (BBtu/d)	2,472	2,341	2,335
Natural gas gathering volumes (BBtu/d)(f)	2,972	2,647	2,963
Crude/condensate gathering volumes (MBbl/d)(f)	307	273	292

Certain items affecting Segment EBDA

(a) 2018 and 2017 amounts include an increases in revenues of $24 million and $8 million, respectively, and 2016 amount includes a decrease in revenues of $50 million, all related to non-cash mark-to-market derivative contracts used to hedge forecasted natural gas, NGL and crude oil sales. 2018 amount also includes increases in revenue of (i) $9 million related to a transportation contract refund; (ii) $5 million related to the early termination of a long-term natural gas transportation contract; and (iii) $4 million from other certain items. 2016 amount also includes an increase in revenue of $39 million associated with revenue collected on a customer's early buyout of a long-term natural gas storage contract.

(b) 2018 amount includes (i) an increase in earnings of $7 million as a result of a property tax refund; (ii) an increase in earnings of $6 million related to the release of certain sales and use tax reserves; and (iii) a decrease in earnings of $2 million related to other certain items. 2017 amount includes a decrease in earnings of (i) $166 million related to the impact of the 2017 Tax Reform; (ii) $3 million related to the non-cash impairment loss associated with the Colden storage field; and (iii) $3 million from other certain items. 2016 amount includes a decrease in earnings of $3 million from other certain items.

(c) 2018 amount includes a decrease in earnings of $600 million related to a non-cash loss on impairment of certain gathering and processing assets in Oklahoma and an increase in earnings of $1 million related to other certain item. 2017 amount includes a decrease in earnings of $27 million related to the non-cash impairment loss associated with the Colden storage field. 2016 amount includes (i) a decrease in earnings of $106 million of project write-offs; (ii) an $84 million pre-tax loss on the sale of a 50% interest in our SNG natural gas pipeline system; and (iii) an $11 million decrease in earnings from other certain items.

(d) 2018 amount includes (i) a net loss of $89 million in our equity investment in Gulf LNG Holdings Group, LLC (Gulf LNG), due to a ruling by an arbitration panel affecting a customer contract, which resulted in a non-cash impairment of our investment partially offset

by our share of earnings recognized by Gulf LNG on the respective customer contract; (ii) an increase in earnings of $41 million for our share of certain equity investees' 2017 Tax Reform provisional adjustments; and (iii) a decrease in earnings of $4 million related to other certain items. 2017 amount includes (i) a $150 million non-cash impairment loss related to our investment in FEP; (ii) a decrease in earnings of $58 million related to 2017 Tax Reform adjustments recorded by equity investees; (iii) an increase in earnings from an equity investment of $22 million on the sale of a claim related to the early termination of a long-term natural gas transportation contract; (iv) an increase in earnings from an equity investment of $12 million related to a customer contract settlement; (v) a decrease in earnings of $12 million related to early termination of debt at an equity investee; and (vi) a decrease in earnings of $10 million related to a non-cash impairment at an equity investee. 2016 amount includes (i) $606 million of non-cash impairment losses primarily related to our investments in MEP and Ruby; (ii) an increase in earnings of $18 million related to the early termination of a customer contract at an equity investee; and (iii) a decrease in earnings of $12 million related to other certain items at equity investees.

(e) 2018, 2017 and 2016 amounts include decreases in earnings of $24 million, $5 million and $10 million, respectively, related to certain litigation matters.

Other

(f) Joint venture throughput is reported at our ownership share.

Below are the changes in both Segment EBDA before certain items and revenues before certain items in 2018 and 2017, when compared with the respective prior year:

Year Ended December 31, 2018 versus Year Ended December 31, 2017

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Midstream	$ 150	14%	$ 142	3%
West Region	100	11%	95	8%
North Region	43	4%	103	7%
South Region	33	5%	7	2%
Other	(3)	150%	(3)	150%
Intrasegment eliminations	—	—%	19	43%
Total Natural Gas Pipelines	$ 323	8%	$ 363	4%

The changes in Segment EBDA for our Natural Gas Pipelines business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable years of 2018 and 2017:

- Midstream's increase of $150 million (14%) was primarily due to increased earnings from Texas intrastate natural gas pipeline operations, KinderHawk, Hiland Midstream and South Texas Midstream. Texas intrastate natural gas pipeline operations were favorably impacted by higher volumes with new and existing customers serving the Mexico and Texas Gulf Coast industrial markets partially offset by lower park and loan revenues and storage margins. KinderHawk and South Texas Midstream benefited from increased drilling and production in the Haynesville and Eagle Ford basins, respectively. Hiland Midstream increased earnings were primarily due to higher gas and crude oil volumes and higher NGL sales prices. While these factors also drove an increase in revenue, these increases in revenues were partially offset by the effect of the January 1, 2018 adoption of Topic 606 which caused a corresponding decrease in cost of goods sold;
- West Region's increase of $100 million (11%) was primarily due to higher earnings from EPNG, CIG and CPGPL. EPNG experienced higher volumes in 2018 from increased Permian basin-related activity and associated capacity sales. CIG and CPGPL earnings were higher due to continued growing production in the Denver Julesburg basin;
- North Region's increase of $43 million (4%) was primarily due to an increase in equity earnings from NGPL, and higher earnings from TGP and KMLP. NGPL increase in earnings was due to increased Permian basin-related activity and lower interest expense resulting from a 2017 refinancing, partially offset by lower storage-related revenue. TGP and KMLP contributed increased earnings primarily from expansion projects recently placed in service; and
- South Region's increase of $33 million (5%) was primarily due to increases in equity earnings from Citrus and SNG, and an increase in earnings from SLNG, partially offset by a decrease in earnings from Southern Gulf LNG due to a loss of revenues from an arbitration ruling calling for a contract termination. Citrus had lower income tax expense due to the 2017 Tax Reform, and SNG increased earnings were from higher transportation revenues from increased system usage and non-recurring 2017 operating expenses. SLNG earnings were driven by higher capitalized AFUDC equity associated with the Elba Liquefaction project.

Year Ended December 31, 2017 versus Year Ended December 31, 2016

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
South Region	$ (143)	(18)%	$ (311)	(48)%
Midstream	(66)	(6)%	887	19%
West Region	(38)	(4)%	(39)	(3)%
North Region	84	7%	84	6%
Other	—	—%	(1)	50%
Intrasegment eliminations	6	100%	(26)	(144)%
Total Natural Gas Pipelines	$ (157)	(4)%	$ 594	7%

The changes in Segment EBDA for our Natural Gas Pipelines business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable years of 2017 and 2016:

- South Region's decrease of $143 million (18%) was primarily due to the sale of a 50% interest in SNG to Southern Company on September 1, 2016, partially offset by an increase in earnings from Elba Express primarily due to an expansion project placed in service in December 2016;
- Midstream's decrease of $66 million (6%) was primarily due to decreases in earnings from South Texas Midstream, KinderHawk and Oklahoma Midstream, partially offset by increased earnings from Texas intrastate natural gas pipeline operations and Altamont Midstream. South Texas Midstream lower earnings were primarily due to lower commodity based service revenues and residue gas sales as a result of lower volumes partially offset by higher NGL sales gross margin primarily due to rising NGL prices. KinderHawk experienced lower volumes, which lowered its earnings and Oklahoma Midstream's lower earnings were primarily due to lower volumes and unfavorable producer mix. Texas intrastate natural gas pipeline operations increased earnings were primarily due to higher transportation margins as a result of higher volumes and higher park and loan revenues partially offset by lower storage and sales margins. Altamont Midstream primarily increased earnings were due to higher natural gas and liquids revenues due to higher commodity prices and volumes. Texas intrastate natural gas pipeline operations, Hiland Midstream and Oklahoma Midstream had increases in revenues due to higher commodity prices which was largely offset by a corresponding increases in costs of sales;
- West Region's decrease of $38 million (4%) was primarily due to a decrease in earnings at CIG, partially offset by higher earnings at EPNG. CIG lower earnings were primarily due to a decrease in tariff rates effective January 1, 2017 as a result of a rate case settlement entered into in 2016. EPNG had higher earnings primarily due to higher transportation revenues driven by incremental Permian basin capacity sales and an increase in volumes due to the ramp up of existing customer volumes associated with an expansion project partially offset by increased operations and maintenance expense; and
- North Region's increase of $84 million (7%) was primarily due to higher earnings from TGP and an increase in equity earnings from NGPL. TGP's increase in earnings was primarily due to higher firm transportation revenues driven by incremental capacity sales and expansion projects recently placed in service. NGPL higher earnings were primarily due to lower interest expense due to a reduction in interest rates due to debt refinancing and the repayment of bank borrowings in 2017.

Products Pipelines

	Year Ended December 31,		
	2018	2017	2016
	(In millions, except operating statistics)		
Revenues	$ 1,713	$ 1,661	$ 1,649
Operating expenses(a)	(594)	(487)	(573)
Loss on impairments and divestitures, net(b)	(36)	—	(76)
Other income	2	—	—
Earnings from equity investments(c)	85	58	65
Other, net	3	(1)	2
Segment EBDA(a)(b)(c)	1,173	1,231	1,067
Certain items(a)(b)(c)	61	(38)	113
Segment EBDA before certain items	$ 1,234	$ 1,193	$ 1,180
Change from prior period	Increase/(Decrease)		
Revenues	$ 52	$ 12	
Segment EBDA before certain items	$ 41	$ 13	
Gasoline (MBbl/d)(d)	1,038	1,038	1,025
Diesel fuel (MBbl/d)	372	351	342
Jet fuel (MBbl/d)	302	297	288
Total refined product volumes (MBbl/d)(e)	1,712	1,686	1,655
NGL (MBbl/d)(e)	114	112	109
Crude and condensate (MBbl/d)(e)	345	327	324
Total delivery volumes (MBbl/d)	2,171	2,125	2,088
Ethanol (MBbl/d)(f)	126	117	115

Certain items affecting Segment EBDA

(a) 2018 amount includes (i) an increase in expense of $31 million associated with a certain Pacific operations litigation matter; (ii) an increase in earnings of $5 million as a result of a property tax refund; and (iii) a decrease in expense of $1 million related to other certain items. 2017 amount includes a decrease in expense of $34 million related to a right-of-way settlement and an increase in expense of $1 million related to hurricane repairs. 2016 amount includes increases in expense of $31 million of rate case liability estimate adjustments associated with prior periods and $20 million related to a legal settlement.

(b) 2018 amount includes a decrease in earnings of $36 million associated with a project write-off on the Utica Marcellus Texas pipeline. 2016 amount includes increases in expense of $65 million related to the Palmetto project write-off and $9 million of non-cash impairment charges related to the sale of a Transmix facility.

(c) 2017 amount includes an increase in equity earnings of $5 million related to the impact of the 2017 Tax Reform at an equity investee. 2016 amount includes a $12 million gain related to the sale of an equity investment.

Other

(d) Volumes include ethanol pipeline volumes.

(e) Joint Venture throughput is reported at our ownership share.

(f) Represents total ethanol volumes, including ethanol pipeline volumes included in gasoline volumes above.

Below are the changes in both Segment EBDA before certain items and revenues before certain items in 2018 and 2017, when compared with the respective prior year:

Year Ended December 31, 2018 versus Year Ended December 31, 2017

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
NGLs	$ 33	27%	$ 4	2%
Southeast Refined Products	26	11%	19	5%
Crude & Condensate	(15)	(4)%	15	4%
West Coast Refined Products	(3)	(1)%	14	2%
Total Products Pipelines	$ 41	3%	$ 52	3%

The changes in Segment EBDA for our Products Pipelines business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable years of 2018 and 2017:

- NGLs' increase of $33 million (27%) was primarily due to increases in earnings from Cochin pipeline and to a lesser extent an increase in earnings from equity earnings from Utopia, which went into service in 2018. Cochin's earnings were higher primarily due to foreign exchange transaction losses in 2017 primarily related to an intercompany note receivable, integrity work during 2017 and an expansion project placed in service during 2018;
- Southeast Refined Products' increase of $26 million (11%) was primarily due to increased equity earnings from Plantation pipeline and earnings from South East Terminals. Plantation pipeline earnings were higher primarily due to lower income tax expense due to the 2017 Tax Reform, lower operating expense attributable to a 2017 project write-off and product net gains as a result of higher product prices. South East Terminals earnings were favorably impacted primarily due to higher revenues as a result of expansion projects that were placed into service in the later part of 2017 and higher volumes with existing customers;
- Crude & Condensate's decrease of $15 million (4%) was primarily due to a decrease of earnings from Kinder Morgan Crude & Condensate Pipeline partially offset by an increase of Double H Pipeline earnings. The Kinder Morgan Crude & Condensate Pipeline lower earnings were primarily due to lower services revenues as a result of unfavorable rates on contract renewals partially offset by recognition of deficiency revenue. Double H Pipeline increase in earnings was primarily due to an increase in volumes and the recognition of deficiency revenue; and
- West Coast Refined Products' decrease of $3 million (1%) was primarily due to lower earnings from Pacific operations partially offset by an increase in Calnev earnings. Pacific operations earnings were lower primarily due to higher operating expenses driven by an unfavorable change in product gain/loss, an increase in 2018 environmental reserves and higher fuel and power costs. Calnev earnings were higher due to an increase in services revenues driven by an increase in volumes, the result of an interruption of service by a provider for a competing pipeline that also serves the Las Vegas market.

Year Ended December 31, 2017 versus Year Ended December 31, 2016

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
West Coast Refined Products	$ 7	1%	$ 11	2%
NGLs	4	3%	9	5%
Southeast Refined Products	3	1%	(9)	(2)%
Crude & Condensate	(1)	—%	1	—%
Total Products Pipelines	$ 13	1%	$ 12	1%

The changes in Segment EBDA for our Products Pipelines business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable years of 2017 and 2016:

- West Coast Refined Products' increase of $7 million (1%) was primarily due to improved earnings at both Pacific operations and Calnev. Pacific operations increase in earnings was primarily due to higher service revenues driven by an increase in volumes partially offset by a volume driven increase in power costs and an increase in right-of-way expense. Calnev earnings were higher primarily due to higher service revenues driven by higher volumes and a decrease in expense related to the reduction of a rate reserve;
- NGLs' increase of $4 million (3%) was primarily due to increased development fee revenues in 2017 for Utopia Pipeline ;
- Southeast Refined Products' increase of $3 million (1%) was primarily due to increased earnings at South East Terminals and to a lesser extent at Transmix processing operations, partially offset by our sale of a 50% interest in Parkway Pipeline on July 1, 2016. South East Terminals increased earnings were primarily due to higher revenues driven by higher volumes as a result of capital expansion projects being placed in service during 2017. The decrease in revenues was driven by lower sales volumes primarily due to the sale of our Indianola plant in August 2016 and lower brokered sales at the Dorsey plant due to an expired contract in May 2017; and
- Crude & Condensate's decrease of $1 million (—%) was primarily due a decrease in earnings on Kinder Morgan Crude & Condensate Pipeline resulting from higher cost of goods sold offset by an increase in earnings from Double Eagle primarily due to higher revenues driven by higher volumes and price.

Terminals

	Year Ended December 31,		
	2018	2017	2016
	(In millions, except operating statistics)		
Revenues(a)	$ 2,019	$ 1,966	$ 1,922
Operating expenses(b)	(818)	(788)	(768)
(Loss) gain on impairments and divestitures, net(c)	(54)	14	(99)
Earnings from equity investments(d)	22	24	19
Other, net	2	8	4
Segment EBDA(a)(b)(c)(d)	1,171	1,224	1,078
Certain items, net(a)(b)(c)(d)	34	(10)	91
Segment EBDA before certain items	$ 1,205	$ 1,214	$ 1,169
Change from prior period	Increase/(Decrease)		
Revenues before certain items	$ 55	$ 68	
Segment EBDA before certain items	$ (9)	$ 45	
Liquids tankage capacity available for service (MMBbl)	90.1	87.6	84.4
Liquids utilization %(e)	93.5%	93.6%	94.7%
Bulk transload tonnage (MMtons)	64.2	59.5	54.8
Ethanol (MMBbl)	61.7	68.1	66.7

Certain items affecting Segment EBDA

(a) 2018, 2017 and 2016 amounts include increases in revenues of $2 million, $9 million and $28 million, respectively, from the amortization of a fair value adjustment (associated with the below market contracts assumed upon acquisition) from our Jones Act tankers. 2017 amount also includes a decrease in revenues of $5 million related to other certain items.

(b) 2018 amount includes a decrease in expense of $18 million related to hurricane damage insurance recoveries, net of repair costs and an increase in expense of $1 million related to other certain item. 2017 amount includes (i) an increase in expense of $21 million related to hurricane repairs; (ii) a decrease in expense of $10 million related to accrued dredging costs; and (iii) a decrease in expense of $2 million related to other certain items. 2016 amount includes an increase in expense of $3 million related to other certain items.

(c) 2018 amount includes a net loss of $53 million on impairments and divestitures, net, primarily related to our Staten Island terminal. 2017 amount includes a gain of $23 million primarily related to the sale of a 40% membership interest in the Deeprock Development joint venture in July 2017 and losses of $8 million related to other divestitures and impairments, net. 2016 amount includes an expense of $109 million related to various losses on impairments and divestitures, net.

(d) 2016 amount includes an increase in earnings of $9 million related to our share of the settlement of a certain litigation matter at an equity investee and a decrease in earnings of $16 million related to various losses on impairments and divestitures of equity investments, net.

Other
(e) The ratio of our tankage capacity in service to tankage capacity available for service.

Below are the changes in both Segment EBDA before certain items and revenues before certain items in 2018 and 2017, when compared with the respective prior year:

Year Ended December 31, 2018 versus Year Ended December 31, 2017

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Northeast	$ (19)	(15)%	$ (20)	(9)%
Gulf Central	(19)	(22)%	(19)	(15)%
Southeast	(8)	(13)%	(4)	(3)%
Alberta Canada	(1)	(1)%	21	13%
Gulf Liquids	31	11%	37	9%
Midwest	6	8%	7	5%
Marine Operations	3	2%	40	13%
All others (including intrasegment eliminations)	(2)	(1)%	(7)	(2)%
Total Terminals	$ (9)	(1)%	$ 55	3%

The changes in Segment EBDA for our Terminals business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable years of 2018 and 2017:

- decrease of $19 million (15%) from our Northeast terminals primarily due to low utilization at our Staten Island terminal;
- decrease of $19 million (22%) from our Gulf Central terminals primarily related to the sale of a 40% membership interest in the Deeprock Development joint venture in July 2017 and the expiration of a crude by rail terminaling contract in August 2018 at our Deer Park Rail Terminal;
- decrease of $8 million (13%) from our Southeast terminals primarily due to the sale of certain terminal assets in December 2017 and higher operating expenses at our steel handling operations;
- decrease of $1 million (1%) from our Alberta Canada terminals primarily due to an increase in operating expenses associated with tank lease fees at our Edmonton South Terminal following the TMPL Sale and the impact of the expiration of a third party crude-by-rail terminaling contract at our Edmonton Rail Terminal joint venture partially offset by an increase in earnings due to the commencement of operations at our Base Line Terminal joint venture;
- increase of $31 million (11%) from our Gulf Liquids terminals primarily driven by contributions from expansion projects at our Pasadena Terminal and the Kinder Morgan Export Terminal as well as organic volume growth at several of our Houston Ship Channel locations;
- increase of $6 million (8%) from our Midwest terminals primarily driven by increased ethanol storage revenues and new liquids customer contracts entered into in 2018; and
- increase of $3 million (2%) from our Marine Operations primarily due to the incremental earnings from the March 2017, June 2017, July 2017 and December 2017 deliveries of the Jones Act tankers, the *American Freedom*, *Palmetto State, American Liberty* and *American Pride,* respectively, partially offset by decreased contributions from existing Jones Act tankers driven by lower charter rates and a reduced operating cost credit attributable to capitalized overhead.

Year Ended December 31, 2017 versus Year Ended December 31, 2016

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Marine Operations	$ 42	27%	$ 72	31%
Gulf Liquids	20	8%	38	11%
Alberta, Canada	8	6%	7	5%
Midwest	7	11%	15	11%
Held for sale operations	(19)	(100)%	(55)	(90)%
Gulf Central	(17)	(16)%	(11)	(8)%
All others (including intrasegment eliminations)	4	1%	2	—%
Total Terminals	$ 45	4%	$ 68	4%

The changes in Segment EBDA for our Terminals business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable years of 2017 and 2016:

- increase of $42 million (27%) from our Marine Operations related to the incremental earnings from the May 2016, July 2016, September 2016, December 2016, March 2017, June 2017, July 2017 and December 2017 deliveries of the Jones Act tankers, the *Magnolia State, Garden State, Bay State, American Endurance, American Freedom, Palmetto State, American Liberty and American Pride*, respectively, partially offset by decreased charter rates on the *Golden State, Pelican State, Sunshine State, Empire State and Pennsylvania* Jones Act tankers;
- increase of $20 million (8%) from our Gulf Liquids terminals primarily related to higher volumes as a result of various expansion projects, including the recently commissioned Kinder Morgan Export Terminal and North Docks terminal, partially offset by lost revenue associated with Hurricane Harvey-related operational disruptions;
- increase of $8 million (6%) from our Alberta, Canada terminals primarily due to escalations in predominantly fixed, take-or-pay terminaling contracts and a true-up in terminal fees in connection with a favorable arbitration ruling;
- increase of $7 million (11%) from our Midwest terminals primarily driven by increased ethanol throughput revenues in 2017 and a new bulk storage and handling contract entered into fourth quarter 2016;
- decrease of $19 million (100%) from our sale of certain bulk terminal facilities to an affiliate of Watco Companies, LLC in December 2016 and early 2017; and
- decrease of $17 million (16%) from our Gulf Central terminals primarily related to the sale of a 40% membership interest in the Deeprock Development joint venture in July 2017 and the subsequent change in accounting treatment of our retained 11% membership interest as well as lost revenue associated with Hurricane Harvey-related operational disruptions.

CO_2

	Year Ended December 31,		
	2018	2017	2016
	(In millions, except operating statistics)		
Revenues(a)	$ 1,255	$ 1,196	$ 1,221
Operating expenses(b)	(453)	(394)	(399)
(Loss) gain on impairments and divestitures, net(c)	(79)	1	(19)
Earnings from equity investments(d)	36	44	24
Segment EBDA(a)(b)(c)(d)	759	847	827
Certain items(a)(b)(c)(d)	148	40	92
Segment EBDA before certain items	$ 907	$ 887	$ 919
Change from prior period	Increase/(Decrease)		
Revenues before certain items	$ 104	$ (43)	
Segment EBDA before certain items	$ 20	$ (32)	
Southwest Colorado CO_2 production (gross) (Bcf/d)(e)	1.2	1.3	1.2
Southwest Colorado CO_2 production (net) (Bcf/d)(e)	0.6	0.6	0.6
SACROC oil production (gross)(MBbl/d)(f)	29.3	27.9	29.3
SACROC oil production (net)(MBbl/d)(g)	24.4	23.2	24.4
Yates oil production (gross)(MBbl/d)(f)	16.7	17.3	18.4
Yates oil production (net)(MBbl/d)(g)	7.4	7.7	8.2
Katz, Goldsmith, and Tall Cotton Oil Production - Gross (MBbl/d)(f)	8.2	8.1	7.0
Katz, Goldsmith, and Tall Cotton Oil Production - Net (MBbl/d)(g)	7.0	6.9	5.9
NGL sales volumes (net)(MBbl/d)(g)	10.0	9.9	10.3
Realized weighted-average oil price per Bbl(h)	$ 57.83	$ 58.40	$ 61.52
Realized weighted-average NGL price per Bbl(i)	$ 32.21	$ 25.15	$ 17.91

Certain items affecting Segment EBDA

(a) 2018, 2017 and 2016 amounts include unrealized losses of $90 million and $54 million, and $63 million, respectively, related to derivative contracts used to hedge forecasted commodity sales. 2017 amount also includes an increase in revenues of $9 million related to the settlement of a CO_2 customer sales contract.

(b) 2018 amount includes an increase in earnings of $21 million as a result of a severance tax refund.

(c) 2018 amount includes oil and gas property impairments of $79 million. 2017 and 2016 amounts include a decrease in expense of $1 million and an increase in expense of $20 million, respectively, related to source and transportation project write-offs.

(d) 2017 and 2016 amounts include an increase in equity earnings of $4 million and a decrease in equity earnings of $9 million, respectively, for our share of a project write-off recorded by an equity investee.

Other

(e) Includes McElmo Dome and Doe Canyon sales volumes.

(f) Represents 100% of the production from the field. We own an approximately 97% working interest in the SACROC unit, an approximately 50% working interest in the Yates unit, an approximately 99% working interest in the Katz unit and a 99% working interest in the Goldsmith Landreth unit and a 100% working interest in the Tall Cotton field.

(g) Net after royalties and outside working interests.

(h) Includes all crude oil production properties.

(i) Includes all NGL sales.

Below are the changes in both Segment EBDA before certain items and revenues before certain items in 2018 and 2017, when compared with the respective prior year:

Year Ended December 31, 2018 versus Year Ended December 31, 2017

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Oil and Gas Producing activities	$ 27	5%	$ 45	5%
Source and Transportation activities	(7)	(2)%	52	16%
Intrasegment eliminations	—	—%	7	18%
Total CO_2	$ 20	2%	$ 104	8%

The changes in Segment EBDA for our CO_2 business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable years of 2018 and 2017:

- increase of $27 million (5%) from our Oil and Gas Producing activities primarily due to increased revenues of $45 million primarily driven by higher NGL prices of $23 million and higher volumes of $22 million partially offset by an increase of $16 million in operating expenses and higher severance tax expense of $2 million; and
- decrease of $7 million (2%) from our Source and Transportation activities primarily due to lower other revenues of $5 million, higher ad valorem tax expense of $4 million and decreased earnings from an equity investee of $3 million partially offset by higher CO_2 sales of $3 million driven by higher contract sales prices of $25 million offset by lower volumes of $22 million and lower operating expenses of $2 million. The increase in revenues of $52 million is primarily due to the effect of the January 1, 2018 adoption of Topic 606, which increased both revenues and operating expenses (costs of sales) by $54 million, as discussed in Note 16 "*Revenue Recognition*" to our consolidated financial statements.

Year Ended December 31, 2017 versus Year Ended December 31, 2016

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Source and Transportation activities	$ 2	1%	$ (9)	(3)%
Oil and Gas Producing activities	(34)	(6)%	(33)	(3)%
Intrasegment eliminations	—	—%	(1)	(3)%
Total CO_2	$ (32)	(3)%	$ (43)	(3)%

The changes in Segment EBDA for our CO_2 business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable years of 2017 and 2016:

- increase of $2 million (1%) from our Source and Transportation activities primarily due to increased earnings from an equity investee of $6 million and lower operating expenses of $5 million partially offset by lower revenues of $9 million driven by lower contract sales prices of $7 million and decreased volumes of $2 million; and
- decrease of $34 million (6%) from our Oil and Gas Producing activities primarily due to decreased revenues of $33 million driven by lower volumes of $22 million and lower commodity prices of $11 million, and higher operating expenses of $1 million.

Kinder Morgan Canada

	Year Ended December 31,		
	2018	2017	2016
	(In millions, except operating statistics)		
Revenues	$ 170	$ 256	$ 253
Operating expenses	(72)	(95)	(87)
Gain on divestiture(a)	596	—	—
Other, net	26	25	15
Segment EBDA(a)	720	186	181
Certain items(a)	(596)	—	—
Segment EBDA before certain items	$ 124	$ 186	$ 181
Change from prior period	Increase/(Decrease)		
Revenues	$ (86)	$ 3	
Segment EBDA before certain items	$ (62)	$ 5	
Transport volumes (MBbl/d)(b)	291	308	316

Certain items affecting Segment EBDA
(a) 2018 amount includes a gain of $596 million on the TMPL Sale.
Other
(b) Represents TMPL average daily volumes reported until date of sale, August 31, 2018.

For the comparable years of 2018 and 2017, the Kinder Morgan Canada business segment had a decrease in Segment EBDA of $62 million (33%) primarily due to the TMPL Sale on August 31, 2018 sale. As a result of the TMPL Sale on August 31, 2018, this business segment does not have results of operations on a prospective basis.

For the comparable years of 2017 and 2016, the Kinder Morgan Canada business segment had an increase in Segment EBDA of $5 million (3%) and an increase in revenues of $3 million (1%) primarily due to (i) higher capitalized equity financing costs due to spending on the TMEP; (ii) currency translation gains due to the strengthening of the Canadian dollar; and (iii) higher incentive revenues partly offset by lower state of Washington volumes and operating expense timing changes.

General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests

	Year Ended December 31,		
	2018	2017	2016
	(In millions)		
General and administrative and corporate charges(a)	$ 588	$ 660	$ 652
Certain items(a)	(24)	(15)	13
General and administrative and corporate charges before certain items(a)	$ 564	$ 645	$ 665
Interest, net(b)	$ 1,917	$ 1,832	$ 1,806
Certain items(b)	(26)	39	193
Interest, net, before certain items(b)	$ 1,891	$ 1,871	$ 1,999
Net income attributable to noncontrolling interests(c)	$ 310	$ 40	$ 13
Noncontrolling interests associated with certain items(c)	(240)	—	8
Net income attributable to noncontrolling interests before certain items(c)	$ 70	$ 40	$ 21

Certain items

(a) 2018 amount includes: (i) an increase in expense of $10 million associated with an estimated environmental reserve adjustment; (ii) a decrease in expense of $12 million related to the release of certain sales and use tax reserves; (iii) an increase in expense of $10 million of asset sale related costs; (iv) an increase in expense of $9 million related to certain corporate litigation matters; and (v) an increase in expense of $7 million related to other certain items. 2017 amount includes: (i) an increase in expense of $10 million for acquisition and divestiture related costs; (ii) an increase in expense of $4 million related to certain corporate litigation matters; (iii) an increase in expense of $5 million related to a pension settlement; and (iv) a decrease in expense of $4 million related to other certain items. 2016 amount includes increases in expense of (i) $14 million related to severance costs; and (ii) $12 million related to acquisition and divestiture costs; offset by decreases in expense of (i) $34 million related to certain corporate litigation matters; and (ii) $5 million related to other certain items.

(b) 2018, 2017 and 2016 amounts include: (i) decreases in interest expense of $32 million, $44 million and $115 million, respectively, related to amortization of non-cash debt fair value adjustments associated with acquisitions and (ii) an increase of $9 million and decreases of $3 million and $44 million, respectively, in interest expense related to non-cash true-ups of our estimates of swap ineffectiveness. 2018 amount also includes increases in interest expense of $47 million related to the write-off of capitalized KML credit facility fees and $2 million related to other certain items. 2017 amount also includes an $8 million increase in interest expense related to other certain items. 2016 amount also includes a $34 million decrease in interest expense related to certain litigation matters.

(c) 2018 amount is primarily associated with the $596 million gain on the TMPL Sale and is disclosed above in "*—Kinder Morgan Canada*." The 2016 amount is associated with Natural Gas Pipelines segment certain items and disclosed above in "*—Natural Gas Pipelines*."

General and administrative expenses and corporate charges before certain items decreased $81 million in 2018 and $20 million in 2017 when compared with the respective prior year. The decrease in 2018 as compared to 2017 was primarily due to higher capitalized costs of $54 million driven by the 2018 construction of Elba Liquefaction, Gulf Coast and Hiland facilities offset by lower spending on TGP, lower vacation and labor accruals of $18 million and $7 million from the sale of TMPL. The decrease in 2017 as compared to 2016 was primarily driven by the sale of a 50% interest in our SNG natural gas pipeline system (effective September 1, 2016), higher capitalized costs, lower state franchise taxes, legal and insurance costs, partially offset by higher labor accruals and pension costs.

In the table above, we report our interest expense as "net," meaning that we have subtracted interest income and capitalized interest from our total interest expense to arrive at one interest amount. Our consolidated interest expense net of interest income before certain items, increased $20 million in 2018 and decreased $128 million in 2017 when compared with the respective prior year. The increase in interest expense in 2018 as compared to 2017 was primarily due to higher short-term interest rates and higher short-term debt balance partially offset by lower average long-term debt balance. The decrease in interest expense in 2017 as compared to 2016 was primarily due to lower weighted average debt balances as proceeds from the May 2017 KML IPO and our September 2016 sale of a 50% interest in SNG were used to pay down debt, partially offset by a slightly higher overall weighted average interest rate on our outstanding debt.

We use interest rate swap agreements to convert a portion of the underlying cash flows related to our long-term fixed rate debt securities (senior notes) into variable rate debt in order to achieve our desired mix of fixed and variable rate debt. As of December 31, 2018 and 2017, approximately 31% and 28%, respectively, of the principal amount of our debt balances were subject to variable interest rates—either as short-term or long-term variable rate debt obligations or as fixed-rate debt converted to variable rates through the use of interest rate swaps. For more information on our interest rate swaps, see Note 14 "*Risk Management—Interest Rate Risk Management*" to our consolidated financial statements.

Net income attributable to noncontrolling interests, represents the allocation of our consolidated net income attributable to all outstanding ownership interests in our consolidated subsidiaries that are not owned by us. Net income attributable to noncontrolling interests before certain items increased $30 million in 2018 and $19 million in 2017 when compared with the respective prior year. The increases were primarily due to the May 30, 2017 sale of approximately 30% of our Canadian business operations to the public in the KML IPO.

Income Taxes

Year Ended December 31, 2018 versus Year Ended December 31, 2017

Our tax expense for the year ended December 31, 2018 is approximately $587 million, as compared with 2017 tax expense of $1,938 million. The $1,351 million decrease in tax expense is primarily due to (i) the decrease in the federal income tax rate as a result of the 2017 Tax Reform; and (ii) the decrease in uncertain tax positions as a result of audit settlements; partially offset by (i) the tax impact on the TMPL Sale; and (ii) the decrease of enhanced oil recovery credits.

Year Ended December 31, 2017 versus Year Ended December 31, 2016

Our tax expense for the year ended December 31, 2017 is approximately $1,938 million, as compared with 2016 tax expense of $917 million. The $1,021 million increase in tax expense is primarily due to (i) an increase in year-over-year earnings as a result of fewer asset impairments and project write-offs in 2017; and (ii) higher tax expense as a result of the 2017 Tax Reform. These increases are partially offset by (i) the 2016 impact of our Regulated Natural Gas Pipelines business segment's $817 million non-tax-deductible goodwill as a result of the sale of a 50% interest in SNG; and (ii) the recognition of enhanced oil recovery credits.

Liquidity and Capital Resources

General

As of December 31, 2018, we had $3,280 million of "Cash and cash equivalents," an increase of $3,016 million (1,142%) from December 31, 2017. We believe our cash position, remaining borrowing capacity on our credit facility (discussed below in "*—Short-term Liquidity*"), and our cash flows from operating activities are adequate to allow us to manage our day-to-day cash requirements and anticipated obligations as discussed further below.

We have consistently generated substantial cash flow from operations, providing a source of funds of $5,043 million and $4,601 million in 2018 and 2017, respectively. The year-to-year increase is discussed below in "*—Cash Flows—Operating Activities.*" Generally, we primarily rely on cash provided from operations to fund our operations as well as our debt service, sustaining capital expenditures, dividend payments, and our growth capital expenditures. We also generally expect that our short-term liquidity needs will be met primarily through retained cash from operations, short-term borrowings or by issuing new long-term debt to refinance certain of our maturing long-term debt obligations. Moreover, as a result of our current common stock dividend policy and our continued focus on disciplined capital allocation, we do not expect the need to access the equity capital markets to fund our growth projects for the foreseeable future.

Additionally, during 2018 the TMPL Sale mentioned above in "*—General—KML—Sale of Trans Mountain Pipeline System and Its Expansion Project*" was a source of liquidity and the primary driver of cash on hand as of December 31, 2018.

On January 3, 2019, pursuant to KML's shareholders' approval on November 29, 2018, KML distributed to its shareholders as a return of capital, the net proceeds from the TMPL Sale, after capital gains taxes, customary purchase price adjustments and the repayment of debt outstanding under a temporary KML credit facility (see "*—KML 2018 Credit Facility*" following). KML's public owners of its restricted voting shares, reflected as noncontrolling interests by us, received approximately $0.9 billion (C$1.2 billion), and part of our approximately 70% portion of the net proceeds of $1.9 billion (C$2.5 billion) (after Canadian tax) were used to immediately repay our outstanding commercial paper borrowings of $0.4 million and in February 2019 to pay down approximately $1.3 billion of maturing long-term debt. To facilitate the return of capital and provide flexibility for KML's dividends going forward, KML's shareholders also approved a reduction in the stated capital of its restricted voting shares by C$1.45 billion, along with a "reverse stock split" of KML's restricted voting shares, and KML's special voting shares that we own, on a one-for-three basis (three shares consolidating to one share) which occurred on January 4, 2019.

KML 2018 Credit Facility

Upon the closing of the TMPL Sale on August 31, 2018, KML established a 4-year, C$500 million unsecured revolving credit facility (the "KML 2018 Credit Facility") for working capital purposes, replacing a temporary credit facility that was put in place following the announcement of the TMPL Sale on May 30, 2018 (the "KML Temporary Credit Facility"). The C$133 million (U.S.$102 million) of outstanding borrowings under the KML Temporary Credit Facility were paid off prior to its termination with a portion of the proceeds from the TMPL Sale. As of December 31, 2018, there were no outstanding borrowings under the KML 2018 Credit Facility.

Credit Ratings and Capital Market Liquidity

We believe that our capital structure will continue to allow us to achieve our business objectives. We expect that our short-term liquidity needs will be met primarily through retained cash from operations or short-term borrowings. Generally, we anticipate re-financing maturing long term debt obligations in the debt capital markets and are therefore subject to certain market conditions which could result in higher costs or negatively affect our and/or our subsidiaries' credit ratings.

As of December 31, 2018, our short-term corporate debt ratings were A-3 (upgraded to A-2 on January 7, 2019), Prime-2 and F3 at Standard and Poor's, Moody's Investor Services and Fitch Ratings, Inc., respectively. We are on a positive outlook for an upgrade by Fitch Ratings, Inc.

The following table represents KMI's and KMP's senior unsecured debt ratings as of December 31, 2018.

Rating agency	Senior debt rating	Outlook
Standard and Poor's(a)	BBB-	Positive
Moody's Investor Services	Baa2	Stable
Fitch Ratings, Inc.	BBB-	Positive

(a) Subsequently was upgraded to BBB on January 7, 2019 with a Stable outlook.

Short-term Liquidity

As of December 31, 2018, our principal sources of short-term liquidity are (i) our $4.5 billion revolving credit facilities and associated $4.0 billion commercial paper program; (ii) the KML 2018 Credit Facility (for the purposes described above); and (iii) cash from operations. The loan commitments under our revolving credit facility can be used for working capital and other general corporate purposes and as a backup to our commercial paper program. Borrowings under our commercial paper program and letters of credit reduce borrowings allowed under ours and KML's respective credit facilities. We provide for liquidity by maintaining a sizable amount of excess borrowing capacity under our credit facility (see Note 9 "*Debt—Credit Facilities and Restrictive Covenants—KMI*" to our consolidated financial statements) and, as previously discussed, we have consistently generated strong cash flows from operations.

As of December 31, 2018, our $3,388 million of short-term debt consisted primarily of (i) $433 million outstanding under our $4.0 billion commercial paper program; and (ii) $2,800 million of senior notes that mature in the next year. As previously discussed, we repaid $1.7 billion of this short-term debt in 2019 from a portion of the TMPL Sale proceeds. We intend to refinance our remaining short-term debt through credit facility borrowings, commercial paper borrowings, or by issuing new long-term debt or paying down short-term debt using cash retained from operations. Our short-term debt balance as of December 31, 2017 was $2,828 million.

We had working capital (defined as current assets less current liabilities) deficits of $1,835 million and $3,466 million as of December 31, 2018 and 2017, respectively. Our current liabilities may include short-term borrowings used to finance our expansion capital expenditures, which we may periodically replace with long-term financing and/or pay down using retained cash from operations. The overall $1,631 million (47%) favorable change from year-end 2017 was primarily due to: (i) the $2,998 million of proceeds from the TMPL Sale, net of cash disposed, partially offset by (i) the $890 million (C$1,195 million) distribution paid to our noncontrolling interests associated with KML on January 3, 2019 ($876 million was the accrued U.S.$ value as of December 31, 2018) and a $516 million increase in current maturities of our senior notes. Generally, our working capital balance varies due to factors such as the timing of scheduled debt payments, timing differences in the collection and payment of receivables and payables, the change in fair value of our derivative contracts, and changes in our cash and cash equivalent balances as a result of excess cash from operations after payments for investing and financing activities (discussed below in "*—Long-term Financing*" and "*—Capital Expenditures*").

We employ a centralized cash management program for our U.S.-based bank accounts that concentrates the cash assets of our wholly owned subsidiaries in joint accounts for the purpose of providing financial flexibility and lowering the cost of borrowing. These programs provide that funds in excess of the daily needs of our wholly owned subsidiaries are concentrated, consolidated or otherwise made available for use by other entities within the consolidated group. We place no material restrictions on the ability to move cash between entities, payment of intercompany balances or the ability to upstream dividends to KMI other than restrictions that may be contained in agreements governing the indebtedness of those entities.

Certain of our wholly owned subsidiaries are subject to FERC-enacted reporting requirements for oil and natural gas pipeline companies that participate in cash management programs. FERC-regulated entities subject to these rules must, among other things, place their cash management agreements in writing, maintain current copies of the documents authorizing and supporting their cash management agreements, and file documentation establishing the cash management program with the FERC.

Long-term Financing

Our equity consists of Class P common stock with a par value of $0.01 per share. We do not expect to need to access the equity capital markets to fund our growth projects for the foreseeable future. Furthermore, through January 2019, we have repurchased approximately 29 million shares of our Class P common stock under a $2 billion share buy-back program authorized by our board of directors in December 2017 that we funded through retained cash. For more information on our equity buy-back program and our equity distribution agreement, see Note 11 "*Stockholders' Equity*" to our consolidated financial statements.

From time to time, we issue long-term debt securities, often referred to as senior notes. All of our senior notes issued to date, other than those issued by certain of our subsidiaries, generally have very similar terms, except for interest rates, maturity dates and prepayment premiums. All of our fixed rate senior notes provide that the notes may be redeemed at any time at a price equal to 100% of the principal amount of the notes plus accrued interest to the redemption date, and, in most cases, plus a make-whole premium. In addition, from time to time our subsidiaries, have issued long-term debt securities. Furthermore, we and almost all of our direct and indirect wholly owned domestic subsidiaries are parties to a cross guaranty wherein we each guarantee the debt of each other. See Note 20 "*Guarantee of Securities of Subsidiaries*" to our consolidated financial statements. As of December 31, 2018 and 2017, the aggregate principal amount outstanding of our various long-term debt obligations (excluding current maturities) was $33,205 million and $34,088 million, respectively. For more information regarding our debt-related transactions in 2018, see Note 9 "*Debt*" to our consolidated financial statements.

We achieve our variable rate exposure primarily by issuing long-term fixed rate debt and then swapping the fixed rate interest payments for variable rate interest payments and through the issuance of commercial paper or credit facility borrowings.

For additional information about our outstanding senior notes and debt-related transactions in 2018 and early 2019, see Note 9 "*Debt*" to our consolidated financial statements. For information about our interest rate risk, see Item 7A "*Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Risk.*"

Capital Expenditures

We account for our capital expenditures in accordance with GAAP. We also distinguish between capital expenditures that are maintenance/sustaining capital expenditures and those that are expansion capital expenditures (which we also refer to as discretionary capital expenditures). Expansion capital expenditures are those expenditures which increase throughput or capacity from that which existed immediately prior to the addition or improvement, and are not deducted in calculating DCF (see "*—Results of Operations—DCF*"). With respect to our oil and gas producing activities, we classify a capital expenditure as an expansion capital expenditure if it is expected to increase capacity or throughput (i.e., production capacity) from the capacity or throughput immediately prior to the making or acquisition of such additions or improvements. Maintenance capital expenditures are those which maintain throughput or capacity. The distinction between maintenance and expansion capital expenditures is a physical determination rather than an economic one, irrespective of the amount by which the throughput or capacity is increased.

Budgeting of maintenance capital expenditures is done annually on a bottom-up basis. For each of our assets, we budget for and make those maintenance capital expenditures that are necessary to maintain safe and efficient operations, meet customer needs and comply with our operating policies and applicable law. We may budget for and make additional maintenance capital expenditures that we expect to produce economic benefits such as increasing efficiency and/or lowering future expenses. Budgeting and approval of expansion capital expenditures are generally made periodically throughout the year on a project-by-project basis in response to specific investment opportunities identified by our business segments from which we generally expect to receive sufficient returns to justify the expenditures. Generally, the determination of whether a capital expenditure is classified as maintenance/sustaining or as expansion capital expenditures is made on a project level. The classification of our capital expenditures as expansion capital expenditures or as maintenance capital expenditures is made consistent with our accounting policies and is generally a straightforward process, but in certain circumstances can be a matter of management judgment and discretion. The classification has an impact on DCF because capital expenditures that are classified as expansion capital expenditures are not deducted from DCF, while those classified as maintenance capital expenditures are. See "*—Common Dividends" and "—Preferred Dividends.*"

Our capital expenditures for the year ended December 31, 2018, and the amount we expect to spend for 2019 to sustain and grow our business are as follows (in millions):

	2018	Expected 2019
Sustaining capital expenditures(a)(b)	$ 652	$ 715
KMI Discretionary capital investments(b)(c)(d)	$ 2,363	$ 3,085
KML Discretionary capital investments(b)(e)	$ 401	$ 24

(a) 2018 and Expected 2019 amounts include $105 million and $127 million, respectively, for our proportionate share of (i) certain equity investee's; (ii) KML's; and (iii) certain consolidating joint venture subsidiaries' sustaining capital expenditures.
(b) 2018 includes $128 million of net changes from accrued capital expenditures, contractor retainage, and other.
(c) 2018 amount includes $279 million of our contributions to certain unconsolidated joint ventures for capital investments and small acquisitions.
(d) Amounts include our actual or estimated contributions to certain unconsolidated joint ventures, net of actual or estimated contributions from certain partners in non-wholly owned consolidated subsidiaries for capital investments.
(e) 2018 amount includes TMEP capital investments for the period ending on August 31, 2018, the closing of the TMPL Sale.

Off Balance Sheet Arrangements

We have invested in entities that are not consolidated in our financial statements. For information on our obligations with respect to these investments, as well as our obligations with respect to related letters of credit, see Note 13 "*Commitments and Contingent Liabilities*" to our consolidated financial statements. Additional information regarding the nature and business purpose of our investments is included in Note 7 "*Investments*" to our consolidated financial statements.

Contractual Obligations and Commercial Commitments

	Payments due by period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
			(In millions)		
Contractual obligations:					
Debt borrowings-principal payments(a)	$ 36,593	$ 3,388	$ 4,627	$ 5,768	$ 22,810
Interest payments(b)	24,493	1,890	3,418	2,992	16,193
Leases and rights-of-way obligations(c)	862	122	209	178	353
Pension and postretirement welfare plans(d)	925	67	40	41	777
Transportation, volume and storage agreements(e)	928	168	307	205	248
Other obligations(f)	276	65	84	35	92
Total	$ 64,077	$ 5,700	$ 8,685	$ 9,219	$ 40,473
Other commercial commitments:					
Standby letters of credit(g)	$ 156	$ 83	$ 73	$ —	$ —
Capital expenditures(h)	$ 304	$ 304	$ —	$ —	$ —

(a) Less than 1 year amount primarily includes $3,277 million of current maturities on senior notes and $111 million associated with our Trust I Preferred Securities that are classified as current obligations because these securities have rights to convert into cash and/or KMI common stock. See Note 9 "*Debt*" to our consolidated financial statements.
(b) Interest payment obligations exclude adjustments for interest rate swap agreements and assume no change in variable interest rates from those in effect at December 31, 2018.
(c) Represents commitments pursuant to the terms of operating lease agreements and liabilities for rights-of-way.
(d) Represents the amount by which the benefit obligations exceeded the fair value of plan assets at year-end for pension and other postretirement benefit plans whose accumulated postretirement benefit obligations exceeded the fair value of plan assets. The payments by period include expected contributions to funded plans in 2019 and estimated benefit payments for unfunded plans in all years.
(e) Primarily represents transportation agreements of $374 million, volume agreements of $338 million and storage agreements for capacity of $183 million.

(f) Primarily includes environmental liabilities related to sites that we own or have a contractual or legal obligation with a regulatory agency or property owner upon which we will perform remediation activities. These liabilities are included within "Accrued contingencies" and "Other long-term liabilities and deferred credits" in our consolidated balance sheets.

(g) The $156 million in letters of credit outstanding as of December 31, 2018 consisted of the following (i) letters of credit totaling $46 million supporting our International Marine Terminals Partnership Plaquemines, Louisiana Port, Harbor, and Terminal Revenue Bonds; (ii) $33 million under nine letters of credit for insurance purposes; (iii) a $24 million letter of credit supporting our Kinder Morgan Operating L.P. "B" tax-exempt bonds; (iv) thirteen letters of credit totaling $8 million supporting our pipeline and terminal operations in Canada; and (v) a combined $45 million in twenty-five letters of credit supporting environmental and other obligations of us and our subsidiaries.

(h) Represents commitments for the purchase of plant, property and equipment as of December 31, 2018.

Cash Flows

Operating Activities

The net increase of $442 million (10%) in cash provided by operating activities in 2018 compared to 2017 was primarily attributable to:

- a $346 million increase in cash associated with net changes in working capital items and other non-current assets and liabilities, primarily driven, among other things, by a $137 income tax refund received in the 2018 period, and an increase in current income tax liabilities associated with the tax gain on the TMPL Sale in the 2018 period. These increases were partially offset by higher payments for litigation matters in the 2018 period compared with the 2017 period; and
- a $96 million increase in operating cash flow resulting from the combined effects of adjusting the $1,696 million increase in net income for the period-to-period net changes in non-cash items including the following: (i) loss on impairments and divestitures, net (see discussion above in "—Results of Operations"); (ii) loss on impairments and divestitures of equity investments, net (see discussion above in "—Results of Operations"); (iii) the change in fair market value of derivative contracts; (iv) DD&A expenses (including amortization of excess cost of equity investments); (v) deferred income taxes; (vi) earnings from equity investments; and (vii) loss on early extinguishment of debt.

Investing Activities

The $3,335 million net decrease in cash used in investing activities in 2018 compared to 2017 was primarily attributable to:

- a $2,998 million increase in cash reflecting proceeds received from the TMPL Sale, net of cash disposed in the 2018 period. See Note 3 "*Divestitures and Acquisition*" for further information regarding this transaction;
- a $284 million decrease in capital expenditures in the 2018 period over the comparative 2017 period primarily due to lower expenditures in our Terminals business segment, partially offset by higher expenditures related to construction projects in our Natural Gas Pipelines business segment;
- a $251 million decrease in cash used for contributions to equity investments primarily due to lower contributions we made to NGPL Holdings LLC, FEP and Utopia Holding LLC in the 2018 period compared to the 2017 period, partially offset by the contributions made to Gulf Coast Express Pipeline LLC in the 2018 period; and
- a $124 million increase in cash proceeds received from the sale of equity investments, primarily driven by a sale of our partial interest in Gulf Coast Express LLC in the 2018 period; partially offset by,
- a $138 million decrease in cash proceeds from sale of property, plant and equipment and other net assets in the 2018 period compared to the 2017 period; and
- a $137 million decrease in cash resulting from lower distributions received from equity investments in excess of cumulative earnings, primarily from MEP, SNG and Citrus Corporation in the 2018 period over the comparative 2017 period.

Financing Activities

The net increase of $143 million in cash used by financing activities in 2018 compared to 2017 was primarily attributable to:

- a combined $1,665 million decrease in cash reflecting $1,245 million net proceeds we received from the KML IPO in May 2017 and $420 million net proceeds received from the KML preferred share issuances in the 2017 period;
- a $498 million increase in dividend payments to our common shareholders;

- a $304 million decrease in cash due to lower contributions received from EIG in the 2018 period compared to the 2017 period as the 2017 period included $386 million we received from EIG Global Energy Partners for our sale of a 49% partnership interest in ELC;
- a $36 million increase in distributions to noncontrolling interests, primarily to KML restricted share holders and preferred shareholders; and
- a $23 million increase in cash used for common shares repurchased under our common share buy-back program in the 2018 period compared to the 2017 period; partially offset by,
- a $2,384 million net increase in cash related to debt activity as a result of $118 million of net debt issuances in the 2018 period compared to $2,266 million of net debt payments in the 2017 period. See Note 9 "*Debt*" for further information regarding our debt activity.

Mandatory Convertible Preferred Stock

As of October 26, 2018, all of our issued and outstanding 1,600,000 shares of 9.750% Series A mandatory convertible preferred stock, with a liquidating preference of $1,000 per share were converted into common stock either at the option of the holders before or automatically on October 26, 2018. Based on the current market price of our common stock at the time of conversion, our Series A Preferred Shares converted into 58 million common shares.

Dividends and Stock Buy-back Program

KMI Preferred Stock Dividends

Dividends on our mandatory convertible preferred stock were payable on a cumulative basis when, as and if declared by our board of directors (or an authorized committee thereof) at an annual rate of 9.750% of the liquidation preference of $1,000 per share on January 26, April 26, July 26 and October 26 of each year, commencing on January 26, 2016 to, and including, October 26, 2018. Prior to the October 26, 2018 conversion of our Series A Preferred Shares into common shares, we paid all dividends on our mandatory convertible preferred stock in cash.

Period	Total dividend per share for the period	Date of declaration	Date of record	Date of dividend
January 26, 2018 through April 25, 2018	$24.375	January 17, 2018	April 11, 2018	April 26, 2018
April 26, 2018 through July 25, 2018	24.375	April 18, 2018	July 11, 2018	July 26, 2018
July 26, 2018 through October 25, 2018	24.375	July 18, 2018	October 11, 2018	October 26, 2018

KMI Common Stock Dividends

The table below reflects the declaration of common stock dividends of $0.80 per common share for 2018.

Three months ended	Total quarterly dividend per share for the period	Date of declaration	Date of record	Date of dividend
March 31, 2018	$0.20	April 18, 2018	April 30, 2018	May 15, 2018
June 30, 2018	0.20	July 18, 2018	July 31, 2018	August 15, 2018
September 30, 2018	0.20	October 17, 2018	October 31, 2018	November 15, 2018
December 31, 2018	0.20	January 16, 2019	January 31, 2019	February 15, 2019

We will continue to return additional value to our shareholders in 2019 through our previously announced dividend increase. We plan to increase our dividend to $1.00 per common share in 2019 and $1.25 per common share in 2020, a growth rate of 25% annually.

The actual amount of common stock dividends to be paid on our capital stock will depend on many factors, including our financial condition and results of operations, liquidity requirements, business prospects, capital requirements, legal, regulatory and contractual constraints, tax laws, Delaware laws and other factors. See Item 1A "*Risk Factors—The guidance we provide for our anticipated dividends is based on estimates. Circumstances may arise that lead to conflicts between using funds to pay anticipated dividends or to invest in our business.*" All of these matters will be taken into consideration by our board of directors in declaring dividends.

Our common stock dividends are not cumulative. Consequently, if dividends on our common stock are not paid at the intended levels, our common stockholders are not entitled to receive those payments in the future. Our common stock dividends generally will be paid on or about the 15th day of each February, May, August and November.

Stock Buy-back Program

On July 19, 2017, our board of directors approved a $2 billion common share buy-back program that began in December 2017. During the years ended December 31, 2018 and 2017, we repurchased approximately 15 million and 14 million, respectively, of our Class P shares for approximately $273 million and $250 million, respectively. 2018 amounts exclude repurchases made in December 2018 of approximately 0.1 million of our Class P shares for approximately $2 million, which settled on January 2, 2019.

Noncontrolling Interests

The caption "Noncontrolling interests" in our accompanying consolidated balance sheets consists of interests that we do not own in the following subsidiaries (in millions):

	December 31,	
	2018	**2017**
KML(a)	$ 514	$ 1,163
Others	339	325
	$ 853	$ 1,488

(a) The reduction in the noncontrolling interests associated with KML is primarily attributable to the accrual of the return of capital distribution for the net proceeds from the TMPL Sale paid to KML's Restricted Voting Shareholders on January 3, 2019 of approximately $0.9 billion. For more information see "*—General—KML—Sale of Trans Mountain Pipeline System and Its Expansion Project*" above.

KML Distributions

KML has a dividend policy pursuant to which it may pay a quarterly dividend on its restricted voting shares in an amount based on a portion of its distributable cash flow. The payment of dividends is not guaranteed, and the amount and timing of any dividends payable will be at the discretion of KML's board of directors. KML intends to pay quarterly dividends, if any, on or about the 45th day (or next business day) following the end of each calendar quarter to holders of its restricted voting shares of record as of the close of business on or about the last business day of the month following the end of each calendar quarter. KML also established a Dividend Reinvestment Plan (DRIP) that allows holders (excluding holders not resident in Canada) of restricted voting shares to elect to have any or all cash dividends payable to such shareholder automatically reinvested in additional restricted voting shares at a price per share calculated by reference to the volume-weighted average of the closing price of the restricted voting shares on the stock exchange on which the restricted voting shares are then listed for the five trading days immediately preceding the relevant dividend payment date, less a discount of between 0% and 5% (as determined from time to time by KML's board of directors, in its sole discretion).

On January 16, 2019, KML's board of directors announced that it would suspend KML's DRIP, effective with the payment of the fourth quarter 2018 dividend on February 15, 2019, in light of KML's reduced need for capital.

For 2019, KML announced that it expects to pay an annual dividend of C$0.65 per split-adjusted restricted voting share.

KML also pays dividends on its 12,000,000 Series 1 Preferred Shares and 10,000,000 Series 3 Preferred Shares, which are fixed, cumulative, preferential, and payable quarterly in the annual amount of C$1.3125 per share and C$1.3000 per share, respectively, on the 15th day of February, May, August and November, as and when declared by KML's board of directors, for the initial fixed rate period to but excluding November 15, 2022 and February 15, 2023, respectively.

During the year ended December 31, 2018, KML paid dividends on its Restricted Voting Shares to the public valued at $52 million, of which $38 million was paid in cash. The remaining value of $14 million for the year ended December 31, 2018 was paid in 1,092,791 KML Restricted Voting Shares. KML also paid dividends to the public on its Series 1 and Series 3 Preferred Shares of $21 million for the year ended December 31, 2018.

Recent Accounting Pronouncements

Please refer to Note 19 "*Recent Accounting Pronouncements*" to our consolidated financial statements for information concerning recent accounting pronouncements.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk.*

Generally, our market risk sensitive instruments and positions have been determined to be "other than trading." Our exposure to market risk as discussed below includes forward-looking statements and represents an estimate of possible changes in fair value or future earnings that would occur assuming hypothetical future movements in energy commodity prices or interest rates. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated based on actual fluctuations in energy commodity prices or interest rates and the timing of transactions.

Energy Commodity Market Risk

We are exposed to energy commodity market risk and other external risks in the ordinary course of business. However, we manage these risks by executing a hedging strategy that seeks to protect us financially against adverse price movements and serves to minimize potential losses. Our strategy involves the use of certain energy commodity derivative contracts to reduce and minimize the risks associated with unfavorable changes in the market price of natural gas, NGL and crude oil. The derivative contracts that we use include exchange-traded and OTC commodity financial instruments, including, but not limited to, futures and options contracts, fixed price swaps and basis swaps.

Our hedging strategy involves entering into a financial position intended to offset our physical position, or anticipated position, in order to minimize the risk of financial loss from an adverse price change. For example, as sellers of crude oil and natural gas, we often enter into fixed price swaps and/or futures contracts to guarantee or lock-in the sale price of our crude oil or the margin from the sale and purchase of our natural gas at the time of market delivery, thereby in whole or in part offsetting any change in prices, either positive or negative.

Our policies require that derivative contracts are only entered into with carefully selected major financial institutions or similar counterparties based upon their credit ratings and other factors, and we maintain strict dollar and term limits that correspond to our counterparties' credit ratings. While it is our policy to enter into derivative transactions principally with investment grade counterparties and actively monitor their credit ratings, it is nevertheless possible that losses will result from counterparty credit risk in the future.

The credit ratings of the primary parties from whom we transact in energy commodity derivative contracts (based on contract market values) are as follows (credit ratings per Standard & Poor's Rating Service):

	Credit Rating
ING	A+
Wells Fargo	A+
Bank of Nova Scotia	A+
Canadian Imperial Bank	A+
JP Morgan	A+

As discussed above, the principal use of energy commodity derivative contracts is to mitigate the market price risk associated with anticipated transactions for the purchase and sale of natural gas, NGL and crude oil. Using derivative contracts for this purpose helps provide increased certainty with regard to operating cash flows which helps us to undertake further capital improvement projects, attain budget results and meet dividend targets. We may categorize such use of energy commodity derivative contracts as cash flow hedges because the derivative contract is used to hedge the anticipated future cash flow of a transaction that is expected to occur but which value is uncertain.

We measure the risk of price changes in the crude oil, natural gas and NGL derivative instruments portfolios utilizing a sensitivity analysis model. The sensitivity analysis applied to each portfolio measures the potential income or loss (i.e., the change in fair value of the derivative instrument portfolio) based upon a hypothetical 10% movement in the underlying quoted market prices. In addition to these variables, the fair value of each portfolio is influenced by fluctuations in the notional amounts of the instruments and the discount rates used to determine the present values. A hypothetical 10% movement in the

underlying commodity prices would have the following effect on the associated derivative contracts' estimated fair value (in millions):

	As of December 31,	
Commodity derivative	**2018**	**2017**
Crude oil	$ 97	$ 125
Natural gas	12	15
NGL	6	10
Total	$ 115	$ 150

As discussed above, we enter into derivative contracts largely for the purpose of mitigating the risks that accompany certain of our business activities and, therefore both in the sensitivity analysis model and in reality, the change in the market value of the derivative contracts' portfolio is offset largely by changes in the value of the underlying physical transactions.

Our sensitivity analysis represents an estimate of the reasonably possible gains and losses that would be recognized on the crude oil, natural gas and NGL portfolios of derivative contracts assuming hypothetical movements in future market rates and is not necessarily indicative of actual results that may occur. It does not represent the maximum possible loss or any expected loss that may occur, since actual future gains and losses will differ from those estimated. Actual gains and losses may differ from estimates due to actual fluctuations in market rates, operating exposures and the timing thereof, as well as changes in our portfolio of derivatives during the year.

Interest Rate Risk

In order to maintain a cost effective capital structure, it is our policy to borrow funds using a mix of fixed rate debt and variable rate debt. The market risk inherent in our debt instruments and positions is the potential change arising from increases or decreases in interest rates as discussed below.

For fixed rate debt, changes in interest rates generally affect the fair value of the debt instrument, but not our earnings or cash flows. Conversely, for variable rate debt, changes in interest rates generally do not impact the fair value of the debt instrument, but may affect our future earnings and cash flows. Generally, there is not an obligation to prepay fixed rate debt prior to maturity and, as a result, changes in fair value should not have a significant impact on the fixed rate debt. We are generally subject to interest rate risk upon refinancing maturing debt. Below are our debt balances, including debt fair value adjustments and the preferred interest in KMGP, and sensitivity to interest rates (in millions):

	December 31, 2018		December 31, 2017	
	Carrying value	**Estimated fair value(c)**	**Carrying value**	**Estimated fair value(c)**
Fixed rate debt(a)	$ 36,480	$ 36,647	$ 37,041	$ 39,255
Variable rate debt	$ 844	$ 822	$ 802	$ 795
Notional principal amount of fixed-to-variable interest rate swap agreements	10,575		9,575	
Debt balances subject to variable interest rates(b)	$ 11,419		$ 10,377	

(a) A hypothetical 10% change in the average interest rates applicable to such debt as of December 31, 2018 and 2017, would result in changes of approximately $1,638 million and $1,525 million, respectively, in the fair values of these instruments.
(b) A hypothetical 10% change in the weighted average interest rate on all of our borrowings (approximately 52 and 50 basis points, respectively, in 2018 and 2017) when applied to our outstanding balance of variable rate debt as of December 31, 2018 and 2017, including adjustments for the notional swap amounts described above, would result in changes of approximately $59 million and $52 million, respectively, in our 2018 and 2017 annual pre-tax earnings.
(c) Fair values were determined using quoted market prices, where applicable, or future cash flows discounted at market rates for similar types of borrowing arrangements.

Fixed-to-variable interest rate swap agreements are entered into for the purpose of converting a portion of the underlying cash flows related to long-term fixed rate debt securities into variable rate debt in order to achieve our desired mix of fixed and variable rate debt. Since the fair value of fixed rate debt varies with changes in the market rate of interest, swap agreements are

entered into to receive a fixed and pay a variable rate of interest. Such swap agreements result in future cash flows that vary with the market rate of interest, and therefore hedge against changes in the fair value of the fixed rate debt due to market rate changes.

We monitor the mix of fixed rate and variable rate debt obligations in light of changing market conditions and from time to time, may alter that mix by, for example, refinancing outstanding balances of variable rate debt with fixed rate debt (or vice versa) or by entering into interest rate swap agreements or other interest rate hedging agreements. As of December 31, 2018, including debt converted to variable rates through the use of interest rate swaps but excluding our debt fair value adjustments, approximately 31% of our debt balances were subject to variable interest rates.

For more information on our interest rate risk management and on our interest rate swap agreements, see Note 14 "*Risk Management*" to our consolidated financial statements.

Foreign Currency Risk

As of December 31, 2018, we had a notional principal amount of $1,358 million of cross-currency swap agreements that effectively convert all of our fixed-rate Euro denominated debt, including annual interest payments and the payment of principal at maturity, to U.S. dollar denominated debt at fixed rates. These swaps eliminate the foreign currency risk associated with our foreign currency denominated debt.

As of December 31, 2018, we had a notional principal amount of C$2,450 million (U.S.$1,888 million) of cross-currency swap agreements that result in our selling fixed C$ and receiving fixed U.S.$. These swaps effectively hedged the foreign currency risk associated with a substantial portion of our share of the TMPL Sale proceeds that KML distributed to us on January 3, 2019, at which time the cross-currency currency swaps also expired.

Item 8. ***Financial Statements and Supplementary Data.***

The information required in this Item 8 is in this report as set forth in the "Index to Financial Statements" on page 72.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.***

None.

Item 9A. ***Controls and Procedures.***

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of December 31, 2018, our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon and as of the date of the evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the design and operation of our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in the reports we file and submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported as and when required, and is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an assessment of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control – Integrated Framework (2013)* issued by the Committee of

Sponsoring Organizations of the Treadway Commission. Based on this assessment, our management concluded that our internal control over financial reporting was effective as of December 31, 2018.

The effectiveness of our internal control over financial reporting as of December 31, 2018, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their audit report, which appears herein.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting during the fourth quarter of 2018 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information.***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance.***

The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2019 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2019.

Item 11. ***Executive Compensation.***

The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2019 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2019.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.***

The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2019 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2019.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence.***

The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2019 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2019.

Item 14. ***Principal Accounting Fees and Services.***

The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2019 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2019.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules.***

(a) (1) Financial Statements and (2) Financial Statement Schedules

See "Index to Financial Statements" set forth on Page 72.

(3) Exhibits

Exhibit Number		Description
3.1	*	Amended and Restated Certificate of Incorporation of KMI (filed as Exhibit 3.1 to KMI's Quarterly Report on Form 10-Q for the three months ended June 30, 2015 (File No. 001-35081))
3.2	*	Amended and Restated Bylaws of KMI (filed as Exhibit 3.1 to KMI's Current Report on Form 8-K, filed October 20, 2017 (File No. 001-35081))

Exhibit Number		Description
3.3	*	Certificate of Elimination of 9.75% Series A Mandatory Convertible Preferred Stock of KMI (filed as Exhibit 3.1 to KMI's Current Report on Form 8-K filed January 22, 2019 (File No. 001-35081))
4.1	*	Form of certificate representing Class P common shares of KMI (filed as Exhibit 4.1 to KMI's Registration Statement on Form S-1 filed on January 18, 2011 (File No. 333-170773))
4.2	*	Shareholders Agreement among KMI and certain holders of common stock (filed as Exhibit 4.2 to KMI's Quarterly Report on Form 10-Q for the three Months ended March 31, 2011 (File No. 001-35081))
4.3	*	Amendment No. 1 to the Shareholders Agreement among KMI and certain holders of common stock (filed as Exhibit 4.3 to KMI's Current Report on Form 8-K filed on May 30, 2012 (File No. 001-35081))
4.4	*	Amendment No. 2 to the Shareholders Agreement among KMI and certain holders of common stock (filed as Exhibit 4.1 to KMI's Current Report on Form 8-K filed on December 3, 2014 (File No. 001-35081))
4.5	*	Form of Senior Indenture between Kinder Morgan Kansas, Inc. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.2 to Kinder Morgan Kansas, Inc.'s Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102963))
4.6	*	Form of Senior Note of Kinder Morgan Kansas, Inc. (included in the Form of Senior Indenture filed as Exhibit 4.2 to Kinder Morgan Kansas, Inc.'s Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102963))
4.7	*	Indenture dated as of December 9, 2005, among Kinder Morgan Finance Company LLC (formerly Kinder Morgan Finance Company, ULC), Kinder Morgan Kansas, Inc. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.1 to Kinder Morgan Kansas, Inc.'s Current Report on Form 8-K filed on December 15, 2005 (File No. 1-06446))
4.8	*	Forms of Kinder Morgan Finance Company LLC Notes (included in the Indenture filed as Exhibit 4.1 to Kinder Morgan Kansas, Inc.'s Current Report on Form 8-K filed on December 15, 2005 (File No. 1-06446))
4.9	*	Indenture dated January 2, 2001 between Kinder Morgan Energy Partners, L.P. and First Union National Bank, as trustee, relating to Senior Debt Securities (including form of Senior Debt Securities) (filed as Exhibit 4.11 to Kinder Morgan Energy Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2000 (File No. 1-11234))
4.10	*	Certificate of the Vice President and Chief Financial Officer of Kinder Morgan Energy Partners, L.P. establishing the terms of the 7.40% Notes due March 15, 2031 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Current Report on Form 8-K filed on March 14, 2001 (File No. 1-11234))
4.11	*	Specimen of 7.40% Notes due March 15, 2031 in book-entry form (filed as Exhibit 4.3 to Kinder Morgan Energy Partners, L.P.'s Current Report on Form 8-K filed on March 14, 2001(File No. 1-11234))
4.12	*	Certificate of the Vice President and Chief Financial Officer of Kinder Morgan Energy Partners, L.P. establishing the terms of the 7.750% Notes due March 15, 2032 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2002 (File No. 1-11234))
4.13	*	Specimen of 7.750% Notes due March 15, 2032 in book-entry form (filed as Exhibit 4.3 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2002 (File No. 1-11234))
4.14	*	Indenture dated August 19, 2002 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100346))
4.15	*	First Supplemental Indenture to Indenture dated August 19, 2002, dated August 23, 2002 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100346))
4.16	*	Form of 7.30% Notes due 2033 (contained in the Indenture filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100346))
4.17	*	Senior Indenture dated January 31, 2003 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102961))

Exhibit Number		Description
4.18	*	Form of Senior Note of Kinder Morgan Energy Partners, L.P. (included in the Form of Senior Indenture filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102961))
4.19	*	Certificate of the Vice President, Treasurer and Chief Financial Officer and the Vice President, General Counsel and Secretary of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P. establishing the terms of the 5.80% Notes due March 15, 2035 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 (File No. 1-11234))
4.20	*	Certificate of the Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P. establishing the terms of the 6.00% Senior Notes due 2017 and 6.50% Senior Notes due 2037 (filed as Exhibit 4.28 to Kinder Morgan Energy Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2006 (File No. 1-11234))
4.21	*	Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 6.95% Senior Notes due 2038 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2007 (File No. 1-11234))
4.22	*	Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 9.00% Senior Notes due 2019 (filed as Exhibit 4.29 to Kinder Morgan Energy Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2008 (File No. 1-11234))
4.23	*	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 6.85% Senior Notes due 2020 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2009 (File No. 1-11234))
4.24	*	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 5.80% Senior Notes due 2021, and the 6.50% Senior Notes due 2039 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2009 (File No. 1-11234))
4.25	*	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 5.30% Senior Notes due 2020, and the 6.55% Senior Notes due 2040 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 (File No. 1-11234))
4.26	*	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 6.375% Senior Notes due 2041 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 (File No. 1-11234))
4.27	*	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 4.150% Senior Notes due 2022, and the 5.625% Senior Notes due 2041 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2011 (File No. 1-11234))
4.28	*	Certificate of the Vice President, Finance and Investor Relations and the Vice President and Secretary of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 3.500% Senior Notes due 2021 and the 5.500% Senior Notes due 2044 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2014 (File No. 1-11234))
4.29	*	Certificate of the Vice President and Treasurer and the Vice President and Secretary of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 4.250% Senior Notes due 2024 and the 5.400% Senior Notes due 2044 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2014 (File No. 1-11234))
4.30	*	Indenture, dated March 1, 2012, between KMI and U.S. Bank National Association, as Trustee (filed as Exhibit 4.1 to KMI's Registration Statement on Form S-3 filed on March 1, 2012 (File No. 001-35081))

Exhibit Number		Description
4.31	*	Certificate of the Vice President and Treasurer and the Vice President and Secretary of KMI establishing the terms of the 2.000% Senior Notes due 2017, the 3.050% Senior Notes due 2019, the 4.300% Senior Notes due 2025, the 5.300% Senior Notes due 2034 and the 5.550% Senior Notes due 2045 (filed as Exhibit 10.53 to KMI's Annual Report on Form 10-K for the year ended December 31, 2014 (File No. 001-35081))
4.32	*	Certificate of the Vice President and Treasurer and Vice President and Secretary of KMI establishing the terms of the 5.050% Senior Notes due 2046 (filed as Exhibit 4.1 to KMI's Quarterly Report on Form 10-Q for the three months ended March 31, 2015 (File No. 001-35081))
4.33	*	Certificate of the Vice President and Treasurer and Vice President and Secretary of KMI establishing the terms of the 1.500% Senior Notes due 2022 and 2.250% Senior Notes due 2027 (filed as Exhibit 4.2 to KMI's Form 8-A, filed March 16, 2015 (File No. 001-35081))
4.34	*	Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of KMI establishing the terms of the 3.150% Senior Notes due January 15, 2023 (filed as Exhibit 4.1 to KMI's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017 (File No. 001-35081))
4.35	*	Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of KMI establishing the terms of the Floating Rate Senior Notes due January 15, 2023 (filed as Exhibit 4.2 to KMI's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017 (File No. 001-35081))
4.36	*	Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of KMI establishing the terms of the 4.300% Senior Notes due 2028 and the 5.200% Senior Notes due 2048 (filed as Exhibit 4.1 to KMI's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018 (File No. 001-35081))
4.37		Certain instruments with respect to long-term debt of KMI and its consolidated subsidiaries which relate to debt that does not exceed 10% of the total assets of KMI and its consolidated subsidiaries are omitted pursuant to Item 601(b) (4) (iii) (A) of Regulation S-K, 17 C.F.R. sec. #229.601. KMI hereby agrees to furnish supplementally to the Securities and Exchange Commission a copy of each such instrument upon request.
10.1	*	KMI 2015 Amended and Restated Stock Incentive Plan (filed as Exhibit 4.5 to KMI's Registration Statement on Form S-8, filed on July 1, 2015 (File No. 333-205430))
10.2	*	Amendment No. 1 to KMI 2015 Amended and Restated Stock Incentive Plan (filed as Exhibit 10.2 to KMI's Current Report on Form 8-K filed on January 24, 2017 (File No. 001-35081))
10.3	*	Amendment No. 2 to KMI 2015 Amended and Restated Stock Incentive Plan (filed as Exhibit 10.2 to KMI's Quarterly Report on Form 10-Q for the three months ended June 30, 2018 (File No. 001-35081))
10.4	*	Amendment No. 3 to KMI 2015 Amended and Restated Stock Incentive Plan (filed as Exhibit 10.1 to KMI's Current Report on Form 8-K filed on January 22, 2019 (File No. 001-35081))
10.5	*	2015 Form of Employee Restricted Stock Unit Agreement (filed as Exhibit 4.6 to KMI's Registration Statement on Form S-8, filed on July 1, 2015 (File No. 333-205430))
10.6	*	2016 Form of Employee Restricted Stock Unit Agreement (filed as Exhibit 10.2 to KMI's Quarterly Report on Form 10-Q for the three months ended June 30, 2016 (File No. 001-35081))
10.7	*	2018 Form of Employee Restricted Stock Unit Agreement (filed as Exhibit 10.3 to KMI's Quarterly Report on Form 10-Q for the three months ended June 30, 2018 (File No. 001-35081))
10.8	*	Amended and Restated Stock Compensation Plan for Non-Employee Directors (filed as Exhibit 10.5 to KMI's Quarterly Report on Form 10-Q for the three months ended June 30, 2015 (File No. 001-35081))
10.9	*	2015 Form of Non-Employee Director Stock Compensation Agreement (filed as Exhibit 10.6 to KMI's Quarterly Report on Form 10-Q for the three months ended June 30, 2015 (File No. 001-35081))
10.10	*	2011 Form of Non-Employee Director Stock Compensation Agreement (filed as Exhibit 10.3 to KMI's Quarterly Report on Form 10-Q for the three months ended March 31, 2011 (File No. 001-35081))
10.11	*	KMI Employees Stock Purchase Plan (filed as Exhibit 10.5 to KMI's Quarterly Report on Form 10-Q for the three months ended March 31, 2011 (File No. 001-35081))
10.12	*	Amended and Restated Annual Incentive Plan of KMI (filed as Exhibit 10.4 to KMI's Quarterly Report on Form 10-Q for the three months ended June 30, 2015 (File No. 001-35081))
10.13	*	Amendment No. 1 to Amended and Restated Incentive Plan of KMI (filed as Exhibit 10.1 to KMI's Current Report on Form 8-K filed January 24, 2017 (File No. 001-35081))

Exhibit Number	Description
10.14	Revolving Credit Agreement, dated November 16, 2018 among KMI, as borrower, Barclays Bank PLC, as administrative agent, and the lenders and issuing banks party thereto
10.15	364-Day Revolving Credit Agreement, dated November 16, 2018 among KMI, as borrower, Barclays Bank PLC, as administrative agent, and the lenders party thereto
10.16	Cross Guarantee Agreement, dated as of November 26, 2014 among KMI and certain of its subsidiaries with schedules updated as of December 31, 2018
21.1	Subsidiaries of KMI
23.1	Consent of PricewaterhouseCoopers LLP
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101	Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Statements of Income for the years ended December 31, 2018, 2017, and 2016; (ii) our Consolidated Statements of Comprehensive Income for the years ended December 31, 2018, 2017, and 2016; (iii) our Consolidated Balance Sheets as of December 31, 2018 and 2017; (iv) our Consolidated Statements of Cash Flows for the years ended December 31, 2018, 2017, and 2016; (v) our Consolidated Statement of Stockholders' Equity as of and for the years ended December 31, 2018, 2017, and 2016; and (vi) the notes to our Consolidated Financial Statements

*Asterisk indicates exhibits incorporated by reference as indicated; all other exhibits are filed herewith, except as noted otherwise.

KINDER MORGAN, INC. AND SUBSIDIARIES
INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Kinder Morgan, Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Kinder Morgan, Inc. and its subsidiaries (the "Company") as of December 31, 2018 and 2017 and the related consolidated statements of income, comprehensive income, cash flows, and stockholders' equity for each of the three years in the period ended December 31, 2018, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017**,** and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and

expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/PricewaterhouseCoopers LLP

Houston, Texas
February 8, 2019

We have served as the Company's auditor since 1997.

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(In Millions, Except Per Share Amounts)

	Year Ended December 31,		
	2018	**2017**	**2016**
Revenues			
Natural gas sales	$ 3,281	$ 3,053	$ 2,454
Services	7,931	7,901	8,146
Product sales and other	2,932	2,751	2,458
Total Revenues	14,144	13,705	13,058
Operating Costs, Expenses and Other			
Costs of sales	4,421	4,345	3,429
Operations and maintenance	2,522	2,472	2,372
Depreciation, depletion and amortization	2,297	2,261	2,209
General and administrative	601	688	703
Taxes, other than income taxes	345	398	421
Loss on impairments and divestitures, net	167	13	387
Other income, net	(3)	(1)	(1)
Total Operating Costs, Expenses and Other	10,350	10,176	9,520
Operating Income	3,794	3,529	3,538
Other Income (Expense)			
Earnings from equity investments	887	578	497
Loss on impairments and divestitures of equity investments, net	(270)	(150)	(610)
Amortization of excess cost of equity investments	(95)	(61)	(59)
Interest, net	(1,917)	(1,832)	(1,806)
Other, net	107	97	78
Total Other Expense	(1,288)	(1,368)	(1,900)
Income Before Income Taxes	2,506	2,161	1,638
Income Tax Expense	(587)	(1,938)	(917)
Net Income	1,919	223	721
Net Income Attributable to Noncontrolling Interests	(310)	(40)	(13)
Net Income Attributable to Kinder Morgan, Inc.	1,609	183	708
Preferred Stock Dividends	(128)	(156)	(156)
Net Income Available to Common Stockholders	$ 1,481	$ 27	$ 552
Class P Shares			
Basic and Diluted Earnings Per Common Share	$ 0.66	$ 0.01	$ 0.25
Basic and Diluted Weighted Average Common Shares Outstanding	2,216	2,230	2,230
Dividends Per Common Share Declared for the Period	$ 0.80	$ 0.50	$ 0.50

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In Millions)

	Year Ended December 31,		
	2018	**2017**	**2016**
Net income	$ 1,919	$ 223	$ 721
Other comprehensive income (loss), net of tax			
Change in fair value of hedge derivatives (net of tax (expense) benefit of $(34), $(82) and $60, respectively)	111	145	(104)
Reclassification of change in fair value of derivatives to net income (net of tax (expense) benefit of $(25), $97 and $67, respectively)	84	(171)	(116)
Foreign currency translation adjustments (net of tax expense of $16, $56 and $20, respectively)	141	101	34
Benefit plan adjustments (net of tax (expense) benefit of $(11), $(27) and $19, respectively)	2	40	(14)
Total other comprehensive income (loss)	338	115	(200)
Comprehensive income	2,257	338	521
Comprehensive income attributable to noncontrolling interests	(328)	(86)	(13)
Comprehensive income attributable to KMI	$ 1,929	$ 252	$ 508

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In Millions, Except Share and Per Share Amounts)

	December 31,	
	2018	2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 3,280	$ 264
Restricted deposits	51	62
Accounts receivable, net	1,498	1,448
Fair value of derivative contracts	260	114
Inventories	385	424
Income tax receivable	23	165
Other current assets	225	238
Total current assets	5,722	2,715
Property, plant and equipment, net	37,897	40,155
Investments	7,481	7,298
Goodwill	21,965	22,162
Other intangibles, net	2,880	3,099
Deferred income taxes	1,566	2,044
Deferred charges and other assets	1,355	1,582
Total Assets	$ 78,866	$ 79,055
LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current portion of debt	$ 3,388	$ 2,828
Accounts payable	1,337	1,340
Distributions payable to KML noncontrolling interests	876	—
Accrued interest	579	621
Accrued taxes	483	256
Accrued contingencies	88	291
Other current liabilities	806	845
Total current liabilities	7,557	6,181
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding	33,105	33,988
Preferred interest in general partner of KMP	100	100
Debt fair value adjustments	731	927
Total long-term debt	33,936	35,015
Other long-term liabilities and deferred credits	2,176	2,735
Total long-term liabilities and deferred credits	36,112	37,750
Total Liabilities	43,669	43,931
Commitments and contingencies (Notes 9, 13 and 18)		
Redeemable Noncontrolling Interest	666	—
Stockholders' Equity		
Preferred stock, $0.01 par value, 10,000,000 shares authorized, 9.75% Series A Mandatory Convertible, $1,000 per share liquidation preference, - and 1,600,000 shares, respectively, issued and outstanding	—	—
Class P shares, $0.01 par value, 4,000,000,000 shares authorized, 2,262,165,783 and 2,217,110,072 shares, respectively, issued and outstanding	23	22
Additional paid-in capital	41,701	41,909
Retained deficit	(7,716)	(7,754)
Accumulated other comprehensive loss	(330)	(541)
Total Kinder Morgan, Inc.'s stockholders' equity	33,678	33,636
Noncontrolling interests	853	1,488
Total Stockholders' Equity	34,531	35,124
Total Liabilities, Redeemable Noncontrolling Interest and Stockholders' Equity	$ 78,866	$ 79,055

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Millions)

	Year Ended December 31,		
	2018	2017	2016
Cash Flows From Operating Activities			
Net income	$ 1,919	$ 223	$ 721
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	2,297	2,261	2,209
Deferred income taxes	405	2,073	1,087
Amortization of excess cost of equity investments	95	61	59
Change in fair market value of derivative contracts	77	40	64
Loss (gain) on early extinguishment of debt	—	4	(45)
Loss on impairments and divestitures, net (Note 4)	167	13	387
Loss on impairments and divestitures of equity investments, net (Note 4)	270	150	610
Earnings from equity investments	(887)	(578)	(497)
Distributions of equity investment earnings	499	426	431
Changes in components of working capital, net of the effects of acquisitions and dispositions			
Accounts receivable, net	(50)	(78)	(107)
Income tax receivable	137	7	(148)
Inventories	15	(90)	49
Other current assets	(16)	(25)	(81)
Accounts payable	21	73	144
Accrued interest, net of interest rate swaps	(22)	10	(18)
Accrued taxes	241	(37)	31
Accrued contingencies and other current liabilities	73	138	11
Rate reparations, refunds and other litigation reserve adjustments	(202)	(100)	(32)
Other, net	4	30	(117)
Net Cash Provided by Operating Activities	5,043	4,601	4,758
Cash Flows From Investing Activities			
Proceeds from the TMPL Sale, net of cash disposed (Note 3)	2,998	—	—
Acquisitions of assets and investments	(39)	(4)	(333)
Capital expenditures	(2,904)	(3,188)	(2,882)
Proceeds from sale of equity interests in subsidiaries, net	—	—	1,401
Proceeds from sales of equity investments	124	—	—
Sales of property, plant and equipment, investments, and other net assets, net of removal costs	(20)	118	330
Contributions to investments	(433)	(684)	(408)
Distributions from equity investments in excess of cumulative earnings	237	374	231
Loans (to) from related parties	(31)	(23)	35
Other, net	—	4	1
Net Cash Used in Investing Activities	(68)	(3,403)	(1,625)
Cash Flows From Financing Activities			
Issuances of debt	14,751	8,868	8,629
Payments of debt	(14,591)	(11,064)	(10,060)
Debt issue costs	(42)	(70)	(19)
Cash dividends - common shares (Note 11)	(1,618)	(1,120)	(1,118)
Cash dividends - preferred shares (Note 11)	(156)	(156)	(154)
Repurchases of common shares (Note 11)	(273)	(250)	—
Contributions from investment partner	181	485	—
Contributions from noncontrolling interests - net proceeds from KML IPO (Note 3)	—	1,245	—
Contributions from noncontrolling interests - net proceeds from KML preferred share issuances (Note 11)	—	420	—
Contributions from noncontrolling interests - other	19	12	117
Distributions to noncontrolling interests	(78)	(42)	(24)
Other, net	(17)	(9)	(8)
Net Cash Used in Financing Activities	(1,824)	(1,681)	(2,637)
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Deposits	(146)	22	2
Net increase (decrease) in Cash, Cash Equivalents and Restricted Deposits	3,005	(461)	498
Cash, Cash Equivalents, and Restricted Deposits, beginning of period	326	787	289
Cash, Cash Equivalents, and Restricted Deposits, end of period	$ 3,331	$ 326	$ 787

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)
(In Millions)

	Year Ended December 31,		
	2018	2017	2016
Cash and Cash Equivalents, beginning of period	$ 264	$ 684	$ 229
Restricted Deposits, beginning of period	62	103	60
Cash, Cash Equivalents, and Restricted Deposits, beginning of period	326	787	289
Cash and Cash Equivalents, end of period	3,280	264	684
Restricted Deposits, end of period	51	62	103
Cash, Cash Equivalents, and Restricted Deposits, end of period	3,331	326	787
Net increase (decrease) in Cash, Cash Equivalents and Restricted Deposits	$ 3,005	$ (461)	$ 498
Noncash Investing and Financing Activities			
Assets acquired by the assumption or incurrence of liabilities	$ —	$ —	$ 43
Net assets contributed to equity investments	—	—	37
Increase in property, plant and equipment from both accruals and contractor retainage	30	14	
Decrease in noncontrolling interests for distribution accrual	905	—	—
Supplemental Disclosures of Cash Flow Information			
Cash paid during the period for interest (net of capitalized interest)	1,879	1,854	2,050
Cash (refunded) paid during the period for income taxes, net	(109)	(140)	4

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In Millions)

	Common stock		Preferred stock							
	Issued shares	Par value	Issued shares	Par value	Additional paid-in capital	Retained deficit	Accumulated other comprehensive loss	Stockholders' equity attributable to KMI	Non-controlling interests	Total
Balance at December 31, 2015	2,229	$ 22	2	$ —	$ 41,661	$ (6,103)	$ (461)	$ 35,119	$ 284	$35,403
Restricted shares	1				66			66		66
Net income						708		708	13	721
Distributions								—	(24)	(24)
Contributions								—	117	117
Preferred stock dividends						(156)		(156)		(156)
Common stock dividends						(1,118)		(1,118)		(1,118)
Other					12			12	(19)	(7)
Other comprehensive loss							(200)	(200)		(200)
Balance at December 31, 2016	2,230	22	2	—	41,739	(6,669)	(661)	34,431	371	34,802
Repurchases of shares	(14)				(250)			(250)		(250)
Restricted shares	1				65			65		65
Net income						183		183	40	223
KML IPO					314		51	365	684	1,049
KML preferred share issuance								—	419	419
Reorganization of foreign subsidiaries					38			38		38
Distributions								—	(48)	(48)
Contributions								—	18	18
Preferred stock dividends						(156)		(156)		(156)
Common stock dividends						(1,120)		(1,120)		(1,120)
Sale and deconsolidation of interest in Deeprock Development, LLC								—	(30)	(30)
Other					3	8		11	(12)	(1)
Other comprehensive income							69	69	46	115
Balance at December 31, 2017	2,217	22	2	—	$ 41,909	$ (7,754)	$ (541)	$ 33,636	$ 1,488	35,124
Impact of adoption of ASUs (Note 2)						175	(109)	66		66
Balance at January 1, 2018	2,217	22	2	—	41,909	(7,579)	(650)	33,702	1,488	35,190
Repurchases of shares	(15)				(273)			(273)		(273)
Mandatory conversion of preferred shares	58	1	(2)		(1)			—		—
Restricted shares	2				65			65		65
Net income						1,609		1,609	310	1,919
Distributions								—	(997)	(997)
Contributions								—	33	33
Preferred stock dividends						(128)		(128)		(128)
Common stock dividends						(1,618)		(1,618)		(1,618)
Other					1			1	1	2
Other comprehensive income							320	320	18	338
Balance at December 31, 2018	2,262	$ 23	—	$ —	$ 41,701	$ (7,716)	$ (330)	$ 33,678	$ 853	$34,531

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. General

We are one of the largest energy infrastructure companies in North America and unless the context requires otherwise, references to "we," "us," "our," "the Company," or "KMI" are intended to mean Kinder Morgan, Inc. and its consolidated subsidiaries. Our pipelines transport natural gas, refined petroleum products, crude oil, condensate, CO_2 and other products, and our terminals transload and store liquid commodities including petroleum products, ethanol and chemicals, and bulk products, including petroleum coke, metals and ores.

Our common stock trades on the NYSE under the symbol "KMI."

2. Summary of Significant Accounting Policies

Basis of Presentation

Our reporting currency is U.S. dollars, and all references to dollars are U.S. dollars, unless stated otherwise. Our accompanying consolidated financial statements have been prepared under the rules and regulations of the SEC. These rules and regulations conform to the accounting principles contained in the FASB's Accounting Standards Codification (ASC), the single source of GAAP. Under such rules and regulations, all significant intercompany items have been eliminated in consolidation. Additionally, certain amounts from prior years have been reclassified to conform to the current presentation.

Adoption of New Accounting Pronouncements

On January 1, 2018, we adopted Accounting Standards Updates (ASU) No. 2014-09, "*Revenue from Contracts with Customers*" and a series of related accounting standard updates designed to create improved revenue recognition and disclosure comparability in financial statements. For more information, see "*—Revenue Recognition*" below and Note 16.

On January 1, 2018, we retroactively adopted ASU No. 2016-18, "*Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force).*" This ASU requires the statements of cash flows to present the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents are now included with cash and cash equivalents when reconciling the beginning of period and end of period amounts presented on the statements of cash flows. The retrospective application of this new accounting guidance resulted in an increase of $41 million and a decrease of $43 million in "Net increase (decrease) in Cash, Cash Equivalents and Restricted Deposits", no change and a decrease of $37 million in "Accrued contingencies and other current liabilities" in Cash Flows from Operating Activities, and a decrease of $41 million and an increase of $80 million in "Other, net" in Cash Flows from Investing Activities in our accompanying consolidated statement of cash flows for the years ended December 31, 2017 and 2016, respectively, from what was previously presented in our Annual Report on Form 10-K for the year ended December 31, 2017.

Amounts included in the restricted deposits in the accompanying consolidated financial statements represent a combination of restricted cash amounts required to be set aside by regulatory agencies to cover obligations for our captive and other insurance subsidiaries, and cash margin deposits posted by us with our counterparties associated with certain energy commodity contract positions.

On January 1, 2018, we adopted ASU No. 2017-05, "*Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets*." This ASU clarifies the scope and application of ASC 610-20 on contracts for the sale or transfer of nonfinancial assets and in substance nonfinancial assets to noncustomers, including partial sales. This ASU also clarifies that the derecognition of all businesses is in the scope of ASC 810 and defines an "in substance nonfinancial asset." We utilized the modified retrospective method to adopt the provisions of this ASU, which required us to apply the new standard to (i) all new contracts entered into after January 1, 2018, and (ii) to contracts that were not completed contracts as of January 1, 2018 through a cumulative adjustment to our "Retained deficit" balance. The cumulative effect of the adoption of this ASU was a $66 million, net of income taxes, adjustment to our "Retained deficit" balance as presented in our consolidated statement of stockholders' equity for the year ended December 31, 2018. This ASU also requires us to classify EIG Global Energy Partners' (EIG) cumulative contribution to ELC as mezzanine equity, which we have included as "Redeemable noncontrolling interest" on our consolidated balance sheet as of December 31, 2018, as EIG has the right under certain

conditions to redeem their interests for cash. The December 31, 2017 balance of $485 million is included in "Other long-term liabilities and deferred credits" on our consolidated balance sheet as of December 31, 2017.

On January 1, 2018, we adopted ASU No. 2017-07, "*Compensation - Retirement Benefits (Topic 715)*." This ASU requires an employer to disaggregate the service cost component from the other components of net benefit cost, allows only the service cost component of net benefit cost to be eligible for capitalization and establishes how to present the service cost component and the other components of net benefit cost in the income statement. Topic 715 required us to retrospectively reclassify $15 million and $34 million of other components of net benefit credits (excluding the service cost component) from "General and administrative" to "Other, net" in our accompanying consolidated statements of income for the years ended December 31, 2017 and 2016, respectively. We prospectively applied Topic 715 related to net benefit costs eligible for capitalization.

On January 1, 2018, we adopted ASU No. 2018-02, "*Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income*." Our accounting policy for the release of stranded tax effects in accumulated other comprehensive income is on an aggregate portfolio basis. This ASU permits companies to reclassify the income tax effects of the 2017 Tax Reform on items within accumulated other comprehensive income to retained earnings. The FASB refers to these amounts as "stranded tax effects." Only the stranded tax effects resulting from the 2017 Tax Reform are eligible for reclassification. The adoption of this ASU resulted in a $109 million reclassification adjustment of stranded income tax effects from "Accumulated other comprehensive loss" to "Retained deficit" on our consolidated statement of stockholders' equity for the year ended December 31, 2018.

Use of Estimates

Certain amounts included in or affecting our financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions which cannot be known with certainty at the time our financial statements are prepared. These estimates and assumptions affect the amounts we report for assets and liabilities, our revenues and expenses during the reporting period, and our disclosures, including as it relates to contingent assets and liabilities at the date of our financial statements. We evaluate these estimates on an ongoing basis, utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Certain accounting policies are of more significance in our financial statement preparation process than others, and set out below are the principal accounting policies we apply in the preparation of our consolidated financial statements.

Cash Equivalents and Restricted Deposits

We define cash equivalents as all highly liquid short-term investments with original maturities of three months or less.

Restricted deposits were $51 million and $62 million as of December 31, 2018 and 2017, respectively.

Accounts Receivable, net

The amounts reported as "Accounts receivable, net" on our accompanying consolidated balance sheets as of December 31, 2018 and 2017 primarily consist of amounts due from customers net of the allowance for doubtful accounts.

Our policy for determining an appropriate allowance for doubtful accounts varies according to the type of business being conducted and the customers being served. Generally, we make periodic reviews and evaluations of the appropriateness of the allowance for doubtful accounts based on a historical analysis of uncollected amounts, and we record adjustments as necessary for changed circumstances and customer-specific information. When specific receivables are determined to be uncollectible, the reserve and receivable are relieved.

The allowance for doubtful accounts was $3 million and $35 million as of December 31, 2018 and 2017, respectively.

Inventories

Our inventories consist of materials and supplies and products such as, NGL, crude oil, condensate, refined petroleum products, transmix and natural gas. We report products inventory at the lower of weighted-average cost or net realizable

value. We report materials and supplies inventories at cost, and periodically review for physical deterioration and obsolescence.

Property, Plant and Equipment, net

Capitalization, Depreciation and Depletion and Disposals

We report property, plant and equipment at its acquisition cost. We expense costs for routine maintenance and repairs in the period incurred.

We generally compute depreciation using either the straight-line method based on estimated economic lives or the composite depreciation method, which applies a single depreciation rate for a group of assets. Generally, we apply composite depreciation rates to functional groups of property having similar economic characteristics. The rates range from 1.01% to 23.0% excluding certain short-lived assets such as vehicles. For FERC-regulated entities, the FERC-accepted composite depreciation rate is applied to the total cost of the composite group until the net book value equals the salvage value. For other entities, depreciation estimates are based on various factors, including age (in the case of acquired assets), manufacturing specifications, technological advances, estimated production life of the oil or gas field served by the asset, contract term for assets on leased or customer property and historical data concerning useful lives of similar assets. Uncertainties that impact these estimates include changes in laws and regulations relating to restoration and abandonment requirements, economic conditions, and supply and demand in the area. When these assets are put into service, we make estimates with respect to useful lives (and salvage values where appropriate) that we believe are reasonable. Subsequent events could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization expense. Historically, adjustments to useful lives have not had a material impact on our aggregate depreciation levels from year to year.

Our oil and gas producing activities are accounted for under the successful efforts method of accounting. Under this method costs that are incurred to acquire leasehold and subsequent development costs are capitalized. Costs that are associated with the drilling of successful exploration wells are capitalized if proved reserves are found. Costs associated with the drilling of exploratory wells that do not find proved reserves, geological and geophysical costs, and costs of certain non-producing leasehold costs are expensed as incurred. The capitalized costs of our producing oil and gas properties are depreciated and depleted by the units-of-production method. Other miscellaneous property, plant and equipment are depreciated over the estimated useful lives of the asset.

We engage in enhanced recovery techniques in which CO_2 is injected into certain producing oil reservoirs. In some cases, the cost of the CO_2 associated with enhanced recovery is capitalized as part of our development costs when it is injected. The cost of CO_2 associated with pressure maintenance operations for reservoir management is expensed when it is injected. When CO_2 is recovered in conjunction with oil production, it is extracted and re-injected, and all of the associated costs are expensed as incurred. Proved developed reserves are used in computing units of production rates for drilling and development costs, and total proved reserves are used for depletion of leasehold costs.

A gain on the sale of property, plant and equipment used in our oil and gas producing activities or in our bulk and liquids terminal activities is calculated as the difference between the cost of the asset disposed of, net of depreciation, and the sales proceeds received. A gain on an asset disposal is recognized in income in the period that the sale is closed. A loss on the sale of property, plant and equipment is calculated as the difference between the cost of the asset disposed of, net of depreciation, and the sales proceeds received or the market value if the asset is being held for sale. A loss is recognized when the asset is sold or when the net cost of an asset held for sale is greater than the market value of the asset. For our pipeline system assets under the composite method of depreciation, we generally charge the original cost of property sold or retired to accumulated depreciation and amortization, net of salvage and cost of removal. Gains and losses are booked for FERC-approved operating unit sales and land sales and are recorded to income or expense accounts in accordance with regulatory accounting guidelines. In those instances where we receive recovery in tariff rates related to losses on dispositions of operating units, we record a regulatory asset for the estimated recoverable amount.

Asset Retirement Obligations

We record liabilities for obligations related to the retirement and removal of long-lived assets used in our businesses. We record, as liabilities, the fair value of asset retirement obligations on a discounted basis when they are incurred and can be reasonably estimated, which is typically at the time the assets are installed or acquired. Amounts recorded for the related assets are increased by the amount of these obligations. Over time, the liabilities increase due to the

change in their present value, and the initial capitalized costs are depreciated over the useful lives of the related assets. The liabilities are eventually extinguished when the asset is taken out of service.

We have various other obligations throughout our businesses to remove facilities and equipment on rights-of-way and other leased facilities. We currently cannot reasonably estimate the fair value of these obligations because the associated assets have indeterminate lives. These assets include pipelines, certain processing plants and distribution facilities, and certain bulk and liquids terminal facilities. An asset retirement obligation, if any, will be recognized once sufficient information is available to reasonably estimate the fair value of the obligation.

Long-lived Asset and Other Intangibles Impairments

We evaluate long-lived assets and investments for impairment whenever events or changes in circumstances indicate that our carrying amount of an asset or investment may not be recoverable. We recognize impairment losses when estimated future cash flows expected to result from our use of the asset and its eventual disposition is less than its carrying amount.

In addition to our annual goodwill impairment test, to the extent triggering events exist, we complete a review of the carrying value of our long-lived assets, including property, plant and equipment as well as other intangibles, and record, as applicable, the appropriate impairments. Because the impairment test for long-lived assets held in use is based on undiscounted cash flows, there may be instances where an asset or asset group is not considered impaired, even when its fair value may be less than its carrying value, because the asset or asset group is recoverable based on the cash flows to be generated over the estimated life of the asset or asset group. If the carrying value of a long-lived asset or asset group is in excess of undiscounted cash flows, we typically use discounted cash flow analyses to determine if an impairment is required.

We evaluate our oil and gas producing properties for impairment of value on a field-by-field basis or, in certain instances, by logical grouping of assets if there is significant shared infrastructure, using undiscounted future cash flows based on total proved and risk-adjusted probable reserves.

Oil and gas producing properties deemed to be impaired are written down to their fair value, as determined by discounted future cash flows based on total proved and risk-adjusted probable and possible reserves or, if available, comparable market values. Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment.

Equity Method of Accounting and Excess Investment Cost

We account for investments which we do not control, but do have the ability to exercise significant influence using the equity method of accounting. Under this method, our equity investments are carried originally at our acquisition cost, increased by our proportionate share of the investee's net income and by contributions made, and decreased by our proportionate share of the investee's net losses and by distributions received.

With regard to our equity investments in unconsolidated affiliates, in almost all cases, either (i) the price we paid to acquire our share of the net assets of such equity investees or (ii) the revaluation of our share of the net assets of any retained noncontrolling equity investment (from the sale of a portion of our ownership interest in a consolidated subsidiary, thereby losing our controlling financial interest in the subsidiary) differed from the underlying carrying value of such net assets. This differential consists of two pieces. First, an amount related to the difference between the investee's recognized net assets at book value and at current fair values (representing the appreciated value in plant and other net assets), and secondly, to any premium in excess of fair value (referred to as equity method goodwill) we paid to acquire the investment. We include both amounts within "Investments" on our accompanying consolidated balance sheets.

The first differential, representing the excess of the fair market value of our investees' plant and other net assets over its underlying book value at either the date of acquisition or the date of the loss of control totaled $470 million and $732 million as of December 31, 2018 and 2017, respectively. Generally, this basis difference relates to our share of the underlying depreciable assets, and, as such, we amortize this portion of our investment cost against our share of investee earnings. As of December 31, 2018, this excess investment cost is being amortized over a weighted average life of approximately twelve years.

The second differential, representing equity method goodwill, totaled $1,967 million for both periods as of December 31, 2018 and 2017. This differential is not subject to amortization but rather to impairment testing as part of our periodic evaluation of the recoverability of our investment as compared to the fair value of net assets accounted for under the

equity method. Our impairment test considers whether the fair value of the equity investment as a whole has declined and whether that decline is other than temporary.

Goodwill

Goodwill is the cost of an acquisition in excess of the fair value of acquired assets and liabilities and is recorded as an asset on our balance sheet. Goodwill is not subject to amortization but must be tested for impairment at least annually. This test requires us to assign goodwill to an appropriate reporting unit and to determine if the implied fair value of the reporting unit's goodwill is less than its carrying amount.

We evaluate goodwill for impairment on May 31 of each year. For this purpose, prior to the TMPL Sale we had seven reporting units as follows: (i) Products Pipelines (excluding associated terminals); (ii) Products Pipelines Terminals (evaluated separately from Products Pipelines for goodwill purposes); (iii) Natural Gas Pipelines Regulated; (iv) Natural Gas Pipelines Non-Regulated; (v) CO_2; (vi) Terminals; and (vii) Kinder Morgan Canada. Subsequent to the TMPL Sale, Kinder Morgan Canada is no longer a reporting unit. We also evaluate goodwill for impairment to the extent events or conditions indicate a risk of possible impairment during the interim periods subsequent to our annual impairment test. Generally, the evaluation of goodwill for impairment involves a two-step test, although under certain circumstance an initial qualitative evaluation may be sufficient to conclude that goodwill is not impaired without conducting the quantitative test.

Step 1 involves comparing the estimated fair value of each respective reporting unit to its carrying value, including goodwill. If the estimated fair value exceeds the carrying value, the reporting unit's goodwill is not considered impaired. If the carrying value exceeds the estimated fair value, step 2 must be performed to determine whether goodwill is impaired and, if so, the amount of the impairment. Step 2 involves calculating an implied fair value of goodwill by performing a hypothetical allocation of the estimated fair value of the reporting unit determined in step 1 to the respective tangible and intangible net assets of the reporting unit. The remaining implied goodwill is then compared to the actual carrying amount of the goodwill for the reporting unit. To the extent the carrying amount of goodwill exceeds the implied goodwill, the difference is the amount of the goodwill impairment.

A large portion of our goodwill is non-deductible for tax purposes, and as such, to the extent there are impairments, all or a portion of the impairment may not result in a corresponding tax benefit.

Refer to Note 8 for further information.

Other Intangibles

Excluding goodwill, our other intangible assets include customer contracts, relationships and agreements, and technology-based assets. As of both December 31, 2018 and 2017, the gross carrying amounts of these intangible assets was $4,305 million and the accumulated amortization was $1,425 million and $1,206 million, respectively, resulting in net carrying amounts of $2,880 million and $3,099 million, respectively. These intangible assets primarily consisted of customer contracts, relationships and agreements associated with our Natural Gas Pipelines and Terminals business segments.

Primarily, these contracts, relationships and agreements relate to the gathering of natural gas, and the handling and storage of petroleum, chemical, and dry-bulk materials, including oil, gasoline and other refined petroleum products, petroleum coke, metals and ores. We determined the values of these intangible assets by first, estimating the revenues derived from a customer contract or relationship (offset by the cost and expenses of supporting assets to fulfill the contract), and second, discounting the revenues at a risk adjusted discount rate.

We amortize the costs of our intangible assets to expense in a systematic and rational manner over their estimated useful lives. The life of each intangible asset is based either on the life of the corresponding customer contract or agreement or, in the case of a customer relationship intangible (the life of which was determined by an analysis of all available data on that business relationship), the length of time used in the discounted cash flow analysis to determine the value of the customer relationship. Among the factors we weigh, depending on the nature of the asset, are the effect of obsolescence, new technology, and competition.

For the years ended December 31, 2018, 2017 and 2016, the amortization expense on our intangibles totaled $219 million, $220 million and $223 million, respectively. Our estimated amortization expense for our intangible assets for each of the next five fiscal years (2019 – 2023) is approximately $213 million, $209 million, $209 million, $207 million, and $203 million, respectively. As of December 31, 2018, the weighted average amortization period for our intangible assets was approximately fifteen years.

Revenue Recognition

Revenue from Contracts with Customers

Beginning in 2018, we account for revenue from contracts with customers in accordance with Accounting Standards Updates ASU No. 2014-09, "*Revenue from Contracts with Customers*" and a series of related accounting standard updates (Topic 606). The unit of account in Topic 606 is a performance obligation, which is a promise in a contract to transfer to a customer either a distinct good or service (or bundle of goods or services) or a series of distinct goods or services provided over a period of time. Topic 606 requires that a contract's transaction price, which is the amount of consideration to which an entity expects to be entitled in exchange for transferring promised goods or services to a customer, is to be allocated to each performance obligation in the contract based on relative standalone selling prices and recognized as revenue when (point in time) or as (over time) control of the goods or services transfers to the customer and the performance obligation is satisfied.

Our customer sales contracts primarily include natural gas sales, NGL sales, crude oil sales, CO_2 sales, and transmix sales contracts, as described below. Generally, for the majority of these contracts: (i) each unit (Mcf, gallon, barrel, etc.) of commodity is a separate performance obligation, as our promise is to sell multiple distinct units of commodity at a point in time; (ii) the transaction price principally consists of variable consideration, which amount is determinable each month end based on our right to invoice at month end for the value of commodity sold to the customer that month; and (iii) the transaction price is allocated to each performance obligation based on the commodity's standalone selling price and recognized as revenue upon delivery of the commodity, which is the point in time when the customer obtains control of the commodity and our performance obligation is satisfied.

Our customer services contracts primarily include transportation service, storage service, gathering and processing service, and terminaling service contracts, as described below. Generally, for the majority of these contracts: (i) our promise is to transfer (or stand ready to transfer) a series of distinct integrated services over a period of time, which is a single performance obligation; (ii) the transaction price includes fixed and/or variable consideration, which amount is determinable at contract inception and/or at each month end based on our right to invoice at month end for the value of services provided to the customer that month; and (iii) the transaction price is recognized as revenue over the service period specified in the contract (which can be a day, including each day in a series of promised daily services, a month, a year, or other time increment, including a deficiency makeup period) as the services are rendered using a time-based (passage of time) or units-based (units of service transferred) output method for measuring the transfer of control of the services and satisfaction of our performance obligation over the service period, based on the nature of the promised service (e.g., firm or non-firm) and the terms and conditions of the contract (e.g., contracts with or without makeup rights).

Firm Services

Firm services (also called uninterruptible services) are services that are promised to be available to the customer at all times during the period(s) covered by the contract, with limited exceptions. Our firm service contracts are typically structured with take-or-pay or minimum volume provisions, which specify minimum service quantities a customer will pay for even if it chooses not to receive or use them in the specified service period (referred to as "deficiency quantities"). We typically recognize the portion of the transaction price associated with such provisions, including any deficiency quantities, as revenue depending on whether the contract prohibits the customer from making up deficiency quantities in subsequent periods, or the contract permits this practice, as follows:

- *Contracts without Makeup Rights.* If contractually the customer cannot make up deficiency quantities in future periods, our performance obligation is satisfied, and revenue associated with any deficiency quantities is generally recognized as each service period expires. Because a service period may exceed a reporting period, we determine at inception of the contract and at the beginning of each subsequent reporting period if we expect the customer to take the minimum volume associated with the service period. If we expect the customer to make up all deficiencies in the specified service period (i.e., we expect the customer to take the minimum service quantities), the minimum volume provision is deemed not substantive and we will recognize the transaction price as revenue in the specified service period as the promised units of service are transferred to the customer. Alternatively, if we expect that there will be any deficiency quantities that the customer cannot or will not make up in the specified service period (referred to as "breakage"), we will recognize the estimated breakage amount (subject to the constraint on variable consideration) as revenue ratably over such service period in proportion to the revenue that we will recognize for actual units of service transferred to the customer in the service period. For certain take-or-pay contracts where we make the service, or a part of the service (e.g., reservation), continuously available over the service period, we typically recognize the take-or-pay amount as revenue ratably over such period based on the passage of time.

- *Contracts with Makeup Rights.* If contractually the customer can acquire the promised service in a future period and make up the deficiency quantities in such future period (the "deficiency makeup period"), we have a performance obligation to deliver those services at the customer's request (subject to contractual and/or capacity constraints) in the deficiency makeup period. At inception of the contract, and at the beginning of each subsequent reporting period, we estimate if we expect that there will be deficiency quantities that the customer will or will not make up. If we expect the customer will make up all deficiencies it is contractually entitled to, any non-refundable consideration received relating to temporary deficiencies that will be made up in the deficiency makeup period will be deferred as a contract liability, and we will recognize that amount as revenue in the deficiency makeup period when either of the following occurs: (i) the customer makes up the volumes or (ii) the likelihood that the customer will exercise its right for deficiency volumes then becomes remote (e.g., there is insufficient capacity to make up the volumes, the deficiency makeup period expires). Alternatively, if we expect at inception of the contract, or at the beginning of any subsequent reporting period, that there will be any deficiency quantities that the customer cannot or will not make up (i.e., breakage), we will recognize the estimated breakage amount (subject to the constraint on variable consideration) as revenue ratably over the specified service periods in proportion to the revenue that we will recognize for actual units of service transferred to the customer in those service periods.

Non-Firm Services

Non-firm services (also called interruptible services) are the opposite of firm services in that such services are provided to a customer on an "as available" basis. Generally, we do not have an obligation to perform these services until we accept a customer's periodic request for service. For the majority of our non-firm service contracts, the customer will pay only for the actual quantities of services it chooses to receive or use, and we typically recognize the transaction price as revenue as those units of service are transferred to the customer in the specified service period (typically a daily or monthly period).

Refer to Note 16 for further information.

Revenue Recognition Policy prior to January 1, 2018

Prior to the implementation of Topic 606, we recognized revenue as services were rendered or goods were delivered and, if applicable, risk of loss had passed. We recognized natural gas, crude and NGL sales revenue when the commodity was sold to a purchaser at a fixed or determinable price, delivery had occurred and risk of loss had transferred, and collectability of the revenue was reasonably assured. Our sales and purchases of natural gas, crude and NGL were primarily accounted for on a gross basis as natural gas sales or product sales, as applicable, and cost of sales, except in circumstances where we solely acted as an agent and did not have price and related risk of ownership, in which case we recognized revenue on a net basis.

For revenues associated with our firm services as previously described, the fixed-fee component of the overall rate was recognized as revenue in the period the service was provided. The per-unit charge was recognized as revenue when the volumes were delivered to the customers' agreed upon delivery point, or when the volumes were injected into/withdrawn from our storage facilities.

Revenues associated with our non-firm services as previously described, were recognized in the same manner utilized for the per-unit rate for volumes actually transported under firm service agreements.

Revenues associated with our crude oil and refined petroleum products transportation and storage services were recorded when products were delivered and services had been provided, and adjusted according to terms prescribed by the toll settlements with shippers and approved by regulatory authorities.

We recognized bulk terminal transfer service revenues based on volumes loaded and unloaded. We recognized liquids terminal tank rental revenue ratably over the contract period. We recognized liquids terminal throughput revenue based on volumes received and volumes delivered. We recognized transmix processing revenues based on volumes processed or sold, and if applicable, when risk of loss had passed. We recognized energy-related product sales revenues based on delivered quantities of product.

Revenues from the sale of crude oil, NGL, CO2 and natural gas production within the CO2 business segment were recorded using the entitlement method, under which revenue was recorded when title passed based on our net interest. We recorded our entitled share of revenues based on entitled volumes and contracted sales prices. Since there was a ready

market for oil and gas production, we sold the majority of our products soon after production at various locations, at which time title and risk of loss had passed to the buyer.

Cost of Sales

Cost of sales primarily includes the cost of energy commodities sold, including natural gas, NGL and other refined petroleum products, adjusted for the effects of our energy commodity activities, as applicable, other than production from our CO_2 business segment.

Operations and Maintenance

Operations and maintenance include costs of services and is primarily comprised of (i) operational labor costs and (ii) operations, maintenance and asset integrity, regulatory and environmental costs. Costs associated with our oil, gas and CO_2 producing activities included within operations and maintenance totaled $363 million, $342 million and $349 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Environmental Matters

We capitalize or expense, as appropriate, environmental expenditures. We capitalize certain environmental expenditures required in obtaining rights-of-way, regulatory approvals or permitting as part of the construction. We accrue and expense environmental costs that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation. We generally do not discount environmental liabilities to a net present value, and we record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, our recording of these accruals coincides with our completion of a feasibility study or our commitment to a formal plan of action. We recognize receivables for anticipated associated insurance recoveries when such recoveries are deemed to be probable. We record at estimated fair value, where appropriate, environmental liabilities assumed in a business combination.

We routinely conduct reviews of potential environmental issues and claims that could impact our assets or operations. These reviews assist us in identifying environmental issues and estimating the costs and timing of remediation efforts. We also routinely adjust our environmental liabilities to reflect changes in previous estimates. In making environmental liability estimations, we consider the material effect of environmental compliance, pending legal actions against us, and potential third-party liability claims. Often, as the remediation evaluation and effort progresses, additional information is obtained, requiring revisions to estimated costs. These revisions are reflected in our income in the period in which they are reasonably determinable.

Pensions and Other Postretirement Benefits

We recognize the differences between the fair value of each of our and our consolidated subsidiaries' pension and other postretirement benefit plans' assets and the benefit obligations as either assets or liabilities on our consolidated balance sheet. We record deferred plan costs and income—unrecognized losses and gains, unrecognized prior service costs and credits, and any remaining unamortized transition obligations—in "Accumulated other comprehensive loss," with the proportionate share associated with less than wholly owned consolidated subsidiaries allocated and included within "Noncontrolling interests," or as a regulatory asset or liability for certain of our regulated operations, until they are amortized as a component of benefit expense.

Noncontrolling Interests

Noncontrolling interests represents the interests in our consolidated subsidiaries that are not owned by us. In our accompanying consolidated income statements, the noncontrolling interest in the net income of our consolidated subsidiaries is shown as an allocation of our consolidated net income and is presented separately as "Net Income Attributable to Noncontrolling Interests." In our accompanying consolidated balance sheets, noncontrolling interests is presented separately as "Noncontrolling interests" within "Stockholders' Equity."

Income Taxes

Income tax expense is recorded based on an estimate of the effective tax rate in effect or to be in effect during the relevant periods. Changes in tax legislation are included in the relevant computations in the period in which such changes are enacted. We do business in a number of states with differing laws concerning how income subject to each state's tax

structure is measured and at what effective rate such income is taxed. Therefore, we must make estimates of how our income will be apportioned among the various states in order to arrive at an overall effective tax rate. Changes in our effective rate, including any effect on previously recorded deferred taxes, are recorded in the period in which the need for such change is identified.

Deferred income tax assets and liabilities are recognized for temporary differences between the basis of assets and liabilities for financial reporting and tax purposes. Deferred tax assets are reduced by a valuation allowance for the amount that is, more likely than not, to not be realized. While we have considered estimated future taxable income and prudent and feasible tax planning strategies in determining the amount of our valuation allowance, any change in the amount that we expect to ultimately realize will be included in income in the period in which such a determination is reached.

In determining the deferred income tax asset and liability balances attributable to our investments, we apply an accounting policy that looks through our investments. The application of this policy resulted in no deferred income taxes being provided on the difference between the book and tax basis on the non-tax-deductible goodwill portion of our investments, including KMI's investment in its wholly-owned subsidiary, KMP.

Foreign Currency Transactions and Translation

Foreign currency transaction gains or losses result from a change in exchange rates between (i) the functional currency, for example the Canadian dollar for a Canadian subsidiary and (ii) the currency in which a foreign currency transaction is denominated, for example the U.S. dollar for a Canadian subsidiary. In our accompanying consolidated statements of income, gains and losses from our foreign currency transactions are included within "Other Income (Expense)—Other, net."

Foreign currency translation is the process of expressing, in U.S. dollars, amounts recorded in a local functional currency other than U.S. dollars, for example the Canadian dollar for a Canadian subsidiary. We translate the assets and liabilities of each of our consolidated foreign subsidiaries that have a local functional currency to U.S. dollars at year-end exchange rates. Income and expense items are translated at weighted-average rates of exchange prevailing during the year and stockholders' equity accounts are translated by using historical exchange rates. The cumulative translation adjustments balance is reported as a component of "Accumulated other comprehensive loss."

Risk Management Activities

We utilize energy commodity derivative contracts for the purpose of mitigating our risk resulting from fluctuations in the market price of commodities including natural gas, NGL and crude oil. In addition, we enter into interest rate swap agreements for the purpose of hedging the interest rate risk associated with our debt obligations. We also enter into cross-currency swap agreements to manage our foreign currency risk with certain debt obligations and net investments in foreign operations. We measure our derivative contracts at fair value and we report them on our balance sheet as either an asset or liability. For certain physical forward commodity derivatives contracts, we apply the normal purchase/normal sale exception, whereby the revenues and expenses associated with such transactions are recognized during the period when the commodities are physically delivered or received.

For qualifying accounting hedges, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives and the methods used for assessing and testing effectiveness, and how any ineffectiveness will be measured and recorded. If we designate a derivative contract as a cash flow accounting hedge, the effective portion of the change in fair value of the derivative is deferred in "Accumulated other comprehensive loss" and reclassified into earnings in the period in which the hedged item affects earnings. Any ineffective portion of the derivative's change in fair value or amount excluded from the assessment of hedge effectiveness is recognized currently in earnings. If we designate a derivative contract as a fair value accounting hedge, the effective portion of the change in fair value of the derivative is recorded as an adjustment to the item being hedged. Any ineffective portion of the derivative's change in fair value is recognized currently in earnings. If we designate a derivative contract as a net investment accounting hedge, the effective portion of the change in fair value of the derivative is reflected in the Cumulative Translation Adjustment (CTA) section of Other Comprehensive Income (OCI) on our consolidated statements of comprehensive income.

For derivative instruments that are not designated as accounting hedges, or for which we have not elected the normal purchase/normal sales exception, changes in fair value are recognized currently in earnings.

Regulatory Assets and Liabilities

Regulatory assets and liabilities represent probable future revenues or expenses associated with certain charges and credits that will be recovered from or refunded to customers through the ratemaking process. We included the amounts of our regulatory assets and liabilities within "Other current assets," "Deferred charges and other assets," "Other current liabilities" and "Other long-term liabilities and deferred credits," respectively, in our accompanying consolidated balance sheets.

The following table summarizes our regulatory asset and liability balances as of December 31, 2018 and 2017 (in millions):

	December 31,	
	2018	2017
Current regulatory assets	$ 66	$ 60
Non-current regulatory assets	245	288
Total regulatory assets(a)	$ 311	$ 348
Current regulatory liabilities	$ 29	$ 107
Non-current regulatory liabilities	206	236
Total regulatory liabilities(b)	$ 235	$ 343

(a) Regulatory assets as of December 31, 2018 include (i) $176 million of unamortized losses on disposal of assets; (ii) $53 million income tax gross up on equity AFUDC; and (iii) $82 million of other assets including amounts related to fuel tracker arrangements. Approximately $98 million of the regulatory assets, with a weighted average remaining recovery period of 23 years, are recoverable without earning a return, including the income tax gross up on equity AFUDC for which there is an offsetting deferred income tax balance for FERC rate base purposes; therefore, it does not earn a return.

(b) Regulatory liabilities as of December 31, 2018 are comprised of customer prepayments to be credited to shippers or other over-collections that are expected to be returned to shippers or netted against under-collections over time. Approximately $136 million of the $206 million classified as non-current is expected to be credited to shippers over a remaining weighted average period of 18 years, while the remaining $70 million is not subject to a defined period.

Earnings per Share

We calculate earnings per share using the two-class method. Earnings were allocated to Class P shares and participating securities based on the amount of dividends paid in the current period plus an allocation of the undistributed earnings or excess distributions over earnings to the extent that each security participates in earnings or excess distributions over earnings. Our unvested restricted stock awards, which may be restricted stock or restricted stock units issued to employees and non-employee directors and include dividend equivalent payments, do not participate in excess distributions over earnings.

The following table sets forth the allocation of net income available to shareholders of Class P shares and participating securities (in millions):

	Year Ended December 31,		
	2018	2017	2016
Net Income Available to Common Stockholders	$ 1,481	$ 27	$ 552
Participating securities:			
Less: Net Income Allocated to Restricted stock awards(a)	(8)	(5)	(4)
Net Income Allocated to Class P Stockholders	$ 1,473	$ 22	$ 548
Basic Weighted Average Common Shares Outstanding	2,216	2,230	2,230
Basic Earnings Per Common Share	$ 0.66	$ 0.01	$ 0.25

(a) As of December 31, 2018, there were approximately 13 million such restricted stock awards.

The following maximum number of potential common stock equivalents are antidilutive and, accordingly, are excluded from the determination of diluted earnings per share (in millions on a weighted average basis):

	Year Ended December 31,		
	2018	2017	2016
Unvested restricted stock awards	12	10	8
Warrants to purchase our Class P shares(a)		116	293
Convertible trust preferred securities	3	3	8
Mandatory convertible preferred stock(b)	48	58	58

(a) On May 25, 2017, approximately 293 million of unexercised warrants expired without the issuance of Class P common stock. Prior to expiration, each warrant entitled the holder to purchase one share of our common stock for an exercise price of $40 per share. The potential dilutive effect of the warrants did not consider the assumed proceeds to KMI upon exercise.

(b) The holder of each convertible preferred share participated in our earnings by receiving preferred stock dividends through the mandatory conversion date of October 26, 2018 at which time our convertible preferred shares were converted to common shares.

3. Divestitures and Acquisition

Sale of Trans Mountain Pipeline System and Its Expansion Project

On August 31, 2018, KML completed the sale of the TMPL, the TMEP, the Puget Sound pipeline system and Kinder Morgan Canada Inc., the Canadian employer of our staff that operate the business, which were indirectly acquired by the Government of Canada through Trans Mountain Corporation (a subsidiary of the Canada Development Investment Corporation) for cash consideration of C$4.43 billion (U.S.$3.4 billion), which is the contractual purchase price of C$4.5 billion net of a preliminary working capital adjustment (the "TMPL Sale"). These assets comprised our Kinder Morgan Canada business segment. We recognized a pre-tax gain from the TMPL Sale of $596 million within "Loss on impairments and divestitures, net" in our accompanying consolidated statement of income during the year ended December 31, 2018, including an incremental working capital adjustment of $26 million accrued as of December 31, 2018.

On January 3, 2019, pursuant to KML's shareholders' approval on November 29, 2018, KML distributed to its shareholders as a return of capital, the net proceeds from the TMPL Sale, after capital gains taxes, customary purchase price adjustments and the repayment of debt outstanding under a temporary KML credit facility (see Note 9, "*Debt—Credit Facilities and Restrictive Covenants—KML*"). KML's public owners of its restricted voting shares, reflected as noncontrolling interests by us, received approximately $0.9 billion (C$1.2 billion), and part of our approximate 70% portion of the net proceeds of $1.9 billion (C$2.5 billion) (after Canadian tax) were used to immediately repay our outstanding commercial paper borrowings of $0.4 billion and in February 2019, to pay down approximately $1.3 billion of maturing long-term debt. To facilitate the return of capital and provide flexibility for KML's dividends going forward, KML's shareholders also approved a reduction in the stated capital of its restricted voting shares by C$1.45 billion, which was recorded in the fourth quarter of 2018, along with a "reverse stock split" of KML's restricted voting shares, and KML's special voting shares that we own, on a one-for-three basis (three shares consolidating to one share) which occurred on January 4, 2019.

May 2017 Sale of Approximate 30% Interest in Canadian Business

On May 30, 2017, KML completed an IPO of 102,942,000 restricted voting shares listed on the Toronto Stock Exchange at a price to the public of C$17.00 per restricted voting share for total gross proceeds of approximately C$1,750 million (US $1,299 million). The net proceeds from the IPO were used by KML to indirectly acquire from us an approximate 30% interest in a limited partnership that holds our Canadian business while we retained the remaining 70% interest. We used the proceeds from KML's IPO to pay down debt.

Subsequent to the IPO, we retained control of KML and the limited partnership, and as a result, they remain consolidated in our consolidated financial statements. The public ownership of the KML restricted voting shares is reflected within "Noncontrolling interests" in our consolidated statements of stockholders' equity and consolidated balance sheets. Earnings attributable to the public ownership of KML are presented in "Net income attributable to noncontrolling interests" in our consolidated statements of income for the periods presented after May 30, 2017.

The net proceeds received of $1,245 million are presented as "Contributions from noncontrolling interests - net proceeds from KML IPO" on our consolidated statement of cash flows for the year ended December 31, 2017. Because we retained control of KML subsequent to the IPO, the $314 million adjustment made to "Additional paid-in capital" on our consolidated statement of stockholders equity for the year ended December 31, 2017 represents the difference between our book value prior

to the sale and our share of book value in KML's net assets after the sale. The impact of the IPO resulted in a $166 million deferred income tax adjustment. At the date of the IPO, $765 million was attributed to the KML public shareholders to reflect their proportionate ownership percentage in the net assets of KML acquired from us and is included in "Noncontrolling interests" on our consolidated statement of stockholders equity. The above amounts recorded to "Additional paid-in capital" and "Noncontrolling interests" are net of IPO fees.

In addition, the amount recorded to "Noncontrolling interests" at the date of the IPO was reduced by $81 million primarily associated with the allocation of currency translation adjustments from "Accumulated other comprehensive loss" to "Noncontrolling interests."

The portion of the Canadian business operations that we sold to the public on May 30, 2017 represented Canadian assets that were included in our Kinder Morgan Canada, Terminals and Product Pipelines business segments and include (i) the Trans Mountain pipeline system; (ii) the Canadian Cochin pipeline system; (iii) the Puget Sound pipeline system; (iv) the Jet Fuel pipeline system; and (v) terminal facilities located in Western Canada. In January 2018, KML completed the registration of its restricted voting shares pursuant to Section 12(g) of the United States Securities Exchange Act of 1934 (the "Exchange Act") and subsequently is subject to the reporting requirements of Section 13(a) of the Exchange Act.

In conjunction with the IPO, Kinder Morgan Canada Limited Partnership (KMC LP) and Kinder Morgan Canada GP Inc. (KMC GP) were formed to hold our Canadian business. We have determined that KMC LP is a variable interest entity because a simple majority or lower threshold of the limited partnership interests do not possess substantive "kick-out rights" (i.e., the right to remove the general partner or to dissolve (liquidate) the entity without cause) or substantive participation rights. We have also determined KMC GP is the primary beneficiary because it has the power to direct the activities that most significantly impact KMC LP's performance, the right to receive benefits and the obligation to absorb losses, that could be significant to KMC LP. As a result, KMC GP consolidates KMC LP. KMC GP is a wholly owned subsidiary of KML, which is indirectly controlled by us through our 100% interest in KML's special voting shares that represent approximately 70% of KML's total voting shares (comprised of restricted voting shares and special voting shares). Consequently, we consolidate KML and the variable interest entity, KMC LP, in our consolidated financial statements.

The following table shows the carrying amount and classification of KMC LP's assets and liabilities in our consolidated balance sheet (in millions):

	December 31,	
	2018	**2017**
Assets		
Total current assets	$ 3,204	$ 270
Property, plant and equipment, net	719	2,956
Total goodwill, deferred charges and other assets	8	322
Total assets	$ 3,931	$ 3,548
Liabilities		
Current portion of debt	$ —	$ —
Total other current liabilities	2,353	236
Long-term debt, excluding current maturities	—	—
Total other long-term liabilities and deferred credits	52	414
Total liabilities	$ 2,405	$ 650

We receive distributions from KMC LP through our indirectly owned limited partnership interests in KMC LP, but otherwise the assets of KMC LP cannot be used to settle our obligations other than those of KML. We do not guarantee the debt, commercial paper or other similar commitments of KMC LP or any of its subsidiaries, and the obligations of KMC LP may only be settled using the assets of KMC LP. KMC LP does not guarantee the debt or other similar commitments of KMI.

Sale of Noncontrolling Interest in ELC

Effective February 28, 2017, we sold a 49% partnership interest in ELC to investment funds managed by EIG. We continue to own a 51% controlling interest in and operate ELC. Under the terms of ELC's limited liability company agreement, we are responsible for placing in service and operating certain supply pipelines and terminal facilities that support the operations of ELC and that are wholly owned by us. In certain limited circumstances that are not expected to occur, EIG has the right to relinquish its interest in ELC and redeem its capital account. The sale proceeds of $386 million, and subsequent

EIG contributions, have been reflected as of December 31, 2018 within "Redeemable Noncontrolling Interest" and as of December 31, 2017, as a deferred credit within "Other long-term liabilities and deferred credits" on our consolidated balance sheets. Once these contingencies expire, EIG's capital account will be reflected in Noncontrolling interests on our consolidated balance sheet.

Terminals Asset Sale

In October 2016, we entered into a definitive agreement to sell several bulk terminals to an affiliate of Watco Companies, LLC for approximately $100 million. The terminals are predominantly located along the inland river system and handle mostly coal and steel products, and are included within our Terminals business segment. The sale of eight of the locations closed in the fourth quarter of 2016, for which we received $37 million of the total consideration, and the balance of this transaction, which included an additional eleven locations, closed in the second quarter of 2017 as certain conditions were satisfied. As a result of this transaction, we recognized a pre-tax loss of $81 million, including a $7 million reduction of goodwill, which is included within "Loss on impairments and divestitures, net" on our accompanying consolidated statement of income for the year ended December 31, 2016.

Sale of Equity Interest in SNG

On September 1, 2016, we completed the sale of a 50% interest in our SNG natural gas pipeline system to The Southern Company (Southern Company), receiving proceeds of $1.4 billion, and the formation of a joint venture, which includes our remaining 50% interest in SNG. We used the proceeds from the sale to reduce outstanding debt. We recognized a pre-tax loss of $84 million on the sale of our interest in SNG which is included within "Loss on impairments and divestitures, net" on the accompanying consolidated statement of income for the year ended December 31, 2016. As a result of this transaction, we no longer hold a controlling interest in SNG or Bear Creek Storage Company, LLC (Bear Creek) (50% of which is owned by SNG) and, as such, we now account for our remaining equity interests in SNG and Bear Creek as equity investments.

Acquisition of BP Products North America Inc. (BP) Terminal Assets

On February 1, 2016, we completed the acquisition of 15 products terminals and associated infrastructure from BP for $349 million, including a transaction deposit paid in 2015 and working capital adjustments paid in 2016. The purchase price consisted of $396 million of property, plant and equipment, $2 million of current assets, and assumed liabilities of $49 million. In conjunction with this transaction, we and BP formed a joint venture with an equity ownership interest of 75% and 25%, respectively. Subsequent to the acquisition, we contributed 14 of the acquired terminals to the joint venture, which we operate, and the remaining terminal is solely owned by us. BP acquired its 25% interest in the joint venture for $84 million, which we reported as "Contributions from noncontrolling interests - other" within our accompanying consolidated statement of cash flows for the year ended December 31, 2016. These terminals are included in our Terminals and Products Pipelines business segments.

4. Impairments and Losses (Gains) on Divestitures

During the years ended December 31, 2018, 2017, and 2016, we recorded impairments of certain equity investments, long-lived assets, and intangible assets, and net gains and losses on divestitures totaling $437 million, $172 million, and $1,013 million, respectively. During 2016, and to a lesser degree in 2017 and 2018, a sustained lower commodity price environment, and negative outlook for certain long-term transportation contracts, led us to cancel certain construction projects, divest of certain assets, write-down certain assets and investments to fair value.

These impairments were driven by market conditions that existed at the time and required management to estimate the fair value of these assets. The estimates of fair value are based on Level 3 valuation estimates using industry standard income approach valuation methodologies which include assumptions primarily involving management's significant judgments and estimates with respect to general economic conditions and the related demand for products handled or transported by our assets as well as assumptions regarding commodity prices, future cash flows based on rate and volume assumptions, terminal values and discount rates. We typically use discounted cash flow analyses to determine the fair value of our assets. We may probability weight various forecasted cash flow scenarios utilized in the analysis as we consider the possible outcomes. We use discount rates representing our estimate of the risk-adjusted discount rates that would be used by market participants specific to the particular asset.

In January 2019, Pacific Gas and Electric (PG&E) filed for Chapter 11 bankruptcy protection. Our exposure to PG&E is limited to our $750 million equity investment in Ruby and an approximate $55 million note receivable from Ruby, where PG&E is Ruby's largest customer. PG&E represents approximately $93 million of annual revenues on Ruby, and our partner's

preferred equity interest in Ruby is senior to our interest. Despite the bankruptcy filing, Ruby continues to perform under its existing service contracts with PG&E and PG&E has provided credit support on its trade payables to Ruby through a prepayment arrangement. While the ultimate outcome of the bankruptcy proceedings remains uncertain, there is the potential for Ruby's existing contracts with PG&E to be canceled in the bankruptcy process. Any cancellation of these contracts could negatively impact Ruby's future revenues and require us to evaluate our investment in Ruby for an other than temporary impairment. This could result in a material impairment of our investment in Ruby at the time such events become known.

We may identify additional triggering events requiring future evaluations of the recoverability of the carrying value of our long-lived assets, investments and goodwill. Because certain assets and investments have been written down to fair value in the last few years, any deterioration in fair value relative to our carrying value increases the likelihood of further impairments. Such non-cash impairments could have a significant effect on our results of operations, which would be recognized in the period in which the carrying value is determined to be not fully recoverable.

We recognized the following non-cash pre-tax impairment charges and losses (gains) on divestitures of assets (in millions):

	Year Ended December 31,		
	2018	2017	2016
Natural Gas Pipelines			
Impairments of long-lived assets(a)	$ 600	$ 30	$ 106
(Gains) losses on divestitures of long-lived assets(b)	(6)	—	94
Impairment of equity investments(c)	270	150	606
Impairment at equity investee(d)	—	10	7
Products Pipelines			
Impairments of long-lived assets(e)	36	—	66
Losses on divestitures of long-lived assets	—	—	10
Gain on divestiture of equity investment	—	—	(12)
Terminals			
Impairments of long-lived assets(f)	59	3	19
(Gains) losses on divestitures of long-lived assets(g)	(6)	(18)	80
Losses on impairments and divestitures of equity investments, net	—	—	16
CO_2			
Impairments of long-lived assets(h)	79	(1)	20
Gain on divestitures of long-lived assets	—	—	(1)
Impairment at equity investee	—	(4)	9
Kinder Morgan Canada			
Gain on divestiture of long-lived assets(i)	(595)	—	—
Other losses (gains) on divestitures of long-lived assets	—	2	(7)
Pre-tax losses on impairments and divestitures, net	$ 437	$ 172	$ 1,013

(a) 2018 amount represents the non-cash impairment associated with certain gathering and processing assets in Oklahoma. 2017 amount represents the impairment of our Colden storage facility, of which $3 million is included in "Costs of sales" on our accompanying consolidated statement of income. 2016 amount represents the project write-off of our portion of the Northeast Energy Direct Market project.

(b) 2016 amount primarily relates to our sale of a 50% interest in SNG.

(c) 2018 amount represents the non-cash impairment of our investment in Gulf LNG Holdings Group, LLC (Gulf LNG) which was driven by a ruling by an arbitration panel affecting a customer contract. Our share of earnings recognized by Gulf LNG on the respective customer contract is included in "Earnings from equity investments" on our accompanying consolidated statement of income for the year ended December 31, 2018. 2017 amount represents the non-cash impairment of our investment in FEP. 2016 amount includes a $350 million non-cash impairment of our investment in MEP and a $250 million non-cash impairment of our investment in Ruby.

(d) 2017 and 2016 amounts represent losses on impairments recorded by equity investees and are included in "Earnings from equity investments" on our accompanying consolidated statements of income.

(e) 2018 amount represents a project write-off associated with the Utica Marcellus Texas pipeline. 2016 amount represents project write-offs associated with the canceled Palmetto project.

(f) 2018 amount primarily relates to non-cash impairments of certain Northeast terminal assets.
(g) 2017 amount includes a $23 million gain related to the sale of a 40% membership interest in the Deeprock Development joint venture. 2016 amount primarily relates to the sale of 20 bulk terminals that handle mostly coal and steel products, predominately located along the inland river system.
(h) 2018 amount represents impairments of oil and gas properties.
(i) 2018 amount represents the gain on the TMPL Sale.

Our largest impairment for the year ended December 31, 2018 was a $600 million non-cash impairment in our Natural Gas Pipelines business segment driven by reduced cash flow estimates for some of our gathering and processing assets in Oklahoma identified during the period as a result of our decision to redirect our focus to other areas of our portfolio. These reduced estimates triggered an impairment analysis as we determined that our carrying value may no longer be recoverable. The impairment analysis for long-lived assets was based upon a two-step process as prescribed in the accounting standards. Step 1 involved comparing the undiscounted future cash flows to be derived from the asset group to the carrying value of the asset group. Based on the results of our step 1 test, we determined that the undiscounted future cash flows were less than the carrying value of the asset group. Step 2 involved using the income approach to calculate the fair value of the asset group and comparing it to the carrying value. The impairment that we recorded represented the difference between the fair and carrying values.

5. Income Taxes

The components of "Income Before Income Taxes" are as follows (in millions):

	Year Ended December 31,		
	2018	2017	2016
U.S.	$ 1,739	$ 1,976	$ 1,466
Foreign	767	185	172
Total Income Before Income Taxes	$ 2,506	$ 2,161	$ 1,638

Components of the income tax provision applicable for federal, foreign and state taxes are as follows (in millions):

	Year Ended December 31,		
	2018	2017	2016
Current tax expense (benefit)			
Federal	$ (22)	$ (137)	$ (148)
State	(45)	(16)	(28)
Foreign	249	18	6
Total	182	(135)	(170)
Deferred tax expense (benefit)			
Federal	425	2,022	998
State	55	4	51
Foreign	(75)	47	38
Total	405	2,073	1,087
Total tax provision	$ 587	$ 1,938	$ 917

We are subject to taxation in Canada and Mexico. In Canada we recognized income tax expense of $168 million, $58 million and $38 million at December 31, 2018, 2017, and 2016, respectively. In Mexico we recognized income tax expense of $6 million, $7 million and $6 million at December 31, 2018, 2017, and 2016, respectively.

The difference between the statutory federal income tax rate and our effective income tax rate is summarized as follows (in millions, except percentages):

	Year Ended December 31,					
	2018		2017		2016	
Federal income tax	$ 526	21.0 %	$ 756	35.0 %	$ 573	35.0 %
Increase (decrease) as a result of:						
State deferred tax rate change	(7)	(0.3)%	10	0.5 %	11	0.7 %
Taxes on foreign earnings, net of federal benefit	131	5.2 %	42	1.9 %	28	1.7 %
Net effects of noncontrolling interests	(65)	(2.6)%	(14)	(0.7)%	(4)	(0.3)%
State income tax, net of federal benefit	46	1.8 %	38	1.8 %	26	1.6 %
Dividend received deduction	(31)	(1.2)%	(56)	(2.6)%	(48)	(2.9)%
Adjustments to uncertain tax positions	(47)	(1.9)%	(12)	(0.6)%	(23)	(1.4)%
Valuation allowance on investment and tax credits	14	0.5 %	13	0.6 %	34	2.1 %
Impact of the 2017 Tax Reform	—	— %	1,240	57.4 %	—	— %
Nondeductible goodwill	58	2.3 %	—	— %	301	18.5 %
General business credit	(64)	(2.6)%	(95)	(4.4)%	—	— %
Other	26	1.2 %	16	0.8 %	19	1.1 %
Total	$ 587	23.4 %	$ 1,938	89.7 %	$ 917	56.1 %

Deferred tax assets and liabilities result from the following (in millions):

	December 31,	
	2018	2017
Deferred tax assets		
Employee benefits	$ 238	$ 251
Accrued expenses	76	73
Net operating loss, capital loss and tax credit carryforwards	1,526	1,113
Derivative instruments and interest rate and currency swaps	9	12
Debt fair value adjustment	33	37
Investments	177	968
Other	—	6
Valuation allowances	(178)	(171)
Total deferred tax assets	1,881	2,289
Deferred tax liabilities		
Property, plant and equipment	270	225
Other	45	20
Total deferred tax liabilities	315	245
Net deferred tax assets	$ 1,566	$ 2,044

Deferred Tax Assets and Valuation Allowances: The step-up in tax basis from the merger transactions that occurred in November 2014 resulted in a deferred tax asset, primarily related to our investment in KMP. As book earnings from our investment in KMP are projected to exceed taxable income (primarily as a result of the partnership's tax depreciation in excess of book depreciation), the deferred tax asset related to our investment in KMP is expected to be fully realized.

We increased our valuation allowances in 2018 by $7 million, primarily due to a $17 million increase for capital loss carryover as a result of the TMPL Sale, a $6 million decrease for foreign operating losses and a $4 million utilization of foreign tax credits.

We have deferred tax assets of $1,249 million related to net operating loss carryovers, $260 million related to general business, alternative minimum, and foreign tax credits, $17 million related to capital losses, and $140 million of valuation allowances related to these deferred tax assets at December 31, 2018. As of December 31, 2017, we had deferred tax assets of $935 million related to net operating loss carryovers, $178 million related to general business, alternative minimum and foreign tax credits and $133 million of valuation allowances related to these deferred tax assets. We expect to generate taxable income and begin to utilize federal net operating loss carryforwards and tax credits in 2022.

Our alternative minimum tax credit carryforwards decreased by $8 million in 2018 as a result of a federal audit settlement. In 2017, our decision to elect to forgo bonus depreciation on property placed in service in that year allowed us to utilize $137 million of minimum tax credits. Section 168(k)(4) of the Internal Revenue Code allows for corporate taxpayers with minimum tax credit carryforwards to forgo bonus depreciation and accelerate their use of the credits to reduce tax liability in that same tax year if the amount of the allowable credit exceeds the taxpayer's tax liability. We received an income tax refund of $145 million in 2018 related to the 2017 credit utilization and 2018 audit settlement.

Expiration Periods for Deferred Tax Assets: As of December 31, 2018, we have U.S. federal net operating loss carryforwards of $1.4 billion that will be carried forward indefinitely and $3.4 billion that will expire from 2019 - 2037; state losses of $3.7 billion which will expire from 2019 - 2038; and foreign losses of $112 million which will expire from 2029 - 2038. We also have $241 million of general business credits which will expire from 2019 - 2028; a capital loss carryover of $17 million which will expire in 2023; and approximately $17 million of foreign tax credits, which will expire from 2020 - 2023. Use of a portion of our U.S. federal carryforwards is subject to the limitations provided under Sections 382 and 383 of the Internal Revenue Code as well as the separate return limitation rules of Internal Revenue Service regulations. If certain substantial changes in our ownership occur, there would be an annual limitation on the amount of carryforwards that could be utilized.

Unrecognized Tax Benefits: We recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based not only on the technical merits of the tax position based on tax law, but also the past administrative practices and precedents of the taxing authority. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate resolution.

A reconciliation of our gross unrecognized tax benefit excluding interest and penalties is as follows (in millions):

	Year Ended December 31,		
	2018	**2017**	**2016**
Balance at beginning of period	$ 97	$ 122	$ 148
Additions based on current year tax positions	3	3	3
Additions based on prior year tax positions	7	—	7
Reductions based on prior year tax positions	—	—	(1)
Reductions based on settlements with taxing authority	(73)	(22)	(26)
Reductions due to lapse in statute of limitations	—	(2)	(9)
Impact of the 2017 Tax Reform	—	(4)	—
Balance at end of period	$ 34	$ 97	$ 122

We recognize interest and/or penalties related to income tax matters in income tax expense. We recognized tax benefits of $15 million, $9 million and an expense of $2 million at December 31, 2018, 2017 and 2016, respectively. As of December 31, 2018, 2017 and 2016, we had $2 million, $19 million and $28 million, respectively, of accrued interest. We had less than $1 million of accrued penalties as of December 31, 2018 and no accrued penalties as of December 31, 2017. All of the $34 million of unrecognized tax benefits, if recognized, would affect our effective tax rate in future periods. In addition, we believe it is reasonably possible that our liability for unrecognized tax benefits will decrease by approximately $21 million during the next year to approximately $13 million, primarily due to settlements with taxing authorities, partially offset by additions for state filing positions taken in prior years.

We are subject to taxation, and have tax years open to examination for the periods 2015-2017 in the U.S., 2005-2017 in various states and 2007-2017 in various foreign jurisdictions.

Impact of 2017 Tax Reform

On December 22, 2017, the U.S. enacted the 2017 Tax Reform. Among the many provisions included in the 2017 Tax Reform is a provision to reduce the U.S. federal corporate income tax rate from 35% to 21% effective January 1, 2018.

As of December 31, 2017, we had deferred tax assets related to our net operating loss carryforwards and tax credits, in addition to tax basis in excess of accounting basis primarily related to our investment in KMP. Prior to the 2017 Tax Reform, the value of these deferred tax assets was recorded at the previous income tax rate of 35%, which represented their expected future benefit to us. As a result of the 2017 Tax Reform, the future benefit of these deferred tax assets was re-measured at the new income tax rate of 21% and we recorded an approximate $1,240 million provisional non-cash adjustment for the year ended December 31, 2017. We determined the effects of the rate change using our best estimate of temporary book-to-tax differences. Upon final analysis and remeasurement of our deferred tax balances, the December 31, 2017 adjustment recorded accurately reflected the change in corporate income tax rates and has not been materially adjusted in subsequent periods.

In addition, the 2017 Tax Reform required a mandatory deemed repatriation of post-1986 undistributed foreign earnings and profits. As of December 31, 2017, we recorded a provisional amount for this 2017 Tax Reform provision and as of December 31, 2018, completed our analysis on this provision. The 2017 Tax Reform transition tax was $2 million.

The income tax rate change in the 2017 Tax Reform had an impact not only on our corporate income taxes but also resulted in us recording an approximate $144 million after-tax ($219 million pre-tax) provisional non-cash adjustment, including our share of equity investee provisional adjustments, related to our FERC regulated business for the year ended December 31, 2017. As a result of the completion of our assessment of the 2017 Tax Reform's effect on our FERC regulated business, we decreased this non-cash provisional adjustment by approximately $27 million after-tax ($36 million pre-tax) during the year ended December 31, 2018.

The 2017 Tax Reform requires a U.S. corporation to record taxes on global intangible low-tax income (GILTI) and elect an accounting policy to either recognize GILTI as a current period expense when incurred or to record deferred taxes for the temporary basis differences expected to reverse in the future as GILTI. Though we did not generate any GILTI during 2018, we have elected to recognize the GILTI tax as a period cost in the future, as applicable.

6. Property, Plant and Equipment, net

Classes and Depreciation

As of December 31, 2018 and 2017, our property, plant and equipment, net consisted of the following (in millions):

	December 31,	
	2018	2017
Pipelines (Natural gas, liquids, crude oil and CO_2)	$ 19,727	$ 20,157
Equipment (Natural gas, liquids, crude oil, CO_2, and terminals)	24,392	24,152
Other(a)	5,447	5,570
Accumulated depreciation, depletion and amortization	(15,359)	(14,175)
	34,207	35,704
Land and land rights-of-way	1,378	1,456
Construction work in process	2,312	2,995
Property, plant and equipment, net	$ 37,897	$ 40,155

(a) Includes general plant, general structures and buildings, computer and communication equipment, intangibles, vessels, transmix products, linefill and miscellaneous property, plant and equipment.

As of December 31, 2018 and 2017, property, plant and equipment, net included $12,349 million and $14,055 million, respectively, of assets which were regulated by either the FERC or the NEB. Depreciation, depletion, and amortization expense

charged against property, plant and equipment was $2,057 million, $2,022 million, and $1,970 million for the years ended December 31, 2018, 2017, and 2016, respectively.

Asset Retirement Obligations

As of December 31, 2018 and 2017, we recognized asset retirement obligations in the aggregate amount of $213 million and $208 million, respectively, of which $4 million were classified as current for both periods. The majority of our asset retirement obligations are associated with our CO_2 business segment, where we are required to plug and abandon oil and gas wells that have been removed from service and to remove the surface wellhead equipment and compressors.

7. Investments

Our investments primarily consist of equity investments where we hold significant influence over investee actions and for which we apply the equity method of accounting. As of December 31, 2018 and 2017, our investments consisted of the following (in millions):

	December 31,	
	2018	**2017**
Citrus Corporation	$ 1,708	$ 1,698
SNG	1,536	1,495
Ruby	750	774
NGPL Holdings LLC	733	687
Gulf LNG Holdings Group, LLC	361	461
Plantation Pipe Line Company	344	331
Utopia Holding LLC	333	276
EagleHawk	299	314
Gulf Coast Express Pipeline LLC	240	—
MEP	235	253
Red Cedar Gathering Company	191	187
Watco Companies, LLC	185	182
Double Eagle Pipeline LLC	140	149
Liberty Pipeline Group LLC	66	71
Bear Creek Storage	65	63
Sierrita Gas Pipeline LLC	55	55
Permian Highway Pipeline	45	—
FEP	44	112
All others	151	190
Total investments	$ 7,481	$ 7,298

As shown in the investment balance table above and the earnings from equity investments table below, our significant equity investments, as of December 31, 2018 consisted of the following:

- Citrus Corporation—We own a 50% interest in Citrus Corporation, the sole owner of Florida Gas Transmission Company, L.L.C. (Florida Gas). Florida Gas transports natural gas to cogeneration facilities, electric utilities, independent power producers, municipal generators, and local distribution companies through a 5,300-mile natural gas pipeline. Energy Transfer Partners L.P. operates Florida Gas and owns the remaining 50% interest in Citrus;
- SNG—We operate SNG and own a 50% interest in SNG; and Evergreen Enterprise Holdings, LLC, a subsidiary of Southern Company, owns the remaining 50% interest;
- Ruby—We operate Ruby and own the common interest in Ruby, the sole owner of the Ruby Pipeline natural gas transmission system. Pembina Pipeline Corporation (Pembina) owns the remaining interest in Ruby in the form of a convertible preferred interest. If Pembina converted its preferred interest into common interest, we and Pembina would each own a 50% common interest in Ruby;

- NGPL Holdings LLC— We operate NGPL Holdings LLC and own a 50% interest in NGPL Holdings LLC, the indirect owner of NGPL and certain affiliates, collectively referred to in this report as NGPL, a major interstate natural gas pipeline and storage system. The remaining 50% interest is owned by Brookfield;
- Gulf LNG Holdings Group, LLC—We operate Gulf LNG Holdings Group, LLC and own a 50% interest in Gulf LNG Holdings Group, LLC, the owner of a LNG receiving, storage and regasification terminal near Pascagoula, Mississippi, as well as pipeline facilities to deliver vaporized natural gas into third party pipelines for delivery into various markets around the country. The remaining 50% interest is owned by a variety of investment entities, including subsidiaries of The Blackstone Group, LP; Warburg Pincus, LLC; Kelso and Company; and Chatham Asset Management, LLC, which is directed by Chatham Asset GP, LLC;
- Plantation—We operate Plantation and own a 51.17% interest in Plantation, the sole owner of the Plantation refined petroleum products pipeline system. A subsidiary of Exxon Mobil Corporation owns the remaining interest. Each investor has an equal number of directors on Plantation's board of directors, and board approval is required for certain corporate actions that are considered substantive participating rights; therefore, we do not control Plantation, and account for the investment under the equity method;
- Utopia Holding L.L.C. — We operate Utopia Holding L.L.C. and own a 50% interest in Utopia Holding L.L.C. Riverstone Investment Group LLC owns the remaining 50% interest;
- BHP Billiton Petroleum (Eagle Ford Gathering) LLC, (EagleHawk)—We own a 25% interest in EagleHawk, the sole owner of natural gas and condensate gathering systems serving the producers of the Eagle Ford shale formation. A subsidiary of BHP Billiton Petroleum (Tx Gathering), LLC operates EagleHawk and owns the remaining 75% ownership interest;
- Gulf Coast Express Pipeline LLC — We operate Gulf Coast Express Pipeline LLC and own 35% interest of Gulf Coast Express Pipeline LLC indirectly through Kinder Morgan Texas Pipeline LLC, our 100% subsidiary. DCP GCX Pipeline LLC, an indirect subsidiary of DCP Midstream, owns 25% interest; Targa GCX Pipeline LLC, an indirect subsidiary of Targa Resources Corp., owns 25% interest and Altus Midstream Company, an indirect subsidiary of Apache Corporation, owns 15% interest;
- MEP—We operate MEP and own a 50% interest in MEP, the sole owner of the MEP natural gas pipeline system. The remaining 50% ownership interest is owned by subsidiaries of Energy Transfer Partners L.P.;
- Red Cedar Gathering Company—We own a 49% interest in Red Cedar Gathering Company, the sole owner of the Red Cedar natural gas gathering, compression and treating system. The Southern Ute Indian Tribe owns the remaining 51% interest and serves as operator of Red Cedar;
- Watco Companies, LLC—We hold a preferred and common equity investment in Watco Companies, LLC, the largest privately held short line railroad company in the U.S. We own 100,000 Class A and 50,000 Class B preferred shares and pursuant to the terms of the investment, receive priority, cumulative cash and stock distributions from the preferred shares at a rate of 3.25% and 3.00% per quarter, respectively, and participate partially in additional profit distributions at a rate equal to 0.4%. Neither class holds any voting powers, but do provide us certain approval rights, including the right to appoint one of the members to Watco's board of managers. In addition to the senior interests, we also hold approximately 13,000 common equity units, which represents a 3.2% common ownership;
- Double Eagle Pipeline LLC - We own a 50% equity interest in Double Eagle Pipeline LLC. The remaining 50% interest is owned by Magellan Midstream Partners;
- Liberty Pipeline Group, LLC (Liberty) —We own a 50% interest in Liberty. ETC NGL Transport, LLC, a subsidiary of Energy Transfer Partners, L.P. owns the remaining 50% interest and serves as operator of Liberty;
- Bear Creek Storage—We own a combined 75% interest in Bear Creek through: our wholly owned subsidiary's (TGP) 50% interest and an additional 25% indirect interest through our 50% equity interest in SNG, which owns the remaining 50% interest;
- Sierrita Gas Pipeline LLC — We operate Sierrita Gas Pipeline LLC and own a 35% interest in Sierrita Gas Pipeline LLC. MGI Enterprises U.S. LLC, a subsidiary of PEMEX, owns 35%; and MIT Pipeline Investment Americas, Inc., a subsidiary of Mitsui & Co., Ltd, owns 30%;
- Permian Highway Pipeline — We operate Permian Highway Pipeline and own a 50% interest of Permian Highway Pipeline indirectly through KMTP, our wholly owned subsidiary. BCP PHP, LLC (BCP), a portfolio company of Blackstone Energy Partners, owns the remaining 50% interest. An affiliate of an anchor shipper exercised its option in January 2019 to acquire a 20% equity interest in the project, bringing KMTP's and BCP's ownership interest to 40% each. Altus Midstream Company (Altus Midstream) (a gas gathering, processing and transportation company formed

by shipper Apache Corporation) has an option to acquire an equity interest in the project from the initial partners by September 2019. If Altus Midstream exercises its option, KMTP, BCP and Altus Midstream will each hold a 26.67% ownership interest in the project. KMTP will build and operate the pipeline;

- FEP —We own a 50% interest in FEP, the sole owner of the Fayetteville Express natural gas pipeline system. Energy Transfer Partners, L.P. owns the remaining 50% interest and serves as operator of FEP;
- Cortez Pipeline Company—We operate the Cortez CO_2 pipeline system, and own a 52.98% interest in the Cortez Pipeline Company, the sole owner of the Cortez CO_2 pipeline system. Mobil Cortez Pipeline Inc. owns 33.25%; and Cortez Vickers Pipeline Company owns the remaining 13.77%.

Our earnings from equity investments were as follows (in millions):

	Year Ended December 31,		
	2018	2017	2016
Gulf LNG Holdings Group, LLC(a)	$ 209	$ 47	$ 48
Citrus Corporation	169	108	102
SNG	141	77	58
NGPL Holdings LLC	66	10	12
FEP	55	53	51
Plantation Pipe Line Company	55	46	37
Cortez Pipeline Company(b)	36	44	24
MEP	31	38	40
Ruby	26	44	15
Watco Companies, LLC	21	19	25
Red Cedar Gathering Company(c)	18	14	24
Utopia Holding LLC	14	—	—
Double Eagle Pipeline LLC	10	7	5
Bear Creek Storage	9	8	2
EagleHawk	7	24	10
Liberty Pipeline Group LLC	7	9	11
Sierrita Gas Pipeline LLC	7	7	7
Gulf Coast Express LLC	2	—	—
All others	4	23	26
Total earnings from equity investments	$ 887	$ 578	$ 497
Amortization of excess costs	(95)	(61)	(59)

(a) 2018 amount includes our share of earnings recognized due to a ruling by an arbitration panel affecting a customer contract.
(b) 2017 and 2016 amounts include $(4) million and $9 million, respectively, representing our share of a non-cash impairment charge (pre-tax) recorded by Cortez Pipeline Company.
(c) 2017 amount includes non-cash impairment charges of $10 million (pre-tax) related to our investment.

Summarized combined financial information for our significant equity investments (listed or described above) is reported below (in millions; amounts represent 100% of investee financial information):

	Year Ended December 31,		
Income Statement	2018	2017	2016
Revenues	$ 5,129	$ 4,703	$ 4,084
Costs and expenses	3,371	3,398	3,056
Net income	$ 1,758	$ 1,305	$ 1,028

Balance Sheet	December 31, 2018	December 31, 2017
Current assets	$ 1,496	$ 956
Non-current assets	23,396	22,344
Current liabilities	2,715	1,241
Non-current liabilities	9,555	10,605
Partners'/owners' equity	12,622	11,454

8. Goodwill

Changes in the amounts of our goodwill for each of the years ended December 31, 2018 and 2017 are summarized by reporting unit as follows (in millions):

	Natural Gas Pipelines Regulated	Natural Gas Pipelines Non-Regulated	CO_2	Products Pipelines	Products Pipelines Terminals	Terminals	Kinder Morgan Canada	Total
Historical Goodwill	$ 15,892	$ 5,812	$ 1,528	$ 2,125	$ 221	$ 1,575	$ 562	$ 27,715
Accumulated impairment losses	(1,643)	(1,597)	—	(1,197)	(70)	(679)	(377)	(5,563)
December 31, 2016	14,249	4,215	1,528	928	151	896	185	22,152
Currency translation	—	—	—	—	—	—	13	13
Divestitures(a)	—	—	—	—	—	(3)	—	(3)
December 31, 2017	14,249	4,215	1,528	928	151	893	198	22,162
Currency translation	—	—	—	—	—	—	(8)	(8)
Divestitures(b)	—	—	—	—	—	—	(190)	(190)
Other	—	—	—	—	—	1	—	1
December 31, 2018	$ 14,249	$ 4,215	$ 1,528	$ 928	$ 151	$ 894	$ —	$ 21,965

(a) 2017 includes $3 million related to certain terminal divestitures.
(b) 2018 includes $190 million related to the TMPL Sale.

Refer to Note 2 "*Summary of Significant Accounting Policies—Goodwill*" for a description of our accounting for goodwill.

We determine the fair value of each reporting unit as of May 31 of each year based primarily on a market approach utilizing enterprise value to estimated earning before interest, taxes, depreciation and amortization (EBITDA) multiples of comparable companies. The value of each reporting unit is determined on a stand-alone basis from the perspective of a market participant representing the price estimated to be received in a sale of the reporting unit in an orderly transaction between market participants at the measurement date. For our Natural Gas Pipelines Non-Regulated reporting unit, our May 31, 2018 annual test included a discounted cash flow analysis (income approach) to evaluate the fair value of this reporting unit to provide additional indication of fair value based on the present value of cash flows this reporting unit is expected to generate in the future. We weighted the market and income approaches for this reporting unit to arrive at an estimated fair value of this reporting unit giving more weighting on the income approach and less on the market approach as we believed the value indicated using the income approach is more representative of the value that could be received from a market participant. As of May 31, 2018, each of our reporting units indicated a fair value in excess of their respective carrying values (by at least 10%) and step 2 was not required. The results of our Step 1 analysis did not indicate an impairment of goodwill and we did not identify any triggers for further impairment analysis during the remainder of the year.

A continued period of volatile commodity prices could result in deterioration of market multiples, comparable sales transactions prices, weighted average costs of capital, and our cash flow estimates. A significant unfavorable change to any one or combination of these factors would result in a change to the reporting unit fair values discussed above potentially resulting in future impairments of long-lived assets, equity method investments, and/or goodwill. Such non-cash impairments could have a significant effect on our results of operations.

9. Debt

We classify our debt based on the contractual maturity dates of the underlying debt instruments. We defer costs associated with debt issuance over the applicable term. These costs are then amortized as interest expense in our accompanying consolidated statements of income.

The following table provides detail on the principal amount of our outstanding debt balances. The table amounts exclude all debt fair value adjustments, including debt discounts, premiums and issuance costs (in millions):

	December 31,	
	2018	2017
Credit facility and commercial paper borrowings(a)	$ 433	$ 365
Corporate senior notes(b)		
6.00%, due January 2018	—	750
7.00%, due February 2018	—	82
5.95%, due February 2018	—	975
7.25%, due June 2018	—	477
9.00%, due February 2019	500	500
2.65%, due February 2019	800	800
3.05%, due December 2019	1,500	1,500
6.85%, due February 2020	700	700
6.50%, due April 2020	535	535
5.30%, due September 2020	600	600
6.50%, due September 2020	349	349
5.00%, due February 2021	750	750
3.50%, due March 2021	750	750
5.80%, due March 2021	400	400
5.00%, due October 2021	500	500
4.15%, due March 2022	375	375
1.50%, due March 2022(c)	860	900
3.95%, due September 2022	1,000	1,000
3.15%, due January 2023	1,000	1,000
Floating rate, due January 2023	250	250
3.45%, due February 2023	625	625
3.50%, due September 2023	600	600
5.625%, due November 2023	750	750
4.15%, due February 2024	650	650
4.30%, due May 2024	600	600
4.25%, due September 2024	650	650
4.30%, due June 2025	1,500	1,500
6.70%, due February 2027	7	7
2.25%, due March 2027(c)	573	600
6.67%, due November 2027	7	7
4.30%, due March 2028	1,250	—
7.25%, due March 2028	32	32
6.95%, due June 2028	31	31
8.05%, due October 2030	234	234
7.40%, due March 2031	300	300
7.80%, due August 2031	537	537
7.75%, due January 2032	1,005	1,005
7.75%, due March 2032	300	300
7.30%, due August 2033	500	500
5.30%, due December 2034	750	750
5.80%, due March 2035	500	500
7.75%, due October 2035	1	1
6.40%, due January 2036	36	36
6.50%, due February 2037	400	400
7.42%, due February 2037	47	47
6.95%, due January 2038	1,175	1,175
6.50%, due September 2039	600	600
6.55%, due September 2040	400	400
7.50%, due November 2040	375	375
6.375%, due March 2041	600	600

	December 31, 2018	December 31, 2017
5.625%, due September 2041	375	375
5.00%, due August 2042	625	625
4.70%, due November 2042	475	475
5.00%, due March 2043	700	700
5.50%, due March 2044	750	750
5.40%, due September 2044	550	550
5.55%, due June 2045	1,750	1,750
5.05%, due February 2046	800	800
5.20%, due March 2048	750	—
7.45%, due March 2098	26	26
TGP senior notes(b)		
7.00%, due March 2027	300	300
7.00%, due October 2028	400	400
8.375%, due June 2032	240	240
7.625%, due April 2037	300	300
EPNG senior notes(b)		
8.625%, due January 2022	260	260
7.50%, due November 2026	200	200
8.375%, due June 2032	300	300
CIG senior notes(b)		
4.15%, due August 2026	375	375
6.85%, due June 2037	100	100
EPC Building, LLC, promissory note, 3.967%, due December 2035	409	421
Trust I Preferred Securities, 4.75%, due March 2028(d)	221	221
KMGP, $1,000 Liquidation Value Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock, due August 2057(e)	100	100
Other miscellaneous debt(f)	250	278
Total debt – KMI and Subsidiaries	36,593	36,916
Less: Current portion of debt(g)	3,388	2,828
Total long-term debt – KMI and Subsidiaries(h)	$ 33,205	$ 34,088

(a) See "—Current portion of debt" below for further details regarding the outstanding credit facility and commercial paper borrowings.

(b) Notes provide for the redemption at any time at a price equal to 100% of the principal amount of the notes plus accrued interest to the redemption date plus a make whole premium and are subject to a number of restrictions and covenants. The most restrictive of these include limitations on the incurrence of liens and limitations on sale-leaseback transactions.

(c) Consists of senior notes denominated in Euros that have been converted to U.S. dollars and are respectively reported above at the December 31, 2018 exchange rate of 1.1467 U.S. dollars per Euro and at the December 31, 2017 exchange rate of 1.2005 U.S. dollars per Euro. As of December 31, 2018 and 2017, the cumulative changes in the exchange rate of U.S. dollars per Euro since issuance had resulted in increases to our debt balance of $46 million and $86 million, respectively, related to the 1.50% series and increases of $30 million and $57 million, respectively, related to the 2.25% series. The cumulative increase in debt due to the changes in exchange rates is offset by a corresponding change in the value of cross-currency swaps reflected in "Deferred charges and other assets" and " Other long-term liabilities and deferred credits" on our consolidated balance sheets. At the time of issuance, we entered into cross-currency swap agreements associated with these senior notes, effectively converting these Euro-denominated senior notes to U.S. dollars (see Note 14 "*Risk Management—Foreign Currency Risk Management*").

(d) Capital Trust I (Trust I), is a 100%-owned business trust that as of December 31, 2018, had 4.4 million of 4.75% trust convertible preferred securities outstanding (referred to as the Trust I Preferred Securities). Trust I exists for the sole purpose of issuing preferred securities and investing the proceeds in 4.75% convertible subordinated debentures, which are due 2028. Trust I's sole source of income is interest earned on these debentures. This interest income is used to pay distributions on the preferred securities. We provide a full and unconditional guarantee of the Trust I Preferred Securities. There are no significant restrictions from these securities on our ability to obtain funds from our subsidiaries by distribution, dividend or loan. The Trust I Preferred Securities are non-voting (except in limited circumstances), pay quarterly distributions at an annual rate of 4.75%, carry a liquidation value of $50 per security plus accrued and unpaid distributions. The Trust I Preferred Securities outstanding as of December 31, 2018 are convertible at any time prior to the close of business on March 31, 2028, at the option of the holder, into the following mixed consideration: (i) 0.7197 of a share of our Class P common stock; and (ii) $25.18 in cash without interest. We have the right to redeem these Trust I Preferred Securities at any time.

(e) As of December 31, 2018 and 2017, KMGP had outstanding, 100,000 shares of its $1,000 Liquidation Value Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock due 2057. Since August 18, 2012, dividends on the preferred stock accumulate at a floating rate of the 3-month LIBOR plus 3.8975% and are payable quarterly in arrears, when and if declared by KMGP's board of directors, on February 18, May 18, August 18 and November 18 of each year, beginning November 18, 2012. The preferred stock has approval rights over a commencement of or filing of voluntary bankruptcy by KMP or its SFPP or Calnev subsidiaries.

(f) Includes capital lease obligations with monthly installments. The lease terms expire between 2024 and 2061.

(g) Amounts include KMI and KML outstanding credit facility borrowings, commercial paper borrowings and other debt maturing within 12 months. See "—Current Portion of Debt" below.

(h) Excludes our "Debt fair value adjustments" which, as of December 31, 2018 and 2017, increased our combined debt balances by $731 million and $927 million, respectively. In addition to all unamortized debt discount/premium amounts, debt issuance costs and purchase accounting on our debt balances, our debt fair value adjustments also include amounts associated with the offsetting entry for hedged debt and any unamortized portion of proceeds received from the early termination of interest rate swap agreements. For further information about our debt fair value adjustments, see "—Debt Fair Value Adjustments" below.

Current Portion of Debt

The following table details the components of our "Current portion of debt" reported on our consolidated balance sheets.

	December 31,	
	2018	2017
$500 million, 364-day credit facility due November 15, 2019(a)	$ —	$ —
$4 billion credit facility due November 16, 2023(a)	—	—
$5 billion, five-year credit facility due November 26, 2019, -% and 2.99%, respectively(a)(b)	—	125
Commercial paper notes, 3.10% and 2.02%, respectively(b)	433	240
KML 2018 Credit Facility(c)	—	—
Current portion of senior notes		
6.00%, due January 2018	—	750
7.00%, due February 2018	—	82
5.95%, due February 2018	—	975
7.25%, due June 2018	—	477
9.00%, due February 2019	500	—
2.65%, due February 2019	800	—
3.05%, due December 2019	1,500	—
Trust I Preferred Securities, 4.75%, due March 2028	111	111
Current portion - Other debt	44	68
Total current portion of debt	$ 3,388	$ 2,828

(a) On November 16, 2018, we replaced our $5 billion, five-year credit facility with two new credit facilities discussed further in "—Credit Facilities and Restrictive Covenants" following.
(b) Interest rates are weighted average rates at December 31, 2018 and 2017, respectively.
(c) Borrowings under the KML 2018 Credit Facility are denominated in C$ and are converted to U.S. dollars. The exchange rate was 0.7330 U.S. dollars per C$ at December 31, 2018 and 0.7971 U.S. dollars per C$ at December 31, 2017. See "—Credit Facilities" below.

We and substantially all of our wholly owned domestic subsidiaries are a party to a cross guarantee agreement whereby each party to the agreement unconditionally guarantees, jointly and severally, the payment of specified indebtedness of each other party to the agreement. Also, see Note 20.

Subsequent Event—Debt Repayments

Using part of our portion of proceeds from the TMPL Sale that KML distributed to us in January 2019, we immediately repaid our outstanding balance of commercial paper borrowings, and then in February 2019, repaid $500 million of maturing 9.00% senior notes and $800 million of maturing 2.65% senior notes which were included in "Current portion of debt" on the accompanying consolidated balance sheet as of December 31, 2018.

Credit Facilities and Restrictive Covenants

KMI

On November 16, 2018, we replaced our five-year, $5 billion revolving credit facility with (i) a new five-year, $4 billion revolving credit facility (Five-year Credit Facility); and (ii) a new 364-day, $500 million revolving credit facility (364-day Credit Facility) with a syndicate of lenders, together, "KMI's New Credit Facilities."

We also continue to maintain a $4 billion commercial paper program through the private placement of short-term notes. The notes mature up to 270 days from the date of issue and are not redeemable or subject to voluntary prepayment by us prior to maturity. The notes are sold at par value less a discount representing an interest factor or if interest bearing, at par.

Borrowings under our revolving credit facility can be used for working capital and other general corporate purposes and as a backup to our commercial paper program. Borrowings under our commercial paper program reduce the borrowings allowed under our Five-year Credit Facility.

Depending on the type of loan request, our credit facility borrowings under either of our credit facilities bear interest at either (i) LIBOR adjusted for a eurocurrency funding reserve plus an applicable margin ranging from 1.000% to 2.000% per annum based on our credit ratings or (ii) the greatest of (1) the Federal Funds Rate plus 0.5%; (2) the Prime Rate; or (3) LIBOR for a one-month eurodollar loan adjusted for a eurocurrency funding reserve, plus 1%, plus, in each case, an applicable margin ranging from 0.100% to 1.000% per annum based on our credit rating. Standby fees for the unused portion of the credit facility will be calculated at a rate ranging from 0.100% to 0.300%for the Five-year Credit Facility and 0.090% to 0.275% for the 364-day Credit Facility based upon our debt credit rating.

KMI's New Credit Facilities contain financial and various other covenants that apply to the Company and its subsidiaries and are common in such agreements, including a maximum ratio of Consolidated Net Indebtedness to Consolidated EBITDA (each as defined in the Five-Year Credit Facility and 364-day Credit Facility, as applicable) of 5.50 to 1.00, for any four-fiscal-quarter period. Other negative covenants include restrictions on the Company's and certain of its subsidiaries' ability to incur debt, grant liens, make fundamental changes or engage in certain transactions with affiliates, or in the case of certain material subsidiaries, permit restrictions on dividends, distributions or making or prepayments of loans to the Company or any guarantor. KMI's New Credit Facilities also restrict the Company's ability to make certain restricted payments if an event of default (as defined in the Five-Year Credit Facility and the 364-Day Credit Facility) has occurred and is continuing or would occur and be continuing.

As of December 31, 2018, we had no borrowings outstanding under our Five-year Credit Facility or our 364-day Credit Facility, $433 million outstanding under our commercial paper program and $99 million in letters of credit. Our availability under these facilities as of December 31, 2018 was $3,968 million. As of December 31, 2018, we were in compliance with all required covenants.

KML

Upon the closing of the TMPL Sale on August 31, 2018, KML's prior credit facility was replaced with a new 4-year, C $500 million unsecured revolving credit facility for working capital purposes ("KML 2018 Credit Facility") under a credit agreement with the Royal Bank of Canada (the "KML Credit Agreement") as agent. In addition, the C$133 million (U.S.$102 million) of outstanding borrowings under KML's prior credit facility were paid off prior to its termination with a portion of the proceeds from the TMPL Sale.

Depending on the type of loan requested, interest on borrowings outstanding are calculated based on: (i) a Canadian prime rate of interest; (ii) a U.S. base rate; (iii) LIBOR; or (iv) bankers' acceptance fees, plus (i) in the case of Canadian prime rate or U.S. base rate loans, an applicable margin of up to 1.25%; or (ii) in the case of LIBOR or bankers' acceptance loans, an applicable margin ranging from 1.00% to 2.25%, with such margin in any case determined by KML's debt credit rating. Standby fees for the unused portion of the KML 2018 Credit Facility will be calculated at a rate ranging from 0.20% to 0.45% based upon KML's debt credit rating.

The KML Credit Agreement contains various financial and other covenants that apply to KML and its subsidiaries and that are common in such agreements, including a maximum ratio of KML's consolidated total funded debt to its consolidated earnings before interest, income taxes, DD&A, and non-cash adjustments as defined in the KML Credit Agreement, of 5.00:1.00 and restrictions on KML's ability to incur debt, grant liens, make dispositions, engage in transactions with affiliates, make restricted payments, make investments, enter into sale leaseback transactions, amend organizational documents and engage in corporate reorganization transactions.

In addition, the KML Credit Agreement contains customary events of default, including non-payment; non-compliance with covenants (in some cases, subject to grace periods); payment default under, or acceleration events affecting, certain other indebtedness; bankruptcy or insolvency events involving KML or guarantors; and changes of control. If an event of default under the KML Credit Agreement exists and is continuing, the lenders could terminate their commitments and accelerate the maturity of the outstanding obligations under the KML Credit Agreement.

On May 30, 2018, in conjunction with the announcement of the TMPL Sale approximately C$100 million of borrowings outstanding under KML's June 16, 2017 revolving credit facilities (the "KML 2017 Credit Facility") were repaid, the underlying credit facilities were terminated, and approximately $46 million of deferred costs associated with the KML 2017 Credit Facility that were being amortized as interest expense over its term were written off.

As of December 31, 2018, KML had no borrowings outstanding under the KML 2018 Credit Facility, and had C$489 million (U.S. $359 million) available under the KML 2018 Credit Facility, after reducing the C$500 million (U.S.$367 million) capacity for the C$11 million (U.S.$8 million) in letters of credit. Of the total C$11 million of letters of credit issued, approximately C$8 million are related to Trans Mountain for which it has issued a backstop letter of credit to KML. As of December 31, 2018, KML was in compliance with all required covenants. As of December 31, 2017, KML had no borrowings outstanding under the KML 2017 Credit Facility.

Maturities of Debt

The scheduled maturities of the outstanding debt balances, excluding debt fair value adjustments as of December 31, 2018, are summarized as follows (in millions):

Year	Total
2019	$ 3,388
2020	2,205
2021	2,422
2022	2,518
2023	3,250
Thereafter	22,810
Total	$ 36,593

Debt Fair Value Adjustments

The carrying value adjustment to debt securities whose fair value is being hedged is included within "Debt fair value adjustments" on our accompanying consolidated balance sheets. "Debt fair value adjustments" also include unamortized debt discount/premiums, purchase accounting debt fair value adjustments, unamortized portion of proceeds received from the early termination of interest rate swap agreements, and debt issuance costs. As of December 31, 2018, the weighted-average amortization period of the unamortized premium from the termination of interest rate swaps was approximately 16 years. The following table summarizes the "Debt fair value adjustments" included on our accompanying consolidated balance sheets (in millions):

	December 31,	
Debt Fair Value Adjustments	2018	2017
Purchase accounting debt fair value adjustments	$ 658	$ 719
Carrying value adjustment to hedged debt	2	115
Unamortized portion of proceeds received from the early termination of interest rate swap agreements	275	297
Unamortized debt discounts, net	(74)	(74)
Unamortized debt issuance costs	(130)	(130)
Total debt fair value adjustments	$ 731	$ 927

Interest Rates, Interest Rate Swaps and Contingent Debt

The weighted average interest rate on all of our borrowings was 5.15% during 2018 and 5.02% during 2017. Information on our interest rate swaps is contained in Note 14. For information about our contingent debt agreements, see Note 13 "*Commitments and Contingent Liabilities—Contingent Debt*").

10. Share-based Compensation and Employee Benefits

Share-based Compensation

Class P Shares

Kinder Morgan, Inc. Amended and Restated Stock Compensation Plan for Non-Employee Directors

We have a Kinder Morgan, Inc. Amended and Restated Stock Compensation Plan for Non-Employee Directors, in which our eligible non-employee directors participate. The plan recognizes that the compensation paid to each eligible non-employee director is fixed by our board, generally annually, and that the compensation is payable in cash. Pursuant to the plan, in lieu of receiving some or all of the cash compensation, each eligible non-employee director may elect to receive shares of Class P common stock. Each election will be generally at or around the first board meeting in January of each calendar year and will be effective for the entire calendar year. An eligible director may make a new election each calendar year. The total number of shares of Class P common stock authorized under the plan is 250,000. During 2018, 2017 and 2016, we made restricted Class P common stock grants to our non-employee directors of 25,800, 17,740 and 31,880, respectively. These grants were valued at time of issuance at $500,000, $400,000 and $400,000, respectively. All of the restricted stock awards made to non-employee directors vest during a six-month period.

Kinder Morgan, Inc. 2015 Amended and Restated Stock Incentive Plan

The Kinder Morgan, Inc. 2015 Amended and Restated Stock Incentive Plan is an equity awards plan available to eligible employees. The total number of shares of Class P common stock authorized under the plan is 33,000,000. The following table sets forth a summary of activity and related balances of our restricted stock awards excluding that issued to non-employee directors (in millions, except share and per share amounts):

	Year Ended December 31, 2018		Year Ended December 31, 2017		Year Ended December 31, 2016	
	Shares	Weighted Average Grant Date Fair Value per Share	Shares	Weighted Average Grant Date Fair Value per Share	Shares	Weighted Average Grant Date Fair Value per Share
Outstanding at beginning of period	10,518,344	$ 28.21	9,038,137	$ 32.72	7,645,105	$ 37.91
Granted	5,389,476	17.73	3,221,691	19.52	2,816,599	21.36
Vested	(2,371,193)	36.34	(1,501,939)	36.67	(1,226,652)	38.53
Forfeited	(382,022)	23.26	(239,545)	28.34	(196,915)	35.74
Outstanding at end of period	13,154,605	22.59	10,518,344	28.21	9,038,137	32.72

The intrinsic value of restricted stock awards vested during the years ended December 31, 2018, 2017 and 2016 was $42 million, $30 million and $25 million, respectively. Restricted stock awards made to employees have vesting periods ranging from 1 year with variable vesting dates to 10 years. Following is a summary of the future vesting of our outstanding restricted stock awards:

Year	Vesting of Restricted Shares
2019	4,048,963
2020	3,537,544
2021	4,814,403
2022	152,104
2023	121,093
Thereafter	480,498
Total Outstanding	13,154,605

The related compensation costs less estimated forfeitures is generally recognized ratably over the vesting period of the restricted stock awards. Upon vesting, the grants will be paid in our Class P common shares.

During 2018, 2017 and 2016, we recorded $63 million, $65 million and $66 million, respectively, in expense related to restricted stock awards and capitalized approximately $13 million, $9 million and $9 million, respectively. At December 31, 2018 and 2017, unrecognized restricted stock awards compensation costs, less estimated forfeitures, was approximately $127 million with a weighted average remaining amortization period of 2.32 years.

KML Restricted Shares

KML adopted the 2017 Restricted Share Unit Plan for Employees, an equity awards plan, for its eligible employees, and the 2017 Restricted Share Unit Plan for Non-Employee Directors, in which its eligible non-employee directors participate. During the year ended December 31, 2018 and 2017, we recognized $6 million and $1 million, respectively, of expense and capitalized $2 million and $1 million, respectively, related to these compensation programs. At December 31, 2018, unrecognized compensation costs, less estimated forfeitures associated with KML's restricted share unit awards, was approximately $3 million, with a weighted average remaining amortization period of 2.1 years.

Pension and Other Postretirement Benefit Plans

Savings Plan

We maintain a defined contribution plan covering eligible U.S. employees. We contribute 5% of eligible compensation for most of the plan participants. Certain collectively bargained participants receive Company contributions in accordance with collective bargaining agreements. The total cost for our savings plan was approximately $48 million, $47 million, and $47 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Pension Plans

Our pension plans are defined benefit plans that cover substantially all of our U.S. employees and provide benefits under a cash balance formula. A participant in the cash balance formula accrues benefits through contribution credits based on a combination of age and years of service, multiplied by eligible compensation. Interest is also credited to the participant's plan account. A participant becomes fully vested in the plan after three years and may take a lump sum distribution upon termination of employment or retirement. Certain collectively bargained and grandfathered employees accrue benefits through career pay or final pay formulas.

Other Postretirement Benefit Plans

We and certain of our subsidiaries provide other postretirement benefits (OPEB), including medical benefits for closed groups of retired employees and certain grandfathered employees and their dependents, and limited postretirement life insurance benefits for retired employees. These plans provide a fixed subsidy to post-age 65 Medicare eligible participants to purchase coverage through a retiree Medicare exchange. Medical benefits under these OPEB plans may be subject to deductibles, co-payment provisions, dollar caps and other limitations on the amount of employer costs, and we reserve the right to change these benefits.

Additionally, our subsidiary SFPP has incurred certain liabilities for postretirement benefits to certain current and former employees, their covered dependents, and their beneficiaries. However, the net periodic benefit costs, contributions and liability amounts associated with the SFPP postretirement benefit plan are not material to our consolidated income statements or balance sheets.

Plans Associated with Foreign Operations

Two of our former subsidiaries, Kinder Morgan Canada Inc. and Trans Mountain Pipeline ULC (as general partner of Trans Mountain Pipeline L.P.), were sponsors of pension and OPEB plans for eligible Canadian and Trans Mountain pipeline employees. These subsidiaries, along with the plan assets of the Canadian pension and OPEB plans, were sold on August 31, 2018 (see Note 3). Prior to 2018, we included the net periodic benefit costs, contributions and liability amounts associated with our Canadian pension plans within our consolidated financial statements. In conjunction with the sale, Kinder Morgan Canada Services was formed and became the Canadian employer of the staff that operates our remaining Canadian assets. Kinder Morgan Canada Services subsequently established a defined contribution pension plan and an OPEB plan for eligible Canadian employees which are not material to our consolidated income statements and balance sheets, and therefore are excluded from the following disclosures.

Benefit Obligation, Plan Assets and Funded Status. The following table provides information about our pension and OPEB plans as of and for each of the years ended December 31, 2018 and 2017 (in millions):

	Pension Benefits		OPEB	
	2018	2017	2018	2017
Change in benefit obligation:				
Benefit obligation at beginning of period	$ 2,982	$ 2,884	$ 425	$ 473
Service cost	52	40	1	1
Interest cost	84	88	12	13
Actuarial (gain) loss	(172)	155	(53)	(16)
Benefits paid	(175)	(180)	(33)	(38)
Participant contributions	—	3	1	2
Medicare Part D subsidy receipts	—	—	1	1
Exchange rate changes	—	13	—	1
Settlements	—	(21)	—	—
Other(a)	(205)	—	(15)	(12)
Benefit obligation at end of period	2,566	2,982	339	425
Change in plan assets:				
Fair value of plan assets at beginning of period	2,296	2,160	335	332
Actual return on plan assets	(128)	292	(5)	29
Employer contributions	30	32	7	9
Participant contributions	—	3	1	2
Medicare Part D subsidy receipts	—	—	1	1
Benefits paid	(175)	(180)	(33)	(38)
Exchange rate changes	—	10	—	—
Settlements	—	(21)	—	—
Other(a)	(159)	—	—	—
Fair value of plan assets at end of period	1,864	2,296	306	335
Funded status - net liability at December 31,	$ (702)	$ (686)	$ (33)	$ (90)

(a) 2018 amounts represent December 31, 2017 balances associated with Canadian pension and OPEB plans that were included in the TMPL Sale. 2017 amounts represent December 31, 2016 balances associated with our Plantation Pipeline OPEB plan that are no longer included in these disclosures.

Components of Funded Status. The following table details the amounts recognized in our balance sheets at December 31, 2018 and 2017 related to our pension and OPEB plans (in millions):

	Pension Benefits		OPEB	
	2018	2017	2018	2017
Non-current benefit asset(a)	$ —	$ —	$ 190	$ 198
Current benefit liability	—	—	(13)	(15)
Non-current benefit liability	(702)	(686)	(210)	(273)
Funded status - net liability at December 31,	$ (702)	$ (686)	$ (33)	$ (90)

(a) 2018 and 2017 OPEB amounts include $32 million and $33 million, respectively, of non-current benefit assets related to a plan we sponsor which is associated with employee services provided to an unconsolidated joint venture, and for which we have recorded an offsetting related party deferred credit.

Components of Accumulated Other Comprehensive (Loss) Income. The following table details the amounts of pre-tax accumulated other comprehensive (loss) income at December 31, 2018 and 2017 related to our pension and OPEB plans which are included on our accompanying consolidated balance sheets, including the portion attributable to our noncontrolling interests, (in millions):

	Pension Benefits		OPEB	
	2018	2017	2018	2017
Unrecognized net actuarial (loss) gain	$ (653)	$ (635)	$ 117	$ 88
Unrecognized prior service (cost) credit	(3)	(4)	14	17
Accumulated other comprehensive (loss) income	$ (656)	$ (639)	$ 131	$ 105

We anticipate that approximately $40 million of pre-tax accumulated other comprehensive loss, inclusive of amounts reported as noncontrolling interests, will be recognized as part of our net periodic benefit cost in 2019, including approximately $42 million of unrecognized net actuarial loss and approximately $2 million of unrecognized prior service credit.

Our accumulated benefit obligation for our pension plans was $2,535 million and $2,840 million at December 31, 2018 and 2017, respectively.

Our accumulated postretirement benefit obligation for our OPEB plans, whose accumulated postretirement benefit obligations exceeded the fair value of plan assets, was $293 million and $373 million at December 31, 2018 and 2017, respectively. The fair value of these plans' assets was approximately $70 million and $84 million at December 31, 2018 and 2017, respectively.

Plan Assets. The investment policies and strategies are established by the Fiduciary Committee for the assets of each of the pension and OPEB plans, which are responsible for investment decisions and management oversight of the plans. The stated philosophy of the Fiduciary Committee is to manage these assets in a manner consistent with the purpose for which the plans were established and the time frame over which the plans' obligations need to be met. The objectives of the investment management program are to (1) meet or exceed plan actuarial earnings assumptions over the long term and (2) provide a reasonable return on assets within established risk tolerance guidelines and to maintain the liquidity needs of the plans with the goal of paying benefit and expense obligations when due. In seeking to meet these objectives, the Fiduciary Committee recognizes that prudent investing requires taking reasonable risks in order to raise the likelihood of achieving the targeted investment returns. In order to reduce portfolio risk and volatility, the Fiduciary Committee has adopted a strategy of using multiple asset classes.

As of December 31, 2018, the allowable range for asset allocations in effect for our pension plan were 34% to 59% equity, 37% to 57% fixed income, 0% to 5% cash, 0% to 2% alternative investments and 0% to 10% company securities (KMI Class P common stock and/or debt securities). As of December 31, 2018, the allowable range for asset allocations in effect for our OPEB plans were 42% to 67% equity, 25% to 51% fixed income and 0% to 20% cash.

Below are the details of our pension and OPEB plan assets by class and a description of the valuation methodologies used for assets measured at fair value.

- Level 1 assets' fair values are based on quoted market prices for the instruments in actively traded markets. Included in this level are cash, equities, exchange traded mutual funds and MLPs. These investments are valued at the closing price reported on the active market on which the individual securities are traded.

- Level 2 assets' fair values are primarily based on pricing data representative of quoted prices for similar assets in active markets (or identical assets in less active markets). Included in this level are short-term investment funds, fixed income securities and derivatives. Short-term investment funds are valued at amortized cost, which approximates fair value. The fixed income securities' fair values are primarily based on an evaluated price which is based on a compilation of primarily observable market information or a broker quote in a non-active market. Derivatives are exchange-traded through clearinghouses and are valued based on these prices.

- Level 3 assets' fair values are calculated using valuation techniques that require inputs that are both significant to the fair value measurement and are unobservable, or are similar to Level 2 assets. Included in this level are guaranteed insurance contracts and immediate participation guarantee contracts. These contracts are valued at contract value, which approximates fair value.

- Plan assets with fair values that are based on the net asset value per share, or its equivalent (NAV), as reported by the issuers are determined based on the fair value of the underlying securities as of the valuation date and include common/collective trust funds, private investment funds, limited partnerships, and fixed income trusts. The plan assets measured at NAV are not categorized within the fair value hierarchy described above, but are separately identified in the following tables.

Listed below are the fair values of our pension and OPEB plans' assets that are recorded at fair value by class and categorized by fair value measurement used at December 31, 2018 and 2017 (in millions):

	Pension Assets							
	2018				2017			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Measured within fair value hierarchy								
Cash	$ —	$ —	$ —	$ —	$ 6	$ —	$ —	$ 6
Short-term investment funds	—	7	—	7	—	65	—	65
Mutual funds(a)	81	—	—	81	245	—	—	245
Equities(b)	227	—	—	227	278	—	—	278
Fixed income securities	—	422	—	422	—	416	—	416
Derivatives	—	6	—	6	—	5	—	5
Subtotal	$ 308	$ 435	$ —	$ 743	$ 529	$ 486	$ —	$ 1,015
Measured at NAV(c)								
Common/collective trusts(d)				857				895
Private investment funds(e)				215				337
Private limited partnerships(f)				49				49
Subtotal				1,121				1,281
Total plan assets fair value				$ 1,864				$ 2,296

(a) Includes mutual funds which are invested in equity.
(b) Plan assets include $94 million and $110 million of KMI Class P common stock for 2018 and 2017, respectively.
(c) Plan assets for which fair value was measured using NAV as a practical expedient.
(d) Common/collective trust funds were invested in approximately 37% fixed income and 63% equity in 2018 and 36% fixed income and 64% equity in 2017.
(e) Private investment funds were invested in approximately 71% fixed income and 29% equity in 2018 and 52% fixed income and 48% equity in 2017.
(f) Includes assets invested in real estate, venture and buyout funds.

	OPEB Assets							
	2018				2017			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Measured within fair value hierarchy								
Short-term investment funds	$ —	$ 4	$ —	$ 4	$ —	$ 7	$ —	$ 7
Equities(a)	—	—	—	—	16	—	—	16
MLPs	—	—	—	—	50	—	—	50
Guaranteed insurance contracts	—	—	51	51	—	—	49	49
Mutual funds	1	—	—	1	1	—	—	1
Subtotal	$ 1	$ 4	$ 51	$ 56	$ 67	$ 7	$ 49	$ 123
Measured at NAV(b)								
Common/collective trusts(c)				250				68
Fixed income trusts				—				66
Limited partnerships(d)				—				78
Subtotal				250				212
Total plan assets fair value				$ 306				$ 335

(a) Plan assets include $2 million of KMI Class P common stock for 2017.
(b) Plan assets for which fair value was measured using NAV as a practical expedient.
(c) Common/collective trust funds were invested in approximately 60% equity and 40% fixed income securities for 2018 and 71% equity and 29% fixed income securities for 2017.
(d) Limited partnerships were invested in global equity securities.

The following tables present the changes in our pension and OPEB plans' assets included in Level 3 for the years ended December 31, 2018 and 2017 (in millions):

	Pension Assets				
	Balance at Beginning of Period	Transfers In (Out)	Realized and Unrealized Gains (Losses), net	Purchases (Sales), net	Balance at End of Period
2017					
Insurance contracts	$ 16	$ —	$ —	$ (16)	$ —

	OPEB Assets				
	Balance at Beginning of Period	Transfers In (Out)	Realized and Unrealized Gains (Losses), net	Purchases (Sales), net	Balance at End of Period
2018					
Insurance contracts	$ 49	$ —	$ 4	$ (2)	$ 51
2017					
Insurance contracts	$ 47	$ —	$ 5	$ (3)	$ 49

Changes in the underlying value of Level 3 assets due to the effect of changes of fair value were immaterial for the years ended December 31, 2018 and 2017.

Expected Payment of Future Benefits and Employer Contributions. As of December 31, 2018, we expect to make the following benefit payments under our plans (in millions):

Fiscal year	Pension Benefits	OPEB(a)
2019	$ 234	$ 33
2020	233	32
2021	225	32
2022	223	31
2023	214	29
2024 - 2028	969	127

(a) Includes a reduction of approximately $2 million in each of the years 2019 - 2023 and approximately $13 million in aggregate for 2024 - 2028 for an expected subsidy related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

In 2019, we expect to contribute approximately $60 million to our pension plans and $7 million, net of anticipated subsidies, to our OPEB plans.

Actuarial Assumptions and Sensitivity Analysis. Benefit obligations and net benefit cost are based on actuarial estimates and assumptions. The following table details the weighted-average actuarial assumptions used in determining our benefit obligation and net benefit costs of our pension and OPEB plans for 2018, 2017 and 2016:

	Pension Benefits			OPEB		
	2018	2017	2016	2018	2017	2016
Assumptions related to benefit obligations:						
Discount rate	4.26%	3.56%	3.83%	4.16%	3.48%	3.69%
Rate of compensation increase	3.50%	3.53%	3.52%	n/a	n/a	n/a
Assumptions related to benefit costs:						
Discount rate for benefit obligations	3.56%	3.83%	4.05%	3.48%	3.69%	3.91%
Discount rate for interest on benefit obligations	3.13%	3.09%	3.24%	3.08%	3.05%	3.18%
Discount rate for service cost	3.56%	3.88%	4.15%	3.82%	4.15%	4.36%
Discount rate for interest on service cost	3.14%	3.24%	3.50%	3.76%	3.95%	4.17%
Expected return on plan assets(a)	7.25%	7.07%	7.31%	7.08%	6.84%	7.07%
Rate of compensation increase	3.50%	3.52%	3.51%	n/a	n/a	n/a

(a) The expected return on plan assets listed in the table above is a pre-tax rate of return based on our targeted portfolio of investments. For the OPEB assets subject to unrelated business income taxes (UBIT), we utilize an after-tax expected return on plan assets to determine our benefit costs, which is based on a UBIT rate of 21% for 2018, 2017 and 2016.

We utilize a full yield curve approach in the estimation of the service and interest cost components of net periodic benefit cost (credit) for our retirement benefit plans by applying the specific spot rates along the yield curve used in the determination of the benefit obligation to their underlying projected cash flows. The expected long-term rates of return on plan assets were determined by combining a review of the historical returns realized within the portfolio, the investment strategy included in the plans' investment policy, and capital market projections for the asset classes in which the portfolio is invested and the target weightings of each asset class.

Actuarial estimates for our OPEB plans assumed a weighted-average annual rate of increase in the per capita cost of covered health care benefits of 7.26%, gradually decreasing to 4.54% by the year 2038. Assumed health care cost trends have a significant effect on the amounts reported for OPEB plans. A one-percentage point change in assumed health care cost trends would have the following effects as of December 31, 2018 and 2017 (in millions):

	2018	2017
One-percentage point increase:		
Aggregate of service cost and interest cost	$ 1	$ 1
Accumulated postretirement benefit obligation	16	22
One-percentage point decrease:		
Aggregate of service cost and interest cost	$ (1)	$ (1)
Accumulated postretirement benefit obligation	(14)	(19)

Components of Net Benefit Cost and Other Amounts Recognized in Other Comprehensive Income. For each of the years ended December 31, the components of net benefit cost and other amounts recognized in pre-tax other comprehensive income related to our pension and OPEB plans are as follows (in millions):

	Pension Benefits			OPEB		
	2018	2017	2016	2018	2017	2016
Components of net benefit cost:						
Service cost	$ 52	$ 40	$ 36	$ 1	$ 1	$ 1
Interest cost	84	88	89	12	13	16
Expected return on assets	(149)	(147)	(151)	(20)	(19)	(19)
Amortization of prior service cost (credit)	—	1	1	(4)	(3)	(3)
Amortization of net actuarial loss (gain)	40	52	35	(6)	(6)	—
Curtailment and settlement loss	—	5	—	—	—	—
Net benefit (credit) cost(a)	27	39	10	(17)	(14)	(5)
Other changes in plan assets and benefit obligations recognized in other comprehensive (income) loss:						
Net loss (gain) arising during period	105	17	116	(32)	(25)	(48)
Prior service cost (credit) arising during period	—	—	—	—	—	—
Amortization or settlement recognition of net actuarial (loss) gain	(87)	(64)	(34)	3	6	—
Amortization of prior service (cost) credit	(1)	(1)	—	3	1	1
Exchange rate changes	—	—	1	—	—	—
Total recognized in total other comprehensive (income) loss	17	(48)	83	(26)	(18)	(47)
Total recognized in net benefit cost (credit) and other comprehensive (income) loss	$ 44	$ (9)	$ 93	$ (43)	$ (32)	$ (52)

(a) 2018 and 2017 OPEB amounts each include $4 million of net benefit credits related to a plan that we sponsor that is associated with employee services provided to an unconsolidated joint venture. We charge or refund these costs or credits associated with this plan to the joint venture as an offset to our net benefit cost or credit and receive our proportionate share of these costs or credits through our share of the equity investee's earnings.

Multiemployer Plans

We participate in several multi-employer pension plans for the benefit of employees who are union members. We do not administer these plans and contribute to them in accordance with the provisions of negotiated labor contracts. Other benefits include a self-insured health and welfare insurance plan and an employee health plan where employees may contribute for their dependents' health care costs. Amounts charged to expense for these plans were approximately $8 million for each of the years ended December 31, 2018, 2017 and 2016. We consider the overall multi-employer pension plan liability exposure to be minimal in relation to the value of its total consolidated assets and net income.

11. Stockholders' Equity

Mandatory Convertible Preferred Stock

As of October 26, 2018, all of our issued and outstanding 1,600,000 shares of 9.75% Series A mandatory convertible preferred stock, with a liquidating preference of $1,000 per share were converted into common stock either at the option of the holders before or automatically on October 26, 2018. Based on the current market price of our common stock at the time of conversion, our Series A Preferred Shares converted into approximately 58 million common shares.

Preferred Stock Dividends

Dividends on our mandatory convertible preferred stock were payable on a cumulative basis when, as and if declared by our board of directors (or an authorized committee thereof) at an annual rate of 9.75% of the liquidation preference of $1,000 per share on January 26, April 26, July 26 and October 26 of each year, commencing on January 26, 2016 to, and including, October 26, 2018. Prior to the October 26, 2018 conversion of our Series A Preferred Shares into common shares, we paid all dividends on our mandatory convertible preferred stock in cash. The following table provides information regarding our preferred stock dividends:

Period	Total dividend per share for the period	Date of declaration	Date of record	Date of dividend
January 26, 2018 through April 25, 2018	$24.375	January 17, 2018	April 11, 2018	April 26, 2018
April 26, 2018 through July 25, 2018	24.375	April 18, 2018	July 11, 2018	July 26, 2018
July 26, 2018 through October 25, 2018	24.375	July 18, 2018	October 11, 2018	October 26, 2018

Common Equity

As of December 31, 2018, our common equity consisted of our Class P common stock.

On July 19, 2017, our board of directors approved a $2 billion common share buy-back program that began in December 2017. During the years ended December 31, 2018 and 2017, we repurchased approximately 15 million and 14 million, respectively, of our Class P shares for approximately $273 million and $250 million, respectively. 2018 amounts exclude repurchases made in December 2018 of approximately 0.1 million of our Class P shares for approximately $2 million which settled on January 2, 2019.

On December 19, 2014, we entered into an equity distribution agreement authorizing us to issue and sell through or to the managers party thereto, as sales agents and/or principals, shares of our Class P common stock having an aggregate offering of up to $5.0 billion from time to time during the term of this agreement. During the years ended December 31, 2018, 2017 and 2016 we did not issue any Class P common stock under this agreement.

KMI Common Stock Dividends

Holders of our common stock participate in any dividend declared by our board of directors, subject to the rights of the holders of any outstanding preferred stock. The following table provides information about our per share dividends:

	Year Ended December 31,		
	2018	2017	2016
Per common share cash dividend declared for the period	$ 0.80	$ 0.50	$ 0.50
Per common share cash dividend paid in the period	0.725	0.50	0.50

On January 16, 2019, our board of directors declared a cash dividend of $0.20 per common share for the quarterly period ended December 31, 2018, which is payable on February 15, 2019 to shareholders of record as of January 31, 2019.

Warrants

The warrant repurchase program dated June 12, 2015, which authorized us to repurchase up to $100 million of warrants, expired along with the warrants on May 25, 2017, at which time 293 million of unexercised warrants to buy KMI common stock expired without the issuance of Class P common stock. Prior to expiration, each of the warrants entitled the holder to purchase one share of our common stock for an exercise price of $40 per share, payable in cash or by cashless exercise.

Noncontrolling Interests

The caption "Noncontrolling interests" in our accompanying consolidated balance sheets consists of interests that we do not own in the following subsidiaries (in millions):

	December 31,	
	2018	2017
KML(a)	$ 514	$ 1,163
Others	339	325
	$ 853	$ 1,488

(a) The reduction in the noncontrolling interests associated with KML is primarily attributable to the accrual of the return of capital distribution for the net proceeds from the TMPL Sale paid to KML's Restricted Voting Shareholders on January 3, 2019 of approximately $0.9 billion.

KML Contributions

KML Restricted Voting Shares

As discussed in Note 3, on May 30, 2017 our indirect subsidiary, KML, issued 102,942,000 restricted voting shares in a public offering listed on the Toronto Stock Exchange. The public ownership of the KML restricted voting shares represents an approximate 30% interest in our Canadian operations and is reflected within "Noncontrolling interests" in our consolidated financial statements as of and for the period presented after May 30, 2017.

KML Preferred Share Offerings

On August 15, 2017, KML completed an offering of 12,000,000 cumulative redeemable minimum rate reset preferred shares, Series 1 (Series 1 Preferred Shares) on the Toronto Stock Exchange at a price to the public of C$25.00 per Series 1 Preferred Share for total gross proceeds of C$300 million (U.S.$235 million). On December 15, 2017, KML completed an offering of 10,000,000 cumulative redeemable minimum rate reset preferred shares, Series 3 (Series 3 Preferred Shares) on the Toronto Stock Exchange at a price to the public of C$25.00 per Series 3 Preferred Share for total gross proceeds of C$250 million (U.S.$195 million). The net proceeds from the Series 1 and Series 3 Preferred Share offerings of C$293 million (U.S. $230 million) and C$243 million (U.S.$189 million), respectively, were used by KML to indirectly subscribe for preferred units in KMC LP, which in turn were used by KMC LP to repay the KML Credit Facility indebtedness recently incurred to, directly or indirectly, finance the development, construction and completion of the TMEP and Base Line Terminal project, and for its general corporate purposes.

KML Distributions

KML has a dividend policy pursuant to which it may pay a quarterly dividend on its restricted voting shares in an amount based on a portion of its DCF. The payment of dividends is not guaranteed and the amount and timing of any dividends payable will be at the discretion of KML's board of directors. If declared by KML's board of directors, KML will pay quarterly dividends, on or about the 45th day (or next business day) following the end of each calendar quarter to holders of its restricted voting shares of record as of the close of business on or about the last business day of the month following the end of each calendar quarter. KML also established a Dividend Reinvestment Plan (DRIP) which allows holders (excluding holders not resident in Canada) of restricted voting shares to elect to have any or all cash dividends payable to such shareholder automatically reinvested in additional restricted voting shares at a price per share calculated by reference to the volume-weighted average of the closing price of the restricted voting shares on the stock exchange on which the restricted voting shares are then listed for the five trading days immediately preceding the relevant dividend payment date, less a discount of between 0% and 5% (as determined from time to time by KML's board of directors, in its sole discretion).

Subsequent Event

On January 16, 2019, KML's board of directors announced that it would suspend KML's DRIP, effective with the payment of the fourth quarter 2018 dividend noted above, in light of KML's reduced need for capital.

KML also pays dividends on its Series 1 Preferred Shares and Series 3 Preferred Shares, which are fixed, cumulative, preferential, and payable quarterly in the annual amount of C$1.3125 per share and C$1.3000 per share, respectively, on the 15th day of February, May, August and November, as and when declared by KML's board of directors, for the initial fixed rate period to but excluding November 15, 2022 and February 15, 2023, respectively.

During the years ended December 31, 2018 and 2017, KML paid dividends on its Restricted Voting Shares to the public valued at $52 million and $18 million, respectively, of which $38 million and $13 million, respectively, was paid in cash. The remaining value of $14 million and $5 million for the years ended December 31, 2018 and 2017, respectively, was paid in 1,092,791 and 418,989, respectively, KML Restricted Voting Shares. KML also paid dividends to the public on its Series 1 and Series 3 Preferred Shares of $21 million for the year ended December 31, 2018 and on its Series 1 Preferred Shares of $3 million for the year ended December 31, 2017.

12. Related Party Transactions

Affiliate Balances

We have transactions with affiliates which consist of (i) unconsolidated affiliates in which we hold an investment accounted for under the equity method of accounting (see Note 7 for additional information related to these investments); and (ii) external joint venture partners of our joint ventures we consolidate, and our proportional method joint ventures, for which we include our proportionate share of balances and activity in our financial statements. The following tables summarize our affiliate balance sheet balances and income statement activity (in millions):

	December 31,	
	2018	2017
Balance sheet location		
Accounts receivable, net	$ 48	$ 34
Other current assets	2	8
Deferred charges and other assets	55	23
	$ 105	$ 65
Current portion of debt	$ 6	$ 6
Accounts payable	26	18
Other current liabilities	7	4
Long-term debt	148	155
Other long-term liabilities and deferred credits	34	35
	$ 221	$ 218

	Year Ended December 31,		
	2018	2017	2016
Income statement location			
Revenues			
Services	$ 171	$ 73	$ 71
Product sales and other	94	89	71
	$ 265	$ 162	$ 142
Operating Costs, Expenses and Other			
Costs of sales	$ 63	$ 20	$ 38
Other operating expenses	91	100	75

13. Commitments and Contingent Liabilities

Leases and Rights-of-Way Obligations

The table below depicts future gross minimum rental commitments under our operating leases and rights-of-way obligations as of December 31, 2018 (in millions):

Year	Commitment
2019	$ 122
2020	107
2021	102
2022	97
2023	81
Thereafter	353
Total minimum payments	$ 862

The remaining terms on our operating leases, including probable elections to exercise renewal options, range from one to thirty-five years. Total lease and rental expenses were $155 million, $140 million and $138 million for the years ended December 31, 2018, 2017 and 2016, respectively. The amount of capital leases included within “Property, plant and equipment, net” in our accompanying consolidated balance sheets as of December 31, 2018 and 2017 is not material to our consolidated balance sheets.

Contingent Debt

Our contingent debt disclosures pertain to certain types of guarantees or indemnifications we have made and cover certain types of guarantees included within debt agreements, even if the likelihood of requiring our performance under such guarantee is remote.

As of December 31, 2018 and 2017, our contingent debt obligations, as well as our obligations with respect to related letters of credit, totaled $714 million and $1,070 million, respectively. December 31, 2018 and 2017 amounts are represented by our proportional share of the debt obligations of four and three equity investees, respectively. Under such guarantees we are severally liable for our percentage ownership share of these equity investees' debt issued in the event of their non-performance. Also included in our contingent debt obligations is a guarantee of a throughput and deficiency agreement supporting certain debt obligations of a subsidiary of our investee, Cortez Pipeline Company. Through this guarantee, we are severally liable for approximately 50% of a Cortez Pipeline Company subsidiary's debt obligations with respect to a $50 million credit facility and $100 million in bonds. In addition, we have guaranteed approximately 100% of the debt issued by another Cortez Pipeline Company subsidiary to fund an expansion project, of which debt consists of a $27 million credit facility and a $120 million private placement note.

Guarantees and Indemnifications

We are involved in joint ventures and other ownership arrangements that sometimes require financial and performance guarantees. In a financial guarantee, we are obligated to make payments if the guaranteed party fails to make payments under, or violates the terms of, the financial arrangement. In a performance guarantee, we provide assurance that the guaranteed party will execute on the terms of the contract. If they do not, we are required to perform on their behalf. We also periodically provide indemnification arrangements related to assets or businesses we have sold. These arrangements include, but are not limited to, indemnifications for income taxes, the resolution of existing disputes and environmental matters.

While many of these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are also circumstances where the amount and duration are unlimited. Currently, we are not subject to any material requirements to perform under quantifiable arrangements. We are unable to estimate a maximum exposure for our guarantee and indemnification agreements that do not provide for limits on the amount of future payments due to the uncertainty of these exposures.

See Note 18 for a description of matters that we have identified as contingencies requiring accrual of liabilities and/or disclosure, including any such matters arising under guarantee or indemnification agreements.

14. Risk Management

Certain of our business activities expose us to risks associated with unfavorable changes in the market price of natural gas, NGL and crude oil. We also have exposure to interest rate and foreign currency risk as a result of the issuance of our debt obligations and net investments in foreign operations. Pursuant to our management's approved risk management policy, we use derivative contracts to hedge or reduce our exposure to some of these risks.

During the year ended December 31, 2018, due to volatility in certain basis differentials, we discontinued hedge accounting on certain of our crude oil derivative contracts as we did not expect them to be highly effective, for accounting purposes, in offsetting the variability in cash flows. As of December 31, 2018, these hedging relationships had been re-designated as the effectiveness improved to required levels. As the forecasted transactions were still probable, accumulated gains and losses prior to the discontinuance remained in "Accumulated other comprehensive loss" unless earnings were impacted by the forecasted transactions; however, changes in the derivative contracts' fair value subsequent to the discontinuance of hedge accounting and prior to the re-designation were reported in earnings. Upon re-designation, we resumed reporting changes in the derivative contracts' fair value in "Accumulated other comprehensive income."

Energy Commodity Price Risk Management

As of December 31, 2018, we had the following outstanding commodity forward contracts to hedge our forecasted energy commodity purchases and sales:

	Net open position long/(short)
Derivatives designated as hedging contracts	
Crude oil fixed price	(21.6) MMBbl
Crude oil basis	(13.7) MMBbl
Natural gas fixed price	(33.3) Bcf
Natural gas basis	(26.1) Bcf
Derivatives not designated as hedging contracts	
Crude oil fixed price	(0.5) MMBbl
Crude oil basis	(4.5) MMBbl
Natural gas fixed price	(4.5) Bcf
Natural gas basis	(26.9) Bcf
NGL fixed price	(3.2) MMBbl

As of December 31, 2018, the maximum length of time over which we have hedged, for accounting purposes, our exposure to the variability in future cash flows associated with energy commodity price risk is through December 2022.

Interest Rate Risk Management

As of December 31, 2018 and 2017, we had a combined notional principal amount of $10,575 million and $9,575 million, respectively, of fixed-to-variable interest rate swap agreements, all of which were designated as fair value hedges. All of our swap agreements effectively convert the interest expense associated with certain series of senior notes from fixed rates to variable rates based on an interest rate of LIBOR plus a spread and have termination dates that correspond to the maturity dates of the related series of senior notes. As of December 31, 2018, the maximum length of time over which we have hedged a portion of our exposure to the variability in the value of debt due to interest rate risk is through March 15, 2035.

Foreign Currency Risk Management

As of both December 31, 2018 and 2017, we had a notional principal amount of $1,358 million of cross-currency swap agreements to manage the foreign currency risk related to our Euro denominated senior notes by effectively converting all of the fixed-rate Euro denominated debt, including annual interest payments and the payment of principal at maturity, to U.S. dollar denominated debt at fixed rates equivalent to approximately 3.79% and 4.67% for the 7-year and 12-year senior notes, respectively. These cross-currency swaps are accounted for as cash flow hedges. The terms of the cross-currency swap agreements correspond to the related hedged senior notes, and such agreements have the same maturities as the hedged senior notes.

During the year ended December 31, 2018, we entered into foreign currency swap agreements with a combined notional principal amount of C$2,450 million (U.S.$1,888 million). These swaps result in our selling fixed C$ and receiving fixed U.S.$, effectively hedging the foreign currency risk associated with a substantial portion of our share of the TMPL Sale proceeds which KML distributed on January 3, 2019, at which time the foreign currency swaps expired. These foreign currency swaps were accounted for as net investment hedges as the foreign currency risk was related to our investment in Canadian dollar denominated foreign operations, and the critical risks of the forward contracts coincided with those of the net investment. As a result, the change in fair value of the foreign currency swaps while outstanding were reflected in the CTA section of OCI.

Fair Value of Derivative Contracts

The following table summarizes the fair values of our derivative contracts included in our accompanying consolidated balance sheets (in millions):

Fair Value of Derivative Contracts

		Asset derivatives		Liability derivatives	
		December 31,		December 31,	
		2018	2017	2018	2017
	Location	Fair value		Fair value	
Derivatives designated as hedging contracts					
Energy commodity derivative contracts	Fair value of derivative contracts/ (Other current liabilities)	$ 135	$ 65	$ (45)	$ (53)
	Deferred charges and other assets/ (Other long-term liabilities and deferred credits)	64	14	—	(24)
Subtotal		199	79	(45)	(77)
Interest rate contracts	Fair value of derivative contracts/ (Other current liabilities)	12	41	(37)	(3)
	Deferred charges and other assets/ (Other long-term liabilities and deferred credits)	121	164	(78)	(62)
Subtotal		133	205	(115)	(65)
Foreign currency contracts	Fair value of derivative contracts/ (Other current liabilities)	91	—	(6)	(6)
	Deferred charges and other assets/ (Other long-term liabilities and deferred credits)	106	166	—	—
Subtotal		197	166	(6)	(6)
Total		529	450	(166)	(148)
Derivatives not designated as hedging contracts					
Energy commodity derivative contracts	Fair value of derivative contracts/ (Other current liabilities)	22	8	(5)	(22)
	Deferred charges and other assets/ (Other long-term liabilities and deferred credits)	—	—	—	(2)
Total		22	8	(5)	(24)
Total derivatives		$ 551	$ 458	$ (171)	$ (172)

Effect of Derivative Contracts on the Income Statement

The following tables summarize the pre-tax impact of our derivative contracts in our accompanying consolidated statements of income (in millions):

Derivatives in fair value hedging relationships	Location	Gain/(loss) recognized in income on derivatives and related hedged item		
		Year Ended December 31,		
		2018	2017	2016
Interest rate contracts	Interest, net	$ (122)	$ (103)	$ (180)
Hedged fixed rate debt	Interest, net	$ 113	$ 105	$ 160

Derivatives in cash flow hedging relationships	Gain/(loss) recognized in OCI on derivative (effective portion)(a)			Location	Gain/(loss) reclassified from Accumulated OCI into income (effective portion)(b)			Location	Gain/(loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)		
	Year Ended December 31,				Year Ended December 31,				Year Ended December 31,		
	2018	2017	2016		2018	2017	2016		2018	2017	2016
Energy commodity derivative contracts	$ 201	$ 37	$(182)	Revenues—Natural gas sales	$ (29)	$ 18	$ 23	Revenues—Natural gas sales	$ —	$ —	$ —
				Revenues—Product sales and other	(30)	55	233	Revenues—Product sales and other	(65)	11	(12)
				Costs of sales	21	14	(26)	Costs of sales	—	—	—
Interest rate contracts(c)	3	—	(3)	Interest, net	(4)	(5)	(4)	Interest, net	—	—	—
Foreign currency contracts	(59)	190	21	Other, net	(67)	186	(43)	Other, net	—	—	—
Total	$ 145	$ 227	$(164)	Total	$(109)	$ 268	$ 183	Total	$ (65)	$ 11	$ (12)

(a) We expect to reclassify an approximate $165 million gain associated with cash flow hedge price risk management activities included in our accumulated other comprehensive loss balance as of December 31, 2018 into earnings during the next twelve months (when the associated forecasted transactions are also expected to occur); however, actual amounts reclassified into earnings could vary materially as a result of changes in market prices.

(b) During the year ended December 31, 2018, we recognized a $3 million loss as a result of our equity investment's forecasted transactions being probable of not occurring and a $21 million gain associated with a write-down of hedged inventory. All other amounts reclassified were the result of the hedged forecasted transactions actually affecting earnings (i.e., when the forecasted sales and purchases actually occurred).

(c) Amounts represent our share of an equity investee's accumulated other comprehensive income (loss).

Derivatives in net investment hedging relationships	Gain/(loss) recognized in OCI on derivative (effective portion)			Location	Gain/(loss) reclassified from Accumulated OCI into income (effective portion)(a)			Location	Gain/(loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)		
	Year Ended December 31,				Year Ended December 31,				Year Ended December 31,		
	2018	2017	2016		2018	2017	2016		2018	2017	2016
Foreign currency contracts	$ 91	$ —	$ —	Loss on impairments and divestitures, net	$ 26	$ —	$ —	Other, net	$ —	$ —	$ —
Total	$ 91	$ —	$ —	Total	$ 26	$ —	$ —	Total	$ —	$ —	$ —

(a) During the year ended December 31, 2018, we recognized a $26 million gain from our accumulated other comprehensive loss balance related to the TMPL Sale. See Note 3.

Derivatives not designated as accounting hedges	Location	Gain/(loss) recognized in income on derivatives		
		Year Ended December 31,		
		2018	2017	2016
Energy commodity derivative contracts	Revenues—Natural gas sales	$ 3	$ 20	$ (10)
	Revenues—Product sales and other	(12)	(16)	(26)
	Costs of sales	2	—	3
Interest rate contracts	Interest, net	—	—	63
Total(a)		$ (7)	$ 4	$ 30

(a) For the years ended December 31, 2018, 2017 and 2016 includes approximate losses of $4 million and gains of $57 million and $73 million, respectively, associated with natural gas, crude and NGL derivative contract settlements.

Credit Risks

In conjunction with certain derivative contracts, we are required to provide collateral to our counterparties, which may include posting letters of credit or placing cash in margin accounts. As of December 31, 2018 and 2017, we had no outstanding letters of credit supporting our commodity price risk management program. As of December 31, 2018, we had cash margins of $16 million posted by our counterparties with us as collateral and reported within “Other Current Liabilities” on our accompanying consolidated balance sheet. As of December 31, 2017, we had cash margins of $1 million posted by us with our counterparties as collateral and reported within “Restricted deposits” on our accompanying consolidated balance sheet. The balance at December 31, 2018 consisted of initial margin requirements of $9 million offset by variation margin requirements of $25 million. We also use industry standard commercial agreements that allow for the netting of exposures associated with transactions executed under a single commercial agreement. Additionally, we generally utilize master netting agreements to offset credit exposure across multiple commercial agreements with a single counterparty.

We also have agreements with certain counterparties to our derivative contracts that contain provisions requiring the posting of additional collateral upon a decrease in our credit rating. As of December 31, 2018, based on our current mark to market positions and posted collateral, we estimate that if our credit rating were downgraded one or two notches we would not be required to post additional collateral.

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Loss

Cumulative revenues, expenses, gains and losses that under GAAP are included within our comprehensive income but excluded from our earnings are reported as "Accumulated other comprehensive loss" within "Stockholders' Equity" in our consolidated balance sheets. Changes in the components of our "Accumulated other comprehensive loss" not including non-controlling interests are summarized as follows (in millions):

	Net unrealized gains/(losses) on cash flow hedge derivatives	Foreign currency translation adjustments	Pension and other postretirement liability adjustments	Total Accumulated other comprehensive loss
Balance at December 31, 2015	$ 219	$ (322)	$ (358)	$ (461)
Other comprehensive (loss) gain before reclassifications	(104)	34	(14)	(84)
Gains reclassified from accumulated other comprehensive loss	(116)	—	—	(116)
Net current-period other comprehensive (loss) income	(220)	34	(14)	(200)
Balance at December 31, 2016	(1)	(288)	(372)	(661)
Other comprehensive gain before reclassifications	145	55	40	240
Gains reclassified from accumulated other comprehensive loss	(171)	—	—	(171)
KML IPO	—	44	7	51
Net current-period other comprehensive (loss) income	(26)	99	47	120
Balance at December 31, 2017	(27)	(189)	(325)	(541)
Other comprehensive gain (loss) before reclassifications	111	(89)	(31)	(9)
Losses reclassified from accumulated other comprehensive loss(a)	84	223	22	329
Impact of adoption of ASU 2018-02 (Note 1)	(4)	(36)	(69)	(109)
Net current-period other comprehensive income (loss)	191	98	(78)	211
Balance at December 31, 2018	$ 164	$ (91)	$ (403)	$ (330)

(a) Amounts for foreign currency translation adjustments and pension and other postretirement liability adjustments reflect the deferred losses recognized in income during the year ended December 31, 2018 related to the TMPL Sale.

15. Fair Value

The fair values of our financial instruments are separated into three broad levels (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine fair value. Each fair value measurement must be assigned to a level corresponding to the lowest level input that is significant to the fair value measurement in its entirety.

The three broad levels of inputs defined by the fair value hierarchy are as follows:

- Level 1 Inputs—quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date;
- Level 2 Inputs—inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability; and
- Level 3 Inputs—unobservable inputs for the asset or liability. These unobservable inputs reflect the entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability, and are developed based on the best information available in the circumstances (which might include the reporting entity's own data).

Fair Value of Derivative Contracts

The following two tables summarize the fair value measurements of our (i) energy commodity derivative contracts; (ii) interest rate swap agreements; and (iii) cross-currency swap agreements, based on the three levels established by the Codification (in millions). The tables also identify the impact of derivative contracts which we have elected to present on our accompanying consolidated balance sheets on a gross basis that are eligible for netting under master netting agreements.

	Balance sheet asset fair value measurements by level						
	Level 1	Level 2	Level 3	Gross amount	Contracts available for netting	Cash collateral held(b)	Net amount
As of December 31, 2018							
Energy commodity derivative contracts(a)	$ 28	$ 193	$ —	$ 221	$ (39)	$ (25)	$ 157
Interest rate contracts	$ —	$ 133	$ —	$ 133	$ (7)	$ —	$ 126
Foreign currency contracts	$ —	$ 197	$ —	$ 197	$ (6)	$ —	$ 191
As of December 31, 2017							
Energy commodity derivative contracts(a)	$ 17	$ 70	$ —	$ 87	$ (42)	$ (12)	$ 33
Interest rate contracts	$ —	$ 205	$ —	$ 205	$ (15)	$ —	$ 190
Foreign currency contracts	$ —	$ 166	$ —	$ 166	$ (6)	$ —	$ 160

	Balance sheet liability fair value measurements by level						
	Level 1	Level 2	Level 3	Gross amount	Contracts available for netting	Collateral posted(b)	Net amount
As of December 31, 2018							
Energy commodity derivative contracts(a)	$ (11)	$ (39)	$ —	$ (50)	$ 39	$ —	$ (11)
Interest rate contracts	$ —	$ (115)	$ —	$ (115)	$ 7	$ —	$ (108)
Foreign currency contracts	$ —	$ (6)	$ —	$ (6)	$ 6	$ —	$ —
As of December 31, 2017							
Energy commodity derivative contracts(a)	$ (3)	$ (98)	$ —	$ (101)	$ 42	$ —	$ (59)
Interest rate contracts	$ —	$ (65)	$ —	$ (65)	$ 15	$ —	$ (50)
Foreign currency contracts	$ —	$ (6)	$ —	$ (6)	$ 6	$ —	$ —

(a) Level 1 consists primarily of NYMEX natural gas futures. Level 2 consists primarily of OTC WTI swaps and NGL swaps.
(b) Any cash collateral paid or received is reflected in this table, but only to the extent that it represents variation margins. Any amount associated with derivative prepayments or initial margins that are not influenced by the derivative asset or liability amounts or those that are determined solely on their volumetric notional amounts are excluded from this table.

Fair Value of Financial Instruments

The carrying value and estimated fair value of our outstanding debt balances is disclosed below (in millions):

	December 31, 2018		December 31, 2017	
	Carrying value	Estimated fair value	Carrying value	Estimated fair value
Total debt	$ 37,324	$ 37,469	$ 37,843	$ 40,050

We used Level 2 input values to measure the estimated fair value of our outstanding debt balance as of both December 31, 2018 and 2017.

16. Revenue Recognition

Adoption of Topic 606

Effective January 1, 2018, we adopted ASU No. 2014-09, "Revenue from Contracts with Customers" and the series of related accounting standard updates that followed (collectively referred to as "Topic 606"). We utilized the modified retrospective method to adopt Topic 606, which required us to apply the new revenue standard to (i) all new revenue contracts entered into after January 1, 2018 and (ii) revenue contracts that were not completed as of January 1, 2018. In accordance with this approach, our consolidated revenues for periods prior to January 1, 2018 were not revised. The cumulative effect of this adoption of Topic 606 as of January 1, 2018 was not material.

The impact to our consolidated financial statement line items from the adoption of Topic 606 for these changes was as follows (in millions):

	Year ended December 31, 2018		
Line Item	**As Reported**	**Amounts Without Adoption of Topic 606**	**Effect of Change Increase/ (Decrease)**
Consolidated Statement of Income			
Natural gas sales	$ 3,281	$ 3,339	$ (58)
Services	7,931	8,134	(203)
Product sales and other	2,932	3,270	(338)
Total Revenues	14,144	14,743	(599)
Cost of sales	4,421	5,020	(599)
Operating Income	3,794	3,794	—

The effect-of-change amounts in the table above are attributable to the non-FERC-regulated portion of our Natural Gas Pipelines business segment, which provides gathering, processing and processed commodity sales services for various producers.

In those instances where we purchase and obtain control of the entire natural gas stream in our producer arrangements, we have determined these are contracts with suppliers rather than contracts with customers, and therefore, these arrangements are not included in the scope of Topic 606. These supplier arrangements are subject to updated guidance in ASC 705, Cost of Sales and Services, whereby any embedded fees within such contracts, which historically have been reported as Services revenue, are now reported as a reduction to Cost of sales upon adoption of Topic 606.

In our natural gas processing arrangements where we extract and sell the commodities derived from the processed natural gas stream (i.e., residue gas or NGLs), we may take control of: (i) none of the commodities we sell, (ii) a portion of the commodities we sell, or (iii) all of the commodities we sell.

In those instances where we remit all of the cash proceeds received from third parties for selling the extracted commodities, less the fees attributable to these arrangements, we have determined that the producer has control over these commodities. Upon adoption of Topic 606, we eliminated recording both sales revenue (Natural gas and Product) and Cost of sales amounts and now only record fees attributable to these arrangements to Service revenues.

In other instances where we do not obtain control of the extracted commodities we sell, we are acting as an agent for the producer and, upon adoption of Topic 606, we have continued to recognize Services revenue for the net amount of consideration we retain in exchange for our service.

When we purchase and obtain control of a portion of the residue gas or NGLs we sell, we have determined these arrangements contain both a supply and a service revenue element and therefore are partially in the scope of Topic 606. In these arrangements, the producer is a supplier for the cash settled portion of the commodity we purchase and a customer with regards to the service provided to gather and redeliver the other component. Upon adoption of Topic 606, fees attributable to the supply element are recorded as a reduction to Cost of sales and fees attributable to the service element are recorded as Services revenue. Previously, we recognized Services revenue for both elements.

Nature of Revenue by Segment

Natural Gas Pipelines Segment

We provide various types of natural gas transportation and storage services, natural gas and NGL sales contracts, and various types of gathering and processing services for producers, including receiving, compressing, transporting and re-delivering quantities of natural gas and/or NGLs made available to us by producers to a specified delivery location.

Natural Gas Transportation and Storage Contracts

The natural gas we receive under our transportation and storage contracts remains under the control of our customers. Under firm service contracts, the customer generally pays a two-part transaction price that includes (i) a fixed fee reserving the right to transport or store natural gas in our facilities up to contractually specified capacity levels (referred to as "reservation") and (ii) a per-unit rate for quantities of natural gas actually transported or injected into/withdrawn from storage. In our firm service contracts we generally promise to provide a single integrated service each day over the life of the contract, which is fundamentally a stand-ready obligation to provide services up to the customer's reservation capacity prescribed in the contract. Our customers have a take-or-pay payment obligation with respect to the fixed reservation fee component, regardless of the quantities they actually transport or store. In other cases, generally described as interruptible service, there is no fixed fee associated with these transportation and storage services because the customer accepts the possibility that service may be interrupted at our discretion in order to serve customers who have firm service contracts. We do not have an obligation to perform under interruptible customer arrangements until we accept and schedule the customer's request for periodic service. The customer pays a transaction price based on a per-unit rate for the quantities actually transported or injected into/withdrawn from storage.

Natural Gas and NGL Sales Contracts

Our sales and purchases of natural gas and NGL are primarily accounted for on a gross basis as natural gas sales or product sales, as applicable, and cost of sales. These customer contracts generally provide for the customer to nominate a specified quantity of commodity products to be delivered and sold to the customers at specified delivery points. The customer pays a transaction price typically based on a market indexed per-unit rate for the quantities sold.

Gathering and Processing Contracts

We provide various types of gathering and processing services for producers, including receiving, processing, compressing, transporting and re-delivering quantities of natural gas made available to us by producers to a specified delivery location. This integrated service can be firm if subject to a minimum volume commitment or acreage dedication or non-firm when offered on an as requested, non-guaranteed basis. In our gathering contracts we generally promise to provide the contracted integrated services each day over the life of the contract. The customer pays a transaction price typically based on a per-unit rate for the quantities actually gathered and/or processed, including amounts attributable to deficiency quantities associated with minimum volume contracts.

Products Pipelines Segment

We provide crude oil and refined petroleum transportation and storage services on a firm or non-firm basis. For our firm transportation service, we typically promise to transport on a stand-ready basis the customer's minimum volume commitment amount. The customer is obligated to pay for its volume commitment amount, regardless of whether or not it flows volumes into our pipeline. The customer pays a transaction price typically based on a per-unit rate for quantities transported, including amounts attributable to deficiency quantities. Our firm storage service generally includes a fixed monthly fee for the portion of storage capacity reserved by the customer and a per-unit rate for actual quantities injected into/withdrawn from storage. The customer is obligated to pay the fixed monthly reservation fee, regardless of whether or not it uses our storage facility (i.e., take-or-pay payment obligation). Non-firm transportation and storage service is provided to our customers when and to the extent we determine the requested capacity is available in our pipeline system and/or terminal storage facility. The customer typically pays a per-unit rate for actual quantities of product injected into/withdrawn from storage and/or transported.

We sell transmix, crude oil or other commodity products. The customer's contracts generally include a specified quantity of commodity products to be delivered and sold to the customers at specified delivery points. The customer pays a transaction price typically based on a market indexed per-unit rate for the quantities sold.

Terminals Segment

We provide various types of liquid tank and bulk terminal services. These services are generally comprised of inbound, storage and outbound handling of customer products.

Liquids Tank Services

Firm Storage and Handling Contracts: We have liquids tank storage and handling service contracts that include a promised tank storage capacity provision and prepaid volume throughput of the stored product. In these contracts, we have a stand-ready obligation to perform this contracted service each day over the life of the contract. The customer pays a transaction price typically in the form of a fixed monthly charge and is obligated to pay whether or not it uses the storage capacity and throughput service (i.e., a take-or-pay payment obligation). These contracts generally include a per-unit rate for any quantities we handle at the request of the customer in excess of the prepaid volume throughput amount and also typically include per-unit rates for additional, ancillary services that may be periodically requested by the customer.

Firm Handling Contracts: For our firm handling service contracts, we typically promise to handle on a stand-ready basis throughput volumes up to the customer's minimum volume commitment amount. The customer is obligated to pay for its minimum volume commitment amount, regardless of whether or not it used the handling service. The customer pays a transaction price typically based on a per-unit rate for volumes handled, including amounts attributable to deficiency quantities.

Bulk Services

Our bulk storage and handling contracts generally include inbound handling of our customers' dry bulk material product (e.g. petcoke, metals, ores) into our storage facility and outbound handling of these products from our storage facility. These services are provided on both a firm and non-firm basis. In our firm bulk storage and handling contracts, we are committed to handle and store on a stand-ready basis the minimum throughput quantity of bulk materials contracted by the customer. In some cases, the customer is obligated to pay for its minimum volume commitment amount, regardless of whether or not it uses the storage and handling service. The customer pays a transaction price typically based on a per-unit rate for quantities handled, including amounts attributable to deficiency quantities. For non-firm storage and handling services, the customer pays a transaction price typically based on a per-unit rate for quantities handled on an as requested, non-guaranteed basis.

CO_2 Segment

Our crude oil, NGL, CO_2 and natural gas production customer sales contracts typically include a specified quantity and quality of commodity product to be delivered and sold to the customer at a specified delivery point. The customer pays a transaction price typically based on a market indexed per-unit rate for the quantities sold.

Kinder Morgan Canada Segment

On August 31, 2018, the assets comprising the Kinder Morgan Canada business segment were sold; therefore, this segment will not have revenues on a prospective basis (see Note 3). Prior to the sale of these assets, we provided crude oil and refined petroleum transportation services generally as described above for non-firm, interruptible transportation services in our Products Pipelines business segment. The TMPL regulated tariff was designed to provide revenues sufficient to recover the costs of providing transportation services to shippers, including a return on invested capital. TMPL's revenue was adjusted according to terms prescribed in our toll settlement with shippers as approved by the National Energy Board (NEB). Differences between transportation revenue recognized pursuant to our toll settlement and actual toll receipts were recognized as regulatory assets or liabilities and settled through future tolls.

Disaggregation of Revenues

The following tables present our revenues disaggregated by revenue source and type of revenue for each revenue source (in millions):

	Year ended December 31, 2018						
	Natural Gas Pipelines	Products Pipelines	Terminals	CO_2	Kinder Morgan Canada	Corporate and Eliminations	Total
Revenues from contracts with customers(a)							
Services							
Firm services(b)	$ 3,215	$ 566	$ 976	$ 2	$ —	$ (13)	$ 4,746
Fee-based services	860	791	581	67	167	—	2,466
Total services revenues	4,075	1,357	1,557	69	167	(13)	7,212
Sales							
Natural gas sales	3,319	—	—	2	—	(11)	3,310
Product sales	1,333	216	18	1,222	—	(1)	2,788
Other sales	8	—	—	—	—	—	8
Total sales revenues	4,660	216	18	1,224	—	(12)	6,106
Total revenues from contracts with customers	8,735	1,573	1,575	1,293	167	(25)	13,318
Other revenues(c)	280	140	444	(38)	3	(3)	826
Total revenues	$ 9,015	$ 1,713	$ 2,019	$ 1,255	$ 170	$ (28)	$ 14,144

(a) Differences between the revenue classifications presented on the consolidated statements of income and the categories for the disaggregated revenues by type of revenue above are primarily attributable to revenues reflected in the "Other revenues" category above (see note (c) below).

(b) Includes non-cancellable firm service customer contracts with take-or-pay or minimum volume commitment elements, including those contracts where both the price and quantity amount are fixed. Excludes service contracts with indexed-based pricing, which along with revenues from other customer service contracts are reported as Fee-based services.

(c) Amounts recognized as revenue under guidance prescribed in Topics of the Accounting Standards Codification other than in Topic 606 and primarily include leases and derivatives. The majority of our lease revenues are from certain firm service contracts that are accounted for as operating leases. See Note 14 for additional information related to our derivative contracts.

Contract Balances

Contract assets and contract liabilities are the result of timing differences between revenue recognition, billings and cash collections. We recognize contract assets in those instances where billing occurs subsequent to revenue recognition, and our right to invoice the customer is conditioned on something other than the passage of time. Our contract assets are substantially related to breakage revenue associated with our firm service contracts with minimum volume commitment payment obligations and contracts where we apply revenue levelization (i.e., contracts with fixed rates per volume that increase over the life of the contract for which we record revenue ratably per unit over the life of the contract based on our performance obligations that are generally unchanged over the life of the contract). Our contract liabilities are substantially related to (i) capital improvements paid for in advance by certain customers generally in our non-regulated businesses, which we subsequently recognize as revenue on a straight-line basis over the initial term of the related customer contracts; (ii) consideration received from customers for temporary deficiency quantities under minimum volume contracts that we expect will be made up in a future period, which we subsequently recognize as revenue when the customer makes up the volumes or the likelihood that the customer will exercise its right for deficiency volumes becomes remote (e.g., there is insufficient capacity to make up the volumes, the deficiency makeup period expires); and (iii) contracts with fixed rates per volume that decrease over the life of the contract where we apply revenue levelization for amounts received for our future performance obligations.

The following table presents the activity in our contract assets and liabilities (in millions):

	Year ended December 31, 2018
Contract Assets	
Balance at January 1, 2018	$ 32
Additions	59
Transfer to Accounts receivable	(67)
Balance at December 31, 2018(a)	$ 24
Contract Liabilities	
Balance at January 1, 2018	$ 206
Additions	453
Transfer to Revenues	(360)
Other(b)	(7)
Balance at December 31, 2018(c)	$ 292

(a) Includes current and non-current balances of $14 million and $10 million reported within "Other current assets" and "Deferred charges and other assets," respectively, in our accompanying consolidated balance sheet at December 31, 2018.
(b) Includes 2018 foreign currency translation adjustments associated with the balances at December 31, 2017.
(c) Includes current and non-current balances of $80 million and $212 million reported within "Other current liabilities" and "Other long-term liabilities and deferred credits," respectively, in our accompanying consolidated balance sheet at December 31, 2018.

Revenue Allocated to Remaining Performance Obligations

The following table presents our estimated revenue allocated to remaining performance obligations for contracted revenue that has not yet been recognized, representing our "contractually committed" revenue as of December 31, 2018 that we will invoice or transfer from contract liabilities and recognize in future periods (in millions):

Year	Estimated Revenue
2019	$ 4,881
2020	4,182
2021	3,528
2022	3,011
2023	2,497
Thereafter	14,138
Total	$ 32,237

Our contractually committed revenue, for purposes of the tabular presentation above, is generally limited to service or commodity sale customer contracts which have fixed pricing and fixed volume terms and conditions, generally including contracts with take-or-pay or minimum volume commitment payment obligations. Our contractually committed revenue amounts generally exclude, based on the following practical expedients that we elected to apply, remaining performance obligations for: (i) contracts with index-based pricing or variable volume attributes in which such variable consideration is allocated entirely to a wholly unsatisfied performance obligation or to a wholly unsatisfied promise to transfer a distinct service that forms part of a series of distinct services; (ii) contracts with an original expected duration of one year or less; and (iii) contracts for which we recognize revenue at the amount for which we have the right to invoice for services performed.

17. Reportable Segments

Our reportable business segments are:

- Natural Gas Pipelines—the ownership and operation of (i) major interstate and intrastate natural gas pipeline and storage systems; (ii) natural gas and crude oil gathering systems and natural gas processing and treating facilities; (iii) NGL fractionation facilities and transportation systems; and (iv) LNG facilities;

- Products Pipelines—the ownership and operation of refined petroleum products, NGL and crude oil and condensate pipelines that primarily deliver, among other products, gasoline, diesel and jet fuel, propane, ethane, crude oil and

condensate to various markets, plus the ownership and/or operation of associated product terminals and petroleum pipeline transmix facilities;

- Terminals—the ownership and/or operation of (i) liquids and bulk terminal facilities located throughout the U.S. and portions of Canada that transload and store refined petroleum products, crude oil, ethanol and chemicals, and bulk products, including petroleum coke, metals and ores; and (ii) Jones Act tankers;

- CO_2—(i) the production, transportation and marketing of CO_2 to oil fields that use CO_2 as a flooding medium to increase recovery and production of crude oil from mature oil fields; (ii) ownership interests in and/or operation of oil fields and gas processing plants in West Texas; and (iii) the ownership and operation of a crude oil pipeline system in West Texas; and

- Kinder Morgan Canada (prior to August 31, 2018)—the ownership and operation of the Trans Mountain pipeline system that transports crude oil and refined petroleum products from Edmonton, Alberta, Canada to marketing terminals and refineries in British Columbia, Canada and the state of Washington. As a result of the TMPL Sale, this segment does not have results of operations on a prospective basis.

We evaluate performance principally based on each segment's EBDA, which excludes general and administrative expenses, interest expense, net, and income tax expense. Our reportable segments are strategic business units that offer different products and services, and they are structured based on how our chief operating decision makers organize their operations for optimal performance and resource allocation. Each segment is managed separately because each segment involves different products and marketing strategies.

We consider each period's earnings before all non-cash DD&A expenses to be an important measure of business segment performance for our reporting segments. We account for intersegment sales at market prices, while we account for asset transfers at either market value or, in some instances, book value.

During 2018, 2017 and 2016, we did not have revenues from any single external customer that exceeded 10% of our consolidated revenues.

Financial information by segment follows (in millions):

	Year Ended December 31,		
	2018	2017	2016
Revenues			
Natural Gas Pipelines			
Revenues from external customers	$ 9,004	$ 8,608	$ 7,998
Intersegment revenues	11	10	7
Products Pipelines			
Revenues from external customers	1699	1645	1631
Intersegment revenues	14	16	18
Terminals			
Revenues from external customers	2,017	1,965	1,921
Intersegment revenues	2	1	1
CO2	1,255	1,196	1,221
Kinder Morgan Canada	170	256	253
Corporate and intersegment eliminations(a)	(28)	8	8
Total consolidated revenues	$ 14,144	$ 13,705	$ 13,058

	Year Ended December 31,		
	2018	2017	2016
Operating expenses(b)			
Natural Gas Pipelines	$ 5,353	$ 5,457	$ 4,393
Products Pipelines	594	487	573
Terminals	818	788	768
CO_2	453	394	399
Kinder Morgan Canada	72	95	87
Corporate and intersegment eliminations	(2)	(6)	2
Total consolidated operating expenses	$ 7,288	$ 7,215	$ 6,222

	Year Ended December 31,		
	2018	2017	2016
Other expense (income)(c)			
Natural Gas Pipelines	$ 593	$ 26	$ 199
Products Pipelines	34	—	76
Terminals	54	(14)	99
CO_2	79	(1)	19
Kinder Morgan Canada	(596)	—	—
Corporate	—	1	(7)
Total consolidated other expense (income)	$ 164	$ 12	$ 386

	Year Ended December 31,		
	2018	2017	2016
DD&A			
Natural Gas Pipelines	$ 1,058	$ 1,011	$ 1,041
Products Pipelines	228	216	221
Terminals	484	472	435
CO_2	473	493	446
Kinder Morgan Canada	29	46	44
Corporate	25	23	22
Total consolidated DD&A	$ 2,297	$ 2,261	$ 2,209

	Year Ended December 31,		
	2018	2017	2016
Earnings from equity investments and amortization of excess cost of equity investments, including loss on impairments			
Natural Gas Pipelines	$ 391	$ 253	$ (269)
Products Pipelines	75	48	56
Terminals	22	24	19
CO_2	34	42	22
Total consolidated equity earnings	$ 522	$ 367	$ (172)

	Year Ended December 31,		
	2018	2017	2016
Other, net-income (expense)			
Natural Gas Pipelines	$ 37	$ 49	$ 19
Products Pipelines	3	(1)	2
Terminals	2	8	4
Kinder Morgan Canada	26	25	15
Corporate	39	16	38
Total consolidated other, net-income (expense)	$ 107	$ 97	$ 78

	Year Ended December 31,		
	2018	2017	2016
Segment EBDA(d)			
Natural Gas Pipelines	$ 3,580	$ 3,487	$ 3,211
Products Pipelines	1,173	1,231	1,067
Terminals	1,171	1,224	1,078
CO_2	759	847	827
Kinder Morgan Canada	720	186	181
Total segment EBDA	7,403	6,975	6,364
DD&A	(2,297)	(2,261)	(2,209)
Amortization of excess cost of equity investments	(95)	(61)	(59)
General and administrative and corporate charges	(588)	(660)	(652)
Interest, net	(1,917)	(1,832)	(1,806)
Income tax expense	(587)	(1,938)	(917)
Total consolidated net income	$ 1,919	$ 223	$ 721

	Year Ended December 31,		
	2018	2017	2016
Capital expenditures			
Natural Gas Pipelines	$ 1,620	$ 1,376	$ 1,227
Products Pipelines	150	127	244
Terminals	380	888	983
CO_2	397	436	276
Kinder Morgan Canada	332	338	124
Corporate	25	23	28
Total consolidated capital expenditures	$ 2,904	$ 3,188	$ 2,882

	2018	2017
Investments at December 31		
Natural Gas Pipelines	$ 6,358	$ 6,218
Products Pipelines	839	777
Terminals	268	263
CO_2	16	6
Kinder Morgan Canada	—	34
Total consolidated investments	$ 7,481	$ 7,298

	2018	2017
Assets at December 31		
Natural Gas Pipelines	$ 51,562	$ 51,173
Products Pipelines	8,429	8,539
Terminals	9,283	9,935
CO_2	3,928	3,946
Kinder Morgan Canada	—	2,080
Corporate assets(e)	5,664	3,382
Total consolidated assets	$ 78,866	$ 79,055

(a) 2017 and 2016 amounts include a management fee of $35 million and $34 million, respectively, for services we perform as operator of an equity investee.
(b) Includes costs of sales, operations and maintenance expenses, and taxes, other than income taxes.
(c) Includes loss on impairments and divestitures, net and other income, net.
(d) Includes revenues, earnings from equity investments, other, net, less operating expenses, loss on impairments and divestitures, net, loss on impairments and divestitures of equity investments, net and other income, net.
(e) Includes cash and cash equivalents, margin and restricted deposits, certain prepaid assets and deferred charges, including income tax related assets, risk management assets related to debt fair value adjustments, corporate headquarters in Houston, Texas and miscellaneous corporate assets (such as information technology, telecommunications equipment and legacy activity) not allocated to our reportable segments.

We do not attribute interest and debt expense to any of our reportable business segments.

Following is geographic information regarding the revenues and long-lived assets of our business (in millions):

	Year Ended December 31,		
	2018	2017	2016
Revenues from external customers			
U.S.	$ 13,596	$ 13,073	$ 12,459
Canada	447	503	483
Mexico and other foreign	101	129	116
Total consolidated revenues from external customers	$ 14,144	$ 13,705	$ 13,058

	December 31,		
	2018	2017	2016
Long-term assets, excluding goodwill and other intangibles			
U.S.	$ 47,468	$ 47,928	$ 49,125
Canada	748	3,071	2,399
Mexico and other foreign	83	80	82
Total consolidated long-lived assets	$ 48,299	$ 51,079	$ 51,606

18. Litigation, Environmental and Other Contingencies

We and our subsidiaries are parties to various legal, regulatory and other matters arising from the day-to-day operations of our businesses or certain predecessor operations that may result in claims against the Company. Although no assurance can be given, we believe, based on our experiences to date and taking into account established reserves and insurance, that the ultimate resolution of such items will not have a material adverse impact on our business, financial position, results of operations or dividends to our shareholders. We believe we have meritorious defenses to the matters to which we are a party and intend to vigorously defend the Company. When we determine a loss is probable of occurring and is reasonably estimable, we accrue an undiscounted liability for such contingencies based on our best estimate using information available at that time. If the estimated loss is a range of potential outcomes and there is no better estimate within the range, we accrue the amount at the low end of the range. We disclose contingencies where an adverse outcome may be material or, in the judgment of management, we conclude the matter should otherwise be disclosed.

FERC Proceedings

FERC Rulemaking on Tax Cuts and Jobs Act for Jurisdictional Natural Gas Pipelines

On March 15, 2018, FERC issued a notice of proposed rule-making (NOPR) which proposed a process to implement for ratemaking purposes the 2017 Tax Reform. The NOPR proposed that each regulated interstate natural gas pipeline make a mandatory filing (Form 501-G) to reflect, based upon certain required assumptions, the rate impact of the reduced statutory corporate tax rate, and in the case of master limited partnerships and other pass-through entities, the elimination of an income tax allowance and unspecified resulting treatment of accumulated deferred income tax (ADIT) in the cost of service. The NOPR also provided four options for regulated entities to consider: (1) make a limited filing under section 4 of the NGA to reduce rates for the impact of the 2017 Tax Reform; (2) commit to file a general section 4 rate case in the near future; (3) file an explanation why no rate change is needed, or (4) take no further action other than filing the required Form 501-G report. On July 18, 2018, FERC issued Order No. 849 (Final Rule) promulgating a final rule to implement the 2017 Tax Reform for jurisdictional natural gas pipelines. The Final Rule continues to require the regulated interstate pipelines to file the Form 501-G reflecting certain mandatory assumptions. The Final Rule also maintains substantially the same four options for regulated entities to implement the reduced corporate tax rate. The Final Rule clarifies that pass-through entities whose income consolidates up to a federal income tax paying entity are eligible for a tax allowance. It also clarifies that the required filing is a one-time informational filing and that FERC is not mandating any adjustment in rates as a function of complying with the Final Rule. Companies are also allowed to file an addendum which may reflect an income tax allowance, alternative capital structure and alternative equity returns. The Final Rule establishes a presumption that negotiated rate contracts should not be disturbed. Kinder Morgan filed for rehearing of the Final Rule, but also filed the required Form 501-G filings. We continue to believe any initial, downward rate pressure will be mitigated and spread out over multiple years given the procedural options presented in the Final Rule, the prospective nature of rate changes under section 5 of the NGA and the fact that the FERC affirmed its intention to respect negotiated rate contracts. Many of our transportation and storage services are rendered pursuant to negotiated rate agreements that, consistent with the Final Rule, will not be subject to adjustment due to changes in tax law. Also, many of our current transactions are provided at discounted rates that are below maximum tariff rates, many of which would not be impacted by a change in the maximum tariff rate. Further, on many of our pipelines we are operating under settlements that preclude customers from requesting rate changes at the FERC during the life of the settlement.

SFPP

The tariffs and rates charged by SFPP are subject to a number of ongoing proceedings at the FERC, including the complaints and protests of various shippers, the most recent of which was filed in 2015 (docketed at OR16-6) challenging SFPP's filed East Line rates. In general, these complaints and protests allege the rates and tariffs charged by SFPP are not just and reasonable under the Interstate Commerce Act (ICA). In some of these proceedings shippers have challenged the overall rate being charged by SFPP, and in others the shippers have challenged SFPP's index-based rate increases. If the shippers prevail on their arguments or claims, they are entitled to seek reparations (which may reach back up to two years prior to the filing date of their complaints) or refunds of any excess rates paid, and SFPP may be required to reduce its rates going forward. These proceedings tend to be protracted, with decisions of the FERC often appealed to the federal courts. The issues involved in these proceedings include, among others, whether indexed rate increases are justified, and the appropriate level of return and income tax allowance SFPP may include in its rates. On March 22, 2016, the D.C. Circuit issued a decision in *United Airlines, Inc. v. FERC* remanding to FERC for further consideration of two issues: (1) the appropriate data to be used to determine the return on equity for SFPP in the underlying docket, and (2) the just and reasonable return to be provided to a tax pass-through entity that includes an income tax allowance in its underlying cost of service. On July 21, 2017, an initial decision by the Administrative Law Judge (ALJ) in OR16-6 concluded that the Complainants are due reparations, with appropriate interest, equal to the difference between what SFPP collected from the Complainants for service on the East Line and the amounts SFPP would have collected had it charged just and reasonable rates for that line. The ALJ ruled that an income tax allowance should be included in the cost of service both to determine reparations and to set going forward rates, and found that the new just and reasonable rates are not knowable until the FERC reviews the initial decision and orders a compliance filing. The FERC will determine which portions of the initial decision to affirm, reject or amend. On March 15, 2018, the FERC announced certain policy changes including a Revised Policy Statement on Treatment of Income Taxes (Revised Policy Statement) and, that same day, the FERC issued orders in a series of pending SFPP proceedings which combined to deny income tax allowance to SFPP, direct SFPP to make compliance filings in its 2008 and 2009 rate filing dockets, and restart the 2011 SFPP complaint proceeding which had been abated. Requests for rehearing were filed in the Revised Policy Statement docket as well as the SFPP dockets in which the Revised Policy Statement was applied. The requests for rehearing in the SFPP dockets remain pending at the FERC. On July 18, 2018, the FERC issued an Order on Rehearing in the Revised Policy Statement docket in which it denied the rehearing petitions and clarified that the issue of entitlement to an income tax allowance will continue to be resolved in individual proceedings, including proceedings involving income tax pass-through entities. The FERC also clarified

that when an income tax allowance is eliminated from cost of service, previously ADIT balances associated with such income tax allowance may also be eliminated. SFPP along with another pipeline entity appealed the Revised Policy Statement along with the Order on Rehearing to the D.C. Circuit. With respect to the various SFPP related complaints and protest proceedings at the FERC, we estimate that the shippers are seeking approximately $30 million in annual rate reductions and approximately $330 million in refunds. Management believes SFPP has meritorious arguments supporting SFPP's rates and intends to vigorously defend SFPP against these complaints and protests. However, to the extent the shippers are successful in one or more of the complaints or protest proceedings, SFPP estimates that applying the principles of FERC precedent, as applicable, to pending SFPP cases would result in rate reductions and refunds substantially lower than those sought by the shippers.

EPNG

The tariffs and rates charged by EPNG are subject to two ongoing FERC proceedings (the "2008 rate case" and the "2010 rate case"). With respect to the 2008 rate case, the FERC issued its decision (Opinion 517-A) in July 2015. The FERC generally upheld its prior determinations, ordered refunds to be paid within 60 days, and stated that it will apply its findings in Opinion 517-A to the same issues in the 2010 rate case. All refund obligations related to the 2008 rate case were satisfied during calendar year 2015. EPNG sought federal appellate review of Opinion 517-A and oral arguments were held on February 15, 2017. On February 21, 2017, the reviewing court delayed the case until the FERC rules on the rehearing requests pending in the 2010 Rate Case. With respect to the 2010 rate case, the FERC issued its decision (Opinion 528-A) on February 18, 2016. The FERC generally upheld its prior determinations, affirmed prior findings of an Administrative Law Judge that certain shippers qualify for lower rates and required EPNG to file revised pro forma recalculated rates consistent with the terms of Opinions 517-A and 528-A. On May 3, 2018, the FERC issued Opinion 528-B upholding its decisions in Opinion 528-A and requiring EPNG to implement the rates required by its rulings and provide refunds within 60 days. On July 2, 2018, EPNG reported to the FERC the refund calculations, and that the refunds had been provided as ordered. Also on July 2, 2018, EPNG initiated appellate review of Opinions 528, 528-A and 528-B. On August 23, 2018, the reviewing court established a briefing schedule and consolidated EPNG's delayed appeal from the 2008 rate case, EPNG's appeal from the 2010 rate case, and the intervenors' delayed appeal in the 2010 case. In accordance with that schedule, EPNG and the intervenors filed their initial briefs on January 8, 2019.

Other Commercial Matters

Union Pacific Railroad Company Easements Landowner Litigation

A purported class action lawsuit was filed in 2015 in a U.S. District Court in California against Union Pacific Railroad Company (UPRR), SFPP, KMGP and Kinder Morgan Operating L.P. "D" by private landowners who claimed to be the lawful owners of subsurface real property allegedly used or occupied by UPRR or SFPP for pipeline easements on rights-of-way held by UPRR. Substantially similar follow-on lawsuits were filed in federal courts by landowners in Nevada, Arizona and New Mexico. These suits, which were brought purportedly as class actions on behalf of all landowners who own land in fee adjacent to and underlying the railroad easement under which the SFPP pipeline is located in those respective states, asserted claims alleging that the defendants' occupation and use of the subsurface real property was improper. Plaintiffs' motions for class certification were denied by the federal courts in Arizona and California. The Ninth Circuit Court of Appeals denied interlocutory review of the class certification decisions, and the New Mexico and Nevada lawsuits were stayed. All pending lawsuits have now been settled or dismissed on terms that are not material to KMI's results of operations, cash flows or dividends to shareholders.

Gulf LNG Facility Arbitration

On March 1, 2016, Gulf LNG Energy, LLC and Gulf LNG Pipeline, LLC (GLNG) received a Notice of Disagreement and Disputed Statements and a Notice of Arbitration from Eni USA Gas Marketing LLC (Eni USA), one of two companies that entered into a terminal use agreement for capacity of the Gulf LNG Facility in Mississippi for an initial term that was not scheduled to expire until the year 2031. Eni USA is an indirect subsidiary of Eni S.p.A., a multi-national integrated energy company headquartered in Milan, Italy. Pursuant to its Notice of Arbitration, Eni USA sought declaratory and monetary relief based upon its assertion that (i) the terminal use agreement should be terminated because changes in the U.S. natural gas market since the execution of the agreement in December 2007 have "frustrated the essential purpose" of the agreement and (ii) activities allegedly undertaken by affiliates of Gulf LNG Holdings Group LLC "in connection with a plan to convert the LNG Facility into a liquefaction/export facility have given rise to a contractual right on the part of Eni USA to terminate" the agreement. A three-member arbitration panel conducted an arbitration hearing in January 2017. On June 29, 2018, the arbitration panel delivered its Award, and the panel's ruling calls for the termination of the agreement and Eni USA's payment of compensation to GLNG. The Award resulted in our recording a net loss in the second quarter of 2018 of our equity investment in GLNG due to a non-cash impairment of our investment in GLNG partially offset by our share of earnings

recognized by GLNG. On September 25, 2018, GLNG filed a lawsuit against Eni USA in the Delaware Court of Chancery to enforce the Award. On February 1, 2019, the Delaware Court of Chancery issued a Final Order and Judgment confirming the Award. On September 28, 2018, GLNG filed a lawsuit against Eni S.p.A. in the Supreme Court of the State of New York in New York County to enforce a Guarantee Agreement entered by Eni S.p.A. in connection with the terminal use agreement. On December 12, 2018, Eni S.p.A. filed a counterclaim seeking unspecified damages from GLNG. GLNG intends to vigorously prosecute and defend both lawsuits.

Brinckerhoff Merger Litigation

In April 2017, a purported class action suit was filed in the Delaware Court of Chancery by Peter Brinckerhoff, a former EPB unitholder on behalf of a class of former unaffiliated unitholders of EPB, seeking to challenge the $9.2 billion merger of EPB into a subsidiary of KMI as part of a series of transactions in November 2014 whereby KMI acquired all of the outstanding equity interests in KMP, Kinder Morgan Management, LLC and EPB that KMI and its subsidiaries did not already own. The suit alleged that the merger consideration did not sufficiently compensate EPB unitholders for the value of three derivative suits concerning drop down transactions which the derivative plaintiff lost standing to pursue after the merger. The suit claimed that the alleged failure to obtain sufficient merger consideration for the drop down lawsuits constituted a breach of the EPB limited partnership agreement and the implied covenant of good faith and fair dealing. The suit also asserted claims against KMI and certain individual defendants for allegedly tortiously interfering with and/or aiding and abetting the alleged breach of the limited partnership agreement. In November 2017, the Court dismissed the suit in its entirety. On June 8, 2018, the Delaware Supreme Court affirmed the dismissal. Also in November 2017, counsel for Brinckerhoff filed a separate lawsuit against KMEP and KMI seeking to recover up to $44 million in attorneys' fees allegedly incurred in connection with the assertion of derivative claims that Brinckerhoff lost standing to pursue. On April 9, 2018, the Court dismissed the suit in its entirety, and that dismissal is final.

Price Reporting Litigation

Beginning in 2003, several lawsuits were filed by purchasers of natural gas against El Paso Corporation, El Paso Marketing L.P. and numerous other energy companies based on a claim under state antitrust law that such defendants conspired to manipulate the price of natural gas by providing false price information to industry trade publications that published gas indices. Several of the cases were previously settled or dismissed, except for two cases pending in a U.S. District Court in Nevada, including a lawsuit brought by an industrial consumer in Kansas in which approximately $500 million in damages plus interest was alleged against all defendants, and a Wisconsin class action in which approximately $300 million in damages plus interest has been alleged against all defendants. The Kansas case has now been settled, and a settlement in principal has been reached in the Wisconsin class action that will require class notice and court approval in 2019. The amount to be paid in settlement of these matters is not material to our results of operations, cash flows or dividends to shareholders.

Pipeline Integrity and Releases

From time to time, despite our best efforts, our pipelines experience leaks and ruptures. These leaks and ruptures may cause explosions, fire, and damage to the environment, damage to property and/or personal injury or death. In connection with these incidents, we may be sued for damages caused by an alleged failure to properly mark the locations of our pipelines and/or to properly maintain our pipelines. Depending upon the facts and circumstances of a particular incident, state and federal regulatory authorities may seek civil and/or criminal fines and penalties.

General

As of December 31, 2018 and 2017, our total reserve for legal matters was $207 million and $350 million, respectively. The reduction in the reserve primarily resulted from the payment of refunds in the EPNG rate case matter discussed above in "*—FERC Proceedings—EPNG.*" The remaining reserve primarily relates to various claims from regulatory proceedings arising in our Products Pipelines business segment.

Environmental Matters

We and our subsidiaries are subject to environmental cleanup and enforcement actions from time to time. In particular, CERCLA generally imposes joint and several liability for cleanup and enforcement costs on current and predecessor owners and operators of a site, among others, without regard to fault or the legality of the original conduct, subject to the right of a liable party to establish a "reasonable basis" for apportionment of costs. Our operations are also subject to federal, state and local laws and regulations relating to protection of the environment. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in pipeline,

terminal and CO_2 field and oil field operations, and there can be no assurance that we will not incur significant costs and liabilities. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies under the terms of authority of those laws, and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities to us.

We are currently involved in several governmental proceedings involving alleged violations of environmental and safety regulations, including alleged violations of the Risk Management Program and leak detection and repair requirements of the Clean Air Act. As we receive notices of non-compliance, we attempt to negotiate and settle such matters where appropriate. These alleged violations may result in fines and penalties, but we do not believe any such fines and penalties, individually or in the aggregate, will be material. We are also currently involved in several governmental proceedings involving groundwater and soil remediation efforts under administrative orders or related state remediation programs. We have established a reserve to address the costs associated with the remediation.

In addition, we are involved with and have been identified as a potentially responsible party in several federal and state superfund sites. Environmental reserves have been established for those sites where our contribution is probable and reasonably estimable. In addition, we are from time to time involved in civil proceedings relating to damages alleged to have occurred as a result of accidental leaks or spills of refined petroleum products, NGL, natural gas and CO_2.

Portland Harbor Superfund Site, Willamette River, Portland, Oregon

In December 2000, the EPA issued General Notice letters to potentially responsible parties including GATX Terminals Corporation (n/k/a KMLT). At that time, GATX owned two liquids terminals along the lower reach of the Willamette River, an industrialized area known as Portland Harbor. Portland Harbor is listed on the National Priorities List and is designated as a Superfund Site under CERCLA. A group of potentially responsible parties formed what is known as the Lower Willamette Group (LWG), of which KMLT is a non-voting member. The LWG agreed to conduct the remedial investigation and feasibility study (RI/FS) leading to the proposed remedy for cleanup of the Portland Harbor site. The EPA issued the FS and the Proposed Plan on June 8, 2016 which included a proposed combination of dredging, capping, and enhanced natural recovery. On January 6, 2017, the EPA issued its Record of Decision (ROD) for the final cleanup plan. The final remedy is more stringent than the remedy proposed in the EPA's Proposed Plan. The estimated cost increased from approximately $750 million to approximately $1.1 billion, and active cleanup is now expected to take as long as 13 years to complete. KMLT and 90 other parties are involved in a non-judicial allocation process to determine each party's respective share of the cleanup costs. We are participating in the allocation process on behalf of KMLT and KMBT in connection with their current or former ownership or operation of four facilities located in Portland Harbor. Our share of responsibility for Portland Harbor Superfund Site costs will not be determined until the ongoing non-judicial allocation process is concluded in several years or a lawsuit is filed that results in a judicial decision allocating responsibility. Until the allocation process is completed, we are unable to reasonably estimate the extent of our liability for the costs related to the design of the proposed remedy and cleanup of the site. In addition to CERCLA cleanup costs, we are reviewing and will attempt to settle, if possible, natural resource damage (NRD) claims asserted by state and federal trustees following their natural resource assessment of the site. At this time, we are unable to reasonably estimate the extent of our potential NRD liability.

Roosevelt Irrigation District v. Kinder Morgan G.P., Inc., Kinder Morgan Energy Partners, L.P., U.S. District Court, Arizona

The Roosevelt Irrigation District filed a lawsuit in 2010 against KMGP, KMEP and others under CERCLA for alleged contamination of the water purveyor's wells. The First Amended Complaint sought $175 million in damages from approximately 70 defendants. KMGP was dismissed from the suit. On August 6, 2013, plaintiffs filed their Second Amended Complaint seeking monetary damages in unspecified amounts and reducing the number of defendants to 26 including KMEP and SFPP. The claims against KMEP and SFPP were related to alleged releases from a specific parcel within the SFPP Phoenix Terminal and the alleged impact of such releases on water wells owned by the plaintiffs and located in the vicinity of the Terminal. During the first quarter of 2018, KMEP and SFPP settled all claims made by the Roosevelt Irrigation District on terms that are not material to KMI's results of operations, cash flows or dividends to shareholders.

Uranium Mines in Vicinity of Cameron, Arizona

In the 1950s and 1960s, Rare Metals Inc., a historical subsidiary of EPNG, mined approximately twenty uranium mines in the vicinity of Cameron, Arizona, many of which are located on the Navajo Indian Reservation. The mining activities were in response to numerous incentives provided to industry by the U.S. to locate and produce domestic sources of uranium to support the Cold War-era nuclear weapons program. In May 2012, EPNG received a general notice letter from the EPA notifying EPNG of the EPA's investigation of certain sites and its determination that the EPA considers EPNG to be a potentially

responsible party within the meaning of CERCLA. In August 2013, EPNG and the EPA entered into an Administrative Order on Consent and Scope of Work pursuant to which EPNG is conducting a radiological assessment of the surface of the mines and the immediate vicinity. On September 3, 2014, EPNG filed a complaint in the U.S. District Court for the District of Arizona seeking cost recovery and contribution from the applicable federal government agencies toward the cost of environmental activities associated with the mines, given the U.S. is the owner of the Navajo Reservation, the U.S.'s exploration and reclamation activities at the mines, and the pervasive control of such federal agencies over all aspects of the nuclear weapons program. Defendants filed an answer and counterclaims seeking contribution and recovery of response costs allegedly incurred by the federal agencies in investigating uranium impacts on the Navajo Reservation. The counterclaim of defendant EPA has been settled, and no viable claims for reimbursement by the other defendants are known to exist. In August 2017, the District Court found the U.S. liable under CERCLA as owner of the Navajo Reservation. The matter seeking cost recovery and contribution from federal government agencies is set for trial in February 2019. We intend to continue to prosecute and defend this case vigorously.

Lower Passaic River Study Area of the Diamond Alkali Superfund Site, Essex, Hudson, Bergen and Passaic Counties, New Jersey

EPEC Polymers, Inc. (EPEC Polymers) and EPEC Oil Company Liquidating Trust (EPEC Oil Trust), former El Paso Corporation entities now owned by KMI, are involved in an administrative action under CERCLA known as the Lower Passaic River Study Area Superfund Site (Site) concerning the lower 17-mile stretch of the Passaic River. It has been alleged that EPEC Polymers and EPEC Oil Trust may be potentially responsible parties (PRPs) under CERCLA based on prior ownership and/or operation of properties located along the relevant section of the Passaic River. EPEC Polymers and EPEC Oil Trust entered into two Administrative Orders on Consent (AOCs) which obligate them to investigate and characterize contamination at the Site. They are also part of a joint defense group of approximately 44 cooperating parties, referred to as the Cooperating Parties Group (CPG), which has entered into AOCs and is directing and funding the work required by the EPA. Under the first AOC, draft remedial investigation and feasibility studies (RI/FS) of the Site were submitted to the EPA in 2015, and EPA approval remains pending. Under the second AOC, the CPG members conducted a CERCLA removal action at the Passaic River Mile 10.9, and the group is currently conducting EPA-directed post-remedy monitoring in the removal area. We have established a reserve for the anticipated cost of compliance with the AOCs.

On April 11, 2014, the EPA announced the issuance of its Focused Feasibility Study (FFS) for the lower eight miles of the Passaic River Study Area, and its proposed plan for remedial alternatives to address the dioxin sediment contamination from the mouth of Newark Bay to River Mile 8.3. The EPA estimates the cost for the alternatives will range from $365 million to $3.2 billion. The EPA's preferred alternative would involve dredging the river bank-to-bank and installing an engineered cap at an estimated cost of $1.7 billion. On March 4, 2016, the EPA issued its Record of Decision (ROD) for the lower eight miles of the Passaic River Study area. The final cleanup plan in the ROD is substantially similar to the EPA's preferred alternative announced on April 11, 2014. On October 5, 2016, the EPA entered into an AOC with Occidental Chemical Company (OCC), a member of the PRP group requiring OCC to spend an estimated $165 million to perform engineering and design work necessary to begin the cleanup of the lower eight miles of the Passaic River. The design work is expected to take four years to complete and the cleanup is expected to take six years to complete. On June 30, 2018 and July 13, 2018, respectively, OCC filed two separate lawsuits in the U.S. District Court for the District of New Jersey seeking cost recovery and contribution under CERCLA from more than 120 defendants, including EPEC Polymers. OCC alleges that each defendant is responsible to reimburse OCC for a proportionate share of the $165 million OCC is required to spend pursuant to its AOC. EPEC Polymers was dismissed without prejudice from the lawsuit on August 8, 2018.

In addition, the EPA and numerous PRPs, including EPEC Polymers, are engaged in an allocation process for the implementation of the remedy for the lower eight miles of the Passaic River Study area. There remains significant uncertainty as to the implementation and associated costs of the remedy set forth in the FFS and ROD. There is also uncertainty as to the impact of the recent EPA FS directive for the upper nine mile segment not subject to the lower eight mile FFS and ROD. In a letter dated October 10, 2018, the EPA directed the CPG to prepare a streamlined FS for the Site that evaluates interim remedy alternatives for sediments in the upper nine miles of the Site. Until this FS is completed and the RI/FS is finalized and allocations are determined, the scope of potential EPA claims for the Site and liability therefor are not reasonably estimable.

Plaquemines Parish Louisiana Coastal Zone Litigation

On November 8, 2013, the Parish of Plaquemines, Louisiana filed a petition for damages in the state district court for Plaquemines Parish, Louisiana against TGP and 17 other energy companies, alleging that defendants' oil and gas exploration, production and transportation operations in the Bastian Bay, Buras, Empire and Fort Jackson oil and gas fields of Plaquemines Parish caused substantial damage to the coastal waters and nearby lands (Coastal Zone) within the Parish, including the erosion of marshes and the discharge of oil waste and other pollutants which detrimentally affected the quality of state waters and plant

and animal life, in violation of the State and Local Coastal Resources Management Act of 1978 (Coastal Zone Management Act). The case is one of numerous similar cases pending in Louisiana. As a result of such alleged violations of the Coastal Zone Management Act, Plaquemines Parish seeks, among other relief, unspecified monetary relief, attorney fees, interest, and payment of costs necessary to restore the allegedly affected Coastal Zone to its original condition, including costs to clear, vegetate and detoxify the Coastal Zone. In connection with this suit, TGP made two tenders for defense and indemnity: (1) to Anadarko, as successor to the entity that purchased TGP's oil and gas assets in Bastian Bay, and (2) to Kinetica, which purchased TGP's pipeline assets in Bastian Bay in 2013. Anadarko accepted TGP's tender (limited to oil and gas assets), and Kinetica rejected TGP's tender. The Louisiana Department of Natural Resources (LDNR) and the Louisiana Attorney General (LAG) intervened in the lawsuit. The Court separated the defendants into several trial groups and set trials to begin in 2019. The case involving TGP was set for trial in 2020. During May 2018, the defendants removed numerous cases which allege violations under the Coastal Zone Management Act to federal court in Louisiana; the case involving TGP was removed to the U.S. District Court for the Eastern District of Louisiana. Thereafter, the defendants moved the U.S. Judicial Panel on Multidistrict Litigation to transfer all such cases, including the case involving TGP, to the U.S. District Court for the Eastern District of Louisiana for coordinated proceedings. On July 31, 2018, the Panel denied the motion. The plaintiffs and intervenors moved to remand all of the cases, including the case involving TGP, to the state district courts. Those motions are pending. All of the cases, including the case involving TGP, remain effectively stayed pending resolution of the removal and remand issues. We will continue to vigorously defend the lawsuit.

Vintage Assets, Inc. Coastal Erosion Litigation

On December 18, 2015, Vintage Assets, Inc. and several individual landowners filed a lawsuit in the State District Court for Plaquemines Parish, Louisiana alleging that its 5,000 acre property is composed of coastal wetlands, and that SNG and TGP failed to maintain pipeline canals and banks, causing widening of the canals, land loss, and damage to the ecology and hydrology of the marsh, in breach of right of way agreements, prudent operating practices, and Louisiana law. The suit also claims that defendants' alleged failure to maintain pipeline canals and banks constitutes negligence and has resulted in encroachment of the canals, constituting trespass. The suit seeks in excess of $80 million in money damages, including recovery of litigation costs, damages for trespass, and money damages associated with an alleged loss of natural resources and projected reconstruction cost of replacing or restoring wetlands. The suit was removed to the U.S. District Court for the Eastern District of Louisiana. The SNG assets at issue were sold to Highpoint Gas Transmission, LLC in 2011, which was subsequently purchased by American Midstream Partners, LP. In response to SNG's demand for defense and indemnity, American Midstream Partners agreed to pay 50% of joint defense costs and expenses, with a percentage of indemnity to be determined upon final resolution of the suit. On October 20, 2016, plaintiffs filed an amended complaint naming Highpoint Gas Transmission, LLC as an additional defendant. A non-jury trial was held during September 2017. On May 4, 2018, the District Court entered a judgment dismissing the tort and negligence claims against all of the defendants, and dismissing certain of the contract claims against TGP. In ruling in favor of plaintiffs on the remaining contract claims, the District Court ordered the Defendants to pay $1,104 in money damages, and issued a permanent injunction ordering the Defendants to restore a total of 9.6 acres of land and maintain certain canals at widths designated by the right of way agreements in effect. The Court stayed the judgment and the injunction pending appeal. The parties each filed a separate appeal to the U.S. Court of Appeals for the Fifth Circuit. On September 13, 2018, Highpoint Gas Transmission, LLC filed a motion to vacate the judgment and dismiss all of the appeals for lack of subject matter jurisdiction. On October 2, 2018, the Court of Appeals dismissed the appeals and remanded the suit to the U.S. District Court for the Eastern District of Louisiana. In doing so, the Court of Appeals ordered the District Court to remand the suit to the State District Court of Plaquemines Parish, Louisiana for further proceedings. The District Court has not yet done so. We will continue to vigorously defend the suit.

General

Although it is not possible to predict the ultimate outcomes, we believe that the resolution of the environmental matters set forth in this note, and other matters to which we and our subsidiaries are a party, will not have a material adverse effect on our business, financial position, results of operations or cash flows. As of December 31, 2018 and 2017, we have accrued a total reserve for environmental liabilities in the amount of $271 million and $279 million, respectively. In addition, as of both December 31, 2018 and 2017, we have recorded a receivable of $13 million for expected cost recoveries that have been deemed probable.

Other Contingencies

In 2017, in order to demonstrate to the NEB that Trans Mountain has sufficient financial resources to meet its responsibilities under Canada's Pipeline Safety Act (the "Act"), we entered into a loan facility with Trans Mountain pursuant to which it may borrow up to C$500 million from us in the event that a TMPL environmental incident occurs giving rise to a liability on the part of Trans Mountain under the Act. Upon the closing of the TMPL Sale on August 31, 2018, the government

of Canada delivered to us a C$500 million cash-collateralized letter of credit to fully backstop our obligation under the loan facility, which will continue until the NEB approves a replacement arrangement with which Trans Mountain may satisfy its financial resources requirement.

19. Recent Accounting Pronouncements

Accounting Standards Updates

Topic 842

On February 25, 2016, the FASB issued ASU No. 2016-02, "*Leases*" followed by a series of related accounting standard updates (collectively referred to as "Topic 842"). Topic 842 establishes a new lease accounting model for leases. The most significant changes include the clarification of the definition of a lease, the requirement for lessees to recognize for all leases a right-of-use asset and a lease liability in the consolidated balance sheet, and additional quantitative and qualitative disclosures which are designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. Expenses are recognized in the consolidated statement of income in a manner similar to current accounting guidance. Lessor accounting under the new standard is substantially unchanged. The new standard will become effective for us beginning with the first quarter 2019. We will adopt the accounting standard using a prospective transition approach, which applies the provisions of the new guidance at the effective date without adjusting the comparative periods presented. We have elected the package of practical expedients permitted under the transition guidance within the new standard, which among other things, allows us to carry forward the historical accounting relating to lease identification and classification for existing leases upon adoption. We have also elected the optional practical expedient permitted under the transition guidance within the new standard related to land easements that allows us to carry forward our historical accounting treatment for land easements on existing agreements upon adoption. We have made an accounting policy election to keep leases with an initial term of 12 months or less off of the consolidated balance sheet. We are finalizing our evaluation of the impacts that the adoption of this accounting guidance will have on the consolidated financial statements, and estimate approximately $500 million of additional right-of-use assets and liabilities will be recognized in our consolidated balance sheet upon adoption.

ASU No. 2016-13

On June 16, 2016, the FASB issued ASU No. 2016-13, "*Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*." This ASU modifies the impairment model to utilize an expected loss methodology in place of the currently used incurred loss methodology, which will result in the more timely recognition of losses. ASU No. 2016-13 will be effective for us as of January 1, 2020, and earlier adoption is permitted. We are currently reviewing the effect of this ASU to our financial statements.

ASU No. 2017-04

On January 26, 2017, the FASB issued ASU No. 2017-04, "*Intangibles - Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment.*" This ASU simplifies the accounting for goodwill impairment by removing Step 2 of the goodwill impairment test, which requires a hypothetical purchase price allocation. Goodwill impairment will now be the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill. ASU No. 2017-04 will be effective for us as of January 1, 2020, and earlier adoption is permitted. We are currently reviewing the effect of this ASU to our financial statements.

ASU No. 2017-12

On August 28, 2017, the FASB issued ASU No. 2017-12, "*Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities*." This ASU better aligns an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results. The guidance expands the ability to hedge nonfinancial and financial risk components, reduces complexity in fair value hedges of interest rate risk, eliminates the requirement to separately measure and report hedge ineffectiveness, and eases certain hedge effectiveness assessment requirements. ASU No. 2017-12 was effective January 1, 2019. We adopted ASU No. 2017-12 with no material impact to our financial statements.

ASU No. 2018-13

On August 28, 2018, the FASB issued ASU No. 2018-13, "*Fair Value Measurement (Topic 820): Disclosure Framework-Changes to the Disclosure Requirements for Fair Value Measurement.*" This ASU amends existing fair value measurement

disclosure requirements by adding, changing, or removing certain disclosures. ASU No. 2018-13 will be effective for us as of January 1, 2020, and earlier adoption is permitted. We are currently reviewing the effect of this ASU to our financial statements.

ASU No. 2018-14

On August 28, 2018, the FASB issued ASU No. 2018-14, "*Compensation - Retirement Benefits - Defined Benefit Plans - General (Subtopic 715-20): Disclosure Framework - Changes to the Disclosure Requirements for Defined Benefit Plans*." This ASU amends existing annual disclosure requirements applicable to all employers that sponsor defined benefit pension and other postretirement plans by adding, removing, and clarifying certain disclosures. ASU No. 2018-14 will be effective for us for the fiscal year ending December 31, 2020, and earlier adoption is permitted. We are currently reviewing the effect of this ASU to our financial statements.

20. Guarantee of Securities of Subsidiaries

KMI, along with its direct subsidiary KMP, are issuers of certain public debt securities. KMI, KMP and substantially all of KMI's wholly owned domestic subsidiaries, are parties to a cross guarantee agreement whereby each party to the agreement unconditionally guarantees, jointly and severally, the payment of specified indebtedness of each other party to the agreement. Accordingly, with the exception of certain subsidiaries identified as Subsidiary Non-Guarantors, the parent issuer, subsidiary issuer and other subsidiaries are all guarantors of each series of public debt. As a result of the cross guarantee agreement, a holder of any of the guaranteed public debt securities issued by KMI or KMP are in the same position with respect to the net assets, income and cash flows of KMI and the Subsidiary Issuer and Guarantors. The only amounts that are not available to the holders of each of the guaranteed public debt securities to satisfy the repayment of such securities are the net assets, income and cash flows of the Subsidiary Non-Guarantors.

In lieu of providing separate financial statements for subsidiary issuer and guarantor, we have included the accompanying condensed consolidating financial statements based on Rule 3-10 of the SEC's Regulation S-X. We have presented each of the parent and subsidiary issuer in separate columns in this single set of condensed consolidating financial statements.

Excluding fair value adjustments, as of December 31, 2018, Parent Issuer and Guarantor, Subsidiary Issuer and Guarantor-KMP, and Subsidiary Guarantors had $15,192 million, $17,910 million, and $2,535 million of Guaranteed Notes outstanding, respectively. Included in the Subsidiary Guarantors debt balance as presented in the accompanying December 31, 2018 condensed consolidating balance sheet are approximately $159 million of capitalized lease debt that is not subject to the cross guarantee agreement.

The accounts within the Parent Issuer and Guarantor, Subsidiary Issuer and Guarantor-KMP, Subsidiary Guarantors and Subsidiary Non-Guarantors are presented using the equity method of accounting for investments in subsidiaries, including subsidiaries that are guarantors and non-guarantors, for purposes of these condensed consolidating financial statements only. These intercompany investments and related activity eliminate in consolidation and are presented separately in the accompanying condensed consolidating balance sheets and statements of income and cash flows.

A significant amount of each Issuers' income and cash flow is generated by its respective subsidiaries. As a result, the funds necessary to meet its debt service and/or guarantee obligations are provided in large part by distributions or advances it receives from its respective subsidiaries. We utilize a centralized cash pooling program among our majority-owned and consolidated subsidiaries, including the Subsidiary Issuers and Guarantors and Subsidiary Non-Guarantors. The following Condensed Consolidating Statements of Cash Flows present the intercompany loan and distribution activity, as well as cash collection and payments made on behalf of our subsidiaries, as cash activities.

Condensed Consolidating Statements of Income and Comprehensive Income
for the Year Ended December 31, 2018
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ —	$ —	$ 12,767	$ 1,526	$ (149)	$ 14,144
Operating Costs, Expenses and Other						
Costs of sales	—	—	4,247	277	(103)	4,421
Depreciation, depletion and amortization	19	—	1,971	307	—	2,297
Other operating expenses	(39)	1	3,693	23	(46)	3,632
Total Operating Costs, Expenses and Other	(20)	1	9,911	607	(149)	10,350
Operating Income (Loss)	20	(1)	2,856	919	—	3,794
Other Income (Expense)						
Earnings from consolidated subsidiaries	2,760	2,533	599	62	(5,954)	—
Earnings from equity investments	—	—	617	—	—	617
Interest, net	(780)	(8)	(1,090)	(39)	—	(1,917)
Amortization of excess cost of equity investments and other, net	27	—	(18)	3	—	12
Income Before Income Taxes	2,027	2,524	2,964	945	(5,954)	2,506
Income Tax (Expense) Benefit	(418)	68	(61)	(176)	—	(587)
Net Income	1,609	2,592	2,903	769	(5,954)	1,919
Net Income Attributable to Noncontrolling Interests	—	—	—	—	(310)	(310)
Net Income Attributable to Controlling Interests	1,609	2,592	2,903	769	(6,264)	1,609
Preferred Stock Dividends	(128)	—	—	—	—	(128)
Net Income Available to Common Stockholders	$ 1,481	$ 2,592	$ 2,903	$ 769	$ (6,264)	$ 1,481
Net Income	$ 1,609	$ 2,592	$ 2,903	$ 769	$ (5,954)	$ 1,919
Total other comprehensive income	320	290	280	136	(688)	338
Comprehensive income	1,929	2,882	3,183	905	(6,642)	2,257
Comprehensive income attributable to noncontrolling interests	—	—	—	—	(328)	(328)
Comprehensive income attributable to controlling interests	$ 1,929	$ 2,882	$ 3,183	$ 905	$ (6,970)	$ 1,929

Condensed Consolidating Statements of Income and Comprehensive Income
for the Year Ended December 31, 2017
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ 35	$ —	$ 12,202	$ 1,614	$ (146)	$ 13,705
Operating Costs, Expenses and Other						
Costs of sales	—	—	4,124	322	(101)	4,345
Depreciation, depletion and amortization	16	—	1,933	312	—	2,261
Other operating expenses	78	1	3,014	522	(45)	3,570
Total Operating Costs, Expenses and Other	94	1	9,071	1,156	(146)	10,176
Operating (Loss) Income	(59)	(1)	3,131	458	—	3,529
Other Income (Expense)						
Earnings from consolidated subsidiaries	3,575	2,681	419	59	(6,734)	—
Earnings from equity investments	—	—	428	—	—	428
Interest, net	(701)	7	(1,104)	(34)	—	(1,832)
Amortization of excess cost of equity investments and other, net	2	—	13	21	—	36
Income Before Income Taxes	2,817	2,687	2,887	504	(6,734)	2,161
Income Tax (Expense) Benefit	(2,634)	(5)	237	464	—	(1,938)
Net Income	183	2,682	3,124	968	(6,734)	223
Net Income Attributable to Noncontrolling Interests	—	—	—	—	(40)	(40)
Net Income Attributable to Controlling Interests	183	2,682	3,124	968	(6,774)	183
Preferred Stock Dividends	(156)	—	—	—	—	(156)
Net Income Available to Common Stockholders	$ 27	$ 2,682	$ 3,124	$ 968	$ (6,774)	$ 27
Net Income	$ 183	$ 2,682	$ 3,124	$ 968	$ (6,734)	$ 223
Total other comprehensive income	69	194	217	160	(525)	115
Comprehensive income	252	2,876	3,341	1,128	(7,259)	338
Comprehensive income attributable to noncontrolling interests	—	—	—	—	(86)	(86)
Comprehensive income attributable to controlling interests	$ 252	$ 2,876	$ 3,341	$ 1,128	$ (7,345)	$ 252

Condensed Consolidating Statements of Income and Comprehensive Income
for the Year Ended December 31, 2016
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ 34	$ —	$ 11,572	$ 1,511	$ (59)	$ 13,058
Operating Costs, Expenses and Other						
Costs of sales	—	—	3,176	266	(13)	3,429
Depreciation, depletion and amortization	18	—	1,872	319	—	2,209
Other operating expenses	758	(36)	2,461	745	(46)	3,882
Total Operating Costs, Expenses and Other	776	(36)	7,509	1,330	(59)	9,520
Operating (Loss) Income	(742)	36	4,063	181	—	3,538
Other Income (Expense)						
Earnings from consolidated subsidiaries	2,948	2,802	245	58	(6,053)	—
Losses from equity investments	—	—	(113)	—	—	(113)
Interest, net	(696)	90	(1,149)	(51)	—	(1,806)
Amortization of excess cost of equity investments and other, net	33	—	(18)	4	—	19
Income Before Income Taxes	1,543	2,928	3,028	192	(6,053)	1,638
Income Tax Expense	(835)	(5)	(33)	(44)	—	(917)
Net Income	708	2,923	2,995	148	(6,053)	721
Net Income Attributable to Noncontrolling Interests	—	—	—	—	(13)	(13)
Net Income Attributable to Controlling Interests	708	2,923	2,995	148	(6,066)	708
Preferred Stock Dividends	(156)	—	—	—	—	(156)
Net Income Available to Common Stockholders	$ 552	$ 2,923	$ 2,995	$ 148	$ (6,066)	$ 552
Net Income	$ 708	$ 2,923	$ 2,995	$ 148	$ (6,053)	$ 721
Total other comprehensive (loss) income	(200)	(341)	(352)	55	638	(200)
Comprehensive income	508	2,582	2,643	203	(5,415)	521
Comprehensive income attributable to noncontrolling interests	—	—	—	—	(13)	(13)
Comprehensive income attributable to controlling interests	$ 508	$ 2,582	$ 2,643	$ 203	$ (5,428)	$ 508

Condensed Consolidating Balance Sheet as of December 31, 2018
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
ASSETS						
Cash and cash equivalents	$ 8	$ —	$ —	$ 3,277	$ (5)	$ 3,280
Other current assets - affiliates	4,465	4,788	23,851	1,031	(34,135)	—
All other current assets	171	17	2,056	212	(14)	2,442
Property, plant and equipment, net	231	—	30,750	6,916	—	37,897
Investments	664	—	6,718	99	—	7,481
Investments in subsidiaries	42,096	40,049	6,077	4,324	(92,546)	—
Goodwill	13,789	22	5,166	2,988	—	21,965
Notes receivable from affiliates	945	20,345	247	1,043	(22,580)	—
Deferred income taxes	3,137	—	—	—	(1,571)	1,566
Other non-current assets	233	105	3,823	74	—	4,235
Total assets	$ 65,739	$ 65,326	$ 78,688	$ 19,964	$ (150,851)	$ 78,866
LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND STOCKHOLDERS' EQUITY						
Liabilities						
Current portion of debt	$ 1,933	$ 1,300	$ 30	$ 125	$ —	$ 3,388
Other current liabilities - affiliates	14,189	14,087	4,898	961	(34,135)	—
All other current liabilities	486	354	1,838	1,510	(19)	4,169
Long-term debt	13,474	16,799	3,020	643	—	33,936
Notes payable to affiliates	1,234	448	20,543	355	(22,580)	—
Deferred income taxes	—	—	503	1,068	(1,571)	—
Other long-term liabilities and deferred credits	745	59	944	428	—	2,176
Total liabilities	32,061	33,047	31,776	5,090	(58,305)	43,669
Redeemable noncontrolling interest	—	—	666	—	—	666
Stockholders' equity						
Total KMI equity	33,678	32,279	46,246	14,874	(93,399)	33,678
Noncontrolling interests	—	—	—	—	853	853
Total stockholders' equity	33,678	32,279	46,246	14,874	(92,546)	34,531
Total Liabilities, Redeemable Noncontrolling Interest and Stockholders' Equity	$ 65,739	$ 65,326	$ 78,688	$ 19,964	$ (150,851)	$ 78,866

Condensed Consolidating Balance Sheet as of December 31, 2017
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
ASSETS						
Cash and cash equivalents	$ 3	$ —	$ —	$ 262	$ (1)	$ 264
Other current assets - affiliates	6,214	5,201	22,402	858	(34,675)	—
All other current assets	243	59	1,938	235	(24)	2,451
Property, plant and equipment, net	236	—	31,093	8,826	—	40,155
Investments	665	—	6,498	135	—	7,298
Investments in subsidiaries	37,983	36,728	5,417	4,232	(84,360)	—
Goodwill	13,789	22	5,166	3,185	—	22,162
Notes receivable from affiliates	1,033	20,363	1,233	776	(23,405)	—
Deferred income taxes	3,635	—	—	—	(1,591)	2,044
Other non-current assets	254	164	4,080	183	—	4,681
Total assets	$ 64,055	$ 62,537	$ 77,827	$ 18,692	$ (144,056)	$ 79,055
LIABILITIES AND STOCKHOLDERS' EQUITY						
Liabilities						
Current portion of debt	$ 924	$ 975	$ 805	$ 124	$ —	$ 2,828
Other current liabilities - affiliates	13,225	14,188	6,512	750	(34,675)	—
All other current liabilities	468	347	2,055	508	(25)	3,353
Long-term debt	13,104	18,206	3,052	653	—	35,015
Notes payable to affiliates	2,009	448	20,593	355	(23,405)	—
Deferred income taxes	—	—	449	1,142	(1,591)	—
Other long-term liabilities and deferred credits	689	117	1,462	467	—	2,735
Total liabilities	30,419	34,281	34,928	3,999	(59,696)	43,931
Stockholders' equity						
Total KMI equity	33,636	28,256	42,899	14,693	(85,848)	33,636
Noncontrolling interests	—	—	—	—	1,488	1,488
Total stockholders' equity	33,636	28,256	42,899	14,693	(84,360)	35,124
Total liabilities and stockholders' equity	$ 64,055	$ 62,537	$ 77,827	$ 18,692	$ (144,056)	$ 79,055

Condensed Consolidating Statements of Cash Flows
for the Year Ended December 31, 2018
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Net cash (used in) provided by operating activities	$ (2,758)	$ 3,879	$ 11,129	$ 1,117	$ (8,324)	$ 5,043
Cash flows from investing activities						
Proceeds from the TMPL Sale, net of cash disposed	—	—	—	2,998	—	2,998
Acquisitions of investments	—	—	(39)	—	—	(39)
Capital expenditures	(24)	—	(1,995)	(885)	—	(2,904)
Proceeds from sales of equity investments	—	—	124	—	—	124
Sales of property, plant and equipment, investments and other net assets, net of removal costs	9	—	(34)	5	—	(20)
Contributions to investments	(12)	—	(413)	(8)	—	(433)
Distributions from equity investments in excess of cumulative earnings	2,342	—	234	1	(2,340)	237
Funding to affiliates	(6,521)	(26)	(7,419)	(1,003)	14,969	—
Loans to related parties	—	—	(31)	—	—	(31)
Net cash (used in) provided by investing activities	(4,206)	(26)	(9,573)	1,108	12,629	(68)
Cash flows from financing activities						
Issuances of debt	14,143	—	—	608	—	14,751
Payments of debt	(12,640)	(975)	(784)	(192)	—	(14,591)
Debt issue costs	(35)	—	—	(7)	—	(42)
Cash dividends - common shares	(1,618)	—	—	—	—	(1,618)
Cash dividends - preferred shares	(156)	—	—	—	—	(156)
Repurchases of common shares	(273)	—	—	—	—	(273)
Funding from affiliates	7,560	2,028	4,542	839	(14,969)	—
Contributions from investment partner	—	—	181	—	—	181
Contributions from parents	—	—	19	—	(19)	—
Contributions from noncontrolling interests	—	—	—	—	19	19
Distributions to parents	—	(4,907)	(5,514)	(317)	10,738	—
Distributions to noncontrolling interests	—	—	—	—	(78)	(78)
Other, net	(12)	—	—	(5)	—	(17)
Net cash provided by (used in) financing activities	6,969	(3,854)	(1,556)	926	(4,309)	(1,824)
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Deposits	—	—	—	(146)	—	(146)
Net increase (decrease) in Cash, Cash Equivalents and Restricted Deposits	5	(1)	—	3,005	(4)	3,005
Cash, Cash Equivalents, and Restricted Deposits, beginning of period	3	1	—	323	(1)	326
Cash, Cash Equivalents, and Restricted Deposits, end of period	$ 8	$ —	$ —	$ 3,328	$ (5)	$ 3,331

Condensed Consolidating Statements of Cash Flows
for the Year Ended December 31, 2017
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Net cash (used in) provided by operating activities	$ (3,184)	$ 3,911	$ 11,523	$ 1,121	$ (8,770)	$ 4,601
Cash flows from investing activities						
Acquisitions of investments	—	—	(4)	—	—	(4)
Capital expenditures	(23)	—	(2,390)	(775)	—	(3,188)
Sales of property, plant and equipment, investments and other net assets, net of removal costs	16	—	94	8	—	118
Contributions to investments	(237)	—	(435)	(12)	—	(684)
Distributions from equity investments in excess of cumulative earnings	2,297	—	326	—	(2,249)	374
Funding (to) from affiliates	(4,419)	779	(7,040)	(1,028)	11,708	—
Loans to related party	(23)	—	—	—	—	(23)
Other, net	—	1	4	(1)	—	4
Net cash (used in) provided by investing activities	(2,389)	780	(9,445)	(1,808)	9,459	(3,403)
Cash flows from financing activities						
Issuances of debt	8,609	—	—	259	—	8,868
Payments of debt	(9,288)	(600)	(897)	(279)	—	(11,064)
Debt issue costs	(12)	—	—	(58)	—	(70)
Cash dividends - common shares	(1,120)	—	—	—	—	(1,120)
Cash dividends - preferred shares	(156)	—	—	—	—	(156)
Repurchases of common shares	(250)	—	—	—	—	(250)
Funding from (to) affiliates	7,327	776	3,797	(192)	(11,708)	—
Contributions from investment partner	—	—	485	—	—	485
Contributions from parents, including net proceeds from KML IPO and preferred share issuance	—	—	—	1,673	(1,673)	—
Contributions from noncontrolling interests - net proceeds from KML IPO	4	—	—	—	1,241	1,245
Contributions from noncontrolling interests - net proceeds from KML preferred share issuances	—	—	—	—	420	420
Contributions from noncontrolling interests - other	—	—	—	—	12	12
Distributions to parents	—	(4,902)	(5,472)	(687)	11,061	—
Distributions to noncontrolling interests	—	—	—	—	(42)	(42)
Other, net	(9)	—	—	—	—	(9)
Net cash provided by (used in) financing activities	5,105	(4,726)	(2,087)	716	(689)	(1,681)
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Deposits	—	—	—	22	—	22
Net (decrease) increase in Cash, Cash Equivalents and Restricted Deposits	(468)	(35)	(9)	51	—	(461)
Cash, Cash Equivalents, and Restricted Deposits, beginning of period	471	36	9	272	(1)	787
Cash, Cash Equivalents, and Restricted Deposits, end of period	$ 3	$ 1	$ —	$ 323	$ (1)	$ 326

Condensed Consolidating Statements of Cash Flows
for the Year Ended December 31, 2016
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Net cash (used in) provided by operating activities	$ (3,981)	$ 4,943	$ 11,641	$ 885	$ (8,730)	$ 4,758
Cash flows from investing activities						
Acquisitions of assets and investments	(2)	—	(331)	—	—	(333)
Capital expenditures	(27)	—	(2,258)	(597)	—	(2,882)
Proceeds from sale of equity interests in subsidiaries, net	—	—	1,401	—	—	1,401
Sales of property, plant and equipment, investments, and other net assets, net of removal costs	6	—	326	(2)	—	330
Contributions to investments	(343)	—	(54)	(11)	—	(408)
Distributions from equity investments in excess of cumulative earnings	2,417	298	190	—	(2,674)	231
Funding to affiliates	(2,820)	(535)	(5,062)	(727)	9,144	—
Loan repayments from related party	—	—	35	—	—	35
Other, net	—	—	3	(2)	—	1
Net cash used in investing activities	(769)	(237)	(5,750)	(1,339)	6,470	(1,625)
Cash flows from financing activities						
Issuances of debt	8,255	—	374	—	—	8,629
Payments of debt	(7,322)	(500)	(2,227)	(11)	—	(10,060)
Debt issue costs	(16)	—	(2)	(1)	—	(19)
Cash dividends - common shares	(1,118)	—	—	—	—	(1,118)
Cash dividends - preferred shares	(154)	—	—	—	—	(154)
Funding from affiliates	5,461	1,116	1,959	608	(9,144)	—
Contributions from parents	—	—	117	—	(117)	—
Contributions from noncontrolling interests	—	—	—	—	117	117
Distributions to parents	—	(5,286)	(6,116)	(73)	11,475	—
Distributions to noncontrolling interests	—	—	—	—	(24)	(24)
Other, net	(8)	—	—	—	—	(8)
Net cash provided by (used in) financing activities	5,098	(4,670)	(5,895)	523	2,307	(2,637)
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Deposits	—	—	—	2	—	2
Net increase (decrease) in Cash, Cash Equivalents and Restricted Deposits	348	36	(4)	71	47	498
Cash, Cash Equivalents, and Restricted Deposits, beginning of period	123	—	13	201	(48)	289
Cash, Cash Equivalents, and Restricted Deposits, end of period	$ 471	$ 36	$ 9	$ 272	$ (1)	$ 787

Supplemental Selected Quarterly Financial Data (Unaudited)

	Quarters Ended			
	March 31	**June 30**	**September 30**	**December 31**
	(In millions, except per share amounts)			
2018				
Revenues	$ 3,418	$ 3,428	$ 3,517	$ 3,781
Operating Income	949	272	1,515	1,058
Net Income (Loss)	542	(130)	1,005	502
Net Income (Loss) Attributable to Kinder Morgan, Inc.	524	(141)	732	494
Net Income (Loss) Available to Common Stockholders	485	(180)	693	483
Basic and Diluted Earnings (Loss) Per Common Share	0.22	(0.08)	0.31	0.21
2017				
Revenues	$ 3,424	$ 3,368	$ 3,281	$ 3,632
Operating Income	977	918	826	808
Net Income (Loss)	445	383	387	(992)
Net Income (Loss) Attributable to Kinder Morgan, Inc.	440	376	373	(1,006)
Net Income (Loss) Available to Common Stockholders	401	337	334	(1,045)
Basic and Diluted Earnings (Loss) Per Common Share	0.18	0.15	0.15	(0.47)

Item 16. ***Form 10-K Summary.***

Not Applicable.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

KINDER MORGAN, INC.
Registrant

/s/ David P. Michels

David P. Michels
Vice President and Chief Financial Officer
(principal financial and accounting officer)

Date: February 8, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ DAVID P. MICHELS David P. Michels	Vice President and Chief Financial Officer (principal financial officer and principal accounting officer)	February 8, 2019
/s/ STEVEN J. KEAN Steven J. Kean	Chief Executive Officer (principal executive officer); Director	February 8, 2019
/s/ RICHARD D. KINDER Richard D. Kinder	Executive Chairman	February 8, 2019
/s/ KIMBERLY A. DANG Kimberly A. Dang	President; Director	February 8, 2019
/s/ TED A. GARDNER Ted A. Gardner	Director	February 8, 2019
/s/ ANTHONY W. HALL, JR. Anthony W. Hall, Jr.	Director	February 8, 2019
/s/ GARY L. HULTQUIST Gary L. Hultquist	Director	February 8, 2019
/s/ RONALD L. KUEHN, JR. Ronald L. Kuehn, Jr.	Director	February 8, 2019
/s/ DEBORAH A. MACDONALD Deborah A. Macdonald	Director	February 8, 2019
/s/ MICHAEL C. MORGAN Michael C. Morgan	Director	February 8, 2019
/s/ ARTHUR C. REICHSTETTER Arthur C. Reichstetter	Director	February 8, 2019
/s/ FAYEZ SAROFIM Fayez Sarofim	Director	February 8, 2019
/s/ C. PARK SHAPER C. Park Shaper	Director	February 8, 2019
/s/ WILLIAM A. SMITH William A. Smith	Director	February 8, 2019
/s/ JOEL V. STAFF Joel V. Staff	Director	February 8, 2019
/s/ ROBERT F. VAGT Robert F. Vagt	Director	February 8, 2019
/s/ PERRY M. WAUGHTAL Perry M. Waughtal	Director	February 8, 2019

EXHIBIT 10.14

$4,000,000,000

REVOLVING CREDIT AGREEMENT

dated as of
November 16, 2018

among

KINDER MORGAN, INC.,
as the Borrower,

THE LENDERS PARTY HERETO

and

BARCLAYS BANK PLC,
as the Administrative Agent

JPMORGAN CHASE BANK, N.A.,
as the Syndication Agent,

and

BARCLAYS BANK PLC,
JPMORGAN CHASE BANK, N.A.,
BANK OF AMERICA, N.A.,
BMO HARRIS BANK N.A.,
CITIGROUP GLOBAL MARKETS INC.,
CREDIT SUISSE AG, CAYMAN ISLANDS BRANCH,
MIZUHO BANK, LTD.,
MUFG BANK, LTD.,
ROYAL BANK OF CANADA,
THE BANK OF NOVA SCOTIA, HOUSTON BRANCH and
WELLS FARGO BANK, NATIONAL ASSOCIATION,
as the Documentation Agents,

BARCLAYS BANK PLC,
JPMORGAN SECURITIES LLC,
BMO CAPITAL MARKETS CORP.,
CITIGROUP GLOBAL MARKETS INC.,
CREDIT SUISSE SECURITIES (USA) LLC,
MERRILL LYNCH, PIERCE, FENNER & SMITH INCORPORATED,
MIZUHO BANK, LTD.,
MUFG BANK, LTD.,
RBC CAPITAL MARKETS,
THE BANK OF NOVA SCOTIA, HOUSTON BRANCH and
WELLS FARGO SECURITIES, LLC,

as the Joint Lead Arrangers and the Joint Book Runners

EXHIBIT 10.14

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REVOLVING CREDIT AGREEMENT

THIS REVOLVING CREDIT AGREEMENT, dated as of November 16, 2018 (this "Agreement") is among:

(a) Kinder Morgan, Inc., a Delaware corporation (the "Borrower");

(b) the banks, financial institutions and other lenders listed on the signature pages hereof under the caption "Lenders" (the "Lenders" and together with each other Person that becomes a Lender pursuant to Section 2.21(b), Section 2.22(c) or Section 9.05, collectively, the "Lenders"); and

(c) Barclays Bank PLC, individually as a Lender and as the administrative agent for the Lenders (in such latter capacity together with any other Person that becomes Administrative Agent pursuant to Section 8.08, the "Administrative Agent").

PRELIMINARY STATEMENTS

The Borrower has requested that the Lenders extend credit to the Borrower in the form of Loans (as defined below) in an aggregate principal amount of $4,000,000,000 (the "Transactions") to be used by Borrower and its subsidiaries for working capital and general corporate purposes, and the Lenders have indicated their willingness to lend on the terms and subject to the conditions set forth herein.

NOW, THEREFORE, the parties hereto agree as follows:

ARTICLE I
DEFINITIONS

SECTION 1.01 Defined Terms. As used in this Agreement, the following terms have the meanings specified below:

"ABR", when used in reference to any Loan or Borrowing, refers to whether such Loan, or the Loans comprising such Borrowing, bear interest at a rate determined by reference to the Alternate Base Rate.

"Adjusted LIBO Rate" means, with respect to any Eurodollar Loan for any Interest Period for such Loan, a rate per annum (rounded upwards, if necessary, to the nearest 1/100 of 1%) determined by the Administrative Agent to be equal to the product of (i) the Eurodollar Rate for such Loan for such Interest Period multiplied by (ii) the Reserve Requirement for such Loan for such Interest Period. In no case shall the Adjusted LIBO Rate be less than zero.

"Administrative Agent" has the meaning specified in the introduction to this Agreement.

"Administrative Agent Fee Letter" has the meaning specified in Section 2.11(c).

"Administrative Questionnaire" means an Administrative Questionnaire in the form supplied by the Administrative Agent.

"Affiliate" of any Person means (i) any Person directly or indirectly controlled by, controlling or under common control with such first Person, (ii) any director or officer of such first Person or of any Person referred to in clause (i) above and (iii) if any Person in clause (i) above is an individual, any member of the immediate family (including parents, siblings, spouse and children) of such individual and any trust

whose principal beneficiary is such individual or one or more members of such immediate family and any Person who is controlled by any such member or trust. For purposes of this definition, any Person that owns directly or indirectly 25% or more of the securities having ordinary voting power for the election of directors or other governing body of a corporation or 25% or more of the partnership or other ownership interests of any other Person (other than as a limited partner of such other Person) will be deemed to *"control"* (including, with its correlative meanings, *"controlled by"* and *"under common control with"*) such corporation or other Person. In no event shall the Administrative Agent or any Lender be deemed to an Affiliate of the Borrower of any of its Subsidiaries.

"Affiliated Entities" means unconsolidated Subsidiaries of the Borrower and Persons not otherwise constituting Subsidiaries of the Borrower in which the Borrower has an equity investment.

"Agreement" has the meaning specified in the introduction to this Agreement (*subject, however*, to Section 1.04(e) hereof).

"Alternate Base Rate" means, for any day, a fluctuating rate per annum equal to the greatest of (a) the Federal Funds Effective Rate in effect on such day *plus* ½ of 1%, (b) the Prime Rate in effect for such day, and (c) the Adjusted LIBO Rate for a Eurodollar Loan with a one month Interest Period that begins on such day (and if such day is not a Business Day, the immediately preceding Business Day) *plus* 1%. Any change in the Alternate Base Rate due to a change in the Prime Rate, the Federal Funds Effective Rate or the Adjusted LIBO Rate shall be effective from the effective date of such change in the Prime Rate, the Federal Funds Effective Rate or the Adjusted LIBO Rate, respectively.

"Anti-Corruption Laws" means all laws, rules, and regulations of any jurisdiction applicable to the Borrower or any of its Subsidiaries from time to time concerning or relating to bribery or corruption.

"Applicable Commitment Fee Rate" means, at any time and from time to time, the percentage per annum equal to the applicable percentage set forth below for the corresponding Performance Level at such time:

Performance Level	Applicable Commitment Fee Rate
I	0.100%
II	0.125%
III	0.150%
IV	0.200%
V	0.250%
VI	0.300%

The Applicable Commitment Fee Rate shall be determined by reference to the Performance Level in effect from time to time and any change in the Applicable Commitment Fee Rate shall be effective from the effective date of the change in the applicable Performance Level giving rise thereto.

"Applicable Margin" means, as to any ABR Borrowing or any Eurodollar Borrowing, as the case may be, at any time and from time to time, a percentage per annum equal to the applicable percentage set forth below for the corresponding Performance Level at such time:

Performance Level	Eurodollar Borrowings Applicable Margin Percentage	ABR Borrowings Applicable Margin Percentage
I	1.000%	0.100%
II	1.125%	0.125%
III	1.250%	0.250%
IV	1.500%	0.500%
V	1.750%	0.750%
VI	2.000%	1.000%

The Applicable Margin shall be determined by reference to the Performance Level in effect from time to time, and any change in the Applicable Margin shall be effective from the effective date of any change in the applicable Performance Level giving rise thereto.

"Applicable Anniversary" has the meaning specified in Section 2.22(a).

"Applicable Percentage" means at any time, for each Lender, the percentage obtained by dividing (a) such Lender's Commitment by (b) the amount of the Total Commitment, *provided* that at any time when the Total Commitment shall have been terminated, each Lender's Applicable Percentage shall be the percentage obtained by dividing (a) such Lender's Credit Exposure by (b) the aggregate Credit Exposure of all Lenders.

"Application" has the meaning specified in Section 2.05(e).

"Approved Fund" means any Fund that is administered or managed by (a) a Lender, (b) an Affiliate of a Lender or (c) an entity or an Affiliate of an entity that administers or manages a Lender.

"Arrangers" means Barclays Bank PLC, J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated (or any other registered broker-dealer wholly-owned by Bank of America Corporation to which all or substantially all of Bank of America Corporation's or any of its subsidiaries' investment banking, commercial lending services or related businesses may be transferred following the date of this Agreement), BMO Capital Markets Corp., Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC, Mizuho Bank, Ltd., MUFG Bank, Ltd., RBC Capital Markets, The Bank of Nova Scotia, Houston Branch and Wells Fargo Securities LLC, as joint lead arrangers and joint book runners.

"Assignment and Acceptance" means an assignment and acceptance entered into by a Lender and an assignee (with the consent of any party whose consent is required by Section 9.05), and accepted by the Administrative Agent, in the form of Exhibit 1.01-A or any other form approved by the Administrative Agent.

"Auto-Extension Letter of Credit" has the meaning specified in Section 2.05(f).

"Availability Period" means the period from the Closing Date to the earlier of (i) the Maturity Date or (ii) the date of termination of the Total Commitment.

"Bail-In Action" means the exercise of any Write-Down and Conversion Powers by the applicable EEA Resolution Authority in respect of any liability of an EEA Financial Institution.

"Bail-In Legislation" means, with respect to any EEA Member Country implementing Article 55 of Directive 2014/59/EU of the European Parliament and of the Council of the European Union, the implementing law for such EEA Member Country from time to time which is described in the EU Bail-In Legislation Schedule.

"Beneficial Ownership Certification" means a certification regarding beneficial ownership or control as required by the Beneficial Ownership Regulation, which certification shall be substantially similar in form and substance to the form of Certification Regarding Beneficial Owners of Legal Entity Customers published jointly, in May 2018, by the Loan Syndications and Trading Association and Securities Industry and Financial Markets Association.

"Beneficial Ownership Regulation" means 31 C.F.R. § 1010.230.

"Benefit Arrangement" means at any time an employee benefit plan within the meaning of Section 3(3) of ERISA which is not a Plan or a Multiemployer Plan and which is maintained or otherwise contributed to by any member of the ERISA Group.

"Benefit Plan" means any of (a) an "employee benefit plan" (as defined in Section 3(3) of ERISA) that is subject to Title I of ERISA, (b) a "plan" as defined in Section 4975 of the Code to which Section 4975 of the Code applies, and (c) any Person whose assets include (for purposes of the Plan Asset Regulations or otherwise for purposes of Title I of ERISA or Section 4975 of the Code) the assets of any such "employee benefit plan" or "plan".

"Board" means the Board of Governors of the Federal Reserve System of the United States of America.

"Board of Directors" means, with respect to any Person, the Board of Directors of such Person or any committee of the Board of Directors of such Person duly authorized to act on behalf of the Board of Directors of such Person.

"Bond Letter of Credit" means irrevocable letter of credit No. S113181 issued by First Union National Bank (now Wells Fargo) in the original face amount of $24,128,548 for the account of the OLP "B" and for the benefit of Trustee.

"Bonds" means the Port Facility Refunding Revenue Bonds (Enron Transportation Services, L.P. Project) Series 1994 in the original aggregate principal amount of $23,700,000, as issued by the Jackson-Union Regional Port District.

"Borrower" has the meaning specified in the introduction to this Agreement.

"Borrower Debt Rating" means, with respect to the Borrower as of any date of determination, the rating that has been most recently announced by each of S&P or Moody's for any non-credit

enhanced, unsecured long-term senior debt issued or to be issued by the Borrower. For purposes of the foregoing:

(a) if, at any time, neither S&P nor Moody's shall have in effect a Borrower Debt Rating, the Applicable Margin or the Applicable Commitment Fee Rate, as the case may be, shall be set in accordance with Performance Level VI under the definition of "*Applicable Margin*" or "*Applicable Commitment Fee Rate*", as the case may be;

(b) if the ratings established by S&P and Moody's shall fall within different Performance Levels, the Applicable Margin or the Applicable Commitment Fee Rate, as the case may be, shall be based upon the higher rating; *provided, however*, that, if the lower of such ratings is two or more Performance Levels below the higher of such ratings, the Applicable Margin or the Applicable Commitment Fee Rate, as the case may be, shall be based upon the rating that is one Performance Level higher than the lower rating;

(c) if any rating established by S&P or Moody's shall be changed, such change shall be effective as of the date on which such change is announced publicly by the rating agency making such change;

(d) if S&P or Moody's shall change the basis on which ratings are established by it, each reference to the Borrower Debt Rating announced by S&P or Moody's shall refer to the then equivalent rating by S&P or Moody's, as the case may be.

"Borrowing" means (a) a borrowing comprised of Committed Loans of the same Type, made, converted or continued on the same date and, in the case of Eurodollar Loans, as to which a single Interest Period is in effect or (b) a Swingline Loan.

"Borrowing Date" means the Business Day upon which any Letter of Credit is to be issued or any Loans are to be made available to the Borrower.

"Borrowing Request" has the meaning specified in Section 2.03(a).

"Business Day" means any day that is not a Saturday, Sunday or other day on which commercial banks in Houston, Texas or New York, New York are authorized or required by law to remain closed; *provided* that, when used in connection with a rate of interest determined by reference to the Eurodollar Rate, the term *"Business Day"* shall also exclude any day on which banks are not open for dealings in dollar deposits in the London interbank market.

"Capital Lease Obligations" of any Person means the obligations of such Person to pay rent or other amounts under any lease of (or other arrangement conveying the right to use) real or personal property, or a combination thereof, which obligations are required to be classified and accounted for as capital leases on a balance sheet of such Person under GAAP, and the amount of such obligations shall be the capitalized amount thereof determined in accordance with GAAP.

"Capital Stock" means, with respect to any Person, any and all shares, interests, rights to purchase, warrants, options, participations or other equivalents (however designated) of such Person's equity, including (a) all common stock and preferred stock, any limited or general partnership interest and any limited liability company member interest, (b) beneficial interests in trusts, and (c) any other interest or participation that confers upon a Person the right to receive a share of the profits and losses of, or distribution of assets of, the issuing Person.

"Cash Collateralize" means, solely for purposes of Sections 2.05(f), 2.19 and 2.20, to pledge and deposit with or deliver to the Administrative Agent, for the benefit of one or more of the Issuing Banks or Lenders, as collateral for their respective LC Exposure, cash or deposit account balances or, if the Administrative Agent and each applicable Issuing Bank shall agree in their sole discretion, other credit support, in each case pursuant to documentation in form and substance satisfactory to the Administrative Agent and each applicable Issuing Bank. "*Cash Collateral*" shall have a meaning correlative to the foregoing and shall include the proceeds of such cash collateral and other credit support.

"Cash Equivalents" means (a) securities issued or unconditionally guaranteed by the United States government or any agency or instrumentality thereof, in each case having maturities of not more than 24 months from the date of acquisition thereof; (b) securities issued by any state of the United States of America or any political subdivision of any such state or any public instrumentality thereof or any political subdivision of any such state or any public instrumentality thereof having maturities of not more than 24 months from the date of acquisition thereof and, at the time of acquisition, having an investment grade rating generally obtainable from either S&P or Moody's (or, if at any time neither S&P nor Moody's shall be rating such obligations, then from another nationally recognized rating service); (c) commercial paper issued by any Lender or any bank holding company owning any Lender; (d) commercial paper maturing no more than 12 months after the date of creation thereof and, at the time of acquisition, having a rating of at least A-2 or P-2 from either S&P or Moody's (or, if at any time neither S&P nor Moody's shall be rating such obligations, an equivalent rating from another nationally recognized rating service); (e) domestic and Eurodollar Rate certificates of deposit or bankers' acceptances maturing no more than two years after the date of acquisition thereof issued by any Lender or any other bank having combined capital and surplus of not less than $250,000,000 in the case of domestic banks and $100,000,000 (or the equivalent in dollars thereof) in the case of foreign banks; (f) repurchase agreements with a term of not more than 30 days for underlying securities of the type described in clauses (a), (b) and (e) above entered into with any bank meeting the qualifications specified in clause (e) above or securities dealers of recognized national standing; (g) marketable short-term money market and similar funds (i) either having assets in excess of $250,000,000 or (ii) having a rating of at least A-2 or P-2 from either S&P or Moody's (or, if at any time neither S&P nor Moody's shall be rating such obligations, an equivalent rating from another nationally recognized rating service); (h) shares of investment companies that are registered under the Investment Company Act of 1940 and substantially all the investments of which are one or more of the types of securities described in clauses (a) through (g) above; and (i) in the case of investments by any Foreign Subsidiary, other customarily utilized high-quality investments in the country where such Foreign Subsidiary is located.

"Certain Items" means such items that are required to be included in the calculation of Net Income in accordance with GAAP that either (i) are non-cash or (ii) by their nature are separately identifiable from the Borrower and the Subsidiaries' normal business operations and are likely to occur only sporadically, and are reflected as such in the Annual Report on Form 10-K of the Borrower or in the Quarterly Report on Form 10-Q of the Borrower, in each case filed with the SEC. For the avoidance of doubt, Certain Items will be unadjusted for noncontrolling interests related thereto.

"CFC" means a Person that is a "controlled foreign corporation" within the meaning of Section 957 of the Code.

"Change in Control" means and will be deemed to have occurred if (a) any person, entity or "group" (within the meaning of Section 13(d) or 14(d) of the Securities Exchange Act of 1934, as amended) shall at any time have acquired direct or indirect beneficial ownership of a percentage of the voting power of the outstanding Voting Stock of the Borrower that exceeds 50% of the voting power of all the outstanding Voting Stock of the Borrower; or (b) Continuing Directors shall not constitute at least a majority of the board of directors of the Borrower.

"Change in Law" means the occurrence, after the date of this Agreement, of any of the following: (a) the adoption or taking effect of any law, rule, regulation or treaty, (b) any change in any law, rule, regulation or treaty or in the administration, interpretation, implementation or application thereof by any Governmental Authority or (c) the making or issuance of any request, rule, guideline or directive (whether or not having the force of law) by any Governmental Authority; *provided* that notwithstanding anything herein to the contrary, (x) the Dodd-Frank Wall Street Reform and Consumer Protection Act and all requests, rules, guidelines or directives thereunder or issued in connection therewith and (y) all requests, rules, guidelines or directives promulgated by the Bank for International Settlements, the Basel Committee on Banking Supervision (or any successor or similar authority) or the United States or foreign regulatory authorities, in each case pursuant to Basel III, shall in each case be deemed to be a "Change in Law", regardless of the date enacted, adopted or issued.

"Charges" has the meaning specified in Section 9.13.

"Citi" means Citibank Global Markets Inc., Citibank, N.A., Citicorp North America Inc., and any of their affiliates.

"Class", when used in reference to any Loan or Borrowing, refers to whether such Loan, or the Loans comprising such Borrowing, are Committed Loans or Swingline Loans.

"Closing Date" means the date on which the conditions specified in Section 3.01 are satisfied (or waived in accordance with Section 9.02).

"Code" means the Internal Revenue Code of 1986, as amended from time to time.

"Commitment" means, with respect to each Lender, the commitment of such Lender to make Committed Loans pursuant to Section 2.01 and to acquire participations in Letters of Credit and Swingline Loans hereunder, expressed as an amount representing the maximum aggregate amount of such Lender's Credit Exposure hereunder, as such commitment may be reduced or increased from time to time pursuant to the terms hereof. The initial amount of each Lender's Commitment as of the Closing Date is set forth on Schedule 1.01, or in the Register maintained by the Administrative Agent pursuant to Section 9.05.

"Commitment Fee" has the meaning specified in Section 2.11(a).

"Committed Letter of Credit" has the meaning specified in Section 2.05(b).

"Committed Loan" means a Loan made pursuant to Section 2.03(a).

"Committed Note" means a promissory note of the Borrower payable to the order of each Lender, in substantially the form of Exhibit 1.01-C, together with all modifications, extensions, renewals and rearrangements thereof.

"Communications" has the meaning specified in Section 9.01(a).

"Connection Income Taxes" means Other Connection Taxes that are imposed on or measured by net income (however denominated) or that are franchise Taxes or branch profits Taxes.

"Consolidated Assets" means, at the date of any determination thereof, the total assets of the Borrower and the Subsidiaries as set forth on a consolidated balance sheet of the Borrower and the Subsidiaries for their most recently completed fiscal quarter, prepared in accordance with GAAP.

"Consolidated EBITDA" means, for any period (without duplication), the Net Income of the Borrower and the Subsidiaries for such period determined on a consolidated basis in accordance with GAAP, increased (a) (to the extent deducted in determining Net Income for such period) by the sum of (i) all book taxes of the Borrower and the Subsidiaries paid or accrued and reflected in the Annual Report on Form 10-K of the Borrower or in the Quarterly Report on Form 10-Q of the Borrower, in each case filed with the SEC, and the pro rata portion of book taxes attributable to Affiliated Entities (net of (x) the noncontrolling interest's portion of such book taxes of KML and (y) the consolidating joint venture partners' share of such book taxes of such consolidating joint venture), for such period; (ii) Consolidated Interest Expense for such period, (iii) all DD&A of the Borrower and the Subsidiaries and the pro rata portion of DD&A attributable to Affiliated Entities (net of (x) the noncontrolling interest's portion of such DD&A of KML and (y) the consolidating joint venture partners' share of such DD&A of such consolidating joint venture), for such period; (iv) Certain Items charges or losses, and (v) amortization, write-off or write-down of debt discount, capitalized interest and debt issuance costs and commissions, discounts and other fees, charges and expenses associated with any letters of credit or Indebtedness, including in connection with the repurchase or repayment thereof, including any premium and acceleration of fees or discounts and other expenses, minus (b) Certain Items of income or gain which were included in determining such consolidated Net Income for such period; provided, that Consolidated EBITDA shall be calculated after giving pro forma effect to acquisitions of any Person, property, business or asset (to the extent not subsequently sold, transferred, abandoned or otherwise disposed) and any sale, transfer, abandonment or other disposition of any Person, property, business or asset made by the Borrower or any Subsidiary during such period, as if the acquisition, sale, transfer, abandonment or other disposition had been effected on the first date of such period.

"Consolidated Interest Expense" means, for any period, the Interest Expense of the Borrower and the Subsidiaries for such period determined on a consolidated basis in accordance with GAAP.

"Consolidated Net Indebtedness" means, at the date of any determination thereof, (a) Indebtedness of the Borrower and the Subsidiaries determined on a consolidated basis in accordance with GAAP minus (b) (i) the aggregate cash included in the cash accounts listed on the consolidated balance sheet of the Borrower and the Subsidiaries as at such date and (ii) Cash Equivalents of the Borrower and the Subsidiaries as at such date, in the case of each of clauses (i) and (ii), to the extent the use thereof for application to payment of Indebtedness is not prohibited by any Requirement of Law or any contract to which the Borrower or any of the Subsidiaries is a party.

"Consolidated Net Tangible Assets" means, at the date of any determination thereof, Consolidated Tangible Assets after deducting therefrom all current liabilities, excluding (i) any current liabilities that by their terms are extendable or renewable at the option of the obligor thereon to a time more than 12 months after the time as of which the amount thereof is being computed; and (ii) current maturities of long-term debt, all as set forth, or on a *pro forma* basis would be set forth, on a consolidated balance sheet of the Borrower and the Subsidiaries for their most recently completed fiscal quarter, prepared in accordance with GAAP.

"Consolidated Tangible Assets" means, at the date of any determination thereof, Consolidated Assets after deducting therefrom the value, net of any applicable reserves and accumulated amortization, of all goodwill, trade names, trademarks, patents and other like intangible assets, all as set forth, or on a pro forma basis would be set forth, on a consolidated balance sheet of the Borrower and the Subsidiaries for their most recently completed fiscal quarter, prepared in accordance with GAAP.

"Continuing Director" means, at any date, an individual (a) who is a member of the board of directors of the Borrower on the Closing Date, (b) who, as at such date, has been a member of such board

of directors for at least the twelve preceding months, or (c) who has been nominated to be a member of such board of directors by, or elected to such board of directors with the approval of, a majority of the other Continuing Directors then in office.

"Credit Event" means the making of any Loan or the issuance or extension of any Letter of Credit or any extension of the Maturity Date pursuant to Section 2.22.

"Credit Exposure" means, with respect to any Lender at any time, the sum of the outstanding principal amount of such Lender's Committed Loans and its LC Exposure and its Swingline Exposure at such time.

"DD&A" means depreciation, depletion and amortization (including amortization of goodwill) and the amortization of excess costs of equity investments, determined in accordance with GAAP.

"Debtor Relief Laws" means the Bankruptcy Code of the United States of America, and all other liquidation, conservatorship, bankruptcy, assignment for the benefit of creditors, moratorium, rearrangement, receivership, insolvency, reorganization, or similar debtor relief Laws of the United States or other applicable jurisdictions from time to time in effect.

"Default" means any event or condition which upon notice, lapse of time or both would, unless cured or waived, become an Event of Default.

"Defaulting Lender" means, subject to Section 2.19(b), any Lender that (a) has failed to (i) fund all or any portion of its Loans within three Business Days of the date such Loans were required to be funded hereunder unless such Lender notifies the Administrative Agent and the Borrower in writing that such failure is the result of such Lender's determination that one or more conditions precedent to funding (each of which conditions precedent, together with any applicable default, shall be specifically identified in such writing) has not been satisfied, or (ii) pay to the Administrative Agent, any Issuing Bank, any Swingline Lender or any other Lender any other amount required to be paid by it hereunder (including in respect of its participation in Letters of Credit or Swingline Loans) within two Business Days of the date when due, (b) has notified the Borrower, the Administrative Agent, any Issuing Bank or any Swingline Lender in writing that it does not intend to comply with its funding obligations hereunder, or has made a public statement to that effect (unless such writing or public statement relates to such Lender's obligation to fund a Loan hereunder and states that such position is based on such Lender's determination that a condition precedent to funding (which condition precedent, together with any applicable default, shall be specifically identified in such writing or public statement) cannot be satisfied), (c) has failed, within three Business Days after written request by the Administrative Agent or the Borrower, to confirm in writing to the Administrative Agent and the Borrower that it will comply with its prospective funding obligations hereunder (*provided* that such Lender shall cease to be a Defaulting Lender pursuant to this clause (c) upon receipt of such written confirmation by the Administrative Agent and the Borrower), or (d) has, or has a direct or indirect parent company that has, (i) become the subject of a proceeding under any Debtor Relief Law, (ii) become subject of a Bail-In Action, or (iii) had appointed for it a receiver, custodian, conservator, trustee, administrator, assignee for the benefit of creditors or similar Person charged with reorganization or liquidation of its business or assets, including the Federal Deposit Insurance Corporation or any other state or federal regulatory authority acting in such a capacity; *provided* that, for the avoidance of doubt, a Lender shall not be a Defaulting Lender solely by virtue of (i) the ownership or acquisition of any equity interest in that Lender or any direct or indirect parent company thereof by a Governmental Authority, or (ii), in the case of a solvent Person, the precautionary appointment of an administrator, guardian, custodian or other similar official by a Governmental Authority under or based on the law of the country where such Person is subject to home

jurisdiction supervision if applicable law requires that such appointment not be publicly disclosed, in each of such cases, so long as such ownership interest or such appointment does not result in or provide such Lender with immunity from the jurisdiction of courts within the United States or from the enforcement of judgments or writs of attachment on its assets or permit such Lender (or such Governmental Authority) to reject, repudiate, disavow or disaffirm any contracts or agreements made with such Lender. Any determination by the Administrative Agent that a Lender is a Defaulting Lender under any one or more of clauses (a) through (d) above shall be conclusive and binding absent manifest error, and such Lender shall be deemed to be a Defaulting Lender (subject to Section 2.19(b)) upon delivery of written notice of such determination to the Borrower and each Lender.

"Dividing Person" has the meaning assigned to such term in the definition of "Division".

"Division" means the division of the assets, liabilities and/or obligations of a Person (the "Dividing Person") among two or more Persons (whether pursuant to a "plan of division" or similar arrangement), which may or may not include the Dividing Person and pursuant to which the Dividing Person may or may not survive.

"Division Successor" means any Person that, upon the consummation of a Division of a Dividing Person, holds all or any portion of the assets, liabilities and/or obligations previously held by such Dividing Person immediately prior to the consummation of such Division. A Dividing Person which retains any of its assets, liabilities and/or obligations after a Division shall be deemed a Division Successor upon the occurrence of such Division.

"Documentation Agents" means Barclays Bank PLC, JPMorgan Chase Bank, N.A., Bank of America, N.A., BMO Harris Bank N.A., Citigroup Global Markets Inc., Credit Suisse AG, Cayman Islands Branch, Mizuho Bank, Ltd., MUFG Bank, Ltd., Royal Bank of Canada, The Bank of Nova Scotia, Houston Branch and Wells Fargo Bank, National Association, as documentation agents.

"dollars" or "$" refers to lawful money of the United States of America.

"Domestic Subsidiary" means any Subsidiary of the Borrower organized under the laws of any jurisdiction within the United States.

"EEA Financial Institution" means (a) any credit institution or investment firm established in any EEA Member Country which is subject to the supervision of an EEA Resolution Authority, (b) any entity established in an EEA Member Country which is a parent of an institution described in clause (a) of this definition, or (c) any financial institution established in an EEA Member Country which is a subsidiary of an institution described in clauses (a) or (b) of this definition and is subject to consolidated supervision with its parent.

"EEA Member Country" means any of the member states of the European Union, Iceland, Liechtenstein, and Norway.

"EEA Resolution Authority" means any public administrative authority or any person entrusted with public administrative authority of any EEA Member Country (including any delegee) having responsibility for the resolution of any EEA Financial Institution.

"Eligible Assignee" means any Person that meets the requirements to be an assignee under Section 9.05(a)(iii), (v) and (vi) (subject to such consents, if any, as may be required under Section 9.05(a)(iii)).

"Environmental Laws" means all laws, rules, regulations, codes, ordinances, orders, decrees, judgments, injunctions, notices or binding agreements issued, promulgated or entered into by any Governmental Authority, relating in any way to the environment, preservation or reclamation of natural resources, the management, release or threatened release of any Hazardous Material or to health and safety matters.

"Environmental Liability" means any liability, contingent or otherwise (including any liability for damages, costs of environmental remediation, fines, penalties or indemnities), of the Borrower or any Subsidiary directly or indirectly resulting from or based upon (a) violation of any Environmental Law, (b) the generation, use, handling, transportation, storage, treatment or disposal of any Hazardous Materials, (c) exposure to any Hazardous Materials, (d) the release of any Hazardous Materials into the environment, or (e) any contract, agreement or other consensual arrangement pursuant to which liability is assumed or imposed with respect to any of the foregoing.

"ERISA" means the Employee Retirement Income Security Act of 1974, as amended from time to time.

"ERISA Group" means the Borrower and all members of a controlled group of corporations and all trades or businesses (whether or not incorporated) under common control which, together with the Borrower, are treated as a single employer under Section 414 of the Code or Section 4001(a)(14) of ERISA.

"EU Bail-In Legislation Schedule" means the EU Bail-In Legislation Schedule published by the Loan Market Association (or any successor person), as in effect from time to time.

"Eurodollar", when used in reference to any Loan or Borrowing, refers to whether such Loan, or the Loans comprising such Borrowing, bear interest at a rate determined by reference to the Adjusted LIBO Rate.

"Eurodollar Rate" means for any Interest Period as to any Eurodollar Loan, (i) the rate per annum determined by the Administrative Agent to be the offered rate which appears on the page of the Reuters Screen which displays the London interbank offered rate administered by ICE Benchmark Administration Limited (such page currently being the LIBOR01 page) (the "LIBO Rate") for deposits (for delivery on the first day of such Interest Period) with a term equivalent to such Interest Period in Dollars, determined as of approximately 11:00 a.m. (London, England time), two Business Days prior to the commencement of such Interest Period, or (ii) in the event the rate referenced in the preceding clause (i) does not appear on such page or service or if such page or service shall cease to be available, the rate determined by the Administrative Agent to be the offered rate on such other page or other service which displays the LIBO Rate for deposits (for delivery on the first day of such Interest Period) with a term equivalent to such Interest Period in Dollars, determined as of approximately 11:00 a.m. (London, England time) two Business Days prior to the commencement of such Interest Period; provided that if LIBO Rates are quoted under either of the preceding clauses (i) or (ii), but there is no such quotation for the Interest Period elected, the LIBO Rate shall be equal to the Interpolated Rate; and provided, further, that if any such rate determined pursuant to the preceding clauses (i) or (ii) is less than zero, the Eurodollar Rate will be deemed to be zero.

"Event of Default" has the meaning specified in Section 7.01.

"Exchange Act" means the Securities Exchange Act of 1934, as amended.

"Excluded Subsidiary" means (i) any Subsidiary that is not a Wholly-owned Domestic Operating Subsidiary, (ii) any Domestic Subsidiary that is a Subsidiary of a CFC or any Domestic Subsidiary (including a disregarded entity for U.S. federal income Tax purposes) substantially all of whose assets (held directly or through Subsidiaries) consist of Capital Stock of one or more CFCs or Indebtedness of such CFCs, (iii) any Immaterial Subsidiary, (iv) any Subsidiary listed on Schedule 1.01A, (v) any other Subsidiary with respect to which, in the reasonable judgment of the Administrative Agent (confirmed in writing by notice to the Borrower), the cost or other consequences (including any adverse Tax consequences) of providing a Guaranty shall be excessive in view of the benefits to be obtained by the Lenders therefrom, (vi) any not-for-profit Subsidiary, (vii) any Subsidiary that is prohibited by a Requirement of Law from providing a Guaranty of the Obligations, and (ix) any Subsidiary acquired by the Borrower and its Subsidiaries after the Closing Date to the extent, and so long as, the financing documentation governing any existing Indebtedness of such Subsidiary (other than Indebtedness created or incurred in anticipation of, or with the intent to circumvent the terms of, this Agreement) that is permitted to survive pursuant to Section 6.01 (and does survive) prohibits such Subsidiary from guaranteeing the Obligations; provided, that notwithstanding the foregoing, any Subsidiary that Guarantees any senior notes or senior debt securities issued by the Borrower shall not constitute an Excluded Subsidiary for so long as such Guarantee is in effect.

"Excluded Taxes" means any of the following Taxes imposed on or with respect to a Recipient or required to be withheld or deducted from a payment to a Recipient, (a) Taxes imposed on or measured by net income (however denominated), franchise Taxes and branch profits Taxes, in each case, (i) imposed as a result of such Recipient being organized under the laws of, or having its principal office or, in the case of any Lender, its applicable lending office located in, the jurisdiction imposing such Tax (or any political subdivision thereof) or (ii) that are Other Connection Taxes, (b) in the case of a Lender, U.S. federal withholding Taxes imposed on amounts payable to or for the account of such Lender with respect to an applicable interest in a Loan or Commitment pursuant to a law in effect on the date on which (i) such Lender acquires such interest in the Loan or Commitment or becomes a party to this Agreement (other than pursuant to an assignment request by the Borrower under Section 2.18(b) or (ii) such Lender changes its lending office, except in each case to the extent that, pursuant to Section 2.16, amounts with respect to such Taxes were payable either to such Lender's assignor immediately before such Lender became a party hereto or to such Lender immediately before it changed its lending office, (c) Taxes attributable to such Recipient's failure to comply with Section 2.16(g) and (d) any U.S. federal withholding Taxes imposed under FATCA.

"Executive Summary" means the Confidential Information Memorandum relating to this Agreement and the Transactions dated October 2018.

"Existing Credit Agreement" means the Revolving Credit Agreement, dated as of September 19, 2014 (as amended, restated or otherwise modified), among the Borrower, the banks and other financial institutions party thereto as lenders and Barclays Bank, PLC as administrative agent.

"Existing LC Subsidiary" means OLP "B" and each other Subsidiary of the Borrower set forth on Exhibit 1.01E for the account of which an Existing Letter of Credit has been issued.

"Existing Letters of Credit" means the letters of credit issued or, in the case of the Bond Letter of Credit, deemed issued, under the Existing Credit Agreement and certain letters of credit issued under a bilateral facility, in each case, listed on Schedule 1.01B.

"Existing Subsidiary Letters of Credit" means, collectively, (i) the Bond Letter of Credit and (ii) each other Existing Letter of Credit that has been issued for the account of an Existing LC Subsidiary.

"Existing Subsidiary Letters of Credit Guaranteed Obligations" has the meaning specified in Section 2.05(n).

"Existing Subsidiary Letters of Credit Guaranty" has the meaning specified in Section 2.05(n).

"Extension Consenting Lender" has the meaning specified in Section 2.22(b).

"Extension Date" has the meaning specified in Section 2.22(b).

"Extension Non-Consenting Lender" has the meaning specified in Section 2.22(b).

"FATCA" means Sections 1471 through 1474 of the Code, as of the date of this Agreement (or any amended or successor version that is substantively comparable and not materially more onerous to comply with), any current or future regulations or official interpretations thereof, any agreements entered into pursuant to Section 1471(b)(1) of the Code, and any law, regulation, rule, promulgation, guidance notes, practices or official agreement implementing an intergovernmental agreement, treaty or convention with respect to the foregoing.

"Federal Funds Effective Rate" means, for any day, the rate calculated by the Federal Reserve Bank of New York based on such day's federal funds transactions by depository institutions (as determined in such manner as the Federal Reserve Bank of New York shall set forth on its public website from time to time) and published on the next succeeding Business Day by the Federal Reserve Bank of New York as the federal funds effective rate; provided, that if the Federal Funds Effective Rate for any day is less than zero, the Federal Funds Effective Rate for such day will be deemed to be zero.

"Fee Letter" has the meaning specified in Section 2.11(c).

"Fee Letters" means, collectively, the Administrative Agent Fee Letter and the Fee Letter.

"Foreign Lender" means any Lender that is not a U.S. Person.

"Foreign Subsidiary" means any Subsidiary of the Borrower that is not a Domestic Subsidiary.

"Fronting Exposure" means, at any time there is a Defaulting Lender, (a) with respect to any Issuing Bank, such Defaulting Lender's Applicable Percentage of the outstanding LC Exposure with respect to Letters of Credit issued by such Issuing Bank other than LC Exposure as to which such Defaulting Lender's participation obligation has been reallocated to other Lenders or Cash Collateralized in accordance with the terms hereof and (b) with respect to any Swingline Lender, such Defaulting Lender's Applicable Percentage of outstanding Swingline Loans made by such Swingline Lender other than Swingline Loans as to which such Defaulting Lender's participation obligation has been reallocated to other Lenders.

"Fund" means any Person (other than a natural person) that is (or will be) engaged in making, purchasing, holding or otherwise investing in commercial loans and similar extensions of credit in the ordinary course of its business.

"GAAP" means generally accepted accounting principles in the United States of America from time to time, including as set forth in the opinions, statements and pronouncements of the

Accounting Principles Board of the American Institute of Certified Public Accountants and the Financing Accounting Standards Board.

"Governmental Authority" means the government of the United States of America or any other nation, or of any political subdivision thereof, whether state or local, and any agency, authority, instrumentality, regulatory body, court, central bank or other entity exercising executive, legislative, judicial, taxing, regulatory or administrative powers or functions of or pertaining to government (including any supra national bodies such as the European Union or the European Central Bank).

"Guarantee" of or by any Person (the "*guarantor*") means any obligation, contingent or otherwise, of the guarantor guaranteeing or having the economic effect of guaranteeing any Indebtedness or other obligation of any other Person (the "*primary obligor*") in any manner, whether directly or indirectly, and including any obligation of the guarantor, direct or indirect, (a) to purchase or pay (or advance or supply funds for the purchase or payment of) such Indebtedness or other obligation or to purchase (or to advance or supply funds for the purchase of) any security for the payment thereof, (b) to purchase or lease property, securities or services for the purpose of assuring the owner of such Indebtedness or other obligation of the payment thereof, (c) to maintain working capital, equity capital or any other financial statement condition or liquidity of the primary obligor so as to enable the primary obligor to pay such Indebtedness or other obligation or (d) as an account party in respect of any letter of credit or letter of guaranty issued to support such Indebtedness or obligation; *provided* that the term Guarantee shall not include endorsements for collection or deposit in the ordinary course of business.

"Guarantors" means each Person that guarantees the Obligations pursuant to the Guaranty.

"Guaranty" means the Guaranty Agreement substantially in the form of Exhibit 1.01-B hereto.

"Hazardous Materials" means all explosive or radioactive substances or wastes and all hazardous or toxic substances, wastes or other pollutants, including petroleum or petroleum distillates, asbestos or asbestos containing materials, polychlorinated biphenyls, radon gas, infectious or medical wastes and all other substances or wastes of any nature regulated pursuant to any Environmental Law.

"Hedging Agreement" means a financial instrument or security which is used as a cash flow or fair value hedge to manage the risk associated with a change in interest rates, foreign currency exchange rates or commodity prices.

"Hybrid Securities" means any trust preferred securities, or deferrable interest subordinated debt with a maturity of at least 20 years, which provides for the optional or mandatory deferral of interest or distributions, issued by the Borrower, or any business trusts, limited liability companies, limited partnerships or similar entities (i) substantially all of the common equity, general partner or similar interests of which are owned (either directly or indirectly through one or more Wholly-owned Subsidiaries) at all times by the Borrower or any of the Subsidiaries, (ii) that have been formed for the purpose of issuing trust preferred securities or deferrable interest subordinated debt, and (iii) substantially all the assets of which consist of (A) subordinated debt of the Borrower or a Subsidiary, and (B) payments made from time to time on the subordinated debt.

"Immaterial Subsidiary" means any Subsidiary that is not a Material Subsidiary.

"Increased Amount Date" has the meaning specified in Section 2.21(a).

"Indebtedness" of any Person means, without duplication, (a) all obligations of such Person for borrowed money, (b) all obligations of such Person evidenced by bonds, debentures, notes or similar instruments (other than surety, performance and guaranty bonds), (c) all obligations of such Person under conditional sale or other title retention agreements relating to property acquired by such Person, (d) all obligations of such Person in respect of the deferred purchase price of property or services (excluding trade accounts payable incurred in the ordinary course of business), (e) all Indebtedness of others secured by (or for which the holder of such Indebtedness has an existing right, contingent or otherwise, to be secured by) any Lien on property owned or acquired by such Person, whether or not the Indebtedness secured thereby has been assumed (determined as the lesser of the amount of the Indebtedness so secured and such property's fair market value), (f) all Guarantees by such Person of Indebtedness of others (*provided* that in the event that any Indebtedness of the Borrower or any Subsidiary shall be the subject of a Guarantee by one or more Subsidiaries or by the Borrower, as the case may be, the aggregate amount of the outstanding Indebtedness of the Borrower and the Subsidiaries in respect thereof shall be determined by reference to the primary Indebtedness so guaranteed, and without duplication by reason of the existence of any such guarantee), (g) all Capital Lease Obligations of such Person, (h) all obligations of such Person as an account party in respect of (i) the full face amount of all letters of credit (drawn or undrawn) supporting the exposure of such Person under Hedging Agreements and (ii) the drawn portion of all other letters of credit and letters of guaranty, (i) all obligations, contingent or otherwise, of such Person in respect of funded bankers' acceptances and (j) Hybrid Securities. The Indebtedness of any Person shall include the Indebtedness of any other Person (including any partnership in which such Person is a general partner) to the extent such Person is liable therefor as a result of such Person's ownership interest in or other relationship with such entity, except to the extent the terms of such Indebtedness provide that such Person is not liable therefor: *provided* that Indebtedness shall not include (1) non-recourse debt, (2) performance guaranties, (3) monetary obligations or guaranties of monetary obligations of Person as lessees under leases that are in accordance with GAAP, recorded as operating leases (and giving effect to the proviso in Section 1.03), and (4) guarantees by such Person of obligations of others which are not obligations described in clauses (a) through (j) of this definition, and *provided further*, that where any such indebtedness or obligation of such Person is made jointly, or jointly and severally, with any third party or parties other than any Subsidiary of such Person, the amount thereof for the purpose of this definition only shall be the *pro rata* portion thereof payable by such Person, so long as such third party or parties have not defaulted on its or their joint and several portions thereof and can reasonably be expected to perform its or their obligations thereunder. For the avoidance of doubt, except as expressly provided in clause (h)(i) above, "Indebtedness" of a Person in respect of such letters of credit shall include, without duplication, only the principal amount of the unreimbursed obligations of such Person in respect of such letters of credit that have been drawn upon by the beneficiaries to the extent of the amount drawn, and shall include no other obligations in respect of such letters of credit.

"Indemnified Parties" has the meaning specified in Section 9.03(b).

"Indemnified Taxes" means (a) Taxes, other than Excluded Taxes, imposed on or with respect to any payment made by or on account of any Obligation and (b) to the extent not otherwise described in (a), Other Taxes.

"Indemnity Matters" means, with respect to any Indemnified Party, all losses, liabilities, claims and damages (including reasonable legal fees and expenses).

"Interest Election Request" has the meaning specified in Section 2.07(b).

"Interest Expense" means (without duplication), with respect to any period for any Person (a) the aggregate amount of interest, whether expensed or capitalized, paid, accrued or scheduled to be paid during such period in respect of the Indebtedness of such Person including (i) the interest portion of any

deferred payment obligation; (ii) the portion of any rental obligation in respect of Capital Lease Obligations allocable to interest expenses; and (iii) any non-cash interest payments or accruals, all determined in accordance with GAAP, less (b) Interest Income of such Person for such period.

"Interest Income" means, with respect to any period for any Person, interest actually received by such Person during such period.

"Interest Payment Date" means (a) with respect to any ABR Loan (including a Swingline Loan), the last Business Day of each March, June, September and December, and (b) with respect to any Eurodollar Loan, the last Business Day of the Interest Period applicable to the Borrowing of which such Loan is a part and, in the case of a Eurodollar Borrowing with an Interest Period of more than three months' duration, each day prior to the last day of such Interest Period that occurs at intervals of three months' duration after the first day of such Interest Period.

"Interest Period" means with respect to any Eurodollar Borrowing, the period commencing on the date of such Borrowing and ending (a) on the date that is one week thereafter or (b) on the numerically corresponding day in the calendar month that is one, two, three or six months thereafter, in each case as the Borrower may elect; *provided* (i) if any Interest Period would end on a day other than a Business Day, such Interest Period shall be extended to the next succeeding Business Day unless, in the case of any Eurodollar Borrowing, such next succeeding Business Day would fall in the next calendar month, in which case such Interest Period shall end on the next preceding Business Day, (ii) any Interest Period that commences on the last Business Day of a calendar month (or on a day for which there is no numerically corresponding day in the last calendar month of such Interest Period) shall end on the last Business Day of the last calendar month of such Interest Period and (iii) no Interest Period shall end after the Stated Maturity Date. For purposes hereof, the date of a Borrowing initially shall be the date on which such Borrowing is made and, in the case of a Eurodollar Borrowing, thereafter shall be the effective date of the most recent conversion or continuation of such Borrowing.

"Interpolated Rate" means, in relation to the LIBO Rate, the rate which results from interpolating on a linear basis between:

(a) the applicable LIBO Rate for the longest period (for which that LIBO Rate is available) which is less than the Interest Period of that Loan; and

(b) the applicable LIBO Rate for the shortest period (for which that LIBO Rate is available) which exceeds the Interest Period of that Loan,

each as of approximately 11:00 a.m. (London, England time) two Business Days prior to the commencement of such Interest Period of that Loan.

"IRS" means the United States Internal Revenue Service.

"Issuing Banks" means Barclays Bank PLC, JPMorgan Chase Bank, N.A., Bank of America, N.A., Citi and Wells Fargo in their capacities as issuers of Letters of Credit hereunder, and each other Lender as the Borrower may from time to time select as an Issuing Bank hereunder pursuant to Section 2.05; *provided* that such Lender has agreed to be an Issuing Bank and the Administrative Agent has consented to such selection.

"KML" means Kinder Morgan Canada Limited and its consolidated subsidiaries.

"Laws" means, collectively, all international, foreign, federal, state and local statutes, treaties, rules, guidelines, regulations, ordinances, codes and administrative or judicial precedents or authorities, including the interpretation or administration thereof by any Governmental Authority charged with the enforcement, interpretation or administration thereof, and all applicable administrative orders, directed duties, requests, licenses, authorizations and permits of, and agreements with, any Governmental Authority.

"LC Disbursement" means a payment made by an Issuing Bank pursuant to a Letter of Credit.

"LC Exposure" means, at any time, the sum of (a) the aggregate undrawn amount of all outstanding Committed Letters of Credit and Uncommitted Letters of Credit at such time plus (b) the aggregate amount of all LC Disbursements that have not yet been reimbursed by or on behalf of the Borrower at such time. The LC Exposure of any Lender at any time shall be its Applicable Percentage of the total LC Exposure at such time.

"LC Sublimit" means $500,000,000.

"Lenders" has the meaning specified in the introduction to this Agreement. Unless context otherwise requires, the term "Lenders" includes the Swingline Lender.

"Letter of Credit" means any Existing Letter of Credit or any letter of credit issued pursuant to this Agreement.

"Letter of Credit Commitment" means, with respect to any Issuing Bank, the commitment of such Issuing Bank to issue Letters of Credit hereunder, expressed as an amount representing the maximum aggregate amount of the LC Exposure with respect to Letters of Credit issued by such Issuing Bank as such commitment may be reduced or terminated from time to time pursuant to Section 2.08. The initial amount of each Issuing Bank's Letter of Credit Commitment is set forth on Schedule 1.01.

"Letter of Credit Request" has the meaning specified in Section 2.05(e).

"LIBO Rate" shall have the meaning ascribed thereto in the definition of "Eurodollar Rate".

"Lien" means, with respect to any asset (a) any mortgage, deed of trust, lien, pledge, hypothecation, encumbrance, charge or security interest in, on or of such asset, and (b) the interest of a vendor or a lessor under any conditional sale agreement, capital lease or title retention agreement (or any financing lease having substantially the same economic effect as any of the foregoing) relating to such asset.

"Loan Documents" mean, collectively, this Agreement, the Guaranty, the Notes, if any, the Applications, the Fee Letters and all other instruments and documents from time to time executed and delivered by the Borrower or the Guarantors in connection herewith and therewith.

"Loan Party" means the Borrower and each Guarantor.

"Loans" means advances made by the Lenders to the Borrower pursuant to this Agreement.

"Material Adverse Effect" means, relative to any occurrence of whatever nature, a material adverse effect on (a) the business assets, liabilities or financial condition of the Borrower and the Subsidiaries taken as a whole, (b) the ability of the Borrower and the Guarantors, taken as a whole, to perform the Obligations or (c) the rights and remedies of the Administrative Agent, any Issuing Bank or any Lender against the Borrower or, taken as a whole, the Guarantors, under any material provision of this Agreement or any other Loan Document.

"Material Subsidiary" means, as at any date of determination, any Subsidiary of the Borrower whose total tangible assets (for purposes of the below, when combined with the tangible assets of such Subsidiary's Subsidiaries, after eliminating intercompany obligations) as at such date of determination are greater than or equal to 5% of Consolidated Tangible Assets as of the last day of the fiscal quarter most recently ended for which financial statements have been delivered pursuant to Section 5.01(a) or (b) (the "Most Recent Financial Statement Date"), as the case may be; provided that if the aggregate total tangible assets of all Material Subsidiaries is less than 85% of Consolidated Tangible Assets as of the Most Recent Financial Statement Date, the Borrower shall designate Subsidiaries as "Material Subsidiaries" in writing to the Administrative Agent along with the delivery of the applicable financial statements pursuant to Section 5.01(a) or (b) such that the deficit described in this proviso ceases to exist; provided further that KML shall not be eligible to be considered as a Material Subsidiary (if applicable) until June 30, 2019.

"Maturity Date" means the earlier of (a) the Stated Maturity Date and (b) the acceleration of the Obligations pursuant to Section 7.01.

"Maximum Rate" has the meaning specified in Section 9.13.

"Minimum Collateral Amount" means, solely for purposes of Sections 2.19 and 2.20, at any time, (i) with respect to Cash Collateral consisting of cash or deposit account balances, an amount equal to 100% of the Fronting Exposure of all Issuing Banks with respect to Letters of Credit issued and outstanding at such time and (ii) otherwise, an amount determined by the Administrative Agent and the Issuing Banks in their sole discretion.

"Moody's" means Moody's Investors Service, Inc.

"Most Recent Financial Statement Date" has the meaning specified in the definition of Material Subsidiary.

"Multiemployer Plan" means a multiemployer plan as defined in Section 4001(a)(3) of ERISA.

"Net Income" means with respect to any Person for any period that net income of such Person for such period determined in accordance with GAAP; *provided* that there shall be excluded, without duplication, from such net income (to the extent otherwise included therein).

(a) net extraordinary gains and losses (other than, in the case of losses, losses resulting from charges against net income to establish or increase reserves for potential environmental liabilities and reserves for exposure of such Person under rate cases);

(b) net gains or losses in respect of dispositions of assets other than in the ordinary course of business;

(c) any gains or losses attributable to write-ups or write-downs of assets; and

(d) proceeds of any key man insurance, or any insurance on property, plant or equipment.

"Net Worth" means, as to the Borrower at any date, the sum of the amount of shareholders' equity of the Borrower determined as of such date in accordance with GAAP, *provided* there shall be excluded, without duplication, from such determination (to the extent otherwise included therein) the amount of accumulated other comprehensive gain or loss as of such date.

"New Commitment" has the meaning specified in Section 2.21(a).

"New Lender" has the meaning specified in Section 2.21(b).

"New Loan" has the meaning specified in Section 2.21(b).

"New Loan Increase Joinder" has the meaning specified in Section 2.21(c).

"Non-Consenting Lender" means any Lender that does not approve any consent, waiver or amendment that (i) requires the approval of all Lenders or all affected Lenders in accordance with the terms of Section 9.02 and (ii) has been approved by the Required Lenders.

"Non-Defaulting Lender" means, at any time, each Lender that is not a Defaulting Lender at such time.

"Non-Extension Notice Date" has the meaning specified in Section 2.05(f).

"Non-Guarantor Subsidiary" has the meaning specified in Section 6.01.

"Non-Wholly-owned Subsidiary" means any Subsidiary that is not a Wholly-owned Subsidiary.

"Note" means a Committed Note or a Swingline Note.

"Notice of Default" has the meaning specified in Section 7.01.

"Notice of Prepayment" has the meaning specified in Section 2.10(b).

"Obligations" means collectively:

(a) the payment of all indebtedness and liabilities by, and performance of all other obligations of, the Borrower in respect of the Loans;

(b) all obligations of the Borrower under, with respect to and relating to the Letters of Credit, whether contingent or matured;

(c) the payment of all other indebtedness and liabilities by and performance of all other obligations of the Borrower to the Administrative Agent, the Issuing Banks and the Lenders under, with respect to, and arising in connection with, the Loan Documents, and the payment of all indebtedness and liabilities of the Borrower to the Administrative Agent, the Issuing Banks and the Lenders for fees, costs, indemnification and expenses (including reasonable attorneys' fees and expenses) under the Loan Documents;

(d) the reimbursement of all sums advanced and costs and expenses incurred by the Administrative Agent under any Loan Document (whether directly or indirectly) in connection with the Obligations or any part thereof or any renewal, extension or change of or substitution for the Obligations or, any part thereof, whether such advances, costs and expenses were made or incurred at the request of the Borrower or the Administrative Agent; and

(e) all renewals, extensions, amendments and changes of, or substitutions or replacements for, all or any part of the items described under clauses (a) through (d) above.

"OLP "B"" means Kinder Morgan Operating L.P. "B", a Delaware limited partnership.

"Operating Subsidiary" means any operating company that is a Subsidiary of the Borrower.

"Other Connection Taxes" means, with respect to any Recipient, Taxes imposed as a result of a present or former connection between such Recipient and the jurisdiction imposing such Tax (other than connections arising from such Recipient having executed, delivered, become a party to, performed its obligations under, received payments under, received or perfected a security interest under, engaged in any other transaction pursuant to or enforced any Loan Document, or sold or assigned an interest in any Loan or any Loan Document).

"Other Taxes" means all present or future stamp, court or documentary, intangible, recording, filing or similar Taxes that arise from any payment made under, from the execution, delivery, performance, enforcement or registration of, from the receipt or perfection of a security interest under, or otherwise with respect to, any Loan Document, except any such Taxes that are Other Connection Taxes imposed with respect to an assignment (other than an assignment made pursuant to Section 2.18(b)).

"Participant" has the meaning assigned to such term in Section 9.05(c).

"Participant Register" has the meaning specified in Section 9.05(c).

"Patriot Act" has the meaning specified in Section 9.15.

"PBGC" means the Pension Benefit Guaranty Corporation referred to and defined in ERISA and any successor entity performing similar functions.

"Performance Level" means a reference to one of Performance Level I, Performance Level II, Performance Level III, Performance Level IV, Performance Level V or Performance Level VI.

"Performance Level I" means, at any date of determination, that the Borrower shall have a Borrower Debt Rating in effect on such date of at least A- by S&P or at least A3 by Moody's.

"Performance Level II" means, at any date of determination, (a) that the Performance Level does not meet the requirements of Performance Level I and (b) that the Borrower shall have a Borrower Debt Rating in effect on such date of at least BBB+ by S&P or at least Baa1 by Moody's.

"Performance Level III" means, at any date of determination, (a) that the Performance Level does not meet the requirements of Performance Level I or Performance Level II and (b) that the Borrower shall have a Borrower Debt Rating in effect on such date of at least BBB by S&P, or at least Baa2 by Moody's.

"Performance Level IV" means, at any date of determination, (a) that the Performance Level does not meet the requirements of Performance Level I, Performance Level II or Performance Level III and (b) that the Borrower shall have a Borrower Debt Rating in effect on such date of at least BBB- by S&P, or at least Baa3 by Moody's.

"Performance Level V" means, at any date of determination, (a) that the Performance Level does not meet the requirements of Performance Level I, Performance Level II, Performance Level III or Performance Level IV and (b) that the Borrower shall have a Borrower Debt Rating in effect on such date of at least BB+ by S&P, or at least Ba1 by Moody's.

"Performance Level VI" means, at any date of determination, that the Performance Level does not meet the requirements of Performance Level I, Performance Level II, Performance Level III, Performance Level IV or Performance Level V.

"Person" means any natural person, corporation, limited liability company, trust, joint venture, association, company, partnership, Governmental Authority or other entity.

"Plan" means any employee pension benefit plan (other than a Multiemployer Plan) subject to the provisions of Title IV of ERISA or Section 412 of the Code or Section 302 of ERISA, and in respect of which the Borrower or any member of its ERISA Group is (or, if such plan were terminated, would under Section 4069 of ERISA be deemed to be) an *"employer"* as defined in Section 3(5) of ERISA.

"Plan Asset Regulations" means 29 CFR § 2510.3-101 et seq., as modified by Section 3(42) of ERISA, as amended from time to time.

"Prime Rate" means the rate of interest last quoted by The Wall Street Journal as the "Prime Rate" in the U.S. or, if The Wall Street Journal ceases to quote such rate, the highest per annum interest rate published by the Federal Reserve Board in Federal Reserve Statistical Release H.15 (519) (Selected Interest Rates) as the "bank prime loan" rate or, if such rate is no longer quoted therein, any similar rate quoted therein (as determined by the Administrative Agent) or any similar release by the Federal Reserve Board (as determined by the Administrative Agent).

"Principal Office" means the principal office of the Administrative Agent, presently located in New York, New York, or such other location as designated by the Administrative Agent from time to time.

"Recipient" means (a) the Administrative Agent, (b) any Lender and (c) any Issuing Bank, as applicable.

"Register" has the meaning specified in Section 9.05(b).

"Regulation D" means Regulation D of the Board, as the same is from time to time in effect, and all official rulings and interpretations thereunder or thereof.

"Regulation T" means Regulation T of the Board, as the same is from time to time in effect, and all official rulings and interpretations thereunder or thereof.

"Regulation U" means Regulation U of the Board, as the same is from time to time in effect, and all official rulings and interpretations thereunder or thereof.

"Regulation X" means Regulation X of the Board, as the same is from time to time in effect, and all official rulings and interpretations thereunder or thereof.

"Related Parties" means, with respect to any Person, such Person's Affiliates and the partners, directors, officers, employees, agents, trustees, administrators, managers, advisors and representatives of such Person and of such Person's Affiliates.

"Required Lenders" means, at any time, subject to the provisions of Section 9.02(b), Lenders having Credit Exposure and unused Commitments representing more than 50% of the sum of the total Credit Exposures and unused Commitments at such time.

"Requirement of Law" means any law, statute, code, ordinance, order, determination, rule, regulation, judgment, decree, injunction, franchise, permit, certificate, license, authorization or other directive or requirement (whether or not having the force of law), including Environmental Laws, energy regulations and occupational, safety and health standards or controls, of any Governmental Authority.

"Reserve Requirement" means, for any day a fraction (expressed as a decimal), the numerator of which is the number one and the denominator of which is the number one minus the aggregate of the maximum reserve percentage (including any marginal, special, emergency or supplemental reserves) expressed as a decimal established by the Board or other Governmental Authority to which the Administrative Agent is subject with respect to the Adjusted LIBO Rate, for eurocurrency funding (currently referred to as "*Eurocurrency Liabilities*" in Regulation D of the Board). Such reserve percentage shall include those imposed pursuant to such Regulation D. Eurodollar Loans shall be deemed to constitute eurocurrency funding and to be subject to such reserve requirements without benefit of or credit for proration, exemptions or offsets that may be available from time to time to any Lender under such Regulation D or any comparable regulations. The Reserve Requirement shall be adjusted automatically on and as of the effective date of any change in any such reserve percentage.

"Responsible Officer" means, as used with respect to the Borrower, the Chairman, Vice Chairman, President, any Vice President, Chief Executive Officer, Chief Financial Officer, Controller or Treasurer of the Borrower.

"Restricted Payment" means any distribution (whether in cash, securities or other property) with respect to any Capital Stock in the Borrower, or any payment (whether in cash, securities or other property), including any deposit, on account of the purchase, redemption, retirement, acquisition, cancellation or termination of any such Capital Stock or any option or other right to acquire any such Capital Stock.

"S&P" means Standard & Poor's Ratings Group, a division of The McGraw-Hill Companies, Inc.

"Sanctioned Country" means, at any time, a country, region or territory which is itself the subject or target of any Sanctions (at the time of this Agreement, Crimea, Cuba, Iran, North Korea, and Syria).

"Sanctioned Person" means, at any time, (a) any Person listed in any Sanctions-related list of designated Persons maintained by the Office of Foreign Assets Control of the U.S. Department of the Treasury, the U.S. Department of State, (b) any Person operating, organized or resident in a Sanctioned Country or (c) any Person owned or controlled by any such Person or Persons described in the foregoing clauses (a) or (b).

"Sanctions" has the meaning specified in Section 4.14(a).

"SEC" means the Securities and Exchange Commission or any Governmental Authority succeeding to its function.

"Solvent" means, with respect to any Person as of any date, that as of such date, (a)(i) the sum of such Person's indebtedness (including contingent liabilities) does not exceed the present fair saleable value of such Person's present assets; (ii) such Person's capital is not unreasonably small in relation to its business as contemplated on such date; and (iii) such Person has not incurred, and does not intend to incur, or believe that it will incur indebtedness (including current obligations) beyond its ability to pay principal and interest on such indebtedness as it becomes due (whether at maturity or otherwise); and (b) such Person is "solvent" within the meaning given that term and similar terms under applicable laws relating to fraudulent transfers and conveyances. For the purposes of this definition, the amount of any contingent liability at any time shall be computed as the amount that, in light of all the facts and circumstances existing at such time, represents the amount that can reasonably be expected to become an actual or matured liability (irrespective of whether such contingent liabilities meet the criteria for accrual under Statement of Financial Accounting Standard No. 5).

"Stated Maturity Date" means, for any Lender, the date that is five years following the Closing Date subject to the extension thereof for such Lender pursuant to Section 2.22 or, if such date is not a Business Day, the immediately preceding Business Day; provided, however, that the Stated Maturity Date of any Lender that is a Non-Consenting Lender to any requested extension pursuant to Section 2.22 shall be the Stated Maturity Date of such Lender in effect immediately prior to the applicable Extension Date for all purposes of this Agreement.

"Subsidiary" means, with respect to any Person (the "parent") at any date, any corporation, limited liability company, partnership, association or other entity the accounts of which would be consolidated with those of the parent in the parent's consolidated financial statements if such financial statements were prepared in accordance with GAAP as of such date, as well as any other corporation, limited liability company, partnership, association or other entity that is, as of such date, otherwise controlled, by the parent or one or more subsidiaries of the parent or by the parent and one or more subsidiaries of the parent. Unless the context otherwise clearly requires, references in this Agreement to a "Subsidiary" or the "Subsidiaries" refer to a Subsidiary or the Subsidiaries of the Borrower.

"Swingline Exposure" means, at any time, the aggregate principal amount of all Swingline Loans outstanding at such time. The Swingline Exposure of any Lender at any time shall be its Applicable Percentage of the total Swingline Exposure at such time.

"Swingline Lender" means Barclays Bank PLC, in its capacity as lender of Swingline Loans hereunder, or any other Lender acceptable to the Borrower and the Administrative Agent, acting in such capacity.

"Swingline Loan" means a Loan made pursuant to Section 2.04(a).

"Swingline Note" means a promissory note of the Company payable to the Swingline Lender in substantially the form of Exhibit 1.01-D, together with all modifications, extensions, renewals and replacements thereof.

"Syndication Agent" means JPMorgan Chase Bank, N.A.

"Taxes" means all present or future taxes, levies, imposts, duties, deductions, or withholdings (including backup withholding) assets, fees or other charges imposed by any Governmental Authority including any interest, additions to tax or penalties applicable thereto.

"Total Capitalization" means, as to the Borrower at any date, the sum of Consolidated Net Indebtedness (determined at such date) and the Net Worth (determined as at the end of the most recent fiscal quarter of the Borrower for which financial statements pursuant to Section 5.01(a) or Section 5.01(b), as applicable, have been delivered).

"Total Commitment" means the sum of the Commitments of the Lenders.

"Transactions" has the meaning specified in the Preliminary Statements.

"Trustee" means The Bank of New York Mellon Trust Company, N.A., as the beneficiary of the Bond Letter of Credit and any successor beneficiary.

"Type", when used in reference to any Loan or Borrowing, refers to whether the rate of interest on such Loan, or on the Loans comprising such Borrowing, is determined by reference to the Adjusted LIBO Rate or the Alternate Base Rate.

"Uncommitted Letter of Credit" has the meaning specified in Section 2.05(b).

"United States" and "U.S." each means United States of America.

"U.S. Person" means any Person that is a "*United States Person*" as defined in Section 7701(a)(30) of the Code.

"U.S. Tax Compliance Certificate" has the meaning specified in Section 2.16(g)(ii)(B)(3).

"Voting Stock" means, with respect to any Person, securities of any class or classes of Capital Stock in such Person entitling holders thereof (whether at all times or only so long as no senior class of stock has voting power by reason of any contingency) to vote in the election of members of the Board of Directors or other governing body of such Person or its managing member or its general partner (or its managing general partner if there is more than one general partner).

"Wells Fargo" means Wells Fargo Bank National Association.

"Wholly-owned Domestic Operating Subsidiary" means any Wholly-owned Subsidiary that constitutes (i) a Domestic Subsidiary and (ii) an Operating Subsidiary.

"Wholly-owned Subsidiary" means a Subsidiary of which all issued and outstanding Capital Stock (excluding in the case of a corporation, directors' qualifying shares) is directly or indirectly owned by the Borrower.

"Withdrawal Liability" means liability to a Multiemployer Plan as a result of a complete or partial withdrawal from such Multiemployer Plan, as such terms are defined in Part I of Subtitle E of Title IV of ERISA.

"Withholding Agent" means the Administrative Agent and the Borrower.

"Write-Down and Conversion Powers" means, with respect to any EEA Resolution Authority, the write-down and conversion powers of such EEA Resolution Authority from time to time under the Bail-In Legislation for the applicable EEA Member Country, which write-down and conversion powers are described in the EU Bail-In Legislation Schedule.

SECTION 1.02 Classification of Loans and Borrowings. For purposes of this Agreement, Loans and Borrowings may be classified and referred to by Type (*e.g.*, a "*Eurodollar Loan*" or "*Eurodollar Borrowing*" or an "*ABR Loan*" or "*ABR Borrowing*").

SECTION 1.03 Accounting Terms; Changes in GAAP. All accounting and financial terms used herein and not otherwise defined herein and the compliance with each covenant contained herein which relates to financial matters shall be determined in accordance with GAAP applied by the Borrower on a consistent basis, except to the extent that a deviation therefrom is expressly stated. Should there be a change in GAAP from that in effect on the Closing Date, such that any of the defined terms set forth in Section 1.01 and/or compliance with the covenants set forth in Article VI would then be calculated in a different manner or with different components or any of such covenants and/or defined terms used therein would no longer constitute meaningful criteria for evaluating the matters addressed thereby prior to such change in GAAP (a) the Borrower and the Required Lenders agree, within the 60-day period following any such change, to negotiate in good faith and enter into an amendment to this Agreement in order to modify the defined terms set forth in Section 1.01 or the covenants set forth in Article VI, or both, in such respects as shall reasonably be deemed necessary by the Required Lenders that the criteria for evaluating the matters addressed by such covenants are substantially the same criteria as were effective prior to any such change in GAAP, and (b) the Borrower shall be deemed to be in compliance with such covenants during the 60-day period following any such change, or until the earlier date of execution of such amendment, if and to the extent that the Borrower would have been in compliance therewith under GAAP as in effect immediately prior to such change; provided, however, that for the avoidance of doubt, any lease that was accounted for by the Borrower or the Subsidiaries as an operating lease as of the Closing Date and any other lease entered into after the Closing Date by the Borrower or any Subsidiary shall be accounted for as an operating lease and not a capital lease to the extent that such lease would have been characterized as an operating lease as of the Closing Date.

SECTION 1.04 Interpretation. In this Agreement, unless a clear contrary intention appears:

(a) the singular number includes the plural number and vice versa;

(b) reference to any gender includes each other gender;

(c) the words "*herein*", "*hereof*" and "*hereunder*" and other words of similar import refer to this Agreement as a whole and not to any particular Article, Section or other subdivision;

(d) reference to any Person includes such Person's successors and assigns but, if applicable, only if such successors and assigns are permitted by this Agreement, and reference to a Person in a particular capacity excludes such Person in any other capacity or individually; *provided* that nothing in this clause (d) is intended to authorize any assignment not otherwise permitted by this Agreement;

(e) except as expressly provided to the contrary herein, reference to any agreement, document or instrument (including this Agreement) means such agreement, document or instrument as amended, supplemented or modified, or extended, renewed, refunded, substituted or replaced, and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof, and reference to

any Note or other note or Indebtedness or other indebtedness includes any note or indebtedness issued pursuant hereto in extension or renewal or refunding thereof or in substitution or replacement therefor;

(f) unless the context indicates otherwise, reference to any Article, Section, Schedule or Exhibit means such Article or Section hereof or such Schedule or Exhibit hereto;

(g) the word "*including*" (and with correlative meaning "*include*") means including, without limiting the generality of any description preceding such term;

(h) with respect to the determination of any period of time, except as expressly provided to the contrary, the word "*from*" means "*from and including*" and the word "*to*" means "*to but excluding*";

(i) reference to any law, rule or regulation means such as amended, modified, codified or reenacted, in whole or in part, and in effect from time to time; and

(j) the words "*asset*" and "*property*" shall be construed to have the same meaning and effect and refer to any and all tangible and intangible assets and properties.

ARTICLE II
THE CREDITS

SECTION 2.01 Commitments.

Subject to the terms and conditions set forth herein, each Lender agrees to make Committed Loans in U.S. dollars to the Borrower from time to time during the Availability Period in an aggregate principal amount that will not result in (i) such Lender's Credit Exposure exceeding such Lender's Commitment or (ii) the sum of the total Credit Exposures exceeding the Total Commitment. Within the foregoing limits and subject to the terms and conditions set forth herein, the Borrower may borrow, prepay and reborrow Committed Loans.

SECTION 2.02 Loans and Borrowings.

(a) Each Committed Loan shall be made as part of a Borrowing consisting of Committed Loans denominated in U.S. dollars made by the Lenders, ratably in accordance with their Applicable Percentage of the Total Commitment on the date such Loan is made hereunder. The failure of any Lender to make any Loan required to be made by it shall not relieve any other Lender of its obligations hereunder; *provided* that the Commitments of the Lenders are several and no Lender shall be responsible for any other Lender's failure to make Loans as required.

(b) Subject to Section 2.13, each Borrowing (other than a Borrowing of Swingline Loans, which must be ABR Loans) shall be comprised entirely of ABR Loans or Eurodollar Loans as the Borrower may request in accordance herewith. Each Lender at its option may make any Eurodollar Loan by causing any domestic or foreign branch or Affiliate of such Lender to make such Loan; *provided* that any exercise of such option shall not affect the obligation of the Borrower to repay such Loan in accordance with the terms of this Agreement.

(c) At the commencement of each Interest Period for any Eurodollar Borrowing, such Borrowing shall be in an aggregate amount that is an integral multiple of $1,000,000 and not less than $3,000,000. At the time that each ABR Borrowing is made, such Borrowing shall be in an aggregate amount that is an integral multiple of $1,000,000 and not less than $1,000,000; *provided* that an ABR

Borrowing may be in an aggregate amount that is equal to the entire unused balance of the Total Commitment or that is required to finance the reimbursement of an LC Disbursement as contemplated by Section 2.05(h). Each Swingline Loan shall be in an amount that is an integral multiple of $100,000 and not less than $1,000,000.

(d) There shall not at any time be more than a total of twelve Eurodollar Borrowings outstanding.

(e) Notwithstanding any other provision of this Agreement, the Borrower shall not be entitled to request, or to elect to convert or continue, any Borrowing if the Interest Period requested with respect thereto would end after the Stated Maturity Date.

SECTION 2.03 Requests for Borrowings.

(a) To request a Borrowing (other than a Borrowing of a Swingline Loan), the Borrower shall notify the Administrative Agent of such request (which request shall be in writing unless otherwise agreed to by the Administrative Agent) (a) in the case of a Eurodollar Borrowing, not later than 11:00 a.m., New York, New York time, three Business Days before the date of the proposed Borrowing and (b) in the case of an ABR Borrowing, not later than 10:00 a.m., New York, New York, time, on the date of the proposed Borrowing. Each such Borrowing Request shall be irrevocable and shall be made by hand delivery, telecopy or electronic communication (e-mail) to the Administrative Agent of a written Borrowing Request in a form of Exhibit 2.03 (a "Borrowing Request") and signed by the Borrower. Each such Borrowing Request shall specify the following information in compliance with Section 2.02:

(i) the aggregate amount of the requested Borrowing;

(ii) the date of such Borrowing, which shall be a Business Day;

(iii) whether such Borrowing is to be an ABR Borrowing or a Eurodollar Borrowing;

(iv) in the case of a Eurodollar Borrowing, the initial Interest Period to be applicable thereto, which shall be a period contemplated by the definition of the term *"Interest Period"*; and

(v) the location and number of the Borrower's account to which funds are to be disbursed, which shall comply with the requirements of Section 2.06;

If no election as to the Type of Borrowing is specified, then the requested Borrowing shall be an ABR Borrowing. If no Interest Period is specified with respect to any requested Eurodollar Borrowing, then the Borrower shall be deemed to have selected an Interest Period of one month's duration. Promptly following receipt of a Borrowing Request in accordance with this Section 2.03, the Administrative Agent shall advise each Lender in writing of the details thereof and of the amount of such Lender's Loan to be made as part of the requested Borrowing.

(b) To request a Borrowing of a Swingline Loan, the Borrower shall notify the Administrative Agent of such request (which request shall be in writing unless otherwise agreed by the Administrative Agent), not later than 12:00 noon, New York, New York, time, on the day of a proposed Swingline Loan. Each such notice shall be irrevocable and shall specify (i) the requested date (which shall be a Business Day) of the Swingline Loan, (ii) the amount of the requested Swingline Loan and (iii) the number of the Borrower's deposit account with the Swingline Lender to which funds are to be disbursed.

The Administrative Agent (if not the Swingline Lender) will promptly advise the Swingline Lender of any such notice received from the Borrower. The Swingline Lender shall make each Swingline Loan available to the Borrower by means of a credit to the deposit account of the Borrower identified in the notice or otherwise agreed upon by the Borrower and the Swingline Lender from time to time by 3:00 p.m., New York, New York, time, on the requested date of such Swingline Loan.

SECTION 2.04 Swingline Loans.

(a) Subject to the terms and conditions set forth herein, the Swingline Lender in its individual capacity agrees, at any time and from time to time on and after the Closing Date, to make a loan or loans (each a "Swingline Loan" and, collectively, the "Swingline Loans") to the Borrower from time to time during the Availability Period, in an aggregate principal amount at any time outstanding that will not result in (i) the aggregate principal amount of outstanding Swingline Loans exceeding $50,000,000 or (ii) the sum of the total Credit Exposures exceeding the Total Commitment; *provided* that (A) each Swingline Loan shall be in a minimum amount of $1,000,000 and shall be repayable in full as provided in Section 2.09, and (B) the Swingline Lender shall not be required to make a Swingline Loan to refinance an outstanding Swingline Loan. Within the foregoing limits and subject to the terms and conditions set forth herein, the Borrower may borrow, prepay and reborrow Swingline Loans.

(b) The Swingline Lender may by written notice given to the Administrative Agent not later than 12:00 noon, New York, New York, time, on any Business Day require the Lenders to acquire participations on such Business Day in all or a portion of the Swingline Loans outstanding. Such notice shall specify the aggregate amount of Swingline Loans in which Lenders will participate. Promptly upon receipt of such notice, the Administrative Agent will give notice thereof to each Lender, specifying in such notice such Lender's Applicable Percentage of such Swingline Loan or Loans. Each Lender hereby absolutely and unconditionally agrees, upon receipt of notice as provided above, to pay to the Administrative Agent, for the account of the Swingline Lender, such Lender's Applicable Percentage of such Swingline Loan or Loans. Each Lender acknowledges and agrees that its obligation to acquire participations in Swingline Loans pursuant to this paragraph is irrevocable and unconditional and shall not be affected by any circumstance whatsoever, including the occurrence and continuance of a Default or Event of Default or reduction or termination of the Total Commitment, and that each such payment shall be made without any offset, abatement, withholding or reduction whatsoever. Each Lender shall comply with its obligation under this paragraph by wire transfer of immediately available funds, in the same manner as provided in Section 2.06 with respect to Loans made by such Lender (and Section 2.06 shall apply, mutatis mutandis, to the payment obligations of the Lenders), and the Administrative Agent shall promptly pay to the Swingline Lender the amounts so received by it from the Lenders. The Administrative Agent shall notify the Borrower of any participations in any Swingline Loan acquired pursuant to this paragraph, and thereafter payments in respect of such Swingline Loan shall be made to the Administrative Agent for the account of the Lenders and not to the Swingline Lender. Any amounts received by the Swingline Lender from the Borrower (or other party on behalf of the Borrower) in respect of a Swingline Loan after receipt by the Swingline Lender of the proceeds of a sale of participations therein shall be promptly remitted to the Administrative Agent for the account of the Lenders; any such amounts received by the Administrative Agent shall be promptly remitted by the Administrative Agent to the Lenders that shall have made their payments pursuant to this paragraph and to the Swingline Lender, as their interests may appear. The purchase of participations in a Swingline Loan pursuant to this paragraph shall not relieve the Borrower of any default in the payment thereof.

SECTION 2.05 Letters of Credit.

(a) Existing Letters of Credit. The parties hereto acknowledge that on and after the Closing Date, each Existing Letter of Credit shall be a Letter of Credit issued by the Issuing Bank shown as

the issuer thereof on Schedule 1.01B for the account of the relevant Existing LC Subsidiary in the case of the Existing Subsidiary Letters of Credit, and for the account of the Borrower in the case of all other Existing Letters of Credit. Any Letter of Credit issued by Wachovia Bank, National Association, or First Union National Bank shall be deemed to be a Letter of Credit issued by Wells Fargo. OLP "B" hereby pledges, assigns, transfers and delivers to Wells Fargo, as the Issuing Bank that has issued the Bond Letter of Credit, all its right, title and interest to all Bonds purchased with funds drawn under the Bond Letter of Credit (the "Pledged Bonds"), and hereby grants to such Issuing Bank a first lien on, and security interest in, its rights, title and interest in and to the Pledged Bonds, the interest thereon and all proceeds thereof or substitutions therefor, as collateral security for the prompt and complete payment when due of the amounts payable in respect of the Bond Letter of Credit. During such time as any Bonds are Pledged Bonds, the Issuing Bank that has issued the Bond Letter of Credit shall be entitled to exercise all of the rights of a holder of Bonds with respect to voting, consenting and directing the Trustee as if such Issuing Bank were the owner of such Bonds, and OLP "B" hereby grants and assigns to such Issuing Bank all such rights.

(b) General. Subject to the terms and conditions set forth herein, the Borrower may request the issuance, amendment, renewal or extension of Letters of Credit from an Issuing Bank for its own account individually, for its own account and that of any Subsidiary as co-applicants, or, in the case of the Existing Subsidiary Letters of Credit, for the account of the relevant Existing LC Subsidiary, in a form reasonably acceptable to the Administrative Agent and such Issuing Bank, at any time and from time to time during the Availability Period. Subject to the terms and conditions set forth herein, such Issuing Bank shall have an obligation to issue a Letter of Credit (each such Letter of Credit, a "Committed Letter of Credit"), and to amend, renew or extend any Letter of Credit previously issued by it, under this Section 2.05 if, after giving effect to any such issuance, amendment, renewal or extension, (i) the LC Exposure for all Letters of Credit issued by such Issuing Bank would not exceed such Issuing Bank's Letter of Credit Commitment at such time, (ii) the total LC Exposure would not exceed the LC Sublimit and (iii) the total Credit Exposure does not exceed the Total Commitment. In addition, at the request of the Borrower, an Issuing Bank may in its sole discretion agree to issue, amend, renew, or extend Letters of Credit for the account of the Borrower individually or for its own account and that of any Subsidiary (each such Letter of Credit, an "Uncommitted Letter of Credit"); *provided*, *however*, after giving effect to any such issuance, amendment, renewal or extension, (i) the total LC Exposure shall not exceed the LC Sublimit, and (ii) the total Credit Exposure shall not exceed the Total Commitment. In the event of any inconsistency between the terms and conditions of this Agreement and the terms and conditions of any Application or other agreement submitted by the Borrower to, or entered into by the Borrower with, the Issuing Bank thereof relating to any Letter of Credit, the terms and conditions of this Agreement shall control. All Letters of Credit issued and deemed issued under this Section 2.05 shall constitute utilization of the Total Commitment including the total Letter of Credit Commitments in an amount equal to the LC Exposure relating to such Letters of Credit. All Letters of Credit issued under this Agreement shall be denominated in U.S. dollars. In no event shall any Issuing Bank be required to issue any Letter of Credit other than a stand-by Letter of Credit.

(c) No Issuing Bank shall be under any obligation to issue any Letter of Credit if:

(i) any order, judgment or decree of any Governmental Authority or arbitrator shall by its terms purport to enjoin or restrain such Issuing Bank from issuing such Letter of Credit, or any Law applicable to such Issuing Bank or any request or directive (whether or not having the force of law) from any Governmental Authority with jurisdiction over such Issuing Bank shall prohibit, or request that such Issuing Bank refrain from, the issuance of letters of credit generally or such Letter of Credit in particular or shall impose upon such Issuing Bank with respect to such Letter of Credit any restriction, reserve or capital requirement (for which such Issuing Bank is not otherwise compensated hereunder) not in effect on the Closing Date, or shall impose upon such

Issuing Bank any unreimbursed loss, cost or expense which was not applicable on the Closing Date and which such Issuing Bank in good faith deems material to it;

(ii) the issuance of such Letter of Credit would violate one or more policies of such Issuing Bank applicable to letters of credit generally;

(iii) except as otherwise agreed by the Administrative Agent and such Issuing Bank, such Letter of Credit is in an initial stated amount less than $10,000;

(iv) such Letter of Credit is to be denominated in a currency other than U.S. dollars;

(v) such Letter of Credit contains any provisions for automatic reinstatement of the stated amount after any drawing thereunder; or

(vi) any Lender is at such time a Defaulting Lender, unless such Issuing Bank has entered into arrangements, including reallocation of such Lender's Applicable Percentage of the outstanding LC Exposure pursuant to Section 2.19(a)(iv) or the delivery of Cash Collateral, satisfactory to such Issuing Bank (in its sole discretion) with the Borrower or such Lender to eliminate such Issuing Bank's actual or potential Fronting Exposure (after giving effect to Section 2.19(a)(iv)) with respect to such Lender arising from either the Letter of Credit then proposed to be issued or such Letter of Credit and all other LC Exposure as to which such Issuing Bank has actual or potential Fronting Exposure, as it may elect in its sole discretion.

(d) No Issuing Bank shall be under any obligation to amend or extend any Letter of Credit if (A) such Issuing Bank would have no obligation at such time to issue the Letter of Credit in its amended form under the terms hereof or (B) the beneficiary of such Letter of Credit does not accept the proposed amendment thereto.

(e) Notice of Issuance, Amendment, Renewal, Extension; Certain Conditions. To request the issuance of a Letter of Credit (or the amendment, renewal or extension of an outstanding Letter of Credit), the Borrower shall hand deliver or telecopy (or transmit by electronic communication (e-mail), if arrangements for doing so have been approved by the designated Issuing Bank) to the designated Issuing Bank and the Administrative Agent not less than five Business Days (or such lesser number as may be otherwise acceptable to such Issuing Bank) in advance of the requested date of issuance, amendment, renewal or extension) a notice (a "Letter of Credit Request") requesting the issuance of a Letter of Credit, or identifying the Letter of Credit to be amended, renewed or extended, the date of issuance, amendment, renewal or extension, the date on which such Letter of Credit is to expire (which shall comply with Section 2.05(f)), the amount of such Letter of Credit, the name and address of the beneficiary thereof and such other information as shall be necessary to prepare, amend, renew or extend such Letter of Credit. If requested by the Issuing Bank that has been requested to issue such Letter of Credit, the Borrower also shall submit a letter of credit application on such Issuing Bank's standard form (an "Application"), appropriately completed and signed by a Responsible Officer of the Borrower and including agreed-upon draft language for such Letter of Credit reasonably acceptable to the applicable Issuing Bank, in connection with any request for a Letter of Credit. A Letter of Credit shall be issued, amended, renewed or extended only if, after giving effect to such issuance, amendment, renewal or extension, (i) at any time prior to the Stated Maturity Date (A) the sum of the total Credit Exposures at any time shall not exceed the Total Commitment, (B) the LC Exposure in respect of Committed Letters of Credit issued by any Issuing Bank shall not exceed the Letter of Credit Commitment of such Issuing Bank and (C) the total LC Exposure shall not exceed the LC Sublimit, and (ii) at any time on and after the Stated Maturity Date, no Lender shall have any Credit Exposure or LC Exposure. Upon the

issuance, amendment, renewal or extension of each Letter of Credit, the Issuing Bank that has issued such Letter of Credit will notify the Administrative Agent, who, in turn, will notify the Lenders, of the amount and type of such Letter of Credit that is issued, amended, renewed or extended pursuant to this Agreement.

(f) Expiration Date. Each Letter of Credit (other than the Bond Letter of Credit) shall expire at or prior to the close of business on the earlier of (i) the date one year after the date of the issuance of such Letter of Credit (unless the Issuing Bank issuing such Letter of Credit otherwise agrees in its sole discretion) and (ii) five Business Days prior to the Stated Maturity Date (except to the extent Cash Collateralized or backstopped pursuant to arrangements satisfactory to the relevant Issuing Bank when required in accordance with Section 2.05(l)). If the Borrower so requests in any applicable Letter of Credit Request, the Issuing Bank may, in its sole and absolute discretion, agree to issue a Letter of Credit that has automatic extension provisions (each, an "Auto-Extension Letter of Credit"); *provided* that any such Auto-Extension Letter of Credit must permit the Issuing Bank to prevent any such extension at least once in each twelve-month period (commencing with the date of issuance of such Letter of Credit) by giving prior notice to the beneficiary thereof not later than a day (the "Non-Extension Notice Date") in each such twelve-month period to be agreed upon at the time such Letter of Credit is issued. Unless otherwise directed by the Issuing Bank, the Borrower shall not be required to make a specific request to the Issuing Bank for any such extension. Once an Auto-Extension Letter of Credit has been issued, the Lenders shall be deemed to have authorized (but may not require) the Issuing Bank to permit the extension of such Letter of Credit at any time to an expiry date not later than the five Business Days prior to the Stated Maturity Date; *provided*, *however*, that (i) the Issuing Bank shall not permit any such extension if the Issuing Bank has determined that it would not be permitted, or would have no obligation, at such time to issue such Letter of Credit in its revised form (as extended) under the terms hereof (by reason of the provisions of clause (e) of this Section 2.05 or otherwise pursuant to the terms hereof) and (ii) an Issuing Bank may permit the extension of such Letter of Credit to an expiry date that is later than the five Business Days prior to the Stated Maturity Date (but in any case to a date that is no later than twelve months since the expiry date as of the last auto-extension), provided that such Letter of Credit is Cash Collateralized or otherwise backstopped pursuant to arrangements satisfactory to the relevant Issuing Bank when required in accordance with Section 2.05(l).

(g) Participations. On the Closing Date, with respect to the Existing Letters of Credit and by the issuance of each other Letter of Credit (or an amendment to a Letter of Credit increasing the amount thereof) and without any further action on the part of the Issuing Banks or the Lenders, the Issuing Bank that has issued such Letter of Credit hereby grants to each Lender, and each Lender hereby acquires from such Issuing Bank, a participation in such Letter of Credit equal to such Lender's Applicable Percentage of the aggregate amount available to be drawn under such Letter of Credit. In consideration and in furtherance of the foregoing, each Lender hereby absolutely and unconditionally agrees to pay to the Administrative Agent, for the account of such Issuing Bank, such Lender's Applicable Percentage of each LC Disbursement made by such Issuing Bank and not reimbursed by the Borrower on the date due as provided in Section 2.05(h), or of any reimbursement payment required to be refunded to the Borrower for any reason. Each Lender acknowledges and agrees that its obligation to acquire participations pursuant to this paragraph in respect of Letters of Credit is irrevocable and unconditional and shall not be affected by any circumstance whatsoever, including any amendment, renewal or extension of any Letter of Credit or the occurrence and continuance of a Default or an Event of Default or reduction or termination of the Total Commitment, and that each such payment shall be made without any offset, abatement, withholding or reduction whatsoever.

(h) Reimbursement. If any Issuing Bank shall make any LC Disbursement in respect of a Letter of Credit, the Borrower shall reimburse such LC Disbursement by paying to the Administrative Agent (whether from its own funds or with the proceeds of Committed Loans) an amount equal to such LC Disbursement not later than 12:00 noon, New York, New York, time, on the Business

Day immediately following the day that the Borrower receives notice of such LC Disbursement; *provided* that if the Borrower fails to make such payment when due, then, upon demand by such Issuing Bank sent to the Administrative Agent and each Lender before 10:00 a.m., New York, New York, time, each Lender shall pursuant to Section 2.06 on the same day make available to the Administrative Agent for delivery to such Issuing Bank, immediately available funds in an amount equal to such Lender's Applicable Percentage of the amount of such payment by such Issuing Bank, and the funding of such amount shall be treated as the funding of an ABR Loan by such Lender to the Borrower. Notwithstanding anything herein or in any other Loan Document to the contrary, the funding obligations of the Lenders set forth in this Section 2.05(h) shall be binding regardless of whether or not a Default or an Event of Default shall exist or the other conditions precedent in Article III are satisfied at such time. If and to the extent any Lender fails to effect any payment due from it under this Section 2.05(h) to the Administrative Agent, then interest shall accrue on the obligation of such Lender to make such payment from the date such payment became due to the date such obligation is paid in full at a rate per annum equal to the Federal Funds Effective Rate. The failure of any Lender to pay its Applicable Percentage of any payment under any Letter of Credit shall not relieve any other Lender of its obligation hereunder to pay to the Administrative Agent its Applicable Percentage of any payment under any Letter of Credit on the date required, as specified above, but no Lender shall be responsible for the failure of any other Lender to pay to the Administrative Agent such other Lender's Applicable Percentage of any such payment.

(i) Obligations Absolute. The Borrower's obligation to reimburse LC Disbursements as *provided* in Section 2.05(h) shall, to the extent permitted by law, be absolute, unconditional and irrevocable, and shall be performed strictly in accordance with the terms of this Agreement under any and all circumstances whatsoever and irrespective of:

(i) any lack of validity or enforceability of any Letter of Credit, this Agreement or any other Loan Document, or any term or provision herein or therein;

(ii) any amendment or waiver of or any consent to departure from all or any of the provisions of any Letter of Credit, this Agreement or any other Loan Document;

(iii) the existence of any claim, setoff, defense or other right that any Loan Party, any Affiliate of any Loan Party or any other Person may at any time have against the beneficiary under any Letter of Credit, any Issuing Bank, the Administrative Agent or any Lender or any other Person, whether in connection with this Agreement or any other related or unrelated agreement or transaction;

(iv) any draft or other document presented under a Letter of Credit proving to be forged, fraudulent or invalid in any respect or any statement therein being untrue or inaccurate in any respect;

(v) payment by any Issuing Bank under a Letter of Credit against presentation of a draft or other document that does not comply with the terms of such Letter of Credit; and

(vi) any other act or omission to act or delay of any kind of the Issuing Banks, the Lenders, the Administrative Agent or any other Person or any other event or circumstance whatsoever, whether or not similar to any of the foregoing, that might, but for the provisions of this Section 2.05, constitute a legal or equitable discharge of either Borrower's obligations hereunder.

Neither the Administrative Agent, the Lenders nor the Issuing Banks, nor any of their Related Parties, shall have any liability or responsibility by reason of or in connection with the issuance or transfer of any Letter of Credit or any payment or failure to make any payment thereunder, including any of the circumstances specified in clauses (i) through (vi) above, as well as any error, omission, interruption, loss or delay in transmission or delivery of any draft, notice or other communication under or relating to any Letter of Credit (including any document required to make a drawing thereunder), any error in interpretation of technical terms or any consequence arising from causes beyond the control of any Issuing Bank; *provided* that the foregoing shall not be construed to excuse any Issuing Bank from liability to the Borrower (or, in the case of the Existing Subsidiary Letters of Credit, the relevant Existing LC Subsidiary) to the extent of any direct damages (as opposed to consequential damages, claims in respect of which are hereby waived by each Borrower to the extent permitted by applicable law) suffered by the Borrower that are caused by such Issuing Bank's failure to exercise the agreed standard of care (as set forth below) in determining whether drafts and other documents presented under a Letter of Credit comply with the terms thereof. The parties hereto expressly agree that each Issuing Bank shall have exercised the agreed standard of care in the absence of gross negligence, willful misconduct or unlawful conduct on the part of such Issuing Bank. Without limiting the generality of the foregoing, it is understood that each Issuing Bank may accept documents that appear on their face to be in substantial compliance with the terms of a Letter of Credit, without responsibility for further investigation, regardless of any notice or information to the contrary, and may make payment upon presentation of documents that appear on their face to be in substantial compliance with the terms of such Letter of Credit; *provided* that each Issuing Bank shall have the right, in its sole discretion, to decline to accept such documents and to make such payment if such documents are not in strict compliance with the terms of such Letter of Credit.

(j) Disbursement Procedures. Each Issuing Bank shall, promptly following its receipt thereof, examine all documents purporting to represent a demand for payment under a Letter of Credit issued by it. Each Issuing Bank shall promptly notify the Administrative Agent and the Borrower and, in the case of the Existing Subsidiary Letters of Credit, the relevant Existing LC Subsidiary, by telephone (confirmed by telecopy) or by electronic communication (e-mail) of such demand for payment and whether such Issuing Bank has made or will make an LC Disbursement thereunder; *provided* that any failure to give or delay in giving such notice shall not relieve the Borrower of its obligation to reimburse such Issuing Bank and the Lenders with respect to any such LC Disbursement.

(k) Interim Interest. If any Issuing Bank shall make any LC Disbursement, then, unless the Borrower shall reimburse such LC Disbursement in full on the date specified in Section 2.05(h), the unpaid amount thereof shall bear interest, for each day from the date such LC Disbursement is made to the date that the Borrower reimburses such LC Disbursement (or all Lenders make the payments to the Administrative Agent contemplated by Section 2.05(h) and treated pursuant to said Section as constituting the funding of ABR Loans), at the rate per annum then applicable to ABR Committed Loans.

(l) Cash Collateralization. If (i) any Event of Default shall occur and be continuing, on the Business Day that the Borrower receives notice from the Administrative Agent or the Required Lenders (or, if the maturity of the Loans has been accelerated, Lenders with LC Exposure representing greater than 51% of the total LC Exposure) demanding the deposit of cash collateral pursuant to this paragraph or (ii) any Letter of Credit remains outstanding on the fifth Business Day prior to the Stated Maturity Date, the Borrower shall deposit in an account with the Administrative Agent, in the name of the Administrative Agent and for the benefit of the Lenders, an amount in cash equal to the LC Exposure as of such date *plus* any accrued and unpaid interest thereon; *provided* that the obligation to deposit such cash collateral shall become effective immediately, and such deposit shall become immediately due and payable, without demand or notice of any kind, upon (A) the occurrence of any event described in the foregoing clauses (i) or (ii) or (B) the occurrence of any Event of Default with respect to the Borrower

described in clause (g) or (h) of Section 7.01. Such deposit shall be held by the Administrative Agent as collateral for the payment and performance of the obligations of the Borrower under this Agreement and the other Loan Documents. The Administrative Agent shall have exclusive dominion and control, including the exclusive right of withdrawal, over such account. Other than any interest earned on the investment of such deposits (which investments shall be made at the option and sole discretion of the Administrative Agent, but only in investments rated at least AA (or equivalent) by at least one nationally recognized rating agency) such deposits shall not bear interest. Interest or profits, if any, on such investments shall accumulate in such account and may, subject to the immediately preceding sentence be reinvested from time to time. Moneys in such account shall be applied by the Administrative Agent to reimburse each Issuing Bank for LC Disbursements for which it has not been reimbursed and, to the extent not so applied, shall be held for the satisfaction of the reimbursement obligations of the Borrower for the LC Exposure at such time or, if the maturity of the Loans has been accelerated (but subject to the consent of Lenders with LC Exposure representing greater than 51% of the total LC Exposure), be applied to satisfy other obligations of the Borrower under this Agreement and the other Loan Documents. If the Borrower is required to provide an amount of cash collateral hereunder as a result of the occurrence of an Event of Default, such amount (to the extent not applied as aforesaid) shall be returned to the Borrower within three Business Days after all Events of Default have been cured or waived. If the Borrower is required to provide an amount of cash collateral hereunder as a result of any Letter of Credit remaining outstanding on the fifth Business Day prior to the Stated Maturity Date, then such cash collateral or portion thereof shall be released promptly following: (i) the elimination of the applicable LC Exposure, (ii) the Administrative Agent's good faith determination that there exists excess cash collateral, or (iii) the extension of the Stated Maturity Date to a date that is more than five Business Days later than the expiry date of the applicable Letter of Credit.

(m) Designation. In addition the Borrower and any Issuing Bank, with the written consent of the applicable Issuing Bank and notice to the Administrative Agent and the Lenders, may designate letters of credit issued by such Issuing Bank that were not originally issued under this Agreement as Letters of Credit issued hereunder, so long as, at the time of such designation, (i) the Borrower would have been able to deliver a Letter of Credit Request with respect to a Letter of Credit hereunder containing the same terms as such letter of credit that was so designated, (ii) such Issuing Bank would have been required to issue a Letter of Credit hereunder containing the same terms as such letter of credit that was so designated and (iii) all the conditions to a credit extension set forth in Section 3.02 have been met immediately prior to such designation. Upon such designation in accordance with the foregoing, such designated letter of credit of such Issuing Bank shall be deemed to be a Letter of Credit issued by such Issuing Bank hereunder.

(n) Existing Subsidiary Letters of Credit Guaranty. Notwithstanding that each Existing Subsidiary Letter of Credit is in support of obligations of, and is for the account of, a Subsidiary, the Borrower shall be obligated to reimburse the Issuing Bank hereunder for any and all drawings under such Existing Subsidiary Letter of Credit in accordance with Section 2.05(h). Notwithstanding the foregoing, to the extent that the Borrower is not treated as the primary obligor for the reimbursement of such Existing Subsidiary Letter of Credit pursuant to the relevant documentation for such Existing Subsidiary Letter of Credit, the Debtor Relief Laws, any other applicable Laws or otherwise, the Borrower hereby absolutely, unconditionally and irrevocably guarantees (this "Existing Subsidiary Letters of Credit Guaranty") the punctual payment and performance when due, whether at stated maturity, by acceleration or otherwise, of the obligations of the Existing LC Subsidiaries under the Existing Subsidiary Letters of Credit, whether for principal, interest (including interest accruing or becoming owing both prior to and subsequent to the commencement of any proceeding against or with respect to the Existing LC Subsidiaries under any Debtor Relief Laws, fees, commissions, expenses (including reasonable attorneys' fees and expenses) or otherwise (all such obligations being the "Existing Subsidiary Letters of Credit Guaranteed Obligations"). The Borrower agrees to pay any and all expenses incurred by

each Lender, the Issuing Bank and the Administrative Agent in enforcing this Existing Subsidiary Letters of Credit Guaranty against the Borrower. This Existing Subsidiary Letters of Credit Guaranty is an absolute, unconditional, present and continuing guaranty of payment and not of collectability and is in no way conditioned upon any attempt to collect from the Existing LC Subsidiaries or any other action, occurrence or circumstance whatsoever. The Borrower agrees that, to the maximum extent permitted by applicable law, the Existing Subsidiary Letters of Credit Guaranteed Obligations may be extended or renewed, and indebtedness thereunder repaid and reborrowed in whole or in part, without notice to or assent by the Borrower, and that it will remain bound upon this Existing Subsidiary Letters of Credit Guaranty notwithstanding any extension, renewal or other alteration of any Existing Subsidiary Letters of Credit Guaranteed Obligations, or any repayment and reborrowing of Loans. To the maximum extent permitted by applicable law, except as otherwise expressly provided in this Agreement or any other Loan Document to which the Borrower is a party, the obligations of the Borrower under this Existing Subsidiary Letters of Credit Guaranty shall be absolute, unconditional and irrevocable, and shall be performed strictly in accordance with the terms hereof under any circumstances whatsoever. The Borrower hereby waives promptness, diligence, notice of acceptance and any other notice with respect to any of the Existing Subsidiary Letters of Credit Guaranteed Obligations and this Existing Subsidiary Letters of Credit Guaranty and waives presentment, demand for payment, notice of intent to accelerate, notice of dishonor or nonpayment and any requirement that the Administrative Agent or any Lender institute suit, collection proceedings or take any other action to collect the Existing Subsidiary Letters of Credit Guaranteed Obligations, including any requirement that the Administrative Agent or any Lender exhaust any right or take any action against the Existing LC Subsidiaries or any other Person or any collateral (it being the intention of the Administrative Agent, the Lenders and the Borrower that this Existing Subsidiary Letters of Credit Guaranty is to be a guaranty of payment and not of collection). It shall not be necessary for the Administrative Agent or any Lender, in order to enforce any payment by the Borrower hereunder, to institute suit or exhaust its rights and remedies against the Existing LC Subsidiaries or any other Person, including others liable to pay any Existing Subsidiary Letters of Credit Guaranteed Obligations, or to enforce its rights against any security ever given to secure payment thereof. The Borrower hereby expressly waives to the maximum extent permitted by applicable law each and every right to which it may be entitled by virtue of the suretyship laws of the State of New York or any other state in which it may be located, including any and all rights it may have pursuant to Rule 31, Texas Rules of Civil Procedure, Section 17.001 of the Texas Civil Practice and Remedies Code and Chapter 34 of the Texas Business and Commerce Code.

SECTION 2.06 Funding of Borrowings.

(a) Each Lender shall make each Loan to be made by it hereunder on the proposed date thereof by wire transfer of immediately available funds by 2:00 p.m., New York, New York time, to the account of the Administrative Agent most recently designated by it for such purpose by notice to the Lenders; *provided* that Swingline Loans shall be made as provided in Section 2.04. The Borrower hereby irrevocably authorizes the Administrative Agent to disburse the proceeds of each Borrowing requested pursuant to Section 2.03 in immediately available funds by crediting or wiring such proceeds to the deposit account of the Borrower identified in the Borrowing Request or otherwise agreed upon by the Borrower and the Administrative Agent from time to time; *provided* that ABR Committed Loans made to finance the reimbursement of an LC Disbursement as provided in Section 2.05(g) and (h) shall be remitted by the Administrative Agent to the Issuing Bank that made such LC Disbursement.

(b) Unless the Administrative Agent shall have received notice from a Lender prior to the proposed date of any Borrowing (or prior to 11:00 a.m., New York, New York, time, on such date in the case of an ABR Borrowing) that such Lender will not make available to the Administrative Agent such Lender's Applicable Percentage of such Borrowing, the Administrative Agent may assume that such Lender has made such Applicable Percentage of such Borrowing available on such date in accordance with

Section 2.06(a) and may, in reliance upon such assumption, make available to the Borrower a corresponding amount. In such event, if a Lender has not in fact made its Applicable Percentage of the applicable Borrowing available to the Administrative Agent, then the applicable Lender and the Borrower severally agree to pay to the Administrative Agent forthwith on demand such corresponding amount with interest thereon, for each day from the date such amount is made available to the Borrower to the date of payment to the Administrative Agent, at (i) in the case of such Lender, the greater of the Federal Funds Effective Rate and a rate determined by the Administrative Agent in accordance with banking industry rules on interbank compensation, or (ii) in the case of the Borrower, the interest rate applicable to ABR Loans. If the Borrower and such Lender shall pay such interest to the Administrative Agent for the same or an overlapping period, the Administrative Agent shall promptly remit to the Borrower the amount of such interest paid by the Borrower for such period. If such Lender pays its share of the applicable Borrowing to the Administrative Agent, then the amount so paid shall constitute such Lender's Loan included in such Borrowing. Any payment by the Borrower shall be without prejudice to any claim the Borrower may have against a Lender that shall have failed to make such payment to the Administrative Agent.

SECTION 2.07 Interest Elections.

(a) Subject to Section 2.13, each Borrowing initially shall be of the Type specified in the applicable Borrowing Request and, in the case of a Eurodollar Borrowing, shall have an initial Interest Period as specified in such Borrowing Request. Thereafter, subject to Section 2.13, the Borrower may elect to convert such Borrowing to a different Type or to continue such Borrowing and, in the case of a Eurodollar Borrowing, may elect Interest Periods therefor, all as provided in this Section 2.07. The Borrower may elect different options with respect to different portions of the affected Borrowing, in which case each such portion shall be allocated ratably among the Lenders holding the Loans comprising such Borrowing, and the Loans comprising each such portion shall be considered a separate Borrowing. This Section 2.07 shall not apply to Swingline Borrowings, which may not be converted or continued.

(b) To make an election pursuant to this Section 2.07, the Borrower shall notify the Administrative Agent of such election (which notification shall be in writing unless otherwise agreed to by the Administrative Agent) by the time that a Borrowing Request would be required under Section 2.03 if the Borrower were requesting a Borrowing of the Type resulting from such election to be made on the effective date of such election. Each such Interest Election Request shall be irrevocable and shall be made by hand delivery or telecopy or by electronic communication (e-mail) to the Administrative Agent of an Interest Election Request in the form of Exhibit 2.07 (an "Interest Election Request").

(c) Each Interest Election Request shall specify the following information in compliance with Section 2.02:

(i) the Borrowing to which such Interest Election Request applies and, if different options are being elected with respect to different portions thereof, the portions thereof to be allocated to each resulting Borrowing (in which case the information to be specified pursuant to clauses (iii) and (iv) below shall be specified for each resulting Borrowing);

(ii) the effective date of the election made pursuant to such Interest Election Request, which shall be a Business Day;

(iii) whether the resulting Borrowing is to be an ABR Borrowing or a Eurodollar Borrowing; and

(iv) if the resulting Borrowing is a Eurodollar Borrowing, the Interest Period to be applicable thereto after giving effect to such election, which shall be a period contemplated by the definition of the term "*Interest Period*".

If any such Interest Election Request requests a Eurodollar Borrowing but does not specify an Interest Period, then the Borrower shall be deemed to have selected an Interest Period of one month's duration.

(d) Promptly following receipt of an Interest Election Request, the Administrative Agent shall advise each Lender in writing of the details thereof and of such Lender's portion of each resulting Borrowing.

(e) If the Borrower fails to deliver a timely Interest Election Request with respect to a Eurodollar Borrowing prior to the end of the Interest Period applicable thereto, then, unless such Borrowing is repaid as provided herein, at the end of such Interest Period such Borrowing shall be converted to an ABR Borrowing. Notwithstanding any contrary provision hereof, if and so long as an Event of Default is continuing and the Administrative Agent, at the request of the Required Lenders, so notifies the Borrower, then so long as an Event of Default has occurred and is continuing (i) no outstanding Borrowing may be converted to or continued as a Eurodollar Borrowing, and (ii) unless repaid, each Eurodollar Borrowing shall be converted to an ABR Borrowing at the end of the Interest Period applicable thereto.

SECTION 2.08 Termination and Reduction of Commitments; Mandatory Prepayments.

(a) Unless previously terminated, the Total Commitment shall terminate on the Maturity Date.

(b) The Borrower may at any time terminate, or from time to time reduce, the Total Commitment or the Letter of Credit Commitments, in whole or in part; *provided* that (i) each partial reduction of the Total Commitment or Letter of Credit Commitments shall be in an amount that is an integral multiple of $1,000,000 and not less than $5,000,000, (ii) the Borrower shall not terminate or reduce the Commitments if, after giving effect to any concurrent prepayment of the Loans in accordance with Section 2.10, the total Credit Exposures would exceed the Total Commitment and (iii) the Borrower shall not terminate or reduce the Letter of Credit Commitments if, after giving effect to such termination or reduction, (A) the total LC Exposure would exceed the total Letter of Credit Commitments as so reduced or (B) the LC Exposure of any Issuing Bank would exceed its Letter of Credit Commitment.

(c) The Borrower shall notify the Administrative Agent of any election to terminate or reduce the Total Commitment or the Letter of Credit Commitments under Section 2.08(a) at least three Business Days prior to the effective date of such termination or reduction, specifying such election and the effective date thereof. Promptly following receipt of any notice, the Administrative Agent shall advise the Lenders of the contents thereof. Each notice delivered by the Borrower pursuant to this Section 2.08 shall be irrevocable; *provided* that a notice of termination of the Total Commitment or the Letter of Credit Commitments delivered by the Borrower may state that such notice is conditioned upon the effectiveness of other credit facilities or other event, in which case such notice may be revoked by the Borrower (by notice to the Administrative Agent on or prior to the specified effective date) if such condition is not satisfied. Any termination or reduction of the Total Commitment or the Letter of Credit Commitments shall be permanent. Except as expressly provided in Section 2.19, each reduction of the Total Commitment shall be made ratably among the Lenders in accordance with their Applicable Percentages.

SECTION 2.09 Repayment of Loans; Evidence of Debt.

(a) The Borrower hereby unconditionally promises to pay (i) to the Administrative Agent for the account of each Lender the then unpaid principal amount of each Committed Loan on the Maturity Date and (ii) to the Swingline Lender the then unpaid principal amount of each Swingline Loan not later than seven days after the date such Swingline Loan is made. In addition, if the total Credit Exposures exceeds the Total Commitment, the Borrower shall pay to the Administrative Agent for the account of each Lender an aggregate principal amount of Committed Loans or Swingline Loans sufficient to cause the total Credit Exposures not to exceed the Total Commitment; *provided*, *however*, if the repayment of the outstanding Committed Loans and/or Swingline Loans does not cause the total Credit Exposures, to be equal to or less than the Total Commitment, the Borrower shall deposit in an account with the Administrative Agent in the name of the Administrative Agent and for the benefit of the Lenders, an amount in cash equal to the amount by which the total Credit Exposures exceeds the Total Commitment, which cash deposit shall be held by the Administrative Agent for the payment of the Obligations of the Borrower under this Agreement and the other Loan Documents. The Administrative Agent shall have exclusive dominion and control, including the exclusive right of withdrawal, over such account other than any interest earned on the investment of such deposit (which investments shall be made at the option and sole discretion of the Administrative Agent, but only in investments rated at least AA (or equivalent) by at least one nationally recognized rating agency, unless an Event of Default shall have occurred and be continuing, and in any event at the Borrower's risk and expense). Interest or profits, if any, on such investments shall accumulate in such account. Moneys in such account shall be applied by the Administrative Agent to reimburse each Issuing Bank for LC Disbursements for which it has not been reimbursed and, to the extent not so applied, shall be held for the satisfaction of the reimbursement obligations of the Borrower for the LC Exposure at such time, or if the maturity of the Loans has been accelerated (but subject to the consent of the Lenders with LC Exposure representing greater than 51% of the total LC Exposure), be applied to satisfy other obligations of the Borrower under this Agreement and the other Loan Documents. At any time when the sum of the total Credit Exposures does not exceed the Total Commitment and so long as no Default under Section 7.01(b) or Event of Default shall then exist, upon the request of the Borrower the amount of such deposit (to the extent not applied as aforesaid) shall be returned to the Borrower within three Business Days after receipt of such request.

(b) Each Lender shall maintain in accordance with its usual practice an account or accounts evidencing the indebtedness of the Borrower to such Lender resulting from each Loan made by such Lender, including the amounts of principal and interest payable and paid to such Lender from time to time hereunder.

(c) The Administrative Agent shall maintain accounts in which it shall record (i) the amount of each Loan made hereunder, the Class and Type thereof and the Interest Period applicable thereto, (ii) the amount of any principal or interest due and payable or to become due and payable from the Borrower to each Lender hereunder and (iii) the amount of any sum received by the Administrative Agent hereunder for the account of the Lenders and each Lender's share thereof.

(d) The entries made in the accounts maintained pursuant to Section 2.09(b) or (c) shall be prima facie evidence of the existence and amounts of the obligations recorded therein; *provided* that the failure of any Lender or the Administrative Agent to maintain such accounts or any error or conflict therein shall not in any manner affect the obligation of the Borrower to repay the Loans in accordance with the terms of this Agreement.

(e) Any Lender may request that Loans made by it be evidenced by a Committed Note or a Swingline Note, as applicable. In such event, the Borrower shall prepare, execute and deliver to such

Lender a Committed Note or a Swingline Note, as applicable. Thereafter, the Loans evidenced by such Committed Note and interest thereon shall at all times (including after assignment pursuant to Section 9.05) be represented by one or more Committed Notes in such forms payable to the payee named therein.

SECTION 2.10 Voluntary Prepayment of Loans.

(a) The Borrower shall have the right at any time and from time to time to prepay any Borrowing in whole or in part, subject to prior notice in accordance with Section 2.10(b).

(b) The Borrower shall notify the Administrative Agent (or, in the case of prepayment of a Swingline Loan, the Swingline Lender) (which notice shall be made in writing by telecopy or electronic communication (e-mail) in the form of Exhibit 2.10 (a "Notice of Prepayment")) of any prepayment hereunder (i) in the case of prepayment of a Eurodollar Borrowing, not later than 11:00 a.m., New York, New York time, three Business Days before the date of prepayment, (ii) in the case of prepayment of an ABR Borrowing (other than Swingline Loans), not later than 11:00 a.m., New York, New York time, one Business Day prior to the date of prepayment or (iii) in the case of prepayment of a Swingline Loan, not later than 11:00 a.m., New York, New York time on the date of the prepayment. Each such notice shall be irrevocable and shall specify the prepayment date, Type and the principal amount of each Borrowing or portion thereof to be prepaid; *provided* that, if a notice of prepayment is given in connection with a conditional notice of termination of the Total Commitment as contemplated by Section 2.08, then such notice of prepayment may be revoked if such notice of termination of the Total Commitment is revoked in accordance with Section 2.08. Each partial prepayment shall be in an aggregate amount not less than, and shall be an integral multiple of, the amounts shown below with respect to the applicable Type of Loan or Borrowing:

Type of Loan/Borrowing	Integral Multiple of	Minimum Aggregate Amount
Eurodollar Borrowing	$1,000,000	$3,000,000
ABR Borrowing	$1,000,000	$1,000,000
Swingline Loan	$100,000	$1,000,000

Promptly following receipt of any such notice relating to a Borrowing, the Administrative Agent shall advise the Lenders in writing of the contents thereof. If the Borrower fails to designate the Type of Borrowings to be prepaid, partial prepayments shall be applied first to the outstanding Swingline Loans until the outstanding principal amount of all Swingline Loans is repaid in full, then to the outstanding ABR Borrowings until the outstanding principal amount of all ABR Borrowings is repaid in full, and then to the outstanding principal amount of Eurodollar Borrowings. Each partial prepayment of any Borrowing shall be in an amount that would be permitted in the case of an advance of a Borrowing of the same Type as provided in Section 2.02. Each prepayment of a Borrowing shall be applied to the Loans included in the prepaid Borrowing in accordance with the Lenders' Applicable Percentage of such Borrowing. Prepayments shall be accompanied by accrued interest to the extent required by Section 2.12.

SECTION 2.11 Fees.

(a) The Borrower agrees to pay to the Administrative Agent for the account of each Lender (other than a Defaulting Lender) a commitment fee (the "Commitment Fee"), which shall be equal to (a) the Applicable Commitment Fee Rate times (b) the daily average undrawn portion of the such

Lender's Commitment (it being understood that (i) such Lender's Applicable Percentage of the face amount of Letters of Credit issued and outstanding shall be considered a drawn portion of such Lender's Commitment for such purpose and (ii) such Lender's Swingline Exposure shall be excluded from the drawn portion of such Lender's Commitment for such purpose), during the period from the Closing Date to the later of (i) the date on which such Commitment terminates and (ii) the date on which the Loans are paid in full; *provided* that, if such Lender continues to have any Credit Exposure after its Commitment terminates, then such Commitment Fee shall continue to accrue on the daily amount of such Lender's Credit Exposure from the date on which its Commitment terminates to the date on which such Lender ceases to have any Credit Exposure. Accrued Commitment Fees shall be payable in arrears on the last Business Day of March, June, September and December of each year and on the date on which the Commitments terminate and the date the Loans are paid in full, commencing on the first such date to occur after the Closing Date. All Commitment Fees shall be computed on the basis of a year of 365 or 366 days, as the case may be, and shall be payable for the actual number of days elapsed (including the first day but excluding the last day).

(b) The Borrower agrees to pay (i) to the Administrative Agent for the account of each Lender (other than a Defaulting Lender) a participation fee with respect to its participations in Letters of Credit which shall accrue at a rate per annum equal to the Applicable Margin for Eurodollar Loans on the average daily amount of such Lender's LC Exposure (excluding any portion thereof attributable to unreimbursed LC Disbursements) during the period from and including the Closing Date to but excluding the later of the date on which such Lender's Commitment terminates and the date on which such Lender ceases to have any LC Exposure and (ii) to each Issuing Bank that has issued a Letter of Credit, a fronting fee which shall accrue a rate agreed to by the Borrower and such Issuing Bank (and notified to the Administrative Agent) on the average daily amount of the LC Exposure in respect of each such Letter of Credit from the date such Letter of Credit is issued to the date on which there ceases to be any LC Exposure with respect to such Letter of Credit. The Borrower also agrees to pay each Issuing Bank's standard fees with respect to the issuance, amendment, renewal or extension of any Letter of Credit issued by it or the processing of drawings thereunder. Accrued participation fees and fronting fees shall be payable in arrears on the last Business Day of March, June, September and December of each year, commencing on the first such date to occur after the Closing Date; *provided* that all such fees shall be payable on the date on which the Total Commitment terminates and any such fees accruing after the date on which the Total Commitment terminates shall be payable on demand. Any other fees payable to any Issuing Bank pursuant to this paragraph shall be payable within 10 days after demand. All participation fees shall be computed on the basis of a year of 360 days, as applicable, and shall be payable for the actual number of days elapsed (including the first day but excluding the last day).

(c) The Borrower agrees to pay, without duplication, to (i) the Administrative Agent and the Lenders, for their own accounts (or that of their applicable Affiliate), fees payable in the amounts and at the times specified in that letter agreement dated October 23, 2018 among the Borrower, Barclays Bank PLC and JPMorgan Chase Bank, N.A. (as from time to time amended, the "Fee Letter") and (ii) the Administrative Agent, for its own account (or that of its applicable Affiliate), fees payable in amounts and at the times specified in that letter agreement dated October 23, 2018 among the Borrower and Barclays Bank PLC (the "Administrative Agent Fee Letter").

(d) All fees payable hereunder shall be paid on the dates due, in immediately available funds, to the Administrative Agent (or to each Issuing Bank, in the case of fees payable to it) (for distribution, in the case of Commitment Fees and participation fees, to the Lenders). Except as required by law, fees paid shall not be refundable under any circumstance.

SECTION 2.12 Interest.

(a) The Loans comprising each ABR Borrowing shall bear interest at a rate per annum equal to the *sum* of Alternate Base Rate *plus* the Applicable Margin. Each Swingline Loan shall be an ABR Loan and shall bear interest at the Alternate Base Rate plus the Applicable Margin.

(b) The Loans comprising each Eurodollar Borrowing shall bear interest at the Adjusted LIBO Rate for the Interest Period in effect for such Borrowing *plus* the Applicable Margin.

(c) Notwithstanding the foregoing, if any principal of or interest on any Loan or any fee or other amount payable by the Borrower hereunder is not paid when due, whether at stated maturity, upon acceleration or otherwise, such overdue amount shall bear interest, after as well as before judgment, at a rate per annum equal to (i) in the case of overdue principal of any Loan, 2% *plus* the rate otherwise applicable to such Loan as provided above or (ii) in the case of any other amount, 2% *plus* the Alternate Base Rate.

(d) Accrued interest on each Loan shall be payable in arrears on each Interest Payment Date for such Loan; *provided* that (i) interest accrued pursuant to Section 2.12(c) shall be payable on demand, (ii) in the event of any repayment or prepayment of any Loan (other than a prepayment of an ABR Committed Loan prior to the end of the Availability Period), accrued interest on the principal amount repaid or prepaid shall be payable on the date of such repayment or prepayment, (iii) in the event of any conversion of any Eurodollar Committed Loan prior to the end of the current Interest Period therefor, accrued interest on such Loan shall be payable on the effective date of such conversion and (iv) all accrued interest shall be payable upon termination of the Total Commitment.

(e) All interest hereunder shall be computed on the basis of a year of 360-day year, except that interest computed by reference to the Alternate Base Rate at times when the Alternate Base Rate is based on the Prime Rate shall be computed on the basis of a year of 365 days (or 366 days in a leap year), and in each case shall be payable for the actual number of days elapsed (including the first day but excluding the last day). The applicable Alternate Base Rate, Adjusted LIBO Rate or LIBO Rate shall be determined by the Administrative Agent, and such determination shall be conclusive absent manifest error.

SECTION 2.13 Alternate Rate of Interest.

(a) If prior to the commencement of any Interest Period for a Eurodollar Borrowing:

(i) the Administrative Agent determines (which determination shall be conclusive absent manifest error) that adequate and reasonable means do not exist for ascertaining the Adjusted LIBO Rate or the LIBO Rate for such Interest Period; or

(ii) the Administrative Agent is advised by the Required Lenders that the Adjusted LIBO Rate or the LIBO Rate, as applicable, for such Interest Period will not adequately and fairly reflect the cost to such Lenders of making or maintaining their Loans included in such Borrowing for such Interest Period;

then the Administrative Agent shall give notice thereof to the Borrower and the Lenders in writing as promptly as practicable thereafter and, until the Administrative Agent notifies the Borrower and the Lenders in writing that the circumstances giving rise to such notice no longer exist, (i) any Interest Election Request that requests the conversion of any Borrowing to, or continuation of any Borrowing as, a Eurodollar Borrowing shall be ineffective, and (ii) if any Borrowing Request requests a Eurodollar Borrowing, such Borrowing shall be made as an ABR Borrowing.

(b) If at any time the Administrative Agent determines (which determination shall be conclusive absent manifest error) that (i) the circumstances set forth in clause (a)(i) have arisen and such circumstances are unlikely to be temporary or (ii) the circumstances set forth in clause (a)(i) have not arisen but the supervisor for the administrator of the LIBO Rate or a Governmental Authority having jurisdiction over the Administrative Agent has made a public statement identifying a specific date after which the LIBO Rate shall no longer be used for determining interest rates for loans, then the Administrative Agent and the Borrower shall endeavor to establish an alternate rate of interest to the LIBO Rate that gives due consideration to the then prevailing market convention for determining a rate of interest for syndicated loans in the United States at such time, and shall enter into an amendment to this Agreement to reflect such alternate rate of interest and such other related changes to this Agreement as may be applicable (but for the avoidance of doubt, such related changes shall not include a reduction of the Applicable Margin). Notwithstanding anything to the contrary in Section 9.02, such amendment shall become effective without any further action or consent of any other party to this Agreement so long as the Administrative Agent shall not have received, within five Business Days of the date notice of such alternate rate of interest is provided to the Lenders, a written notice from the Required Lenders stating that such Required Lenders object to such amendment. Until an alternate rate of interest shall be determined in accordance with this clause (b) (but, in the case of the circumstances described in clause (ii) of the first sentence of this Section 2.13(b), only to the extent the LIBO Rate for such Interest Period is not available or published at such time on a current basis), (x) any Interest Election Request that requests the conversion of any Borrowing to, or continuation of any Borrowing as, a Eurodollar Borrowing shall be ineffective and (y) if any Borrowing Request requests a Eurodollar Borrowing, such Borrowing shall be made as an ABR Borrowing; provided that, if such alternate rate of interest shall be less than zero, such rate shall be deemed to be zero for the purposes of this Agreement.

SECTION 2.14 Increased Costs.

(a) If any Change in Law shall:

(i) impose, modify or deem applicable any reserve, special deposit or similar requirement against assets of, deposits with or for the account of, or credit extended by, any Lender (except any such reserve requirement reflected in the Adjusted LIBO Rate) or any Issuing Bank;

(ii) subject any Recipient to any Taxes (other than (A) Indemnified Taxes, (B) Taxes described in clauses (b) through (d) of the definition of Excluded Taxes and (C) Connection Income Taxes) on its Loans, loan principal, Letters of Credit, Commitments, or other Obligations, or its deposits, reserves, other liabilities or capital attributable thereto; or

(iii) impose on any Lender, any Issuing Bank or the London interbank market any other condition, cost or expense (other than Taxes) affecting this Agreement or Eurodollar Loans made by such Lender or any Letter of Credit or participation therein;

and the result of any of the foregoing shall be to increase the cost to such Lender or such other Recipient of making, converting to, continuing or maintaining any Loan or of maintaining its obligation to make any such Loan, or to increase the cost to such Lender, such Issuing Bank or such other Recipient of participating in, issuing or maintaining any Letter of Credit (or of maintaining any obligation to participate in or to issue any Letter of Credit), or to reduce the amount of any sum received or receivable by such Lender, Issuing Bank or other Recipient hereunder (whether of principal, interest or any other amount) then, upon request of such Lender, Issuing Bank or other Recipient, the Borrower will pay to such Lender or other Recipient, as the case may be, such additional amount or amounts as will

compensate such Lender, Issuing Bank or other Recipient, as the case may be, for such additional costs incurred or reduction suffered.

(b) If any Lender or Issuing Bank determines that any Change in Law affecting such Lender or Issuing Bank or any lending office of such Lender or such Lender's or Issuing Bank's holding company, if any, regarding capital or liquidity requirements, has or would have the effect of reducing the rate of return on such Lender's or Issuing Bank's capital or on the capital of such Lender's or Issuing Bank's holding company, if any, as a consequence of this Agreement, the Commitment of such Lender or the Loans made by, or participations in Letters of Credit or Swingline Loans held by, such Lender, or the Letters of Credit issued by any Issuing Bank, to a level below that which such Lender or Issuing Bank or such Lender's or Issuing Bank's holding company could have achieved but for such Change in Law (taking into consideration such Lender's or Issuing Bank's policies and the policies of such Lender's or Issuing Bank's holding company with respect to capital adequacy and/or liquidity requirements), then from time to time the Borrower will pay to such Lender or Issuing Bank, as the case may be, such additional amount or amounts as will compensate such Lender or Issuing Bank or such Lender's or Issuing Bank's holding company for any such reduction suffered.

(c) A certificate of a Lender or any Issuing Bank setting forth the amount or amounts necessary to compensate such Lender or Issuing Bank or its holding company, as the case may be, as specified in paragraph (a) or (b) of this Section 2.14 and delivered to the Borrower, shall be conclusive absent manifest error. The Borrower shall pay such Lender or Issuing Bank, as the case may be, the amount shown as due on any such certificate within 10 Business Days after receipt thereof.

(d) Failure or delay on the part of any Lender or any Issuing Bank to demand compensation pursuant to this Section 2.14 shall not constitute a waiver of such Lender's or Issuing Bank's right to demand such compensation; *provided* that the Borrower shall not be required to compensate a Lender or any Issuing Bank pursuant to this Section 2.14 for any increased costs or reductions incurred more than six months prior to the date that such Lender or such Issuing Bank, as the case may be, notifies the Borrower of the Change in Law giving rise to such increased costs or reductions and of such Lender's or such Issuing Bank's intention to claim compensation therefor (except that, if the Change in Law giving rise to such increased costs or reductions is retroactive, then the six-month period referred to above shall be extended to include the period of retroactive effect thereof).

SECTION 2.15 Break Funding Payments. In the event of (a) the payment of any principal of any Eurodollar Loan other than on the last day of an Interest Period applicable thereto (including as a result of an Event of Default), (b) the conversion of any Eurodollar Loan other than on the last day of the Interest Period applicable thereto, (c) the failure to borrow (unless such failure was caused by the failure of a Lender to make such Loan), convert, continue or prepay any Eurodollar Loan, or the failure to convert an ABR Loan to a Eurodollar Loan, on the date specified in any notice delivered pursuant hereto (regardless of whether such notice is permitted to be revocable under Section 2.08 and is revoked in accordance herewith), or (d) the assignment of any Eurodollar Loan other than on the last day of the Interest Period applicable thereto as a result of a request by the Borrower pursuant to Section 2.18, then, in any such event, the Borrower shall compensate each Lender for the loss, cost and expense attributable to such event. In the case of a Eurodollar Loan, the loss to any Lender attributable to any such event shall be deemed to include an amount determined by such Lender to be equal to the excess, if any, of (i) the amount of interest that such Lender would pay for a deposit equal to the principal amount of such Loan for the period from the date of such payment, conversion, failure or assignment to the last day of the then current Interest Period for such Loan (or, in the case of a failure to borrow, convert or continue, the duration of the Interest Period that would have resulted from such borrowing, conversion or continuation) if the interest rate payable on such deposit were equal to the Adjusted LIBO Rate for such Interest Period, over (ii) the amount of interest that such Lender

would earn on such principal amount for such period if such Lender were to invest such principal amount for such period at the interest rate that would be bid by such Lender (or an affiliate of such Lender) for dollar deposits from other banks in the Eurodollar market at the commencement of such period. A certificate of any Lender setting forth any amount or amounts that such Lender is entitled to receive pursuant to this Section 2.15 shall be delivered to the Borrower and shall be conclusive absent manifest error. The Borrower shall pay such Lender the amount shown as due on any such certificate within 10 Business Days after receipt thereof.

SECTION 2.16 Taxes.

(a) Defined Terms. For purposes of this Section 2.16, the term "Requirement of Law" includes FATCA.

(b) Payments Free of Taxes. Any and all payments by or on account of any obligation of the Borrower under any Loan Document shall be made without deduction or withholding for any Taxes, except as required by a Requirement of Law. If any Requirement of Law (as determined in the good faith discretion of the Withholding Agent) requires the deduction or withholding of any Tax from any such payment by the Withholding Agent, then the Withholding Agent shall be entitled to make such deduction or withholding and shall timely pay the full amount deducted or withheld to the relevant Governmental Authority in accordance with applicable Requirement of Law and, if such Tax is an Indemnified Tax, then the sum payable by the Borrower shall be increased as necessary so that after such deduction or withholding has been made (including such deductions and withholdings applicable to additional sums payable under this Section 2.16) the applicable Recipient receives an amount equal to the sum it would have received had no such deduction or withholding been made.

(c) Payment of Other Taxes by the Borrower. Without duplication of any obligation under this Section 2.16, the Borrower shall timely pay to the relevant Governmental Authority in accordance with applicable Requirement of Law, or at the option of the Administrative Agent timely reimburse it for the payment of, any Other Taxes.

(d) Indemnification by the Borrower. Without duplication of any obligation under this Section 2.16, the Borrower shall indemnify each Recipient, within 10 days after demand therefor, for the full amount of any Indemnified Taxes (including Indemnified Taxes imposed or asserted on or attributable to amounts payable under this Section) payable or paid by such Recipient or required to be withheld or deducted from a payment to such Recipient and any reasonable expenses arising therefrom or with respect thereto, whether or not such Indemnified Taxes were correctly or legally imposed or asserted by the relevant Governmental Authority; *provided, however*, the Borrower shall not be required to indemnify a Recipient pursuant to this Section 2.16(d) for any Indemnified Taxes unless such Recipient makes written demand on the Borrower for indemnification for such Indemnified Taxes no later than six months after the earlier of (i) the date on which such Recipient receives written demand from the relevant Governmental Authority for payment of such Indemnified Taxes or (ii) the date on which such Recipient has made payment of such Indemnified Taxes. A certificate as to the amount of such payment or liability delivered to the Borrower by a Lender (with a copy to the Administrative Agent), or by the Administrative Agent on its own behalf or on behalf of a Lender, shall be conclusive absent manifest error.

(e) Indemnification by the Lenders. Each Lender shall severally indemnify the Administrative Agent, within 10 days after demand therefor, for (i) any Taxes attributable to such Lender (but only to the extent that the Borrower has not already indemnified the Administrative Agent for such Taxes and without limiting the obligation of the Borrower to do so), (ii) any Taxes attributable to such Lender's failure to comply with the provisions of Section 9.05(c) relating to the maintenance of a Participant

Register and (iii) any Excluded Taxes attributable to such Lender, in each case, that are payable or paid by the Administrative Agent in connection with any Loan Document, and any reasonable expenses arising therefrom or with respect thereto, whether or not such Taxes were correctly or legally imposed or asserted by the relevant Governmental Authority. A certificate as to the amount of such payment or liability delivered to any Lender by the Administrative Agent shall be conclusive absent manifest error. Each Lender hereby authorizes the Administrative Agent to set off and apply any and all amounts at any time owing to such Lender under any Loan Document or otherwise payable by the Administrative Agent to the Lender from any other source against any amount due to the Administrative Agent under this paragraph (e).

(f) Evidence of Payments. As soon as practicable after any payment of Taxes by the Borrower to a Governmental Authority pursuant to this Section 2.16, the Borrower shall deliver to the Administrative Agent the original or a certified copy of a receipt issued by such Governmental Authority evidencing such payment, a copy of the return reporting such payment or other evidence of such payment reasonably satisfactory to the Administrative Agent.

(g) Status of Lenders. (i) Any Lender that is entitled to an exemption from or reduction of withholding Tax with respect to payments made under any Loan Document shall deliver to the Borrower and the Administrative Agent, at the time or times reasonably requested by the Borrower or the Administrative Agent, such properly completed and executed documentation reasonably requested by the Borrower or the Administrative Agent as will permit such payments to be made without withholding or at a reduced rate of withholding. In addition, any Lender, if reasonably requested by the Borrower or the Administrative Agent, shall deliver such other documentation prescribed by applicable Requirement of Law or reasonably requested by the Borrower or the Administrative Agent as will enable the Borrower or the Administrative Agent to determine whether or not such Lender is subject to backup withholding or information reporting requirements. Notwithstanding anything to the contrary in the preceding two sentences, the completion, execution and submission of such documentation (other than such documentation set forth in subsections (ii)(A), (ii)(B) and (ii)(D) below) shall not be required if in the Lender's reasonable judgment such completion, execution or submission would subject such Lender to any material unreimbursed cost or expense or would materially prejudice the legal or commercial position of such Lender.

(ii) Without limiting the generality of the foregoing, in the event that the Borrower is a U.S. Borrower,

(A) any Lender that is a U.S. Person shall deliver to the Borrower and the Administrative Agent on or prior to the date on which such Lender becomes a Lender under this Agreement (and from time to time thereafter upon the reasonable request of the Borrower or the Administrative Agent), executed originals of IRS Form W-9 certifying that such Lender is exempt from U.S. federal backup withholding Tax;

(B) any Foreign Lender shall, to the extent it is legally entitled to do so, deliver to the Borrower and the Administrative Agent (in such number of copies as shall be requested by the recipient) on or prior to the date on which such Foreign Lender becomes a Lender under this Agreement (and from time to time thereafter upon the reasonable request of the Borrower or the Administrative Agent), whichever of the following is applicable:

(1) in the case of a Foreign Lender claiming the benefits of an income Tax treaty to which the United States is a party (x) executed originals of IRS Form W-8BEN or IRS Form W-8BEN-E establishing an exemption from, or reduction of, U.S. federal withholding Tax pursuant to the "interest" article of such Tax treaty and (y) IRS Form W-8BEN or IRS Form W-8BEN-E establishing an

exemption from, or reduction of, U.S. federal withholding Tax pursuant to the "business profits" or "other income" article of such Tax treaty;

(2) executed originals of IRS Form W-8ECI;

(3) in the case of a Foreign Lender claiming the benefits of the exemption for portfolio interest under Section 881(c) of the Code, (x) a certificate substantially in the form of Exhibit 2.16-A to the effect that such Foreign Lender is not a "bank" within the meaning of Section 881(c)(3)(A) of the Code, a "10 percent shareholder" of the Borrower within the meaning of Section 881(c)(3)(B) of the Code, or a "controlled foreign corporation" described in Section 881(c)(3)(C) of the Code (a "U.S. Tax Compliance Certificate") and (y) executed originals of IRS Form W-8BEN or IRS Form W-8BEN-E; or

(4) to the extent a Foreign Lender is not the beneficial owner, executed originals of IRS Form W-8IMY, accompanied by IRS Form W-8ECI, IRS Form W-8BEN or IRS Form W-8BEN-E, a U.S. Tax Compliance Certificate substantially in the form of Exhibit 2.16-B or Exhibit 2.16-C, IRS Form W-9, and/or other certification documents from each beneficial owner, as applicable; *provided* that if the Foreign Lender is a partnership and one or more direct or indirect partners of such Foreign Lender are claiming the portfolio interest exemption, such Foreign Lender may provide a U.S. Tax Compliance Certificate substantially in the form of Exhibit 2.16-D on behalf of each such direct and indirect partner;

(C) any Foreign Lender shall, to the extent it is legally entitled to do so, deliver to the Borrower and the Administrative Agent (in such number of copies as shall be requested by the recipient) on or prior to the date on which such Foreign Lender becomes a Lender under this Agreement (and from time to time thereafter upon the reasonable request of the Borrower or the Administrative Agent), executed originals of any other form prescribed by applicable Requirement of Law as a basis for claiming exemption from or a reduction in U.S. federal withholding Tax, duly completed and executed, together with such supplementary documentation as may be prescribed by applicable Requirement of Law to permit the Borrower or the Administrative Agent to determine the withholding or deduction required to be made; and

(D) if a payment made to a Lender under any Loan Document would be subject to U.S. federal withholding Tax imposed by FATCA if such Lender were to fail to comply with the applicable reporting requirements of FATCA (including those contained in Section 1471(b) or 1472(b) of the Code, as applicable), such Lender shall deliver to the Borrower and the Administrative Agent at the time or times prescribed by Requirement of Law and at such time or times reasonably requested by the Borrower or the Administrative Agent such documentation prescribed by applicable Requirement of Law (including as prescribed by Section 1471(b)(3)(C)(i) of the Code) and such additional documentation reasonably requested by the Borrower or the Administrative Agent as may be necessary for the Borrower and the Administrative Agent to comply with their obligations under FATCA and to determine that such Lender has complied with such Lender's obligations under FATCA or to determine the amount to deduct and withhold from such payment. Solely for purposes of this clause (D), "*FATCA*" shall include any amendments made to FATCA after the date of this Agreement.

Each Lender agrees that if any form or certification it previously delivered expires or becomes obsolete or inaccurate in any respect, it shall update such form or certification or promptly notify the Borrower and the Administrative Agent in writing of its legal inability to do so.

(h) Treatment of Certain Refunds. If any party determines, in its sole discretion exercised in good faith, that it has received a refund of any Taxes as to which it has been indemnified pursuant to this Section 2.16 (including by the payment of additional amounts pursuant to this Section 2.16), it shall pay to the indemnifying party an amount equal to such refund (but only to the extent of indemnity payments made under this Section with respect to the Taxes giving rise to such refund), net of all out-of-pocket expenses (including Taxes) of such indemnified party and without interest (other than any interest paid by the relevant Governmental Authority with respect to such refund). Such indemnifying party, upon the request of such indemnified party, shall repay to such indemnified party the amount paid over pursuant to this paragraph (h) (plus any penalties, interest or other charges imposed by the relevant Governmental Authority) in the event that such indemnified party is required to repay such refund to such Governmental Authority. Notwithstanding anything to the contrary in this paragraph (h), in no event will the indemnified party be required to pay any amount to an indemnifying party pursuant to this paragraph (h) the payment of which would place the indemnified party in a less favorable net after-Tax position than the indemnified party would have been in if the Tax subject to indemnification and giving rise to such refund had not been deducted, withheld or otherwise imposed and the indemnification payments or additional amounts with respect to such Tax had never been paid. This paragraph shall not be construed to require any indemnified party to make available its Tax returns (or any other information relating to its Taxes that it deems confidential) to the indemnifying party or any other Person.

(i) On or before the date that Barclays Bank PLC (or any successor or replacement Administrative Agent) becomes the Administrative Agent hereunder, it shall deliver to the Borrower two duly executed originals of either (i) IRS Form W-9 (or any applicable successor form) certifying that the Administrative Agent is not subject to backup withholding, or (ii) IRS Form W-8IMY (or any applicable successor form) establishing that the Administrative Agent will act as a withholding agent for any U.S. federal withholding tax imposed with respect to any payments made to Lenders under any Loan Document.

(j) Survival. Each party's obligations under this Section 2.16 shall survive the resignation or replacement of the Administrative Agent or any assignment of rights by, or the replacement of, a Lender, the termination of the Commitments and the repayment, satisfaction or discharge of all obligations under any Loan Document.

SECTION 2.17 Payments Generally; Pro Rata Treatment; Sharing of Set-offs.

(a) The Borrower shall make each payment required to be made by the Borrower hereunder (whether of principal, interest or fees, or under Section 2.14, 2.15 or 2.16, or otherwise) prior to 12:00 noon, New York, New York time, on the date when due, in immediately available funds, without set-off or counterclaim. Any amounts received after such time on any date may, in the discretion of the Administrative Agent, be deemed to have been received on the next succeeding Business Day for purposes of calculating interest thereon. All such payments shall be made to the Administrative Agent at its Principal Office, except payments made directly to an Issuing Bank or the Swingline Lender as expressly provided herein and except that payments pursuant to Sections 2.14, 2.15, 2.16 and 9.03 shall be made directly to the Persons entitled thereto. The Administrative Agent shall distribute any such payments received by it for the account of any other Person to the appropriate recipient promptly following receipt thereof. If any payment hereunder shall be due on a day that is not a Business Day, the date for payment shall be extended to the next succeeding Business Day, and, in the case of any payment

accruing interest, interest thereon shall be payable for the period of such extension. All payments hereunder shall be made in dollars.

(b) If at any time insufficient funds are received by and available to the Administrative Agent to pay fully all amounts of principal, unreimbursed LC Disbursements, interest and fees then due hereunder, such funds shall be applied (i) first, to pay interest and fees then due hereunder, ratably among the parties entitled thereto in accordance with the amounts of interest and fees then due to such parties, and (ii) second, to pay principal and unreimbursed LC Disbursements then due hereunder, ratably among the parties entitled thereto in accordance with the amount of principal and unreimbursed LC Disbursements then due to such parties.

(c) If any Lender shall, by exercising any right of setoff or counterclaim or otherwise, obtain payment in respect of any principal of or interest on any of its Loans or other obligations hereunder resulting in such Lender receiving payment of a proportion of the aggregate amount of its Loans and accrued interest thereon or other such obligations greater than its *pro rata* share thereof as provided herein, then the Lender receiving such greater proportion shall (a) notify the Administrative Agent of such fact, and (b) purchase (for cash at face value) participations in the Loans and such other obligations of the other Lenders, or make such other adjustments as shall be equitable, so that the benefit of all such payments shall be shared by the Lenders ratably in accordance with the aggregate amount of principal of and accrued interest on their respective Loans and other amounts owing them*; provided* that:

(i) if any such participations are purchased and all or any portion of the payment giving rise thereto is recovered, such participations shall be rescinded and the purchase price restored to the extent of such recovery, without interest; and

(ii) the provisions of this paragraph shall not be construed to apply to (x) any payment made by the Borrower pursuant to and in accordance with the express terms of this Agreement (including the application of funds arising from the existence of a Defaulting Lender), or (y) any payment obtained by a Lender as consideration for the assignment of or sale of a participation in any of its Loans or participations in LC Disbursements to any assignee or participant, other than to the Borrower or any Subsidiary thereof (as to which the provisions of this paragraph shall apply).

The Borrower consents to the foregoing and agrees, to the extent it may effectively do so under applicable law, that any Lender acquiring a participation pursuant to the foregoing arrangements may exercise against the Borrower rights of setoff and counterclaim with respect to such participation as fully as if such Lender were a direct creditor of the Borrower in the amount of such participation.

(d) Unless the Administrative Agent shall have received notice from the Borrower prior to the date on which any payment is due to the Administrative Agent for the account of the Lenders or the Issuing Banks hereunder that the Borrower will not make such payment, the Administrative Agent may assume that the Borrower has made such payment on such date in accordance herewith and may, in reliance upon such assumption, distribute to the Lenders or such Issuing Bank, as the case may be, the amount due. In such event, if the Borrower has not in fact made such payment, then each of the Lenders or the Issuing Banks, as the case may be, severally agrees to repay to the Administrative Agent forthwith on demand the amount so distributed to such Lender or such Issuing Bank with interest thereon, for each day from the date such amount is distributed to it to the date of payment to the Administrative Agent, at the greater of the Federal Funds Effective Rate and a rate determined by the Administrative Agent in accordance with banking industry rules or interbank compensation.

(e) If any Lender shall fail to make any payment required to be made by it pursuant to Section 2.04(b), 2.05(h), 2.06(b), 2.17(d) or 8.08, then the Administrative Agent may, in its discretion (notwithstanding any contrary provision hereof), (i) apply any amounts thereafter received by the Administrative Agent for the account of such Lender to satisfy such Lender's obligations under such Sections until all such unsatisfied obligations are fully paid and/or (ii) hold any such amounts in a segregated account as cash collateral for, and application to, any future funding obligations of such Lender under such Sections; in the case of each of (i) and (ii) above, in any order as determined by the Administrative Agent in its discretion.

SECTION 2.18 Mitigation of Obligations; Replacement of Lenders.

(a) Designation of a Different Lending Office. If any Lender requests compensation under Section 2.14, or requires the Borrower to pay any Indemnified Taxes or additional amounts to any Lender or any Governmental Authority for the account of any Lender pursuant to Section 2.16, then such Lender shall (at the request of the Borrower) use reasonable efforts to designate a different lending office for funding or booking its Loans hereunder or to assign its rights and obligations hereunder to another of its offices, branches or affiliates, if, in the judgment of such Lender, such designation or assignment (i) would eliminate or reduce amounts payable pursuant to Section 2.14 or 2.16, as the case may be, in the future, and (ii) would not subject such Lender to any unreimbursed cost or expense and would not otherwise be disadvantageous to such Lender. The Borrower hereby agrees to pay all reasonable costs and expenses incurred by any Lender in connection with any such designation or assignment.

(b) Replacement of Lenders. If any Lender requests compensation under Section 2.14, or if the Borrower is required to pay any Indemnified Taxes or additional amounts to any Lender or any Governmental Authority for the account of any Lender pursuant to Section 2.16 and, in each case, such Lender has declined or is unable to designate a different lending office in accordance with Section 2.18(a), or if any Lender is a Defaulting Lender or a Non-Consenting Lender, then the Borrower may, at its sole expense and effort, upon notice to such Lender and the Administrative Agent, require such Lender to assign and delegate, without recourse (in accordance with and subject to the restrictions contained in, and consents required by, Section 9.05), all of its interests, rights (other than its existing rights to payments pursuant to Section 2.14 or Section 2.16) and obligations under this Agreement and the related Loan Documents to an Eligible Assignee that shall assume such obligations (which assignee may be another Lender, if a Lender accepts such assignment); *provided* that:

(i) the Borrower shall have paid to the Administrative Agent the assignment fee (if any) specified in Section 9.05;

(ii) such Lender shall have received payment of an amount equal to the outstanding principal of its Loans and participations in LC Disbursements, accrued interest thereon, accrued fees and all other amounts payable to it hereunder and under the other Loan Documents (including any amounts under Section 2.15) from the assignee (to the extent of such outstanding principal and accrued interest and fees) or the Borrower (in the case of all other amounts);

(iii) in the case of any such assignment resulting from a claim for compensation under Section 2.14 or payments required to be made pursuant to Section 2.16, such assignment will result in a reduction in such compensation or payments thereafter;

(iv) such assignment does not conflict with applicable law; and

(v) in the case of any assignment resulting from a Lender becoming a Non-Consenting Lender, the applicable assignee shall have consented to the applicable amendment, waiver or consent.

A Lender shall not be required to make any such assignment or delegation if, prior thereto, as a result of a waiver by such Lender or otherwise, the circumstances entitling the Borrower to require such assignment and delegation cease to apply.

SECTION 2.19 Defaulting Lenders. (a) Notwithstanding anything to the contrary contained in this Agreement, if any Lender becomes a Defaulting Lender, then, until such time as such Lender is no longer a Defaulting Lender, to the extent permitted by applicable law:

(i) Such Defaulting Lender's right to approve or disapprove any amendment, waiver or consent with respect to this Agreement shall be restricted as set forth in Section 9.02.

(ii) Any payment of principal, interest, fees or other amounts received by the Administrative Agent for the account of such Defaulting Lender (whether voluntary or mandatory, at maturity, pursuant to Article VII or otherwise) or received by the Administrative Agent from a Defaulting Lender pursuant to Section 9.09 shall be applied at such time or times as may be determined by the Administrative Agent as follows: *first*, to the payment of any amounts owing by such Defaulting Lender to the Administrative Agent hereunder; *second*, to the payment on a *pro rata* basis of any amounts owing by such Defaulting Lender to any Issuing Bank or Swingline Lender hereunder; *third*, to Cash Collateralize the Issuing Banks' Fronting Exposure with respect to such Defaulting Lender in accordance with Section 2.20; *fourth*, as the Company may request (so long as no Default or Event of Default exists), to the funding of any Loan in respect of which such Defaulting Lender has failed to fund its portion thereof as required by this Agreement, as determined by the Administrative Agent; *fifth*, if so determined by the Administrative Agent and the Borrower, to be held in a deposit account and released *pro rata* in order to (x) satisfy such Defaulting Lender's potential future funding obligations with respect to Loans under this Agreement and (y) Cash Collateralize the Issuing Banks' future Fronting Exposure with respect to such Defaulting Lender with respect to future Letters of Credit issued under this Agreement, in accordance with Section 2.20; *sixth*, to the payment of any amounts owing to the Lenders, the Issuing Banks or the Swingline Lender as a result of any judgment of a court of competent jurisdiction obtained by any Lender, any Issuing Bank or the Swingline Lender against such Defaulting Lender as a result of such Defaulting Lender's breach of its obligations under this Agreement; *seventh,* so long as no Default or Event of Default exists, to the payment of any amounts owing to the Borrower as a result of any judgment of a court of competent jurisdiction obtained by the Borrower against such Defaulting Lender as a result of such Defaulting Lender's breach of its obligations under this Agreement; and *eighth*, to such Defaulting Lender or as otherwise directed by a court of competent jurisdiction; *provided* that if (x) such payment is a payment of the principal amount of any Loans or LC Disbursements in respect of which such Defaulting Lender has not fully funded its appropriate share, and (y) such Loans were made or the related Letters of Credit were issued at a time when the conditions set forth in Section 3.02 were satisfied or waived, such payment shall be applied solely to pay the Loans of, and LC Disbursements owed to, all Non-Defaulting Lenders on a *pro rata* basis prior to being applied to the payment of any Loans of, or LC Disbursements owed to, such Defaulting Lender until such time as all Loans and funded and unfunded participations in Letter of Credit Commitments and Swingline Loans are held by the Lenders *pro rata* in accordance with the Commitments without giving effect to Section 2.19(a)(iv). Any payments, prepayments or other amounts paid or payable to a Defaulting Lender that are applied (or held) to pay amounts owed by a Defaulting Lender or to

post Cash Collateral pursuant to this Section 2.19(a)(ii) shall be deemed paid to and redirected by such Defaulting Lender, and each Lender irrevocably consents hereto.

(iii) (A) Each Defaulting Lender shall be entitled to receive a Commitment Fee for any period during which that Lender is a Defaulting Lender only to extent allocable to the sum of (1) the outstanding principal amount of the Loans funded by it, and (2) its Applicable Percentage of the stated amount of Letters of Credit for which it has provided Cash Collateral pursuant to Section 2.20.

(B) Each Defaulting Lender shall be entitled to receive letter of credit fees under Section 2.11(b) for any period during which that Lender is a Defaulting Lender only to the extent allocable to its Applicable Percentage of the stated amount of Letters of Credit for which it has provided Cash Collateral pursuant to Section 2.20.

(C) With respect to any Commitment Fee or letter of credit fee under Section 2.11(b) not required to be paid to any Defaulting Lender pursuant to clause (A) or (B) above, the Borrower shall (x) pay to each Non-Defaulting Lender that portion of any such fee otherwise payable to such Defaulting Lender with respect to such Defaulting Lender's LC Exposure or Swingline Loans that has been reallocated to such Non-Defaulting Lender pursuant to clause (iv) below, (y) pay to each Issuing Bank and Swingline Lender, as applicable, the amount of any such fee otherwise payable to such Defaulting Lender to the extent allocable to such Issuing Bank's or Swingline Lender's Fronting Exposure to such Defaulting Lender, and (z) not be required to pay the remaining amount of any such fee.

(iv) All or any part of such Defaulting Lender's LC Exposure and Swingline Loans shall be reallocated among the Non-Defaulting Lenders in accordance with their respective Applicable Percentages (calculated without regard to such Defaulting Lender's Commitment) but only to the extent that (x) the conditions set forth in Section 3.02 are satisfied at the time of such reallocation (and, unless the Borrower shall have otherwise notified the Administrative Agent at such time, the Borrower shall be deemed to have represented and warranted that such conditions are satisfied at such time), and (y) such reallocation does not cause the aggregate Credit Exposure of any Non-Defaulting Lender to exceed such Non-Defaulting Lender's Commitment. Subject to Section 9.18, no reallocation hereunder shall constitute a waiver or release of any claim of any party hereunder against a Defaulting Lender arising from that Lender having become a Defaulting Lender, including any claim of a Non-Defaulting Lender as a result of such Non-Defaulting Lender's increased exposure following such reallocation.

(v) If the reallocation described in clause (iv) above cannot, or can only partially, be effected, the Borrower shall, without prejudice to any right or remedy available to it hereunder or under law, (x) *first*, prepay Swingline Loans in an amount equal to the Swingline Lenders' Fronting Exposure and (y) *second*, Cash Collateralize the Issuing Banks' Fronting Exposure in accordance with the procedures set forth in Section 2.20.

(b) If the Borrower, the Administrative Agent, the Swingline Lender and each Issuing Bank agree in writing that a Lender is no longer a Defaulting Lender, the Administrative Agent will so notify the parties hereto, whereupon as of the effective date specified in such notice and subject to any conditions set forth therein (which may include arrangements with respect to any Cash Collateral), that Lender will, to the extent applicable, purchase at par that portion of outstanding Loans of the other Lenders or take such other actions as the Administrative Agent may determine to be necessary to cause

the Loans and funded and unfunded participations in Letters of Credit and Swingline Loans to be held *pro rata* by the Lenders in accordance with their respective Commitments (without giving effect to Section 2.19(a)(iv), whereupon, that Lender will cease to be a Defaulting Lender; *provided* that no adjustments will be made retroactively with respect to fees accrued or payments made by or on behalf of the Borrower while that Lender was a Defaulting Lender; and *provided*, *further*, that except to the extent otherwise expressly agreed by the affected parties, no change hereunder from Defaulting Lender to Lender will constitute a waiver or release of any claim of any party hereunder arising from that Lender's having been a Defaulting Lender.

(c) So long as any Lender is a Defaulting Lender, (i) the Swingline Lender shall not be required to fund any Swingline Loans unless it is satisfied that it will have no Fronting Exposure after giving effect to such Swingline Loan and (ii) no Issuing Bank shall be required to issue, extend, renew or increase any Letter of Credit unless it is satisfied that it will have no Fronting Exposure after giving effect thereto.

SECTION 2.20 Cash Collateral.

At any time that there shall exist a Defaulting Lender, within one Business Day following the written request of the Administrative Agent or any Issuing Bank (with a copy to the Administrative Agent) the Borrower shall Cash Collateralize the Issuing Banks' Fronting Exposure with respect to such Defaulting Lender (determined after giving effect to Section 2.19(a)(iv) and any Cash Collateral provided by such Defaulting Lender) in an amount not less than the Minimum Collateral Amount.

(a) The Borrower, and to the extent provided by any Defaulting Lender, such Defaulting Lender, hereby grants to the Administrative Agent, for the benefit of the Issuing Banks, and agrees to maintain, a first priority security interest in all such Cash Collateral as security for the Defaulting Lenders' LC Exposure, to be applied pursuant to clause (b) below. If at any time the Administrative Agent determines that Cash Collateral is subject to any right or claim of any Person other than the Administrative Agent and the Issuing Banks as herein provided, or that the total amount of such Cash Collateral is less than the Minimum Collateral Amount, the Borrower will, promptly upon demand by the Administrative Agent, pay or provide to the Administrative Agent additional Cash Collateral in an amount sufficient to eliminate such deficiency (after giving effect to any Cash Collateral provided by the Defaulting Lender).

(b) Application. Notwithstanding anything to the contrary contained in this Agreement, Cash Collateral provided under this Section 2.20 or Section 2.19 in respect of Letters of Credit shall be applied to the satisfaction of the Defaulting Lender's LC Exposure (including, as to Cash Collateral provided by a Defaulting Lender, any interest accrued on such obligation) for which the Cash Collateral was so provided, prior to any other application of such property as may otherwise be provided for herein.

(c) Termination of Requirement. Cash Collateral (or the appropriate portion thereof) provided to reduce any Issuing Bank's Fronting Exposure shall no longer be required to be held as Cash Collateral pursuant to this Section 2.20 following (i) the elimination of the applicable Fronting Exposure (including by the termination of Defaulting Lender status of the applicable Lender), or (ii) the determination by the Administrative Agent and each Issuing Bank that there exists excess Cash Collateral; *provided* that, subject to Section 2.19 the Person providing Cash Collateral and each Issuing Bank may agree that Cash Collateral shall be held to support future anticipated Fronting Exposure or other obligations and *provided further* that to the extent that such Cash Collateral was provided by the Borrower, such Cash Collateral shall remain subject to the security interest granted pursuant to the Loan Documents.

SECTION 2.21 Accordion Facilities.

(a) Before the Maturity Date, the Borrower may by written notice to Administrative Agent elect to request the establishment of one or more increases in the Total Commitment (each increase to the Total Commitment, a "New Commitment" and, collectively, the "New Commitments"), in an aggregate amount not to exceed $1,000,000,000. Each such notice shall specify the date (each, an "Increased Amount Date") on which the Borrower proposes that the New Commitments shall be effective, which shall be a date not less than ten Business Days after the date on which such notice is delivered to the Administrative Agent; *provided* that any Lender offered or approached to provide all or a portion of the New Commitments may elect or decline, in its sole discretion, to provide a New Commitment. Such New Commitments shall become effective as of such Increased Amount Date; *provided further* that, (i) no Event of Default shall exist on such Increased Amount Date before or after giving effect to such New Commitments; (ii) the Borrower shall make any payments required pursuant to this Agreement (including Section 2.15) to the Administrative Agent and the Lenders (other than any Defaulting Lender), in connection with the New Commitments, as applicable; (iii) the Administrative Agent, the Swingline Lender and the Issuing Banks shall have consented to such prospective lender (such consent not to be unreasonably withheld or delayed) and (iv) such New Commitment will be documented solely as an increase to the Total Commitment, without any change to the terms of revolving facility provided for herein. The proceeds of each New Commitment shall be used for working capital and general corporate purposes. For the avoidance of doubt, no Lender shall be obligated to provide any portion of the New Commitments.

(b) On any Increased Amount Date on which New Commitments are effected, subject to the satisfaction of the foregoing terms and conditions, (a) each of the Lenders with Commitments shall assign to each Lender with a New Commitment (each such Lender and each Eligible Assignee that agrees to an extension of the Maturity Date in accordance with Section 2.22(c), a "New Lender") and each of the New Lenders shall purchase from each of the Lenders with Commitments, at the principal amount thereof (together with accrued interest), such interests in the Committed Loans outstanding on such Increased Amount Date as shall be necessary in order that, after giving effect to all such assignments and purchases, such Committed Loans will be held by existing Lenders with Committed Loans and New Lenders ratably in accordance with their Commitments after giving effect to the addition of such New Commitments to the Total Commitment, (b) each New Commitment shall be deemed for all purposes a Commitment and each Loan made thereunder (a "New Loan") shall be deemed, for all purposes, a Committed Loan and (c) each New Lender shall become a Lender with respect to the New Commitment and all matters relating thereto.

(c) The New Commitments shall be effected by a joinder agreement (the "New Loan Increase Joinder") substantially in the form of Exhibit 2.21 executed by the Borrower, the Administrative Agent and each Lender making such New Commitment, in form and substance reasonably satisfactory to each of them, and consented to by the Administrative Agent, the Issuing Banks and the Swingline Lender. Each New Loan Increase Joinder may, without the consent of any other Lenders, effect such amendments to this Agreement and the other Loan Documents as may be necessary or appropriate, in the opinion of the Administrative Agent, to effect the provisions of this Section 2.21.

SECTION 2.22 Extension of Maturity Date.

(a) At least 60 days but not more than 90 days prior to any anniversary of the Effective Date (the "Applicable Anniversary"), the Borrower, by written notice to the Administrative Agent, may request an extension of the Maturity Date in effect at such time by one year from its then scheduled expiration (which request may be conditioned on a minimum level of Commitments from Extension Consenting Lenders and New Lenders); provided that the Maturity Date shall not be extended

more than twice. The Administrative Agent shall promptly notify each Lender of such request, and each Lender shall in turn, in its sole discretion, not later than 30 days prior to the Applicable Anniversary, notify the Borrower and the Administrative Agent in writing as to whether such Lender will consent to such extension. If any Lender shall fail to notify the Administrative Agent and the Borrower in writing of its consent to any such request for extension of the Maturity Date at least 30 days prior to the Applicable Anniversary, such Lender shall be deemed to be an Extension Non-Consenting Lender with respect to such request. The Administrative Agent shall notify the Borrower not later than 25 days prior to the Applicable Anniversary of the decision of the Lenders regarding the Borrower's request for an extension of the Maturity Date.

(b) If all the Lenders consent in writing to any such request in accordance with Section 2.22(a), the Maturity Date in effect at such time shall, effective as at the Applicable Anniversary (the "Extension Date"), be extended for one year; provided that on each Extension Date the applicable conditions set forth in Section 3.02 shall be satisfied. If less than all of the Lenders consent in writing to any such request in accordance with Section 2.22(a), the Maturity Date in effect at such time shall, effective as at the applicable Extension Date and subject to Section 2.22(d), be extended as to those Lenders that so consented (each a "Extension Consenting Lender") but shall not be extended as to any other Lender (each a "Extension Non-Consenting Lender"). To the extent that the Maturity Date is not extended as to any Lender pursuant to this Section 2.22 and the Commitment of such Lender is not assumed in accordance with Section 2.22(c) on or prior to the applicable Extension Date, the Commitment of such Extension Non-Consenting Lender shall automatically terminate in whole on such unextended Maturity Date without any further notice or other action by the Borrower, such Lender or any other Person; provided that such Extension Non-Consenting Lender's rights under Sections 2.14, 2.16 and 9.03, and its obligations under Section 8.08, shall survive the Maturity Date for such Lender as to matters occurring prior to such date. It is understood and agreed that no Lender shall have any obligation whatsoever to agree to any request made by the Borrower for any requested extension of the Maturity Date.

(c) If less than all of the Lenders consent to any such request pursuant to Section 2.22(a), the Administrative Agent shall promptly so notify the Extension Consenting Lenders, and each Extension Consenting Lender may, in its sole discretion, give written notice to the Administrative Agent not later than ten days prior to the Extension Date of the amount of the Extension Non-Consenting Lenders' Commitments for which it is willing to accept an assignment. If the Extension Consenting Lenders notify the Administrative Agent that they are willing to accept assignments of Commitments in an aggregate amount that exceeds the amount of the Commitments of the Extension Non-Consenting Lenders, such Commitments shall be allocated among the Extension Consenting Lenders willing to accept such assignments in such amounts as are agreed between the Borrower and the Administrative Agent. If after giving effect to the assignments of Commitments described above there remains any Commitments of Extension Non-Consenting Lenders, the Borrower may arrange for one or more Extension Consenting Lenders or other Eligible Assignees as New Lenders to assume, effective as of the Extension Date, any Extension Non-Consenting Lender's Commitment and all of the obligations of such Extension Non-Consenting Lender under this Agreement thereafter arising, without recourse to or warranty by, or expense to, such Extension Non-Consenting Lender; provided, however, that the amount of the Commitment of any such New Lender as a result of such substitution shall in no event be less than $20,000,000 unless the amount of the Commitment of such Extension Non-Consenting Lender is less than $20,000,000, in which case such New Lender shall assume all of such lesser amount; and provided further that:

(i) any such Extension Consenting Lender or New Lender shall have paid to such Extension Non-Consenting Lender (A) the aggregate principal amount of, and any interest accrued and unpaid to the effective date of the assignment on, the outstanding Borrowings, if any,

of such Extension Non-Consenting Lender plus (B) any accrued but unpaid facility fees owing to such Extension Non-Consenting Lender as of the effective date of such assignment;

(ii) all additional costs reimbursements, expense reimbursements and indemnities payable to such Extension Non-Consenting Lender, and all other accrued and unpaid amounts owing to such Extension Non-Consenting Lender hereunder, as of the effective date of such assignment shall have been paid to such Extension Non-Consenting Lender;

(iii) with respect to any such New Lender, the applicable processing and recordation fee required under Section 9.05 for such assignment shall have been paid; and

(iv) each Issuing Bank shall have consented to any such assignment to a New Lender.

provided further that such Extension Non-Consenting Lender's rights under Sections 2.14, 2.16 and 9.03, and its obligations under Section 8.08, shall survive such substitution as to matters occurring prior to the date of substitution. At least five Business Days prior to any Extension Date, (A) each such New Lender, if any, shall have delivered to the Borrower and the Administrative Agent an Assumption Agreement, duly executed by such New Lender, such Extension Non-Consenting Lender, the Borrower and the Administrative Agent and (B) any such Extension Consenting Lender shall have delivered confirmation in writing satisfactory to the Borrower and the Administrative Agent as to the increase in the amount of its Commitment. Upon the payment or prepayment of all amounts referred to in clauses (i), (ii) and (iii) of the immediately preceding sentence, each such Extension Consenting Lender or New Lender, as of the Extension Date, will be substituted for such Extension Non-Consenting Lender under this Agreement and shall be a Lender for all purposes of this Agreement, without any further acknowledgment by or the consent of the other Lenders, and the obligations of each such Extension Non-Consenting Lender hereunder shall, by the provisions hereof, be released and discharged.

(d) If (after giving effect to any assignments or assumptions pursuant to Section 2.22(c)) Lenders having Commitments equal to more than 50% of the Commitments in effect immediately prior to the Extension Date consent in writing to a requested extension (whether by execution or delivery of an Assumption Agreement or otherwise) not later than one Business Day prior to such Extension Date, the Administrative Agent shall so notify the Borrower, and, subject to the satisfaction of the applicable conditions in Section 3.02, the Maturity Date for each Extension Consenting Lender and each New Lender then in effect shall be extended for the additional one year period as described in Section 2.22(b); provided that the Maturity Date for each Extension Non-Consenting Lender shall not be so extended. Promptly following each Extension Date, the Administrative Agent shall notify the Lenders (including, without limitation, each New Lender) of the extension of the scheduled Maturity Date in effect immediately prior thereto and shall thereupon record in the Register the relevant information with respect to each such Extension Consenting Lender and each such New Lender. On and after each Extension Date, the Applicable Percentage of each Lender's participation in Letter of Credit Commitments shall be calculated after giving effect to the Commitments of the Lenders after the occurrence of such Extension Date.

ARTICLE III
CONDITIONS PRECEDENT

SECTION 3.01 Conditions Precedent to the Closing Date. The obligations of the Lenders to make Loans hereunder and the obligations of the Issuing Banks to issue Letters of Credit hereunder shall not become effective until the date on which each of the following conditions is satisfied or waived in accordance with Section 9.02:

(a) The Administrative Agent shall have received the following, each dated as of the Closing Date:

(i) this Agreement executed by each party hereto;

(ii) the Guaranty executed by each party thereto;

(iii) a certificate of an officer and of the secretary or an assistant secretary of the Borrower and each Guarantor, certifying, *inter alia* (A) true and complete copies of each of the certificate of incorporation or other appropriate organizational document, as amended and in effect, of such Person, the bylaws or similar organizational document, as amended and in effect, of such Person and the resolutions adopted by the Board of Directors or similar governing body of such Person (1) authorizing the execution, delivery and performance by such Person of each Loan Document to which such Person is or will be a party, (2) approving the Loan Documents to which such Person is or will be a party and (3) authorizing officers of such Person to execute and deliver the Loan Documents to which such Person is or will be a party and any related documents and (B) the incumbency and specimen signatures of the officers of such Person executing any documents on its behalf; provided, that there shall be no requirement to deliver such certificates for any Guarantor that is not a Material Subsidiary;

(iv) a certificate of a Responsible Officer of the Borrower certifying as to the satisfaction of the conditions in Sections 3.01(c) and (e); and

(v) signed opinions addressed to the Administrative Agent and the Lenders from legal counsel to the Borrower and the Guarantors covering the matters reasonably requested by the Administrative Agent; provided, that there shall be no requirement to deliver opinions of legal counsel for any Guarantor that is not a Material Subsidiary.

(b) The Administrative Agent shall have received a certificate of appropriate officials as to the existence and good standing of the Borrower and each Guarantor.

(c) There shall not have occurred any change, effect, event or occurrence since December 31, 2017 that, individually or in the aggregate, has had, or would reasonably be expected to have, a Material Adverse Effect.

(d) The Administrative Agent shall have received evidence that the Existing Credit Agreement has been, or substantially concurrently with the Closing Date will be, terminated and the obligations outstanding thereunder repaid in full pursuant to customary payoff documentation, including evidence of the release of Liens, if any, granted in connection therewith.

(e) The conditions precedent set forth in Sections 3.02(b) and (d) shall have theretofore been satisfied or waived in accordance with Section 9.02.

(f) (i) The Administrative Agent shall have received (for distribution to the Lenders so requesting) at least three business days prior to the Closing Date all documentation and other information about the Borrower and Guarantors as required by regulatory authorities under applicable "know your customer" and anti-money laundering rules and regulations, including without limitation the Patriot Act, to the extent reasonably requested by any Lender to the Administrative Agent and conveyed by the Administrative Agent to the Borrower in writing at least 10 days prior to the Closing Date and (ii) to the extent the Borrower qualifies as a "legal entity customer" under the Beneficial Ownership Regulation, at

least five days prior to the Closing Date, any Lender that has requested, in a written notice to the Borrower at least 10 days prior to the Closing Date, a Beneficial Ownership Certification in relation to the Borrower shall have received such Beneficial Ownership Certification (provided that, upon the execution and delivery by such Lender of its signature page to this Agreement, the condition set forth in this clause (ii) shall be deemed to be satisfied).

(g) All fees required to be paid on the Closing Date pursuant to the Fee Letters referenced in Section 2.11(c) and all reasonable out-of-pocket expenses required to be paid on the Closing Date, to the extent invoiced at least two Business Days prior to the Closing Date shall have been paid.

The Administrative Agent shall notify the Borrower and the Lenders of the Closing Date in writing promptly upon such conditions precedent being satisfied (or waived in accordance with Section 9.02), and such notice shall be conclusive and binding.

SECTION 3.02 Conditions Precedent to Each Credit Event. Except with respect to Committed Loans made by the Lenders pursuant to Section 2.05(h), the obligations of (i) the Lenders to make Loans hereunder (ii) the obligations of the Issuing Banks to issue or extend any Letter of Credit under this Agreement and (iii) each extension of the Maturity Date pursuant to Section 2.22 is subject to the satisfaction or waiver in accordance with Section 9.02 of the following conditions precedent:

(a) The conditions precedent set forth in Section 3.01 shall have theretofore been satisfied or waived in accordance with Section 9.02;

(b) The representations and warranties set forth in Article IV and in the other Loan Documents shall be true and correct in all material respects as of, and as if such representations and warranties were made on, the Borrowing Date of the proposed Loan or Letter of Credit, as the case may be (unless such representation and warranty expressly relates to an earlier date), and by the Borrower's delivery of a Borrowing Request, the Borrower shall be deemed to have certified to the Administrative Agent and the Lenders that such representations and warranties are true and correct in all material respects;

(c) The Company shall have complied with the provisions of Section 2.03, Section 2.04 or Section 2.05, as the case may be;

(d) No Default or Event of Default shall have occurred and be continuing or would result from such Credit Event; and

(e) A Borrowing Request shall have been delivered in accordance with the terms of Section 2.03.

The acceptance by the Borrower of the benefits of each Credit Event shall constitute a representation and warranty by the Borrower to each of the Lenders that all of the conditions specified in this Section 3.02 above exist as of that time.

ARTICLE IV
REPRESENTATIONS AND WARRANTIES

On the Closing Date and on each Borrowing Date, the Borrower makes the following representations and warranties to the Administrative Agent and the Lenders:

SECTION 4.01 Organization and Qualification. The Borrower and each of the Material Subsidiaries (a) is a corporation, partnership or limited liability company duly organized or formed, validly

existing and in good standing under the laws of the state of its incorporation, organization or formation, (b) has all requisite corporate, partnership, limited liability company or other power and all material governmental licenses, authorizations, consents and approvals required to carry on its business as now conducted and (c) is duly qualified to do business and is in good standing in every jurisdiction in which the failure to be so qualified would, individually or together with all such other failures of the Borrower and the Subsidiaries, have a Material Adverse Effect.

SECTION 4.02 Authorization, Validity, Etc. The Borrower and each Guarantor has all requisite corporate (or other organizational) power and authority to execute and deliver, and to incur and perform its obligations under this Agreement and under the other Loan Documents to which it is a party and, in the case of the Borrower, to make the Borrowings hereunder, and all such actions have been duly authorized by all necessary proceedings on its behalf. This Agreement and the other Loan Documents have been duly and validly executed and delivered by or on behalf of the Borrower (and, on the Closing Date, with respect to the Guaranty, each Guarantor) party thereto and constitute valid and legally binding agreements of the Borrower and each Guarantor, as applicable, enforceable against the Borrower or the Guarantor in accordance with the respective terms thereof, except (a) as may be limited by bankruptcy, insolvency, reorganization, moratorium, fraudulent transfer, fraudulent conveyance or other similar laws relating to or affecting the enforcement of creditors' rights generally, and by general principles of equity (including principles of good faith, reasonableness, materiality and fair dealing) which may, among other things, limit the right to obtain equitable remedies (regardless of whether considered in a proceeding in equity or at law) and (b) as to the enforceability of provisions for indemnification for violation of applicable securities laws, limitations thereon arising as a matter of law or public policy.

SECTION 4.03 Governmental Consents, Etc. No authorization, consent, approval, license or exemption of or registration, declaration or filing with any Governmental Authority, is necessary for the valid execution and delivery of, or the incurrence and performance by the Borrower or each Guarantor of its obligations under, any Loan Document to which it is a party, except those that have been obtained and such matters relating to performance as would ordinarily be done in the ordinary course of business after the Closing Date.

SECTION 4.04 No Breach or Violation of Agreements or Restrictions, Etc. Neither the execution and delivery of, nor the incurrence and performance by any Loan Party of its obligations under, the Loan Documents to which it is a party, nor the extensions of credit contemplated by the Loan Documents, will (a) breach or violate any applicable Requirement of Law, (b) result in any breach or violation of any of the terms, covenants, conditions or provisions of, or constitute a default under, or result in the creation or imposition of (or the obligation to create or impose) any Lien upon any of its property or assets (other than Liens created or contemplated by this Agreement) pursuant to the terms of, any indenture, mortgage, deed of trust, agreement or other instrument to which it or any of the Subsidiaries is party or by which any of its properties or assets, or those of any of the Subsidiaries is bound or to which it is subject, except for breaches, violations and defaults under clauses (a) and (b) that neither individually nor in the aggregate could reasonably be expected to result in a Material Adverse Effect, or (c) violate any provision of the organizational documents of such Loan Party.

SECTION 4.05 Properties. Each of the Borrower and the Material Subsidiaries has good title to, or valid leasehold or other interests in, all its real and personal property material to its business free of all Liens securing Indebtedness except for such Liens permitted under Section 6.02.

SECTION 4.06 Litigation and Environmental Matters. (a) Except as disclosed in the most recent Annual Report on Form 10-K delivered by the Borrower to the Lenders, there is no action, suit or proceeding by or before any arbitrator or Governmental Authority pending against or, to the knowledge

of the Borrower, threatened against or affecting the Borrower or any of the Material Subsidiaries as to which there is a reasonable possibility of an adverse determination and that, if adversely determined, could reasonably be expected to result in a Material Adverse Effect.

(b) Except as disclosed in the most recent Annual Report on Form 10-K delivered by the Borrower to the Lenders, the associated liabilities and costs of the Borrower's compliance with Environmental Laws (including any capital or operating expenditures required for clean-up or closure of properties currently or previously owned, any capital or operating expenditures required to achieve or maintain compliance with environmental protection standards imposed by Environmental Laws or as a condition of any license, permit or contract, any related constraints on operating activities, including any periodic or permanent shutdown of any facility or reduction in the level of or change in the nature of operations conducted thereat, any costs or liabilities in connection with off-site disposal of wastes or Hazardous Materials, and any actual or potential liabilities to third parties, including employees, and any related costs and expenses) are unlikely to result in a Material Adverse Effect.

SECTION 4.07 Financial Statements.

(a) The consolidated balance sheet of the Borrower and the Subsidiaries as at December 31, 2017 and the related consolidated statements of income, comprehensive income, shareholders' equity and cash flows of the Borrower and the Subsidiaries for the fiscal year ended on said date, with the opinion thereon of PricewaterhouseCoopers LLP and set forth in the Borrower's 2017 Annual Report on Form 10-K, as filed with the SEC, fairly present, in all material respects, the consolidated financial position of the Borrower and the Subsidiaries as of such date and their consolidated results of operations and cash flows for such fiscal year in accordance with GAAP.

(b) The unaudited consolidated balance sheets of the Borrower and the Subsidiaries as at March 31, 2018, June 30, 2018 and September 30, 2018 and the related consolidated statements of income and cash flows of the Borrower and the Subsidiaries for the three month period ended on such date and set forth in the Borrower's Quarterly Report on Form 10-Q for its fiscal quarter then ended, as filed with the SEC, fairly present, in all material respects, the consolidated financial position of the Borrower and the Subsidiaries as of such date and their consolidated results of their operations cash flows for the applicable time period ended on said date (subject to the absence of footnotes and to normal year-end and audit adjustments), in accordance with GAAP applied on a basis consistent with the financial statements referred to in Section 4.07(a).

(c) On the Closing Date and since the date of the Annual Report on Form 10-K delivered by the Borrower to the Lenders with respect to the fiscal year ended December 31, 2017, there has been no material adverse change in the business, assets, liabilities or financial condition of the Borrower and the Subsidiaries, taken as a whole.

SECTION 4.08 Disclosure.

(a) As of the Closing Date only, information heretofore furnished by the Borrower to the Administrative Agent or any Lender for purposes of or in connection with this Agreement or any transaction contemplated hereby, together with the Executive Summary is, when taken as a whole, true and accurate in all material respects on the date as of which such information is stated or certified. The Executive Summary and the reports, financial statements, certificates or other written information furnished by or on behalf of the Borrower to the Administrative Agent or any Lender in connection with the syndication or negotiation of this Agreement or delivered hereunder (as modified or supplemented by other information so furnished) on or prior to the Closing Date, when taken as a whole, do not contain any material misstatement

of fact or omits to state any material fact necessary to make the statements therein, in the light of the circumstances under which they were made, not misleading; *provided* that, with respect to any projected financial information, the Borrower represents only that such information was prepared in good faith based upon assumptions believed by the Borrower to be reasonable at the time (it being recognized, however, that projections as to future events are not to be viewed as facts and that the actual results during the period or periods covered by any projects may materially different from the projected results).

(b) As of the Closing Date, to the knowledge of the Borrower, the information included in the Beneficial Ownership Certification provided on or prior to the Closing Date to any Lender in connection with this Agreement is true and correct in all respects.

SECTION 4.09 Investment Company Act. The Borrower is not, and no Loan Party is required to register as, an "*investment company*," as such term is defined in the Investment Company Act of 1940, as amended.

SECTION 4.10 ERISA. Each member of the ERISA Group has fulfilled its obligations under the minimum funding standards of ERISA and the Code with respect to each Plan and is in compliance in all material respects with the presently applicable provisions of ERISA and the Code with respect to each Plan, except where the failure to so fulfill such obligations and such noncompliance individually, or together with all such failures to fulfill such obligations and all such noncompliance, could not reasonably be expected to result in a Material Adverse Effect. No member of the ERISA Group has (i) sought a waiver of the minimum funding standard under Section 412 of the Code in respect of any Plan, (ii) failed to make any contribution or payment to any Plan or Multiemployer Plan or in respect of any Benefit Arrangement, or made any amendment to any Plan or Benefit Arrangement, which has resulted or could result in the imposition of a Lien or the posting of a bond or other security under ERISA or the Code or (iii) incurred any liability under Title IV of ERISA other than a liability to the PBGC for premiums under Section 4007 of ERISA, which waiver, failure, amendment or liability individually, or collectively with all such waivers, failures, amendments or liabilities, could reasonably be expected to result in a Material Adverse Effect. Except where the failure to so fulfill such obligations and such noncompliance could individually, or together with all such failures to fulfill such obligations and all such noncompliance could reasonably be expected to result in a Material Adverse Effect, (i) no "reportable event", as defined in Section 4043 of ERISA or the regulations issued thereunder, has occurred with respect to a Plan (other than an event for which the 30 day notice period is waived),. (ii) neither the Borrower nor any member of its ERISA Group has received any notice from the PBGC or a plan administrator relating to an intention to terminate any Plan or Plans or to appoint a trustee to administer any Plan and (iii) neither the Borrower or any members of its ERISA Group has any liability with respect to the withdrawal or partial withdrawal from any Plan or Multiemployer Plan, nor has the Borrower, any members of its ERISA Group, or any Multiemployer Plan from the Borrower or member of its ERISA Group received any notice concerning the imposition of Withdrawal Liability or a determination that a Multiemployer Plan is, or is expected to be, insolvent within the meaning of Title IV of ERISA.

SECTION 4.11 Tax Returns and Payments. The Borrower and the Material Subsidiaries have caused to be filed all federal income Tax returns and other material Tax returns, statements and reports (or obtained extensions with respect thereto) which are required to be filed and have paid or deposited or made adequate provision in accordance with GAAP for the payment of all Taxes (including estimated Taxes shown on such returns, statements and reports) which are shown to be due pursuant to such returns, except for Taxes being contested in good faith by appropriate proceedings for which adequate reserves in accordance with GAAP have been created on the books of the Borrower and the Subsidiaries and where the failure to pay such Taxes (individually or in the aggregate for the Borrower and the Subsidiaries) would not have a Material Adverse Effect.

SECTION 4.12 Compliance with Laws and Agreements. Each of the Borrower and the Material Subsidiaries is in compliance with all laws, regulations and orders of any Governmental Authority applicable to it or its property and all indentures, agreements and other instruments binding upon it or its property, except where the failure to do so, individually or in the aggregate for the Borrower and the Material Subsidiaries, could not reasonably be expected to result in a Material Adverse Effect.

SECTION 4.13 Purpose of Loans.

(a) All proceeds of the Loans will be used for the purposes set forth in Section 5.07.

(b) Neither the Borrower nor any agent acting on its behalf has taken or will take any action which might cause this Agreement or any other Loan Document to violate Regulation T, Regulation U, Regulation X, or any other regulation of the Board or to violate the Exchange Act. Margin stock does not constitute more than 25% of the assets of the Borrower, or of the Borrower and the Subsidiaries on a consolidated basis, and the Borrower does not intend or foresee that it will ever do so.

SECTION 4.14 Foreign Assets Control Regulations, etc. (a) To the extent applicable, neither any Letter of Credit nor any part of the proceeds of the Loans will (i) be used to violate in any material respect the Trading with the Enemy Act, as amended, or (ii) be used, directly or indirectly or made available to any subsidiary, joint venture partner or any other Person to fund or support any activities or business of or with any Person, or in any country or territory, that, at the time of such funding or extension, is, or whose government is, at the time of making such Loans or extension of such Letters of Credit, the subject of any economic or financial sanctions or trade embargoes administered or enforced by the U.S. Government, including any enforced by the U.S. Department of Treasury's Office of Foreign Assets Control or the U.S. Department of State (collectively, "Sanctions").

(b) Neither the Borrower nor any Subsidiary, nor, to the knowledge of the Borrower, any director, officer, employee, agent, affiliate or representative of the Borrower or any Subsidiary is a Person that is, or is owned or controlled by, a Sanctioned Person. The Borrower and the Subsidiaries are in compliance, in all material respects, with the Patriot Act.

(c) Neither any Letter of Credit nor any part of the proceeds of the Loans will be used, directly or indirectly, for any payments to any person in violation of any Anti-Corruption Laws, to the extent the Anti-Corruption Laws apply to the Borrower or one of the Subsidiaries.

SECTION 4.15 Solvency. On the Closing Date, after giving effect to the Transactions, the Borrower and its Subsidiaries, on a consolidated basis, are Solvent.

ARTICLE V
AFFIRMATIVE COVENANTS

From the Closing Date until the Commitments have expired or been terminated and principal of and interest on each Loan and all fees payable hereunder shall have been paid in full and all Letters of Credit shall have expired or terminated (or other arrangements satisfactory to the applicable Issuing Bank made with respect thereto) and all LC Disbursements shall have been reimbursed, the Borrower covenants and agrees with the Lenders that:

SECTION 5.01 Financial Statements and Other Information. The Borrower will furnish to the Administrative Agent:

(a) within ten days after the date in each fiscal year on which the Borrower is required to file its Annual Report on Form 10-K with the SEC or, if earlier, 100 days after the end of each fiscal year (i) such Annual Report, and (ii) its audited consolidated balance sheet and the related consolidated statements of income, comprehensive income, operations, shareholders' equity and cash flows as of the end of and for such year, setting forth in each case in comparative form the figures as of the end of and for the previous fiscal year, all reported on by, and accompanied by an opinion (without a "*going concern*" or like qualification or exception and without any qualification or exception as to the scope of their audit) of, PricewaterhouseCoopers LLP, or other independent public accountants of recognized national standing to the effect that such consolidated financial statements present fairly in all material respects the financial position, results of operations and cash flows of the Borrower and the Subsidiaries on a consolidated basis in accordance with GAAP; *provided*, *however*, that (x) the Borrower shall be deemed to have furnished said Annual Report on Form 10-K for purposes of clause (i) if it shall have timely made the same available on "EDGAR" and/or on its home page on the worldwide web (at the date of this Agreement located at http://www.kindermorgan.com) and complied with the last grammatical paragraph of this Section 5.01 in respect thereof, and (y) if said Annual Report contains such consolidated balance sheet and such consolidated statements of results of income, comprehensive income, shareholders' equity and cash flows, and the report thereon of such independent public accountants (without qualification or exception, and to the effect, as specified above), the Borrower shall not be required to comply with clause (ii);

(b) within five days after each date in each fiscal year on which the Borrower is required to file a Quarterly Report on Form 10-Q with the SEC or, if earlier, 50 days after the end of each fiscal quarter (i) such Quarterly Report, and (ii) its consolidated balance sheet and the related consolidated statements of income and cash flows as of the end of and for the fiscal quarter to which said Quarterly Report relates and the then elapsed portion of the fiscal year, setting forth in each case in comparative form the figures as of the end and for the corresponding period or periods of the previous fiscal year, all certified by a Responsible Officer as presenting fairly in all material respects the financial condition and results of operations of the Borrower and the Subsidiaries on a consolidated basis in accordance with GAAP, subject to normal year-end audit adjustments and the absence of footnotes; *provided*, *however*, that (x) the Borrower shall be deemed to have furnished said Quarterly Report for purposes of clause (i) if it shall have timely made the same available on "EDGAR" and/or on its home page on the worldwide web (at the date of this Agreement located at http://www.kindermorgan.com) and complied with the last grammatical paragraph of this Section 5.01 in respect thereof, and (y) if said Quarterly Report contains such consolidated balance sheet and consolidated statements of income and cash flows, and such certifications, the Borrower shall not be required to comply with clause (ii);

(c) simultaneously with the delivery of each set of financial statements referred to in clauses (a) and (b) above, a certificate in substantially the form of Exhibit 5.01 signed by an authorized financial or accounting officer of the Borrower (i) setting forth in reasonable detail the calculations required to establish whether the Borrower was in compliance with the requirements of Section 6.07, (ii) (A) in the case of the first set of financial statements delivered following the Closing Date, setting forth a list of the Material Subsidiaries, and (B) in the case of each set of financial statements delivered thereafter, an update of any change in the list of the Material Subsidiaries or stating that there has been no such change, and (iii) stating whether any Default or Event of Default exists on the date of such certificate and, if any Default or Event of Default then exists, setting forth the details thereof and the action which the Borrower is taking or proposes to take with respect thereto;

(d) prompt written notice of the following:

(i) the occurrence of any Default or Event of Default;

(ii) any other development that results in, or could reasonably be expected to result in, a Material Adverse Effect; and

(iii) any change in the information provided in the Beneficial Ownership Certification delivered to such Lender that would result in a change to the list of beneficial owners identified in such certification;

(each notice delivered under this Section 5.01(d) to be accompanied by a statement of a Responsible Officer setting forth the details of the event or development requiring such notice and any action taken or proposed to be taken with respect thereto);

(e) without duplication of any other requirement of this Section 5.01, promptly upon the mailing thereof to the public shareholders of the Borrower generally, copies of all financial statements, reports and proxy statements so mailed;

(f) promptly upon the filing thereof with the SEC, copies of all registration statements (other than the exhibits thereto and any registration statements on Form S-8 or its equivalent) and reports on Form 8-K which the Borrower shall have filed with the SEC;

(g) if and when any member of the ERISA Group (i) gives or is required to give notice to the PBGC of any "*reportable event*" (as defined in Section 4043 of ERISA) (other than such event as to which the 30-day notice requirement is waived) with respect to any Plan which would reasonably be expected to constitute grounds for a termination of such Plan under Title IV of ERISA, or knows that the plan administrator of any Plan has given or is required to give notice of any such reportable event, a copy of the notice of such reportable event given or required to be given to the PBGC; (ii) receives notice of complete or partial material Withdrawal Liability under Title IV of ERISA or notice that any Multiemployer Plan is insolvent, is in "endangered" or "critical" status (within the meaning of Section 432 of the Code or Section 305 of ERISA) or has been terminated, a copy of such notice; (iii) receives notice from the PBGC under Title IV of ERISA of an intent to terminate, impose liability (other than for premiums under Section 4007 of ERISA) in respect of, or appoint a trustee to administer any Plan, a copy of such notice; (iv) fails to satisfy, or applies for a waiver of, the minimum funding standard under Section 412 of the Code, a copy of such application; (v) gives notice of intent to terminate any Plan under Section 4041(c) of ERISA, a copy of such notice and other information filed with the PBGC; (vi) gives notice of withdrawal from any Plan pursuant to Section 4063 of ERISA, a copy of such notice; or (vii) fails to make any payment or contribution to any Plan or Multiemployer Plan or in respect of any Benefit Arrangement or makes any amendment to any Plan or Benefit Arrangement which has resulted or could result in the imposition of a Lien or the posting of a bond or other security, a certificate of the chief financial officer or the chief accounting officer of the Borrower setting forth details as to such occurrence and action, if any, which the Borrower or applicable member of the ERISA Group is required or proposes to take; and

(h) (x) from time to time such other information (other than projections) regarding the business, affairs or financial condition of the Borrower or any Subsidiary as the Required Lenders or the Administrative Agent may reasonably request and (y) promptly following any request therefor, information and documentation reasonably requested by the Administrative Agent for distribution to the Lenders so requesting for purposes of compliance with applicable "know your customer" and anti-money laundering rules and regulations, including the Patriot Act and the Beneficial Ownership Regulation.

Information required to be delivered pursuant to Section 5.01(a), 5.01(b) or 5.01(f) above shall be deemed to have been delivered on the date on which the Borrower provides notice to the Administrative Agent and the Lenders that such information has been posted on "EDGAR" or the Borrower's

website or another website identified in such notice and accessible by the Administrative Agent and the Lenders without charge (and the Borrower hereby agrees to provide such notice); *provided* that such notice may be included in a certificate delivered pursuant to Section 5.01(c).

SECTION 5.02 Existence, Conduct of Business. The Borrower will, and will cause each of the Material Subsidiaries to, do or cause to be done all things necessary to preserve, renew and keep in full force and effect its legal existence and the rights, licenses, permits, privileges and franchises material to the conduct of its business, except where the failure to do so (individually or collectively with all such failures) could not reasonably expected to have a Material Adverse Effect; *provided* that the foregoing shall not prohibit any merger, consolidation, liquidation or dissolution permitted under Section 6.03.

SECTION 5.03 Payment of Obligations. The Borrower will, and will cause each of the Material Subsidiaries to, pay, before the same shall become delinquent or in default, its Indebtedness and Tax liabilities but excluding Indebtedness (other than the Obligations) that is not in excess of $150,000,000, except where (a) the validity or amount thereof is being contested in good faith by appropriate proceedings, (b) the Borrower or such Material Subsidiary has set aside on its books adequate reserves with respect thereto in accordance with GAAP or (c) the failure to make payment pending such contest could not reasonably be expected to result in a Material Adverse Effect.

SECTION 5.04 Maintenance of Properties; Insurance.

(a) The Borrower will keep, and will cause each Material Subsidiary to keep, all property material to the conduct its business (taken as a whole) in good working order and condition, ordinary wear and tear excepted, in the reasonable judgment of the Borrower.

(b) The Borrower will maintain or cause to be maintained with, in the good faith judgment of the Borrower, financially sound and reputable insurers, or through self-insurance, insurance with respect to its properties and business and the properties and businesses of the Subsidiaries against loss or damage of the kinds customarily insured against by business enterprises of established reputation engaged in the same or similar business and similarly situated, of such types and in such amounts as are customarily carried under similar circumstances by such other corporations. Such insurance may include self-insurance or be subject to co-insurance, deductibility or similar clauses which, in effect, result in self-insurance of certain losses, *provided* that such self-insurance is in accord with the approved practices of business enterprises of established reputation similarly situated and adequate insurance reserves are maintained in connection with such self-insurance, and, notwithstanding the foregoing provisions of this Section 5.04 the Borrower or any Subsidiary may effect workers' compensation or similar insurance in respect of operations in any state or other jurisdiction any through an insurance fund operated by such state or other jurisdiction or by causing to be maintained a system or systems of self-insurance in accord with applicable laws.

SECTION 5.05 Books and Records; Inspection Rights. The Borrower will, and will cause each of the Material Subsidiaries to, keep, in accordance with GAAP, books of record and account. The Borrower will, and will cause each of the Material Subsidiaries to, permit any representatives designated by the Administrative Agent or any Lender, upon reasonable prior notice during normal business hours, and, if the Borrower shall so request, in the presence of a Responsible Officer or an appointee of a Responsible Officer, at the expense of the Administrative Agent or such Lender (unless an Event of Default exists, in which event the expense shall be that of the Borrower) to visit and inspect its properties, to examine and make extracts from its books and records (subject to compliance with confidentiality agreements and applicable copyright law), and to discuss its affairs, finances and condition

with its officers, all at such times, and as often, as reasonably requested, but unless an Event of Default exists, no more frequently than once during each calendar year.

SECTION 5.06 Compliance with Laws. The Borrower will, and will cause each of the Material Subsidiaries to, comply with all Requirements of Law applicable to it or its property, except where the failure to do so, individually or in the aggregate, could not reasonably be expected to result in a Material Adverse Effect. The Borrower will maintain in effect and enforce policies and procedures designed to ensure compliance by the Borrower, its Subsidiaries and their respective directors, officers, employees and agents with Anti-Corruption Laws and applicable Sanctions.

SECTION 5.07 Use of Proceeds. The proceeds of the Loans will be used for working capital and other general corporate purposes.

SECTION 5.08 Additional Guarantors. The Borrower shall cause each Subsidiary (including, without limitation, any Division Successor) (other than any Excluded Subsidiary) formed or otherwise purchased or acquired after the Closing Date (including each Subsidiary that ceases to constitute an Excluded Subsidiary after the Closing Date) to execute a supplement to the Guaranty and become a Guarantor within 45 days of the occurrence of the applicable event specified in this Section 5.08 (or such longer period of time as the Administrative Agent shall reasonably agree).

ARTICLE VI
NEGATIVE COVENANTS

From the Closing Date until the Commitments have expired or terminated and principal of and interest on each Loan and all fees payable hereunder have been paid in full and all Letters of Credit have expired or terminated (or other arrangements satisfactory to the applicable Issuing Bank made with respect thereto) and all LC Disbursements shall have been reimbursed, the Borrower covenants and agrees with the Lenders that:

SECTION 6.01 Indebtedness of Non-Guarantor Subsidiaries. The Borrower will not permit any Subsidiary that is not a Guarantor (each a "Non-Guarantor Subsidiary") to create, incur or assume Indebtedness other than the following:

(a) Indebtedness existing as of the Closing Date and set forth on Schedule 6.01 and any Indebtedness incurred to refund, extend, refinance or otherwise replace such Indebtedness; provided that the principal amount of such Indebtedness does not exceed the principal amount of Indebtedness refinanced (plus the amount of penalties, premiums, fees, accrued interest and reasonable expenses and other obligations incurred therewith) at the time of the refinancing;

(b) Indebtedness owing to the Borrower or its Subsidiaries;

(c) Indebtedness that is (or was) secured by Liens permitted pursuant to Section 6.02(b) or (c) and any Indebtedness incurred to refund, extend, refinance or otherwise replace such Indebtedness; provided, that the principal amount of such Indebtedness does not exceed the principal amount of Indebtedness refinanced (plus the amount of penalties, premiums, fees, accrued interest and reasonable expenses and other obligations incurred therewith) at the time of refinancing;

(d) (i) Indebtedness attaching to any property or asset prior to the acquisition thereof by any Non-Guarantor Subsidiary or of, or attaching to any property or asset of, any Person that becomes a Non-Guarantor Subsidiary after the date hereof prior to the time such Person becomes a Non-Guarantor

Subsidiary, in each case, outstanding prior to the acquisition of such property or asset or such Person becoming a Non-Guarantor Subsidiary; *provided* that such Indebtedness was not incurred in contemplation of or in connection with such acquisition or such Person becoming a Non-Guarantor Subsidiary, as the case may be and (ii) and any Indebtedness incurred to refund, extend, refinance or otherwise replace such Indebtedness (plus the amount of penalties, premiums, fees, accrued interest and reasonable expenses and other obligations incurred therewith);

(e) Indebtedness of Foreign Subsidiaries; and

(f) Indebtedness of Non-Wholly-owned Subsidiaries.

SECTION 6.02 Liens. The Borrower will not, and will not permit any Subsidiary to, create, incur, assume or permit to exist any Lien securing Indebtedness on any property or asset now owned or hereafter acquired by it except:

(a) Liens existing as of the Closing Date (including any replacement, extension or renewal of any such Lien permitted upon or in the same assets (other than after acquired property that is affixed or incorporated into the property covered by such Lien) theretofore subject to such Lien or the replacement, extension or renewal (without increase in the amount or change in any direct or contingent obligor except to the extent otherwise permitted hereunder) of the Indebtedness secured thereby);

(b) Liens securing (A) Capital Lease Obligations, or (B) Indebtedness incurred to finance the acquisition, construction, expansion or improvement of any fixed or capital assets of the Borrower or its Subsidiaries; *provided* that (x) such Liens attach at all times only to the assets so financed except for accessions to such property, improvements thereof and general intangibles relating thereto, and the proceeds and the products thereof and (y) individual financings of equipment provided by one lender may be cross collateralized to other financings of equipment provided by such lender;

(c) Liens existing on any property or asset prior to the acquisition thereof by the Borrower or any Subsidiary or existing on any property or asset of any Person that becomes a Subsidiary after the date hereof prior to the time such Person becomes a Subsidiary, in each case, pursuant to security documents in effect prior to the acquisition of such property or asset or such Person becoming a Subsidiary ("Existing Security Documents"), and securing Indebtedness whose incurrence, for purposes of this Agreement, by virtue of acquisition of such property or asset, or by virtue of such Person so becoming a Subsidiary, would not result in a violation of Section 6.07; *provided* that (i) such Lien is not created in contemplation of or in connection with such acquisition or such Person becoming a Subsidiary, as the case may be, (ii) such Lien shall not apply to any other property or assets of the Borrower or any Subsidiary except to the extent such Lien attaches to such property or assets pursuant to Existing Security Documents, (iii) such Lien shall secure only those obligations which it secures on the date of such acquisition or the date such Person becomes a Subsidiary, as the case may be, and extensions, renewals and replacements thereof that do not increase the outstanding principal amount thereof. For purposes of this Section 6.02(c), the Indebtedness so secured shall be deemed to have been incurred on the last day of the fiscal quarter then most recently ended; and

(d) Liens, not otherwise permitted by the foregoing clauses (a) and (b), securing Indebtedness in an aggregate amount not exceeding 15% of Consolidated Net Tangible Assets.

SECTION 6.03 Fundamental Changes. The Borrower will not, and will not permit any Material Subsidiary to, merge into or consolidate with any other Person, or permit any other Person to merge into or consolidate with it, or sell, transfer, lease or otherwise dispose of (including pursuant to a Division

and whether in one transaction or in a series of transactions) all (or substantially all) of its assets, or all or substantially all of the stock of or other equity interest in any of the Material Subsidiaries (in each case, whether now owned or hereafter acquired), or liquidate or dissolve, unless: (a) at the time thereof and immediately after giving effect thereto no Event of Default or Default shall have occurred and be continuing; and (b) (i) the Borrower or a Material Subsidiary is the surviving entity or the recipient of the assets so sold, transferred, leased or otherwise disposed of in any such sale, transfer, lease or other disposition of assets, *provided,* that no such merger, consolidation, sale, transfer, lease or other disposition shall have the effect of releasing the Borrower from any of the Obligations or (ii) such merger, consolidation, sale, transfer, lease or other disposition, when taken together with all other consolidations, mergers or sales of assets by the Borrower or any Material Subsidiary since the Closing Date, shall not result in the disposition by the Borrower and the Material Subsidiaries of assets in an amount that would constitute all or substantially all of the consolidated assets of the Borrower and the Material Subsidiaries.

SECTION 6.04 Restricted Payments. The Borrower will not declare or make, or agree to pay or make, directly or indirectly, any Restricted Payment except (a) distributions with respect to the Capital Stock of the Borrower, so long as both before and after the making of such distribution, no Event of Default shall have occurred and be continuing, (b) any Capital Stock split, Capital Stock reverse split, dividend of Borrower Capital Stock or similar transaction will not constitute a Restricted Payment, and (c) acquisitions by officers, directors and employees of the Borrower of equity interests in the Borrower through cashless exercise of options pursuant to, and in accordance with the terms of, management and/or employee stock plans, stock subscription agreements or shareholder agreements.

SECTION 6.05 Transactions with Affiliates. The Borrower will conduct, and cause each of the Subsidiaries to conduct, all transactions with any of its Affiliates (other than the Borrower or the Subsidiaries) on terms that are substantially as favorable to the Borrower or such Subsidiary as it would obtain in a comparable arm's-length transaction with a Person that is not an Affiliate, provided that the foregoing shall be deemed to be satisfied with respect to any transaction that is approved by a majority of the independent members of the Borrower's board of directors, or of a committee thereof consisting solely of independent directors, and provided, further that the foregoing restrictions shall not apply to:

(a) the payment of customary fees for management, consulting and financial services rendered to the Borrower and the Subsidiaries and (ii) customary investment banking fees paid for services rendered to the Borrower and the Subsidiaries in connection with divestitures, acquisitions, financings and other transactions;

(b) transactions permitted by Section 6.04;

(c) the payment of any fees or expenses incurred or paid by the Borrower or any of its Subsidiaries in connection with the Transactions, this Agreement and the other Loan Documents and the transactions contemplated hereby and thereby;

(d) the issuance of Capital Stock of the Borrower to the management of the Borrower or any of its Subsidiaries in connection with the Transactions or pursuant to arrangements described in clause (f) of this Section 6.05;

(e) loans, advances, provision of credit support and other investments by (or to) the Borrower and the Subsidiaries;

(f) employment and severance arrangements among the Borrower and the Subsidiaries and their respective officers and employees in the ordinary course of business;

(g) payments by the Borrower and the Subsidiaries pursuant to tax sharing agreements among the Borrower and the Subsidiaries on customary terms to the extent attributable to the ownership or operation of the Borrower and the Subsidiaries;

(h) the payment of customary fees and reasonable out of pocket costs to, and indemnities provided on behalf of, directors, managers, consultants, officers and employees of the Borrower and the Subsidiaries in the ordinary course of business to the extent attributable to the ownership or operation of the Borrower and the Subsidiaries; and

(i) transactions pursuant to agreements set forth on Schedule 6.05 or any amendment thereto to the extent such an amendment is not adverse, taken as a whole, to the Lenders in any material respect.

SECTION 6.06 Restrictive Agreements. The Borrower will not, and will not permit any of the Material Subsidiaries that are not Guarantors to, directly or indirectly, enter into, incur or permit to exist any agreement or other arrangement that prohibits, restricts or imposes any condition upon the ability of any non-Guarantor Material Subsidiary to pay dividends or other distributions with respect to any shares of its Capital Stock or to make or repay loans (including subordinate loans) or advances to the Borrower or any Guarantor, *provided* that the foregoing shall not apply to (a) restrictions and conditions imposed by law or by this Agreement, (b) customary restrictions and conditions contained in agreements relating to the sale of all or substantially all of the Capital Stock or assets of a Subsidiary pending such sale, *provided* such restrictions and conditions apply only to the Subsidiary that is to be sold and such sale is permitted hereunder, (c) restrictions and conditions existing on the date hereof identified on Schedule 6.06 (but shall apply to any extension or renewal of, or any amendment or modification expanding the scope of, any such restriction or condition) and (d) restrictions or conditions contained in, or existing by reason of, any agreement or instrument relating to any Subsidiary at the time such Subsidiary was merged or consolidated with or into, or acquired by, the Borrower or a Subsidiary or became a Subsidiary and not created in contemplation thereof.

SECTION 6.07 Ratio of Consolidated Net Indebtedness to Consolidated EBITDA. Commencing with the last day of the first full fiscal quarter following the Closing Date and on the last day of each fiscal quarter ended thereafter, the Borrower will not permit the ratio of Consolidated Net Indebtedness to Consolidated EBITDA for the most recent four full fiscal quarters ended as of the last day of such applicable fiscal quarter, to exceed 5.50:1.00.

In addition, for purposes of this Section 6.07, Hybrid Securities up to an aggregate amount of 5% of Total Capitalization (after giving effect to the following exclusion) shall be excluded from Consolidated Net Indebtedness.

SECTION 6.08 Use of Proceeds. The Borrower will not request any Borrowing or Letter of Credit, and the Borrower shall not use, and shall procure that its Subsidiaries and its or their respective directors, officers, employees and agents shall not use, the proceeds of any Borrowing or Letter of Credit (A) in furtherance of an offer, payment, promise to pay, or authorization of the payment or giving of money, or anything else of value, to any Person in violation of any Anti-Corruption Laws, (B) for the purpose of funding, financing or facilitating any activities, business or transaction of or with any Sanctioned Person, or in any Sanctioned Country, or (C) in any manner that would result in the violation of any Sanctions applicable to any party hereto.

ARTICLE VII
EVENTS OF DEFAULT

SECTION 7.01 Events of Default and Remedies. If any of the following events ("Events of Default") shall occur and be continuing:

(a) the principal of any Loan or any reimbursement obligation in respect of any LC Disbursement shall not be paid when and as the same shall become due and payable, whether at the due date thereof or at a date fixed for prepayment thereof or otherwise;

(b) any interest on any Loan or any fee or any other amount (other than an amount referred to in clause (a) of this Article) payable by a Loan Party under this Agreement or any other Loan Document shall not be paid, when and as the same shall become due and payable, and such failure shall continue unremedied for a period of five Business Days;

(c) any representation or warranty made or, for purposes of Article III, deemed made by or on behalf of the Borrower herein, at the direction of the Borrower or by any Loan Party in any other Loan Document or in any document, certificate or financial statement delivered in connection with this Agreement or any other Loan Document shall prove to have been incorrect in any material respect when made or deemed made or reaffirmed, as the case may be;

(d) the Borrower shall fail to observe or perform any covenant, condition or agreement contained in Section 5.01(d)(i), 5.02 (with respect to the Borrower's existence) or 5.07 or in Article VI;

(e) any Loan Party shall fail to perform or observe any other term, covenant or agreement contained in this Agreement (other than those specified in Section 7.01(a), Section 7.01(b) or Section 7.01(d)) or any other Loan Document to which it is a party and, in any event, such failure shall remain unremedied for 30 calendar days after the earlier of (i) written notice of such failure shall have been given to the Borrower by the Administrative Agent or any Lender or, (ii) a Responsible Officer of the Borrower becomes aware of such failure;

(f) other than as specified in Section 7.01(a) or (b), (i) the Borrower or any Subsidiary fails to make (whether as primary obligor or as guarantor or other surety) any payment of principal of, or interest or premium, if any, on any item or items of Indebtedness (other than as specified in Section 7.01(a) or Section 7.01(b)) or any payment in respect of any Hedging Agreement, in each case when the same becomes due and payable (whether by scheduled maturity, required payment or prepayment, acceleration, demand or otherwise), beyond any period of grace provided with respect thereto (not to exceed 30 days); *provided* that the aggregate outstanding principal amount of all Indebtedness or payment obligations in respect of all Hedging Agreements as to which such a payment default shall occur and be continuing is equal to or exceeds $150,000,000, or (ii) the Borrower or any Subsidiary fails to duly observe, perform or comply with any agreement with any Person or any term or condition of any instrument, if such failure, either individually or in the aggregate, shall have resulted in the acceleration of the payment of Indebtedness with an aggregate face amount which is equal to or exceeds $150,000,000; *provided* that this Section 7.01(f) shall not apply to secured Indebtedness that becomes due as a result of the voluntary sale or transfer of the property or assets securing such Indebtedness, so long as such Indebtedness is paid in full when due;

(g) an involuntary case shall be commenced or an involuntary petition shall be filed seeking (i) liquidation, reorganization or other relief in respect of the Borrower or any Material Subsidiary or its debts, or of a substantial part of its assets, under any Debtor Relief Laws or (ii) the appointment of a

receiver, trustee, custodian, sequestrator, conservator or similar official for the Borrower or any Material Subsidiary or for a substantial part of its assets, and, in any such case, such proceeding or petition shall continue undismissed for 60 days or an order or decree approving or ordering any of the foregoing shall be entered;

(h) the Borrower or any Material Subsidiary shall (i) voluntarily commence any proceeding or file any petition seeking liquidation, winding-up, reorganization or other relief under any Debtor Relief Laws, (ii) consent to the institution of, or fail to contest in a timely and appropriate manner, any proceeding or petition described in Section 7.01(g), (iii) apply for or consent to the appointment of a receiver, trustee, custodian, sequestrator, conservator or similar official for the Borrower or any Material Subsidiary or for a substantial part of its assets, (iv) file an answer admitting the material allegations of a petition filed against it in any such proceeding, (v) make a general assignment for the benefit of creditors or (vi) take any action for the purpose of effecting any of the foregoing;

(i) the Borrower or any Material Subsidiary shall become unable, admit in writing or fail generally to pay its debts as they become due;

(j) one or more judgments for the payment of money in an aggregate amount in excess of $150,000,000 shall be rendered against the Borrower, any Subsidiary or any combination thereof and the same shall (x) not be covered by insurance and (y) remain undischarged for a period of 60 consecutive days during which execution shall not be effectively stayed, or any action shall be legally taken by a judgment creditor to attach or levy upon any assets of the Borrower or any Subsidiary to enforce any such judgment;

(k) a Change in Control shall occur;

(l) any member of the ERISA Group shall fail to pay when due an amount which it shall have become liable to pay under Title IV of ERISA; or notice of intent to terminate a Plan shall be filed under Title IV of ERISA by any member of the ERISA Group, any plan administrator or any combination of the foregoing; or the PBGC shall institute proceedings under Title IV of ERISA to terminate, to impose liability (other than for premiums under Section 4007 of ERISA) in respect of, or to cause a trustee to be appointed to administer any Plan; or a condition shall exist by reason of which the PBGC would be entitled to obtain a decree adjudicating that any Plan must be terminated; or there shall occur a complete or partial withdrawal from, or a default, within the meaning of Section 4219(c)(5) of ERISA, with respect to, one or more Multiemployer Plans which could cause one or more members of the ERISA Group to incur a current payment obligation; and in each of the foregoing instances such condition could reasonably be expected to result in a Material Adverse Effect;

then, and in any such event, and at any time thereafter (but for the avoidance of doubt, in each case, not prior to the Closing Date) if any Event of Default shall then be continuing, the Administrative Agent, may, and upon the written request of the Required Lenders shall, by written notice (including notice sent by telecopy or electronic mail) to the Borrower (a "Notice of Default") take any or all of the following actions, without prejudice to the rights of the Administrative Agent, any Lender or other holder of any of the Obligations to enforce its claims against the Borrower (*provided* that, if an Event of Default specified in Section 7.01(g) or Section 7.01(h) shall occur with respect to the Borrower or any Material Subsidiary, the actions described in clauses (i), (ii) and (v) below shall occur automatically without the giving of any Notice of Default): (i) declare the Total Commitment terminated, whereupon the Commitments of the Lenders shall forthwith terminate immediately and any accrued Commitment Fees shall forthwith become due and payable without any other notice of any kind; (ii) declare the principal of and any accrued interest in respect of all Loans, and all the other Obligations owing hereunder and under the other Loan Documents, to be, whereupon the same shall become, forthwith due and payable without presentment, demand, notice of demand or of dishonor

and nonpayment, protest, notice of protest, notice of intent to accelerate, declaration or notice of acceleration or any other notice of any kind, all of which are hereby waived by the Borrower; (iii) exercise any rights or remedies under the Loan Documents; (iv) terminate any Letter of Credit which may be terminated in accordance with its terms (whether by the giving of written notice to the beneficiary or otherwise); and (v) direct the Borrower to comply, and the Borrower agrees that upon receipt of such notice (or upon the occurrence of an Event of Default specified in Section 7.01(g) or Section 7.01(h)) it will comply, with the provisions of Section 2.05(l).

ARTICLE III
THE ADMINISTRATIVE AGENT

SECTION 8.01 Appointment and Authority. Each of the Lenders and the Issuing Banks hereby irrevocably appoints Barclays Bank PLC to act on its behalf as the Administrative Agent hereunder and under the other Loan Documents and authorizes the Administrative Agent to take such actions on its behalf and to exercise such powers as are delegated to the Administrative Agent by the terms hereof or thereof, together with such actions and powers as are reasonably incidental thereto. The provisions of this Article are solely for the benefit of the Administrative Agent, the Lenders and the Issuing Banks and, except as specifically provided in Section 8.06(a) and (b), the Borrower shall not have rights as a third-party beneficiary of any of such provisions. It is understood and agreed that the use of the term "agent" herein or in any other Loan Documents (or any other similar term) with reference to the Administrative Agent is not intended to connote any fiduciary or other implied (or express) obligations arising under agency doctrine of any applicable law. Instead such term is used as a matter of market custom, and is intended to create or reflect only an administrative relationship between contracting parties.

SECTION 8.02 Rights as a Lender. The Person serving as the Administrative Agent hereunder shall have the same rights and powers in its capacity as a Lender as any other Lender and may exercise the same as though it were not the Administrative Agent, and the term *"Lender"* or *"Lenders"* shall, unless otherwise expressly indicated or unless the context otherwise requires, include the Person serving as the Administrative Agent hereunder in its individual capacity. Such Person and its Affiliates may accept deposits from, lend money to, own securities of, act as the financial advisor or in any other advisory capacity for, and generally engage in any kind of business with, the Borrower or any Subsidiary or other Affiliate thereof as if such Person were not the Administrative Agent hereunder and without any duty to account therefor to the Lenders.

SECTION 8.03 Exculpatory Provisions.

(a) The Administrative Agent shall not have any duties or obligations except those expressly set forth herein and in the other Loan Documents, and its duties hereunder shall be administrative in nature. Without limiting the generality of the foregoing, the Administrative Agent:

(i) shall not be subject to any fiduciary or other implied duties, regardless of whether a Default or an Event of Default has occurred and is continuing;

(ii) shall not have any duty to take any discretionary action or exercise any discretionary powers, except discretionary rights and powers expressly contemplated hereby or by the other Loan Documents that the Administrative Agent is required to exercise as directed in writing by the Required Lenders (or such other number or percentage of the Lenders as shall be expressly provided for herein or in the other Loan Documents); *provided* that the Administrative Agent shall not be required to take any action that, in its opinion or the opinion of its counsel, may expose the Administrative Agent to liability or that is contrary to any Loan Document or applicable law,

including for the avoidance of doubt any action that may be in violation of the automatic stay under any Debtor Relief Law or that may effect a forfeiture, modification or termination of property of a Defaulting Lender in violation of any Debtor Relief Law; and

(iii) shall not, except as expressly set forth herein and in the other Loan Documents, have any duty to disclose, and shall not be liable for the failure to disclose, any information relating to the Borrower or any of its Affiliates that is communicated to or obtained by the Person serving as the Administrative Agent or any of its Affiliates in any capacity.

(b) The Administrative Agent shall not be liable for any action taken or not taken by it (i) with the consent or at the request of the Required Lenders (or such other number or percentage of the Lenders as shall be necessary, or as the Administrative Agent shall believe in good faith shall be necessary, under the circumstances as provided in Sections 9.02 and 9.03) or (ii) in the absence of its own gross negligence or willful misconduct as determined by a court of competent jurisdiction by final and nonappealable judgment. The Administrative Agent shall be deemed not to have knowledge of any Default or Event of Default unless and until notice describing such Default is given to the Administrative Agent in writing by the Borrower, a Lender or an Issuing Bank.

(c) The Administrative Agent shall not be responsible for or have any duty to ascertain or inquire into (i) any statement, warranty or representation made in or in connection with this Agreement or any other Loan Document, (ii) the contents of any certificate, report or other document delivered hereunder or thereunder or in connection herewith or therewith, (iii) the performance or observance of any of the covenants, agreements or other terms or conditions set forth herein or therein or the occurrence of any Default or Event of Default or the enforceability, effectiveness or genuineness of this Agreement, any other Loan Document or any other agreement, instrument or document, or (v) the satisfaction of any condition set forth in Article III or elsewhere herein, other than to confirm receipt of items expressly required to be delivered to the Administrative Agent.

SECTION 8.04 Reliance by Administrative Agent. The Administrative Agent shall be entitled to rely upon, and shall not incur any liability for relying upon, any notice, request, certificate, consent, statement, instrument, document or other writing (including any electronic message, Internet or intranet website posting or other distribution) believed by it to be genuine and to have been signed, sent or otherwise authenticated by the proper Person. The Administrative Agent also may rely upon any statement made to it orally or by telephone and believed by it to have been made by the proper Person, and shall not incur any liability for relying thereon. In determining compliance with any condition hereunder to the making or extension of a Loan or the issuance, extension, renewal or increase of a Letter of Credit, that by its terms must be fulfilled to the satisfaction of a Lender or an Issuing Bank, the Administrative Agent may presume that such condition is satisfactory to such Lender or Issuing Bank unless the Administrative Agent shall have received notice to the contrary from such Lender or Issuing Bank prior to the making or extension of such Loan or the issuance of such Letter of Credit. The Administrative Agent may consult with legal counsel (who may be counsel for the Borrower), independent accountants and other experts selected by it, and shall not be liable for any action taken or not taken by it in accordance with the advice of any such counsel, accountants or experts.

SECTION 8.05 Delegation of Duties. The Administrative Agent may perform any and all of its duties and exercise its rights and powers hereunder or under any other Loan Document by or through any one or more sub agents appointed by the Administrative Agent. The Administrative Agent and any such sub agent may perform any and all of its duties and exercise its rights and powers by or through their respective Related Parties. The exculpatory provisions of this Article shall apply to any such sub agent and to the Related Parties of the Administrative Agent and any such sub agent, and shall apply to their respective

activities in connection with the syndication of the revolving credit facility provided for herein as well as activities as Administrative Agent. The Administrative Agent shall not be responsible for the negligence or misconduct of any sub-agents except to the extent that a court of competent jurisdiction determines in a final and nonappealable judgment that the Administrative Agent acted with gross negligence or willful misconduct in the selection of such sub agents.

SECTION 8.06 Resignation of Administrative Agent.

(a) The Administrative Agent may at any time give notice of its resignation to the Lenders, the Issuing Banks and the Borrower. Upon receipt of any such notice of resignation, the Required Lenders shall have the right to appoint a successor, subject to (so long as no Default or Event of Default exists) the prior written consent of the Borrower (which consent will not be unreasonably withheld or delayed), which shall be a bank with an office in the United States, or an Affiliate of any such bank with an office in the United States. If no such successor shall have been so appointed by the Required Lenders and shall have accepted such appointment within 30 days after the retiring Administrative Agent gives notice of its resignation (or such earlier day as shall be agreed by the Required Lenders) (the "Resignation Effective Date"), then the retiring Administrative Agent may (but shall not be obligated to), subject to (so long as no Default or Event of Default exists) the prior written consent of the Borrower (which consent will not be unreasonably withheld), on behalf of the Lenders and the Issuing Banks, appoint a successor Administrative Agent meeting the qualifications set forth above. Whether or not a successor has been appointed, such resignation shall become effective in accordance with such notice on the Resignation Effective Date.

(b) If the Person serving as Administrative Agent is a Defaulting Lender pursuant to clause (d) of the definition thereof, the Required Lenders may, to the extent permitted by applicable law, by notice in writing to the Borrower and such Person remove such Person as Administrative Agent and, subject to (so long as no Default or Event of Default exists) the prior written consent of the Borrower (which consent will not be unreasonably withheld or delayed), appoint a successor. If no such successor shall have been so appointed by the Required Lenders and shall have accepted such appointment within 30 days (or such earlier day as shall be agreed by the Required Lenders) (the "Removal Effective Date"), then such removal shall nonetheless become effective in accordance with such notice on the Removal Effective Date.

(c) With effect from the Resignation Effective Date or the Removal Effective Date (as applicable) (1) the retiring or removed Administrative Agent shall be discharged from its duties and obligations hereunder and under the other Loan Documents (except that in the case of any collateral security held by the Administrative Agent on behalf of the Lenders or the Issuing Banks under any of the Loan Documents, the retiring or removed Administrative Agent shall continue to hold such collateral security until such time as a successor Administrative Agent is appointed) and (2) except for any indemnity payments owed to the retiring or removed Administrative Agent, all payments, communications and determinations provided to be made by, to or through the Administrative Agent shall instead be made by or to each Lender and Issuing Bank directly, until such time, if any, as the Required Lenders appoint a successor Administrative Agent as provided for above. Upon the acceptance of a successor's appointment as Administrative Agent hereunder, such successor shall succeed to and become vested with all of the rights, powers, privileges and duties of the retiring or removed Administrative Agent (other than any rights to indemnity payments owed to the retiring or removed Administrative Agent), and the retiring or removed Administrative Agent shall be discharged from all of its duties and obligations hereunder or under the other Loan Documents. The fees payable by the Borrower to a successor Administrative Agent shall be the same as those payable to its predecessor unless otherwise agreed between the Borrower and such successor. After the retiring or removed Administrative Agent's resignation or removal hereunder and under the other Loan Documents, the provisions of this Article and Section 9.03 shall continue in effect for the benefit of such retiring or removed Administrative Agent, its sub agents and their respective Related Parties in respect of any actions taken or

omitted to be taken by any of them while the retiring or removed Administrative Agent was acting as Administrative Agent.

SECTION 8.07 Non-Reliance on Administrative Agent and Other Lenders.

(a) Each Lender acknowledges that it has, independently and without reliance upon the Administrative Agent or any other Lender or any of their Related Parties and based on such documents and information as it has deemed appropriate, made its own credit analysis and decision to enter into this Agreement. Each Lender and Issuing Bank also acknowledges that it will, independently and without reliance upon the Administrative Agent or any other Lender or any of their Related Parties and based on such documents and information as it shall from time to time deem appropriate, continue to make its own decisions in taking or not taking action under or based upon this Agreement, any other Loan Document or any related agreement or any document furnished hereunder or thereunder.

(b) Each Lender acknowledges that Simpson Thacher & Bartlett LLP is acting in this transaction as special legal counsel to the Administrative Agent only. Each Lender and Issuing Bank will consult with its own legal counsel to the extent it deems necessary with this Agreement and the other Loan Documents and the matters contemplated herein and therein.

SECTION 8.08 INDEMNIFICATION. **THE LENDERS AGREE TO INDEMNIFY THE ADMINISTRATIVE AGENT, THE ARRANGERS, THE SYNDICATION AGENT AND THE DOCUMENTATION AGENTS RATABLY IN ACCORDANCE WITH THEIR APPLICABLE PERCENTAGES FOR THE INDEMNITY MATTERS AS DESCRIBED IN SECTION 9.03 TO THE EXTENT NOT INDEMNIFIED OR REIMBURSED BY THE BORROWER UNDER SECTION 9.03, BUT WITHOUT LIMITING THE OBLIGATIONS OF THE BORROWER UNDER SAID SECTION 9.03 AND FOR ANY AND ALL OTHER LIABILITIES, OBLIGATIONS, LOSSES, DAMAGES, PENALTIES, ACTIONS, JUDGMENTS, SUITS, COSTS, EXPENSES OR DISBURSEMENTS OF ANY KIND AND NATURE WHATSOEVER WHICH MAY BE IMPOSED ON, INCURRED BY OR ASSERTED AGAINST THE ADMINISTRATIVE AGENT, ANY ARRANGER, THE SYNDICATION AGENT OR ANY DOCUMENTATION AGENT IN ANY WAY RELATING TO OR ARISING OUT OF: (A) THIS AGREEMENT OR ANY OTHER LOAN DOCUMENT CONTEMPLATED BY OR REFERRED TO HEREIN OR THE TRANSACTIONS CONTEMPLATED HEREBY, BUT EXCLUDING, UNLESS A DEFAULT OR AN EVENT OF DEFAULT HAS OCCURRED AND IS CONTINUING, NORMAL ADMINISTRATIVE COSTS AND EXPENSES INCIDENT TO THE PERFORMANCE OF ITS AGENCY DUTIES, IF ANY, HEREUNDER OR UNDER ANY SUCH OTHER LOAN DOCUMENT OR (B) THE ENFORCEMENT OF ANY OF THE TERMS OF THIS AGREEMENT OR OF ANY OTHER LOAN DOCUMENT; WHETHER OR NOT ANY OF THE FOREGOING SPECIFIED IN THIS SECTION 8.08 ARISES FROM THE SOLE OR CONCURRENT NEGLIGENCE OF THE ADMINISTRATIVE AGENT, ANY ARRANGER, THE SYNDICATION AGENT OR ANY DOCUMENTATION AGENT, AS THE CASE MAY BE; *PROVIDED* THAT NO LENDER SHALL BE LIABLE FOR ANY OF THE FOREGOING TO THE EXTENT THEY ARISE FROM THE GROSS NEGLIGENCE, WILLFUL MISCONDUCT OR UNLAWFUL CONDUCT OF THE ADMINISTRATIVE AGENT, ANY ARRANGER, THE SYNDICATION AGENT OR ANY DOCUMENTATION AGENT AS DETERMINED BY A COURT OF COMPETENT JURISDICTION IN A FINAL AND NONAPPEALABLE JUDGMENT.**

SECTION 8.09 No Reliance on Agents or other Lenders. Each Lender acknowledges and agrees that it has, independently and without reliance on the Administrative Agent, any Arranger, the Syndication Agent, any Documentation Agent or any other Lender, and based on such documents and

information as it has deemed appropriate, made its own credit analysis of the Borrower and its Subsidiaries and its decision to enter into this Agreement, and that it will, independently and without reliance upon the Administrative Agent, any Arranger, the Syndication Agent, any Documentation Agent or any other Lender, and based on such documents and information as it shall deem appropriate at the time, continue to make its own analysis and decisions in taking or not taking action under this Agreement. None of the Administrative Agent, the Arrangers, the Syndication Agent or the Documentation Agents shall be required to keep itself informed as to the performance or observance by the Borrower of this Agreement, the other Loan Documents or any other document referred to or provided for herein or to inspect the properties or books of the Borrower. Except for notices, reports and other documents and information expressly required to be furnished to the Lenders by the Administrative Agent hereunder, none of the Administrative Agent, the Arrangers, the Syndication Agent or the Documentation Agents shall have any duty or responsibility to provide any Lender with any credit or other information concerning the affairs, financial condition or business of the Borrower (or any of its Affiliates) which may come into the possession of the Administrative Agent, any Arranger, the Syndication Agent, any Documentation Agent or any of their respective Affiliates. In this regard, each Lender acknowledges that Simpson Thacher & Bartlett LLP is acting in this transaction as special counsel to the Administrative Agent only. Each Lender will consult with its own legal counsel to the extent that it deems necessary in connection with this Agreement and other Loan Documents and the matters contemplated herein and therein.

SECTION 8.10 Duties of the Syndication Agent, Documentation Agents, Arrangers. Notwithstanding the indemnity of the Syndication Agent, the Documentation Agents and the Arrangers contained in Section 8.08 and in Section 9.03, nothing contained in this Agreement shall be construed to impose any obligation or duty whatsoever on any Person named on the cover of this Agreement or elsewhere in this Agreement as a Syndication Agent, a Documentation Agent, an Arranger, a "lead arranger" or a "bookrunner", other than those applicable to all Lenders as such.

SECTION 8.11 Certain ERISA Matters.

(a) Each Lender (x) represents and warrants, as of the date such Person became a Lender party hereto, to, and (y) covenants, from the date such Person became a Lender party hereto to the date such Person ceases being a Lender party hereto, for the benefit of, the Administrative Agent and the Joint Lead Arrangers and their respective Affiliates, and not, for the avoidance of doubt, to or for the benefit of the Borrower or any other Loan Party, that at least one of the following is and will be true:

(i) such Lender is not using "plan assets" (within the meaning of the Plan Asset Regulations) of one or more Benefit Plans in connection with the Loans, the Letters of Credit or the Commitments,

(ii) the transaction exemption set forth in one or more PTEs, such as PTE 84-14 (a class exemption for certain transactions determined by independent qualified professional asset managers), PTE 95-60 (a class exemption for certain transactions involving insurance company general accounts), PTE 90-1 (a class exemption for certain transactions involving insurance company pooled separate accounts), PTE 91-38 (a class exemption for certain transactions involving bank collective investment funds) or PTE 96-23 (a class exemption for certain transactions determined by in-house asset managers), is applicable with respect to such Lender's entrance into, participation in, administration of and performance of the Loans, the Letters of Credit, the Commitments and this Agreement, and the conditions for exemptive relief thereunder are and will continue to be satisfied in connection therewith,

(iii) (A) such Lender is an investment fund managed by a "Qualified Professional Asset Manager" (within the meaning of Part VI of PTE 84-14), (B) such Qualified Professional Asset Manager made the investment decision on behalf of such Lender to enter into, participate in, administer and perform the Loans, the Letters of Credit, the Commitments and this Agreement, (C) the entrance into, participation in, administration of and performance of the Loans, the Letters of Credit, the Commitments and this Agreement satisfies the requirements of sub-sections (b) through (g) of Part I of PTE 84-14 and (D) to the best knowledge of such Lender, the requirements of subsection (a) of Part I of PTE 84-14 are satisfied with respect to such Lender's entrance into, participation in, administration of and performance of the Loans, the Letters of Credit, the Commitments and this Agreement, or

(iv) such other representation, warranty and covenant as may be agreed in writing between the Administrative Agent, in its sole discretion, and such Lender.

(b) In addition, unless sub-clause (i) in the immediately preceding clause (a) is true with respect to a Lender or such Lender has not provided another representation, warranty and covenant as provided in sub-clause (iv) in the immediately preceding clause (a), such Lender further (x) represents and warrants, as of the date such Person became a Lender party hereto, to, and (y) covenants, from the date such Person became a Lender party hereto to the date such Person ceases being a Lender party hereto, for the benefit of, the Administrative Agent and the Joint Lead Arrangers and their respective Affiliates, and not, for the avoidance of doubt, to or for the benefit of the Borrower or any other Loan Party, that none of the Administrative Agent or the Joint Leader Arrangers or any of their respective Affiliates is a fiduciary with respect to the assets of such Lender (including in connection with the reservation or exercise of any rights by the Administrative Agent under this Agreement, any Loan Document or any documents related to hereto or thereto),

(c) The Administrative Agent and the Joint Leader Arrangers hereby inform the Lenders that each such Person is not undertaking to provide impartial investment advice, or to give advice in a fiduciary capacity, in connection with the transactions contemplated hereby, and that such Person has a financial interest in the transactions contemplated hereby in that such Person or an Affiliate thereof (i) may receive interest or other payments with respect to the Loans, the Letters of Credit, the Commitments and this Agreement, (ii) may recognize a gain if it extended the Loans, the Letters of Credit or the Commitments for an amount less than the amount being paid for an interest in the Loans, the Letters of Credit or the Commitments by such Lender or (iii) may receive fees or other payments in connection with the transactions contemplated hereby, the Loan Documents or otherwise, including structuring fees, commitment fees, arrangement fees, facility fees, upfront fees, underwriting fees, ticking fees, agency fees, administrative agent or collateral agent fees, utilization fees, minimum usage fees, letter of credit fees, fronting fees, deal-away or alternate transaction fees, amendment fees, processing fees, term out premiums, banker's acceptance fees, breakage or other early termination fees or fees similar to the foregoing.

ARTICLE IX
MISCELLANEOUS

SECTION 9.01 Notices, Etc.

(a) All notices, consents, requests, approvals, demands and other communications (collectively "Communications") provided for herein shall be in writing (including facsimile Communications) and mailed, telecopied or delivered:

(i) if to the Borrower, to it at:

1001 Louisiana Street, Suite 1000
Houston, Texas 77002
Attention: Anthony Ashley
Telecopy No.: (713) 445-8302;

With a copy to:

1001 Louisiana Street, Suite 1000
Houston, Texas 77002
Attention: General Counsel
Telecopy No.: (713) 495-2877;

(ii) if to the Administrative Agent, to it at

c/o Barclays Bank PLC
745 Seventh Avenue
27th Floor
New York, NY 10019
Attention: Patrick Shields
Email: patrick.shields@barclays.com
Phone: 212-526-9531

(iii) if to the Swingline Lender, to it at

c/o Barclays Bank PLC
745 Seventh Avenue
27th Floor
New York, NY 10019
Attention: Patrick Shields
Email: patrick.shields@barclays.com
Phone: 212-526-9531

c/o Barclays Bank PLC
400 Jefferson Park
Whippany, NJ 07981
Attention: Bobby Fitzpatrick
Email: bobby.fitzpatrick@barclays.com
Phone: 201-499-5043

(i) if to any other Lender or to any Issuing Bank, to it at its address (or telecopy number) set forth in the Administrative Questionnaire delivered by such Person to the Administrative Agent or in the Assignment and Acceptance executed by such Person;

or, in the case of any party hereto, such other address or telecopy number as such party may hereafter specify for such purpose by notice to the other parties.

(b) Communications to the Lenders hereunder may be delivered or furnished by electronic communications (including electronic mail and internet or intranet websites) pursuant to procedures approved by the Administrative Agent; *provided* that the foregoing shall not apply to notices

pursuant to Article II unless otherwise agreed by the Administrative Agent and the applicable Lender. The Administrative Agent or the Borrower may, in its discretion, agree to accept notices and other communications to it hereunder by electronic communications pursuant to procedures approved by it; *provided* that approval of such procedures may be limited to particular notices or communications.

(c) Unless the Administrative Agent otherwise prescribes, (i) notices and other communications sent to an e-mail address shall be deemed received upon the sender's receipt of an acknowledgement from the intended recipient (such as by the "return receipt requested" function, as available, return e-mail or other written acknowledgement), and (ii) notices or communications posted to an Internet or intranet website shall be deemed received upon the deemed receipt by the intended recipient, at its e-mail address as described in the foregoing clause (i), of notification that such notice or communication is available and identifying the website address therefor; *provided* that, for both clauses (i) and (ii) above, if such notice, email or other communication is not sent during the normal business hours of the recipient, such notice or communication shall be deemed to have been sent at the opening of business on the next business day for the recipient.

(d) Any party hereto may change its address or telecopy number for notices and other communications hereunder by notice to the other parties hereto.

(e) Platform.

(i) The Borrower agrees that the Administrative Agent may, but shall not be obligated to, make the Communications available to the Lenders and the Issuing Banks by posting the Communications on Debt Domain, Intralinks, Syndtrak or a substantially similar electronic transmission system (the "Platform").

The Platform is provided "*as is*" and "*as available*." The Agent Parties (as defined below) do not warrant the adequacy of the Platform and expressly disclaim liability for errors or omissions in the Electronic Communications (as defined below). No warranty of any kind, express, implied or statutory, including, without limitation, any warranty of merchantability, fitness for a particular purpose, non-infringement of third-party rights or freedom from viruses or other code defects, is made by any Agent Party in connection with the Communications or the Platform. In no event shall the Administrative Agent or any of its Related Parties (collectively, the "Agent Parties") have any liability to the Borrower, any Lender, any Issuing Bank or any other Person or entity for damages of any kind, including, without limitation, direct or indirect, special, incidental or consequential damages, losses or expenses (whether in tort, contract or otherwise) arising out of the Borrower or the Administrative Agent's transmission of communications through the Platform. "Electronic Communications" means, collectively, any notice, demand, communication, information, document or other material provided by or on behalf of the Borrower pursuant to any Loan Document or the transactions contemplated therein which is distributed to the Administrative Agent, any Lender or any Issuing Bank by means of electronic communications pursuant to this Section, including through the Platform.

SECTION 9.02 Waivers; Amendments; Releases.

(a) No failure or delay by the Administrative Agent, any Issuing Bank or any Lender in exercising, and no course of dealing with respect to, any right or power hereunder shall operate as a waiver thereof, nor shall any single or partial exercise of any such right or power, or any abandonment or discontinuance of steps to enforce such a right or power, preclude any other or further exercise thereof or the exercise of any other right or power. No notice to or demand on the Borrower in any case shall entitle the Borrower to any other or further notice or demand in similar or other circumstances. No waiver of any provision of this Agreement or consent to any departure therefrom shall in any event be effective unless the

same shall be permitted by Section 9.02(b), and then such waiver or consent shall be effective only in the specific instance and for the purpose for which given. Without limiting the generality of the foregoing, the making of a Loan or issuance of a Letter of Credit shall not be construed as a waiver of any Default or Event of Default, regardless of whether the Administrative Agent, any Lender or any Issuing Bank may have had notice or knowledge of such Default at the time.

(b) No provision of this Agreement or any other Loan Document (other than each Fee Letter, which may be amended by the parties thereto) provision may be waived, amended or modified except pursuant to an agreement or agreements in writing entered into by the Borrower (or to the extent another Loan Party and not the Borrower is party thereto, such Loan Party) and the Required Lenders or by the Borrower and the Administrative Agent with the consent of the Required Lenders; *provided* that no such agreement shall (i) increase the Commitment of any Lender without the written consent of such Lender, other than increases of Commitments as provided in Section 2.21 and extensions of Commitments as provided in Section 2.22, (ii) reduce the principal amount of any Loan or LC Disbursement or reduce the rate of interest thereon, or reduce any fees payable hereunder, without the written consent of each Lender affected thereby (for the avoidance of doubt, any amendment imposing an alternative interest rate basis in accordance with Section 2.13(b) shall become effective as provided in Section 2.13(b)), (iii) postpone the scheduled date of payment of the principal amount of any Loan or LC Disbursement, or any interest thereon, or any fees or other amounts payable hereunder, or reduce the amount of, waive or excuse any such payment, or postpone the scheduled date of expiration of any Commitment, without the written consent of each Lender affected thereby, other than extensions of the Maturity Date as provided in Section 2.22, (iv) change Section 2.17(b) or (c) in a manner that would alter the *pro rata* sharing of payments required thereby, without the written consent of each Lender, (v) amend Section 2.19 or 2.20 without the consent of the Administrative Agent, the Swingline Lender and the Issuing Banks in addition to the consent of the Required Lenders, (vi) release all or substantially all of the value of the Guarantees under the Guaranty or change any of the provisions of this Section 9.02(b), or the definition of "*Required Lenders*" or any other provision hereof specifying the number or percentage of Lenders required to waive, amend or modify any rights hereunder or make any determination or grant any consent hereunder, without the written consent of each Lender; *provided*, *further*, that no such agreement shall amend, modify or otherwise affect the rights or duties of the Administrative Agent, the Swingline Lender or any Issuing Bank hereunder without the prior written consent of the Administrative Agent, the Swingline Lender or such Issuing Bank, as the case may be. Except as provided herein, during such period as a Lender is a Defaulting Lender, to the fullest extent permitted by applicable law, such Lender will not be entitled to vote in respect of amendments and waivers hereunder and the Commitment and the outstanding Loans or other extensions of credit of such Lender hereunder will not be taken into account in determining whether the Required Lenders or all of the Lenders, as required, have approved any such amendment or waiver (and the definition of "*Required Lenders*" will automatically be deemed modified accordingly for the duration of such period); *provided* that any such amendment or waiver referred to in clauses (i) through (vi) or the first of this Section 9.02(b) above or that would alter the terms set forth in such proviso shall require the consent of such Defaulting Lender.

Notwithstanding the foregoing, the Administrative Agent and the Borrower may amend any Loan Document to correct any obvious errors, mistakes, omissions, defects or inconsistencies and such amendment shall become effective without any further consent of any other party to such Loan Document other than the Administrative Agent and the Borrower.

(c) Notwithstanding the provisions of Section 9.02(b), amendments to this Agreement pursuant to Section 2.21(c) and Section 2.22 may be effected without the consent of any Lenders other than the Administrative Agent, the Issuing Banks, the Swingline Lender and each Lender making a New Commitment or extending a Commitment.

(d) The Lenders hereby irrevocably agree that any Guarantor shall be automatically released from the Guarantee upon consummation of any transaction not prohibited hereunder resulting in such Subsidiary ceasing to constitute a Subsidiary or upon any Subsidiary becoming an Excluded Subsidiary, provided that with respect to any Excluded Subsidiary that is a Guarantor on the Closing Date or that has become a Guarantor after the Closing Date at the request of the Borrower, such Excluded Subsidiary shall be automatically released from the Guaranty upon written notice thereof from a Responsible Officer of the Borrower to the Administrative Agent certifying that (i) such Excluded Subsidiary is an Excluded Subsidiary and (ii) on such date, or concurrently with such release, such Excluded Subsidiary shall be automatically released as a guarantor under the Cross Guarantee Agreement, dated as of November 26, 2014 (as amended, restated, supplemented or otherwise modified from time to time) entered by the Borrower and the other signatories party thereto, and is not a guarantor of the Bonds or any other material Indebtedness of the Borrower or any Subsidiary. The Lenders hereby authorize the Administrative Agent to execute and deliver any instruments, documents, and agreements necessary or desirable to evidence and confirm the release of any Guarantor pursuant to the foregoing provisions of this paragraph, all without the further consent or joinder of any Lender.

SECTION 9.03 Payment of Expenses, Indemnities, etc. The Borrower agrees:

(a) to pay (i) all reasonable out-of-pocket expenses incurred by the Administrative Agent and its Affiliates, including the reasonable fees, charges and disbursements of counsel for the Administrative Agent, in connection with the syndication of the credit facility provided for herein, the preparation and administration of this Agreement or any amendments, modifications or waivers of the provisions hereof, (ii) all reasonable out-of-pocket expenses incurred by any Issuing Bank in connection with the issuance, amendment, renewal or extension of any Letter of Credit or any demand for payment thereunder and (iii) all out-of-pocket expenses incurred by the Administrative Agent, any Issuing Bank or any Lender, including the fees, charges and disbursements of any counsel for the Administrative Agent, any Issuing Bank or any Lender, in connection with the enforcement or protection of its rights in connection with this Agreement, including its rights under this Section, or in connection with the Loans made or Letters of Credit issued hereunder, including all such out-of-pocket expenses incurred during any workout, restructuring or negotiations in respect of such Loans or Letters of Credit.

(b) TO INDEMNIFY THE ADMINISTRATIVE AGENT, EACH ISSUING BANK, EACH ARRANGER, THE SYNDICATION AGENT, EACH DOCUMENTATION AGENT AND EACH LENDER AND EACH OF THEIR AFFILIATES AND EACH OF THEIR OFFICERS, DIRECTORS, EMPLOYEES, REPRESENTATIVES, AGENTS, ATTORNEYS, ACCOUNTANTS AND EXPERTS ("INDEMNIFIED PARTIES") FROM, HOLD EACH OF THEM HARMLESS AGAINST AND PROMPTLY UPON DEMAND PAY OR REIMBURSE EACH OF THEM FOR, THE INDEMNITY MATTERS WHICH MAY BE REASONABLY INCURRED BY OR ASSERTED AGAINST OR INVOLVE ANY OF THEM (WHETHER OR NOT ANY OF THEM IS DESIGNATED A PARTY THERETO AND WHETHER OR NOT THE CLAIM IS BROUGHT BY THE BORROWER OR A THIRD PARTY) AS A RESULT OF, ARISING OUT OF OR IN ANY WAY RELATED TO (I) ANY ACTUAL OR PROPOSED USE BY THE BORROWER OF THE PROCEEDS OF ANY OF THE LOANS OR ANY LETTER OF CREDIT, (II) THE EXECUTION, DELIVERY AND PERFORMANCE OF THE LOAN DOCUMENTS, (III) THE OPERATIONS OF THE BUSINESS OF THE BORROWER AND THE SUBSIDIARIES, (IV) THE FAILURE OF THE BORROWER OR ANY SUBSIDIARY TO COMPLY WITH THE TERMS OF THIS AGREEMENT, OR WITH ANY REQUIREMENT OF LAW, (V) ANY INACCURACY OF ANY REPRESENTATION OR ANY BREACH OF ANY WARRANTY OF THE BORROWER SET FORTH IN ANY OF THE LOAN DOCUMENTS, (VI) THE ISSUANCE, EXECUTION AND DELIVERY OR TRANSFER OF OR PAYMENT OR FAILURE TO PAY UNDER ANY LETTER OF CREDIT, (VII) THE PAYMENT OF A DRAWING UNDER ANY LETTER OF CREDIT NOTWITHSTANDING THE NON-

COMPLIANCE, NON-DELIVERY OR OTHER IMPROPER PRESENTATION OF THE MANUALLY EXECUTED DRAFT(S) AND CERTIFICATION(S), OR (VIII) ANY OTHER ASPECT OF THE LOAN DOCUMENTS, INCLUDING THE REASONABLE FEES AND DISBURSEMENTS OF COUNSEL AND ALL OTHER EXPENSES INCURRED IN CONNECTION WITH INVESTIGATING, DEFENDING OR PREPARING TO DEFEND ANY SUCH ACTION, SUIT, PROCEEDING (INCLUDING ANY INVESTIGATIONS, LITIGATION OR INQUIRIES) OR CLAIM AND INCLUDING ALL INDEMNITY MATTERS ARISING BY REASON OF THE ORDINARY NEGLIGENCE OF ANY INDEMNIFIED PARTY, BUT EXCLUDING ALL INDEMNITY MATTERS ARISING SOLELY (I) BY REASON OF CLAIMS BETWEEN THE LENDERS OR ANY LENDER AND THE ADMINISTRATIVE AGENT, ANY ARRANGER, THE SYNDICATION AGENT, ANY DOCUMENTATION AGENT, OR A LENDER'S SHAREHOLDERS AGAINST THE ADMINISTRATIVE AGENT OR LENDER (OTHER THAN CLAIMS IN ITS ROLE AS AGENT OR ARRANGER) OR (II) BY REASON OF THE GROSS NEGLIGENCE, WILLFUL MISCONDUCT OR UNLAWFUL CONDUCT ON THE PART OF THE INDEMNIFIED PARTY SEEKING INDEMNIFICATION AS DETERMINED BY A COURT OF COMPETENT JURISDICTION IN A FINAL AND NONAPPEALABLE JUDGMENT. FOR THE AVOIDANCE OF DOUBT, THIS SECTION 9.03(B) SHALL NOT APPLY WITH RESPECT TO TAXES OTHER THAN ANY TAXES THAT REPRESENT LOSSES, CLAIMS, DAMAGES, ETC. ARISING FROM ANY NON-TAX CLAIM.

(c) TO INDEMNIFY AND HOLD HARMLESS FROM TIME TO TIME THE INDEMNIFIED PARTIES FROM AND AGAINST ANY AND ALL LOSSES, CLAIMS, COST RECOVERY ACTIONS, ADMINISTRATIVE ORDERS OR PROCEEDINGS, DAMAGES AND LIABILITIES TO WHICH ANY SUCH PERSON MAY BECOME SUBJECT (I) UNDER ANY ENVIRONMENTAL LAW APPLICABLE TO THE BORROWER OR ANY SUBSIDIARY OR ANY OF THEIR PROPERTIES OR ASSETS, INCLUDING THE TREATMENT OR DISPOSAL OF HAZARDOUS MATERIALS ON ANY OF THEIR PROPERTIES OR ASSETS, (II) AS A RESULT OF THE BREACH OR NON-COMPLIANCE BY THE BORROWER OR ANY SUBSIDIARY WITH ANY ENVIRONMENTAL LAW APPLICABLE TO THE BORROWER OR ANY SUBSIDIARY, (III) DUE TO PAST OWNERSHIP BY THE BORROWER OR ANY SUBSIDIARY OF ANY OF THEIR PROPERTIES OR ASSETS OR PAST ACTIVITY ON ANY OF THEIR PROPERTIES OR ASSETS WHICH, THOUGH LAWFUL AND FULLY PERMISSIBLE AT THE TIME, COULD RESULT IN PRESENT LIABILITY, (IV) THE PRESENCE, USE, RELEASE, STORAGE, TREATMENT OR DISPOSAL OF HAZARDOUS MATERIALS ON OR AT ANY OF THE PROPERTIES OWNED OR OPERATED BY THE BORROWER OR ANY SUBSIDIARY, OR (V) ANY OTHER ENVIRONMENTAL, HEALTH OR SAFETY CONDITION IN CONNECTION WITH THE LOAN DOCUMENTS (EXPRESSLY INCLUDING ANY SUCH CLAIM, DAMAGE LOSS, LIABILITY, COST, PENALTY, FEE OR EXPENSE ATTRIBUTABLE TO THE ORDINARY, SOLE OR CONTRIBUTORY NEGLIGENCE OF SUCH INDEMNIFIED PARTY, BUT EXCLUDING ANY SUCH CLAIM, DAMAGE, LOSS, LIABILITY, COST, PENALTY, FEE OR EXPENSE RESULTING FROM THE GROSS NEGLIGENCE OR WILLFUL MISCONDUCT OF SUCH INDEMNIFIED PARTY AS DETERMINED BY A COURT OF COMPETENT JURISDICTION IN A FINAL AND NONAPPEALABLE JUDGMENT). FOR THE AVOIDANCE OF DOUBT, THIS SECTION 9.03(C) SHALL NOT APPLY WITH RESPECT TO TAXES OTHER THAN ANY TAXES THAT REPRESENT LOSSES, CLAIMS, DAMAGES, ETC. ARISING FROM ANY NON-TAX CLAIM.

(d) No Indemnified Party may settle any claim to be indemnified without the consent of the indemnitor, such consent not to be unreasonably withheld; *provided* that the indemnitor may not reasonably withhold consent to any settlement that an Indemnified Party proposes, if the indemnitor does not have the financial ability to pay all its obligations outstanding and asserted against the indemnitor at

that time, including the maximum potential claims against the Indemnified Party to be indemnified pursuant to this Section 9.03.

(e) In the case of any indemnification hereunder, the Indemnified Party, as appropriate, shall give notice to the Borrower of any such claim or demand being made against the Indemnified Party and the Borrower shall have the non-exclusive right to join in the defense against any such claim or demand; *provided* that if the Borrower provides a defense, the Indemnified Party shall bear its own cost of defense unless there is a conflict between the Borrower and such Indemnified Party.

(f) THE FOREGOING INDEMNITIES SHALL EXTEND TO THE INDEMNIFIED PARTIES NOTWITHSTANDING THE SOLE OR CONCURRENT NEGLIGENCE OF EVERY KIND OR CHARACTER WHATSOEVER, WHETHER ACTIVE OR PASSIVE, WHETHER AN AFFIRMATIVE ACT OR AN OMISSION, INCLUDING, ALL TYPES OF NEGLIGENT CONDUCT IDENTIFIED IN THE RESTATEMENT (SECOND) OF TORTS OF ONE OR MORE OF THE INDEMNIFIED PARTIES OR BY REASON OF STRICT LIABILITY IMPOSED WITHOUT FAULT ON ANY ONE OR MORE OF THE INDEMNIFIED PARTIES. TO THE EXTENT THAT AN INDEMNIFIED PARTY IS FOUND TO HAVE COMMITTED AN ACT OF GROSS NEGLIGENCE OR WILLFUL MISCONDUCT OR ENGAGED IN UNLAWFUL CONDUCT (AS DETERMINED BY A COURT OF COMPETENT JURISDICTION IN A FINAL AND NONAPPEALABLE JUDGMENT), THIS CONTRACTUAL OBLIGATION OF INDEMNIFICATION SHALL CONTINUE BUT SHALL ONLY EXTEND TO THE PORTION OF THE CLAIM THAT IS DEEMED TO HAVE OCCURRED BY REASON OF EVENTS OTHER THAN THE GROSS NEGLIGENCE, WILLFUL MISCONDUCT OR UNLAWFUL CONDUCT OF THE INDEMNIFIED PARTY (AS DETERMINED BY A COURT OF COMPETENT JURISDICTION IN A FINAL AND NONAPPEALABLE JUDGMENT).

(g) The Borrower's obligations under this Section 9.03 shall survive any termination of this Agreement, the payment of the Loans and the expiration of the Letters of Credit and shall continue thereafter in full force and effect.

(h) To the extent that the Borrower fails to pay any amount required to be paid by it to the Administrative Agent, the Swingline Lender or any Issuing Bank under this Section 9.03, each Lender severally agrees to pay to the Administrative Agent, the Swingline Lender or such Issuing Bank, as the case may be, such Lender's Applicable Percentage (determined as of the time that the applicable unreimbursed expense or indemnity payment is sought) of such unpaid amount; *provided* that the unreimbursed expense or indemnified loss, claim, damage, liability or related expense, as the case may be, was incurred by or asserted against the Administrative Agent, the Swingline Lender or such Issuing Bank in its capacity as such.

(i) The Borrower shall pay any amounts due under this Section 9.03 within 30 days of the receipt by the Borrower of notice of the amount due.

(j) To the fullest extent permitted by applicable law, no party shall assert, and each party hereby waives, any claim against any other party, on any theory of liability, for special, indirect, consequential or punitive damages (as opposed to direct or actual damages) arising out of, in connection with, or as a result of this Agreement, any other Loan Document or any agreement or instrument contemplated hereby, the transactions contemplated hereby or thereby, any Loan or Letter of Credit or the use of the proceeds thereof; *provided, howev*er, that the foregoing limitation shall not be deemed to impair or affect the indemnification obligations of the Borrower under the Loan Documents. No Indemnified Party referred to in paragraph (b) above shall be liable for any damages arising from the use by unintended recipients of any information or other materials distributed by it through telecommunications, electronic or other

information transmission systems in connection with this Agreement or the other Loan Documents or the transactions contemplated hereby or thereby.

SECTION 9.04 Successors and Assigns Generally. The provisions of this Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective successors and assigns permitted hereby, except that the Borrower may not assign or otherwise transfer any of its rights or obligations hereunder without the prior written consent of the Administrative Agent and each Lender, and no Lender may assign or otherwise transfer any of its rights or obligations hereunder except (i) to an assignee in accordance with the provisions of Section 9.05(a), (ii) by way of participation in accordance with the provisions of Section 9.05(c), or (iii) by way of pledge or assignment of a security interest subject to the restrictions of Section 9.05(d) (and any other attempted assignment or transfer by any party hereto shall be null and void). Nothing in this Agreement, expressed or implied, shall be construed to confer upon any Person (other than the parties hereto, their respective successors and assigns permitted hereby, Participants to the extent provided in Section 9.05(c) and, to the extent expressly contemplated hereby, the Related Parties of each of the Administrative Agent and the Lenders) any legal or equitable right, remedy or claim under or by reason of this Agreement.

SECTION 9.05 Assignments by Lenders.

(a) Any Lender may at any time assign to one or more assignees all or a portion of its rights and obligations under this Agreement (including all or a portion of its Commitment, Letter of Credit Commitment and the Loans at the time owing to it); *provided* that any such assignment shall be subject to the following conditions:

(i) (A) in the case of an assignment of the entire remaining amount of the assigning Lender's Commitment and/or the Loans at the time owing to it or contemporaneous assignments to related Approved Funds that equal at least the amount specified in paragraph (a)(i)(B) of this Section; and

(B) in any case not described in the proviso to paragraph (a)(i)(A) of this Section, the aggregate amount of the Commitment (which for this purpose includes Loans outstanding thereunder) or, if the applicable Commitment is not then in effect, the principal outstanding balance of the Loans of the assigning Lender subject to each such assignment (determined as of the date the Assignment and Acceptance with respect to such assignment is delivered to the Administrative Agent or, if "Trade Date" is specified in the Assignment and Acceptance, as of the Trade Date) shall not be less than $5,000,000, unless each of the Administrative Agent and, so long as no Event of Default has occurred and is continuing, the Borrower otherwise consents (each such consent not to be unreasonably withheld or delayed); *provided*, however, in the case of an assignment to a Lender, an Affiliate of a Lender or an Approved Fund, no minimum amount need be assigned.

(ii) Each partial assignment shall be made as an assignment of a proportionate part of all the assigning Lender's rights and obligations under this Agreement with respect to the Loans or the Commitment assigned.

(iii) No consent shall be required for any assignment except to the extent required by paragraph (a)(i)(B) of this Section and, in addition:

(A) the consent of the Borrower (such consent not to be unreasonably withheld or delayed) shall be required unless (x) an Event of Default has occurred and is

continuing at the time of such assignment or (y) such assignment is to a Lender, an Affiliate of a Lender or an Approved Fund, *provided* that the Borrower's consent shall not be required during the primary syndication of the credit facility evidenced by this Agreement;

(B) the consent of the Administrative Agent (such consent not to be unreasonably withheld or delayed) shall be required for assignments if such assignment is to a Person that is not a Lender, an Affiliate of such Lender or an Approved Fund with respect to such Lender; and

(C) the consent of each Issuing Bank and the Swingline Lender (such consents not to be unreasonably withheld or delayed) shall be required for any assignment.

(iv) The parties to each assignment shall execute and deliver to the Administrative Agent an Assignment and Acceptance, together with a processing and recordation fee of $3,500; *provided* that the Administrative Agent may, in its sole discretion, elect to waive such processing and recordation fee in the case of any assignment. The assignee, if it is not a Lender, shall deliver to the Administrative Agent an Administrative Questionnaire.

(v) No such assignment shall be made to (A) the Borrower or any of the Borrower's Affiliates or Subsidiaries or (B) to any Defaulting Lender or any of its Subsidiaries, or any Person who, upon becoming a Lender hereunder, would constitute any of the foregoing Persons described in this clause (B).

(vi) No such assignment shall be made to a natural Person.

(vii) In connection with any assignment of rights and obligations of any Defaulting Lender hereunder, no such assignment shall be effective unless and until, in addition to the other conditions thereto set forth herein, the parties to the assignment shall make such additional payments to the Administrative Agent in an aggregate amount sufficient, upon distribution thereof as appropriate (which may be outright payment, purchases by the assignee of participations or subparticipations, or other compensating actions, including funding, with the consent of the Borrower and the Administrative Agent, the applicable *pro rata* share of Loans previously requested but not funded by the Defaulting Lender, to each of which the applicable assignee and assignor hereby irrevocably consent), to (x) pay and satisfy in full all payment liabilities then owed by such Defaulting Lender to the Administrative Agent, each Issuing Bank, the Swingline Lender and each other Lender hereunder (and interest and fees accrued thereon), and (y) acquire (and fund as appropriate) its full *pro rata* share of all Loans and participations in Letters of Credit and Swingline Loans in accordance with its Applicable Percentage. Notwithstanding the foregoing, in the event that any assignment of rights and obligations of any Defaulting Lender hereunder shall become effective under applicable law without compliance with the provisions of this paragraph, then the assignee of such interest shall be deemed to be a Defaulting Lender for all purposes of this Agreement until such compliance occurs.

Subject to acceptance and recording thereof by the Administrative Agent pursuant to paragraph (b) of this Section, from and after the effective date specified in each Assignment and Acceptance, the assignee thereunder shall be a party to this Agreement and, to the extent of the interest assigned by such Assignment and Acceptance, have the rights and obligations of a Lender under this Agreement, and the assigning Lender thereunder shall, to the extent of the interest assigned by such Assignment and Acceptance, be released from its obligations under this Agreement (and, in the case of an Assignment and

Acceptance covering all of the assigning Lender's rights and obligations under this Agreement, such Lender shall cease to be a party hereto) but shall continue to be entitled to the benefits of Sections 2.14, 2.15 and 9.03 and with respect to facts and circumstances occurring prior to the effective date of such assignment; *provided*, that except to the extent otherwise expressly agreed by the affected parties, no assignment by a Defaulting Lender will constitute a waiver or release of any claim of any party hereunder arising from that Lender's having been a Defaulting Lender. Any assignment or transfer by a Lender of rights or obligations under this Agreement that does not comply with this paragraph shall be treated for purposes of this Agreement as a sale by such Lender of a participation in such rights and obligations in accordance with paragraph (c) of this Section.

(b) Upon its receipt of a duly completed Assignment and Acceptance executed by an assigning Lender and an assignee, the assignee's completed Administrative Questionnaire (unless the assignee shall already be a Lender hereunder), the processing and recordation fee, if any, referred to in Section 9.05(a) and any written consent to such assignment required by Section 9.05(a), the Administrative Agent shall accept such Assignment and Acceptance and record the information contained therein in the Register (as defined below). No assignment shall be effective for purposes of this Agreement unless it has been recorded in the Register as provided in this paragraph. The Administrative Agent, acting solely for this purpose as a non-fiduciary agent of the Borrower, shall maintain at one of its offices in New York, New York a copy of each Assignment and Acceptance delivered to it and a register for the recordation of the names and addresses of the Lenders, and the Commitments of, and principal amounts (and stated interest) of the Loans owing to, each Lender pursuant to the terms hereof from time to time (the "Register"). The entries in the Register shall be conclusive absent manifest error, and the Borrower, the Administrative Agent and the Lenders shall treat each Person whose name is recorded in the Register pursuant to the terms hereof as a Lender hereunder for all purposes of this Agreement. The Register shall be available for inspection by the Borrower and any Lender (with respect to its own interest only), at any reasonable time and from time to time upon reasonable prior notice.

(c) Any Lender may at any time, without the consent of, or notice to, the Borrower, the Administrative Agent, the Swingline Lender or the Issuing Banks, sell participations to any Person (other than a natural Person or the Borrower or any of the Borrower's Affiliates or Subsidiaries) (each, a "Participant") in all or a portion of such Lender's rights and/or obligations under this Agreement (including all or a portion of its Commitment and/or the Loans owing to it); *provided* that (i) such Lender's obligations under this Agreement shall remain unchanged, (ii) such Lender shall remain solely responsible to the other parties hereto for the performance of such obligations, and (iii) the Borrower, the Administrative Agent, the Issuing Banks and the Lenders shall continue to deal solely and directly with such Lender in connection with such Lender's rights and obligations under this Agreement. For the avoidance of doubt, each Lender shall be responsible for the indemnity under Section 8.08 with respect to any payments made by such Lender to its Participant(s).

Any agreement or instrument pursuant to which a Lender sells such a participation shall provide that such Lender shall retain the sole right to enforce this Agreement and to approve any amendment, modification or waiver of any provision of this Agreement; *provided* that such agreement or instrument may provide that such Lender will not, without the consent of the Participant, agree to any amendment, modification or waiver described in the first proviso Section 9.02(b) that affects such Participant. The Borrower agrees that each Participant shall be entitled to the benefits of Sections 2.14, 2.15 and 2.16 (subject to the requirements and limitations therein, including the requirements under Section 2.16 (it being understood that the documentation required under Section 2.16 shall be delivered to the participating Lender)) to the same extent as if it were a Lender and had acquired its interest by assignment pursuant to paragraph (a) of this Section; *provided* that such Participant (A) agrees to be subject to the provisions of Sections 2.18 as if it were an assignee under paragraph (a) of this Section; and (B) shall not be entitled to receive any greater

payment under Sections 2.14 and 2.16, with respect to any participation, than its participating Lender would have been entitled to receive, except to the extent such entitlement to receive a greater payment results from a Change in Law that occurs after the Participant acquired the applicable participation. Each Lender that sells a participation agrees, at the Borrower's request and expense, to use reasonable efforts to cooperate with the Borrower to effectuate the provisions of Section 2.18 with respect to any Participant. To the extent permitted by law, each Participant also shall be entitled to the benefits of Section 9.09 as though it were a Lender; *provided* that such Participant agrees to be subject to Section 2.17 as though it were a Lender. Each Lender that sells a participation shall, acting solely for this purpose as a non-fiduciary agent of the Borrower, maintain a register on which it enters the name and address of each Participant and the principal amounts (and stated interest) of each Participant's interest in the Loans or other obligations under the Loan Documents (the "Participant Register"); *provided* that no Lender shall have any obligation to disclose all or any portion of the Participant Register (including the identity of any Participant or any information relating to a Participant's interest in any commitments, loans, letters of credit or its other obligations under any Loan Document) to any Person except to the extent that such disclosure is necessary to establish that such commitment, loan, letter of credit or other obligation is in registered form under Section 5f.103-1(c) of the United States Treasury Regulations. The entries in the Participant Register shall be conclusive absent manifest error, and such Lender shall treat each Person whose name is recorded in the Participant Register as the owner of such participation for all purposes of this Agreement notwithstanding any notice to the contrary. For the avoidance of doubt, the Administrative Agent (in its capacity as Administrative Agent) shall have no responsibility for maintaining a Participant Register.

(d) Any Lender may at any time pledge or assign a security interest in all or any portion of its rights under this Agreement to secure obligations of such Lender, including any pledge or assignment to secure obligations to a Federal Reserve Bank or any central bank having jurisdiction over such Lender; *provided* that no such pledge or assignment shall release such Lender from any of its obligations hereunder or substitute any such pledgee or assignee for such Lender as a party hereto.

SECTION 9.06 Survival; Reinstatement.

(a) All covenants, agreements, representations and warranties made by the Borrower herein and in the certificates or other instruments delivered in connection with or pursuant to this Agreement shall be considered to have been relied upon by the other parties hereto and shall survive the execution and delivery of this Agreement and the making of any Loans and issuance of any Letters of Credit, regardless of any investigation made by any such other party or on its behalf and notwithstanding that the Administrative Agent, any Issuing Bank or any Lender may have had notice or knowledge of any Default or Event of Default or incorrect representation or warranty at the time any credit is extended hereunder, and shall continue in full force and effect as long as the principal of or any accrued interest on any Loan or any fee or any other amount payable under this Agreement is outstanding and unpaid or any Letter of Credit is outstanding or so long as the Commitments have not expired or terminated. The provisions of Sections 2.14, 2.15, 2.16 and 9.03 and Article VIII shall survive and remain in full force and effect regardless of the consummation of the transactions contemplated hereby, the repayment of the Loans, the expiration or termination of the Letters of Credit and the Commitments or the termination of this Agreement or any provision hereof.

(b) To the extent that any payments on the Obligations are subsequently invalidated, declared to be fraudulent or preferential, set aside or required to be repaid to a trustee, debtor in possession, receiver or other Person under any bankruptcy law, common law or equitable cause, then to such extent, the Obligations so satisfied shall be revived and continue as if such payment or proceeds had not been received.

SECTION 9.07 Counterparts; Integration; Effectiveness; Electronic Execution.

(a) This Agreement may be executed in counterparts (and by different parties hereto on different counterparts), each of which shall constitute an original, but all of which when taken together shall constitute a single contract. This Agreement, the other Loan Documents and the Fee Letters constitute the entire contract among the parties hereto relating to the subject matter hereof and supersede any and all previous agreements and understandings, oral or written, relating to the subject matter hereof (including the Executive Summary). Except as provided in Section 3.01, this Agreement shall become effective when it shall have been executed by the Administrative Agent and when the Administrative Agent shall have received counterparts hereof which, when taken together, bear the signatures of each of the other parties hereto, and thereafter shall be binding upon and inure to the benefit of the parties hereto and their respective successors and assigns. Delivery of an executed counterpart of a signature page of this Agreement by facsimile or electronic (*i.e.*, "*pdf*" or "*tif*") format shall be effective as delivery of a manually executed counterpart of this Agreement.

(b) The words "execution," "signed," "signature," and words of like import in any Assignment and Acceptance shall be deemed to include electronic signatures or the keeping of records in electronic form, each of which shall be of the same legal effect, validity or enforceability as a manually executed signature or the use of a paper-based recordkeeping system, as the case may be, to the extent and as provided for in any applicable law, including the Federal Electronic Signatures in Global and National Commerce Act, the New York State Electronic Signatures and Records Act, or any other similar state laws based on the Uniform Electronic Transactions Act.

SECTION 9.08 Severability. Any provision of this Agreement held to be invalid, illegal or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such invalidity, illegality or unenforceability without affecting the validity, legality and enforceability of the remaining provisions hereof; and the invalidity of a particular provision in a particular jurisdiction shall not invalidate such provision in any other jurisdiction.

SECTION 9.09 Right of Setoff. If an Event of Default shall have occurred and be continuing, each Lender, each Issuing Bank and each of their respective Affiliates is hereby authorized at any time and from time to time, to the fullest extent permitted by applicable law, to set off and apply any and all deposits (general or special, time or demand, provisional or final, in whatever currency) at any time held, and other obligations (in whatever currency) at any time owing, by such Lender, such Issuing Bank or any such Affiliate, to or for the credit or the account of a Loan Party against any and all of the obligations of a Loan Party now or hereafter existing under this Agreement or any other Loan Document to such Lender, such Issuing Bank or their respective Affiliates, irrespective of whether or not such Lender, Issuing Bank or Affiliate shall have made any demand under this Agreement or any other Loan Document and although such obligations of the Loan Parties may be contingent or unmatured or are owed to a branch, office or Affiliate of such Lender or Issuing Bank different from the branch, office or Affiliate holding such deposit or obligated on such indebtedness; *provided* that in the event that any Defaulting Lender shall exercise any such right of setoff, (x) all amounts so set off shall be paid over immediately to the Administrative Agent for further application in accordance with the provisions of Section 2.19 pending such payment, shall be segregated by such Defaulting Lender from its other funds and deemed held in trust for the benefit of the Administrative Agent, the Issuing Banks and the Lenders, and (y) the Defaulting Lender shall provide promptly to the Administrative Agent a statement describing in reasonable detail the Obligations owing to such Defaulting Lender as to which it exercised such right of setoff. The rights of each Lender, each Issuing Bank and their respective Affiliates under this Section are in addition to other rights and remedies (including other rights of setoff) that such Lender, such Issuing Bank or their respective Affiliates may have. Each Lender and Issuing Bank agrees to notify the Borrower and the Administrative Agent promptly after any such setoff and application; *provided* that the failure to give such notice shall not affect the validity of such setoff and

application. The rights of each Lender under this Section 9.09 are in addition to other rights and remedies (including other rights of setoff) which such Lender may have.

SECTION 9.10 Governing Law; Jurisdiction; Consent to Service of Process. (a) This Agreement and the other Loan Documents shall be construed in accordance with and governed by the laws of the State of New York.

(b) **ANY LEGAL ACTION OR PROCEEDING WITH RESPECT TO THIS AGREEMENT AND THE OTHER LOAN DOCUMENTS SHALL BE BROUGHT IN THE COURTS OF THE STATE OF NEW YORK SITTING IN THE BOROUGH OF MANHATTAN OR OF THE UNITED STATES FOR THE SOUTHERN DISTRICT OF NEW YORK AND, BY EXECUTION AND DELIVERY OF THIS AGREEMENT, EACH OF THE PARTIES HERETO HEREBY IRREVOCABLY ACCEPTS FOR ITSELF AND IN RESPECT OF ITS PROPERTY AND ASSETS, UNCONDITIONALLY, THE EXCLUSIVE JURISDICTION OF THE AFORESAID COURTS WITH RESPECT TO ANY SUCH ACTION OR PROCEEDING. THE BORROWER HEREBY IRREVOCABLY DESIGNATES, APPOINTS AND EMPOWERS C T CORPORATION SYSTEM, WITH OFFICES ON THE DATE HEREOF AT 111 8TH AVENUE, NEW YORK, NEW YORK 10011, AS ITS DESIGNEE, APPOINTEE AND AGENT TO RECEIVE AND ACCEPT FOR AND ON ITS BEHALF, AND IN RESPECT OF ITS PROPERTY, SERVICE OF ANY AND ALL LEGAL PROCESS, SUMMONS, NOTICES AND DOCUMENTS WHICH MAY BE SERVED IN ANY SUCH ACTION OR PROCEEDING. IF FOR ANY REASON SUCH DESIGNEE, APPOINTEE AND AGENT SHALL CEASE TO BE AVAILABLE TO ACT AS SUCH, THE BORROWER AGREES TO DESIGNATE A NEW DESIGNEE, APPOINTEE AND AGENT IN NEW YORK, NEW YORK ON THE TERMS AND FOR THE PURPOSES OF THIS PROVISION SATISFACTORY TO THE ADMINISTRATIVE AGENT. THE BORROWER FURTHER IRREVOCABLY CONSENTS TO THE SERVICE OF PROCESS OUT OF ANY OF THE AFOREMENTIONED COURTS IN ANY SUCH ACTION OR PROCEEDING BY THE MAILING OF COPIES THEREOF BY REGISTERED OR CERTIFIED MAIL, POSTAGE PREPAID, TO IT AT ITS ADDRESS PROVIDED IN SECTION 9.01, SUCH SERVICE TO BECOME EFFECTIVE THIRTY DAYS AFTER SUCH MAILING. NOTHING HEREIN SHALL AFFECT THE RIGHT OF THE ADMINISTRATIVE AGENT OR ANY LENDER TO SERVE PROCESS IN ANY OTHER MANNER PERMITTED BY LAW.**

(c) **THE BORROWER HEREBY IRREVOCABLY WAIVES ANY OBJECTION WHICH IT MAY NOW OR HEREAFTER HAVE TO THE LAYING OF VENUE OF ANY OF THE AFORESAID ACTIONS OR PROCEEDINGS ARISING OUT OF OR IN CONNECTION WITH THIS AGREEMENT BROUGHT IN THE COURTS REFERRED TO IN CLAUSE (b) ABOVE AND HEREBY FURTHER IRREVOCABLY WAIVES, TO THE MAXIMUM EXTENT PERMITTED BY APPLICABLE LAW, THE RIGHT TO PLEAD OR CLAIM, AND AGREES NOT TO PLEAD OR CLAIM, THAT ANY SUCH ACTION OR PROCEEDING BROUGHT IN ANY SUCH COURT HAS BEEN BROUGHT IN AN INCONVENIENT FORUM.**

(d) **EACH PARTY HERETO HEREBY (i) IRREVOCABLY WAIVES, TO THE MAXIMUM EXTENT PERMITTED BY LAW, ANY RIGHT IT MAY HAVE TO CLAIM OR RECOVER IN ANY SUCH LITIGATION ANY SPECIAL, EXEMPLARY, PUNITIVE OR CONSEQUENTIAL DAMAGES, OR DAMAGES OTHER THAN, OR IN ADDITION TO, ACTUAL DAMAGES; (ii) CERTIFIES THAT NO PARTY HERETO NOR ANY REPRESENTATIVE OR AGENT OR COUNSEL FOR ANY PARTY HERETO HAS REPRESENTED, EXPRESSLY OR OTHERWISE, OR IMPLIED THAT SUCH PARTY WOULD NOT, IN THE EVENT OF LITIGATION, SEEK TO ENFORCE THE FOREGOING**

WAIVERS, AND (iii) ACKNOWLEDGES THAT IT HAS BEEN INDUCED TO ENTER INTO THIS AGREEMENT AND THE TRANSACTIONS CONTEMPLATED HEREBY AND THEREBY BY, AMONG OTHER THINGS, THE MUTUAL WAIVERS AND CERTIFICATIONS CONTAINED IN THIS SECTION 9.10.

SECTION 9.11 **WAIVER OF JURY TRIAL. EACH PARTY HERETO HEREBY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN ANY LEGAL PROCEEDING DIRECTLY OR INDIRECTLY ARISING OUT OF OR RELATING TO THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY (WHETHER BASED ON CONTRACT, TORT OR ANY OTHER THEORY). EACH PARTY HERETO (A) CERTIFIES THAT NO REPRESENTATIVE, AGENT OR ATTORNEY OF ANY OTHER PARTY HAS REPRESENTED, EXPRESSLY OR OTHERWISE, THAT SUCH OTHER PARTY WOULD NOT, IN THE EVENT OF LITIGATION, SEEK TO ENFORCE THE FOREGOING WAIVER AND (B) ACKNOWLEDGES THAT IT AND THE OTHER PARTIES HERETO HAVE BEEN INDUCED TO ENTER INTO THIS AGREEMENT BY, AMONG OTHER THINGS, THE MUTUAL WAIVERS AND CERTIFICATIONS IN THIS SECTION 9.11.**

SECTION 9.12 Confidentiality. Each of the Administrative Agent, the Issuing Banks and the Lenders agrees to maintain the confidentiality of the Information (as defined below), except that Information may be disclosed (a) to their Affiliates, to their and their Affiliates' directors, officers and employees and agents, including accountants, legal counsel and other advisors who have been informed of the confidential nature of the information provided, (b) disclosures in connection with any pledge or assignment permitted under Section 9.05(d) and, to the extent requested by any regulatory authority, including any self-regulatory authority such as the National Association of Insurance Commissioners or any similar organization, or any nationally recognized rating agency that requires access to information about a Lender's investment portfolio, (c) to the extent a Lender reasonably believes it is required by applicable laws or regulations or by any subpoena or similar legal process (and, to the extent not prohibited under applicable law), such Lender will provide prompt notice thereof to the Borrower), (d) to any other party to this Agreement, (e) in connection with the exercise of any remedies hereunder or any suit, action or proceeding relating to this Agreement or any other Loan Document or the enforcement of rights hereunder or thereunder, (f) subject to an understanding with such Person that such Person will comply with this Section 9.12, to (i) any assignee of or Participant in, or any prospective assignee of or Participant in, any of its rights or obligations under this Agreement or (ii) any actual or prospective party (or its Related Parties) to any swap, derivative, or other transaction under which payments are to be made by reference to the Borrower, and its obligations under this Agreement or the payments hereunder, (g) with the consent of the Borrower or (h) to the extent such Information (i) becomes publicly available other than as a result of a breach of this Section 9.12 or (ii) becomes available to the Administrative Agent, any Issuing Bank or any Lender from a source other than the Borrower (unless such source is actually known by the individual providing the information to be bound by a confidentiality agreement or other legal or contractual obligation of confidentiality with respect to such information). In addition, the Administrative Agent and the Lenders may disclose the existence of this Agreement and information about this Agreement to market data collectors, similar service providers to the lending industry and service providers to the Administrative Agent and the Lenders in connection with the administration of this Agreement, the other Loan Documents, and the Commitments. For the purposes of this Section 9.12, "Information" means all information received from the Borrower relating to the Borrower or its business, other than any such information that is known to a Lender, publicly known or otherwise available to the Administrative Agent or any Lender other than through disclosure (a) by the Borrower, or (b) from a source actually known to a Lender to be bound by a confidentiality agreement or other legal or contractual obligation of confidentiality with respect to such information. Any Person required to maintain the confidentiality of Information as provided in this Section 9.12 shall be considered

to have complied with its obligation to do so if such Person maintains the confidentiality of such Information in accordance with procedures adopted in good faith to protect confidential Information of third parties delivered to a lender.

SECTION 9.13 Interest Rate Limitation. Notwithstanding anything herein to the contrary, if at any time the interest rate applicable to any Loan, together with all fees, charges and other amounts which are treated as interest on such Loan under applicable law (collectively the "Charges"), shall exceed the maximum lawful rate (the "Maximum Rate") which may be contracted for, charged, taken, received or reserved by the Lender holding such Loan in accordance with applicable law, the rate of interest payable in respect of such Loan hereunder, together with all Charges payable in respect thereof, shall be limited to the Maximum Rate and, to the extent lawful, the interest and Charges that would have been payable in respect of such Loan but were not payable as a result of the operation of this Section 9.13 shall be cumulated and the interest and Charges payable to such Lender in respect of other Loans or periods shall be increased (but not above the Maximum Rate therefor) until such cumulated amount, together with interest thereon at the Federal Funds Effective Rate to the date of repayment, shall have been received by such Lender.

SECTION 9.14 **EXCULPATION PROVISIONS**. EACH OF THE PARTIES HERETO SPECIFICALLY AGREES THAT IT HAS A DUTY TO READ THIS AGREEMENT, THE NOTES AND (IN THE CASE OF THE BORROWER AND THE ADMINISTRATIVE AGENT) THE FEE LETTERS AND AGREES THAT IT IS CHARGED WITH NOTICE AND KNOWLEDGE OF THE TERMS OF THIS AGREEMENT AND THE OTHER LOAN DOCUMENTS; THAT IT HAS IN FACT READ THIS AGREEMENT AND IS FULLY INFORMED AND HAS FULL NOTICE AND KNOWLEDGE OF THE TERMS, CONDITIONS AND EFFECTS OF THIS AGREEMENT AND THE OTHER LOAN DOCUMENTS; THAT IT HAS BEEN REPRESENTED BY INDEPENDENT LEGAL COUNSEL OF ITS CHOICE THROUGHOUT THE NEGOTIATIONS PRECEDING ITS EXECUTION OF THIS AGREEMENT AND THE OTHER LOAN DOCUMENTS; AND HAS RECEIVED THE ADVICE OF ITS ATTORNEY IN ENTERING INTO THIS AGREEMENT AND THE OTHER LOAN DOCUMENTS; AND THAT IT RECOGNIZES THAT CERTAIN OF THE TERMS OF THIS AGREEMENT AND THE OTHER LOAN DOCUMENTS RESULT IN ONE PARTY ASSUMING THE LIABILITY INHERENT IN SOME ASPECTS OF THE TRANSACTION AND RELIEVING THE OTHER PARTY OF ITS RESPONSIBILITY FOR SUCH LIABILITY. EACH PARTY HERETO AGREES AND COVENANTS THAT IT WILL NOT CONTEST THE VALIDITY OR ENFORCEABILITY OF ANY EXCULPATORY PROVISION OF THIS AGREEMENT ON THE BASIS THAT THE PARTY HAD NO NOTICE OR KNOWLEDGE OF SUCH PROVISION OR THAT THE PROVISION IS NOT *"CONSPICUOUS."*

SECTION 9.15 U.S. Patriot Act. Each Lender that is subject to the requirements of the USA PATRIOT ACT (Title III of Pub. L. 107-56 (signed into law October 26, 2001)) (the "Patriot Act") and the Beneficial Ownership Regulation hereby notifies the Loan Parties that pursuant to the requirements of the Patriot Act and the Beneficial Ownership Regulation, it is required to obtain, verify, and record information that identifies the Loan Parties, which information includes the name and address of the Loan Parties and other information that will allow such Lender to identify the Loan Parties in accordance with the Patriot Act and the Beneficial Ownership Regulation.

SECTION 9.16 No Advisory or Fiduciary Responsibility. In connection with all aspects of each transaction contemplated hereby, the Borrower acknowledges and agrees, and acknowledges its Affiliates' understanding, that: (i) the credit facility provided for hereunder and any related arranging or other services in connection therewith (including in connection with any amendment, waiver or other modification hereof or of any other Loan Document) are an arm's-length commercial transaction between the Borrower, on the one hand, and the Administrative Agent, the Arrangers,

the Syndication Agent, the Documentation Agents, the Issuing Banks and the Lenders, on the other hand, and the Borrower is capable of evaluating and understanding and understands and accepts the terms, risks and conditions of the transactions contemplated hereby and by the other Loan Documents (including any amendments, waiver or other modification hereof or thereof); (ii) in connection with the process leading to such transaction, the Administrative Agent, the Arrangers, the Syndication Agent, the Documentation Agents, the Issuing Banks and the Lenders are and have been acting solely as principals and are not the financial advisors, agents or fiduciaries, for the Borrower or any of its Affiliates, stockholders, creditors or employees or any other Person; (iii) the Administrative Agent, the Arrangers, Syndication Agent, the Documentation Agents, the Issuing Banks and the Lenders have not assumed and will not assume an advisory, agency or fiduciary responsibility in favor of the Borrower with respect to any of the transactions contemplated hereby or the process leading thereto, including with respect to any amendment, waiver or other modification hereof or of any other Loan Document (irrespective of whether the Administrative Agent, any Arranger, the Syndication Agent, any Documentation Agent, any Issuing Bank or any Lender advised or is currently advising the Borrower or any of its Affiliates on other matters) and the Administrative Agent, the Arrangers, the Syndication Agent, the Documentation Agents, the Issuing Banks and the Lenders have no obligation to the Borrower or any of its Affiliates with respect to the transactions contemplated hereby except those obligations expressly set forth herein and in the other Loan Documents; (iv) the Administrative Agent, the Arrangers, the Syndication Agent, the Documentation Agents, the Issuing Banks, the Lenders and their respective Affiliates may be engaged in a broad range of transactions that involve interests that differ from those of the Borrower and its Affiliates, and the Administrative Agent, the Arrangers, the Syndication Agent, the Documentation Agents, the Issuing Banks and the Lenders have no obligation to disclose any of such interests by virtue of any advisory, agency or fiduciary relationship; and (v) the Administrative Agent, the Arrangers, the Syndication Agent, the Documentation Agents, the Issuing Banks and the Lenders have not provided and will not provide any legal, accounting, regulatory or Tax advice with respect to any of the transactions contemplated hereby (including any amendment, waiver or other modification hereof or of any other Loan Document) and the Loan Parties have consulted its own legal, accounting, regulatory and Tax advisors to the extent it has deemed appropriate. Each Loan Parties hereby waive and release, to the fullest extent permitted by law, any claims that it may have against the Administrative Agent, the Arrangers, the Syndication Agent, the Documentation Agents, the Issuing Banks or the Lenders with respect to any breach or alleged breach of agency or fiduciary duty.

SECTION 9.17 Headings. Section headings herein are included herein for convenience of reference only and shall not constitute a part hereof for any other purpose or be given any substantive effect.

SECTION 9.18 Acknowledgement and Consent to Bail-In of EEA Financial Institutions. (a) Notwithstanding anything to the contrary in any Loan Document or in any other agreement, arrangement or understanding among any such parties, each party hereto acknowledges that any liability of any EEA Financial Institution arising under any Loan Document, to the extent such liability is unsecured, may be subject to the write-down and conversion powers of an EEA Resolution Authority and agrees and consents to, and acknowledges and agrees to be bound by: (a) the application of any Write-Down and Conversion Powers by an EEA Resolution Authority to any such liabilities arising hereunder which may be payable to it by any party hereto that is an EEA Financial Institution; and

(b) the effects of any Bail-in Action on any such liability, including, if applicable:

(i) a reduction in full or in part or cancellation of any such liability;

(ii) a conversion of all, or a portion of, such liability into shares or other instruments of ownership in such EEA Financial Institution, its parent undertaking, or a bridge

institution that may be issued to it or otherwise conferred on it, and that such shares or other instruments of ownership will be accepted by it in lieu of any rights with respect to any such liability under this Agreement or any other Loan Document; or

(iii) the variation of the terms of such liability in connection with the exercise of the write-down and conversion powers of any EEA Resolution Authority.

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The parties hereto have caused this Agreement to be duly executed as of the date and year first above written.

KINDER MORGAN, INC.,
as the Borrower

By: /s/ Anthony B. Ashley /s/
Name: Anthony B. Ashley
Title: Treasurer

BARCLAYS BANK PLC,
as the Administrative Agent and as a Lender

By: /s/ Sydney G. Dennis
Name: Sydney G. Dennis
Title: Director

JPMORGAN CHASE BANK, N.A.,
as a Lender

By: /s/ Stephanie Balette /s/
Name: Stephanie Balette
Title: Authorized Officer

Bank of America, N.A.,
as a Lender

By: /s/ Tyler Ellis /s/
Name: Tyler Ellis
Title: Director

BMO Harris Bank, N.A.,
as a Lender

By: /s/ Melissa Guzman /s/
Name: Melissa Guzman
Title: Director

CITIBANK, N.A.,
as a Lender

By: /s/ Maureen Maroney /s/
Name: Maureen Maroney
Title: Vice President

CREDIT SUISSE AG, CAYMAN ISLANDS BRANCH,
as a Lender

By: /s/ Nupur Kumar /s/
Name: Nupur Kumar
Title: Authorized Signatory

By: /s/ Christopher Zybrick /s/
Name: Christopher Zybrick
Title: Authorized Signatory

Mizuho Bank, Ltd.,
as a Lender

By: /s/ Donna DeMagistris /s/
Name: Donna DeMagistris
Title: Authorized Signatory

MUFG BANK, LTD.
as a Lender

By: /s/ Christopher Facenda /s/
Name: Christopher Facenda
Title: Director

ROYAL BANK OF CANADA,
as a Lender

By: /s/ Jason S. York /s/
Name: Jason S. York
Title: Authorized Signatory

The Bank of Nova Scotia, Houston Branch,
as a Lender

By: /s/ Alfredo Brahim /s/
Name: Alfredo Brahim
Title: Director

Wells Fargo Bank, N.A.,
as a Lender

By: /s/ Doug McDowell /s/
Name: Doug McDowell
Title: Managing Director

Commerzbank AG, New York Branch,
as a Lender

By: /s/ Barbara Stacks /s/
Name: Barbara Stacks
Title: Director

By: /s/ James Boyle /s/
Name: James Boyle
Title: Director

Sumitomo Mitsui Banking Corporation,
as a Lender

By: /s/ Katsuyuki Kubo /s/
Name: Katsuyuki Kubo
Title: Managing Director

CANADIAN IMPERIAL BANK OF COMMERCE,
New York Branch,
as a Lender

By: /s/ Donovan C. Broussard /s/
Name: Donovan C. Broussard
Title: Authorized Signatory

By: /s/ Trudy Nelson /s/
Name: Trudy Nelson
Title: Authorized Signatory

CREDIT AGRICOLE CORPORATE AND
INVESTMENT BANK,
as a Lender

By: /s/ Dixon Schultz /s/
Name: Dixon Schultz
Title: Managing Director

By: /s/ Michael Willis /s/
Name: Michael Willis
Title: Managing Director

SUNTRUST BANK,
as a Lender

By: /s/ Carmen Malizia /s/
Name: Carmen Malizia
Title: Director

PNC Bank, National Association,
as a Lender

By: /s/ Stephen Monto /s/
Name: Stephen Monto
Title: SVP

SOCIETE GENERALE,
as a Lender

By: /s/ Diego Medina /s/
Name: Diego Medina
Title: Director

THE TORONTO-DOMINION BANK, NEW YORK BRANCH
as a Lender

By: /s/ Annie Dorval /s/
Name: Annie Dorval
Title: Authorized Signatory

MORGAN STANLEY SENIOR FUNDING, INC.,
as a Lender

By: /s/ Michael King /s/
Name: Michael King
Title: Vice President

MORGAN STANLEY BANK, N.A.,
as a Lender

By: /s/ Michael King /s/
Name: Michael King
Title: Authorized Signatory

Compass Bank,
as a Lender

By: /s/ Mark H. Wolf /s/
Name: Mark H. Wolf
Title: Senior Vice President

ING Capital LLC,
as a Lender

By: /s/ Subha Pasumarti /s/
Name: Subha Pasumarti
Title: Managing Director

By: /s/ Tanja van der Woude /s/
Name: Tanja van der Woude
Title: Director

REGIONS BANK,
as a Lender

By: /s/ David Valentine /s/
Name: David Valentine
Title: Managing Director

Intesa Sanpaolo S.p.A. – New York Branch,
as a Lender

By: /s/ Christophe Hamonet /s/
Name: Christophe Hamonet
Title: Reginal Business Manager

By: /s/ Francesco Di Mario /s/
Name: Francesco Di Mario
Title: FVP – Head of Credit

NATIONAL BANK OF CANADA,
as a Lender

By: /s/ Rahul Rahul /s/
Name: Rahul Rahul
Title: Authorized Signatory

By: /s/ Mark Williamson /s/
Name: Mark Williamson
Title: Authorized Signatory

Acknowledged and agreed, solely for the purpose of Section 2.05(a):

KINDER MORGAN OPERATING L.P. "B"

By: Kinder Morgan G.P., Inc.,
its General Partner

By: /s/ Anthony B. Ashley /s/
Name: Anthony B. Ashley
Title: Treasurer

SCHEDULE 1.01
Commitments

Lender	Commitment	Letter of Credit Commitment
Barclays Bank PLC	$195,000,000	$100,000,000
JPMorgan Chase Bank, N.A.	$195,000,000	$100,000,000
Bank of America, N.A.	$195,000,000	$100,000,000
BMO Harris Bank, N.A.	$195,000,000	N/A
Citibank, N.A.	$195,000,000	$100,000,000
Credit Suisse AG, Cayman Islands Branch	$195,000,000	N/A
Mizuho Bank, Ltd.	$195,000,000	N/A
MUFG Bank, Ltd.	$195,000,000	N/A
Royal Bank of Canada	$195,000,000	N/A
The Bank of Nova Scotia, Houston Branch	$195,000,000	N/A
Wells Fargo Bank, N.A.	$195,000,000	$100,000,000
Commerzbank AG, New York Branch	$144,500,000	N/A
Sumitomo Mitsui Banking Corporation	$144,500,000	N/A
Canadian Imperial Bank of Commerce, New York Branch	$144,500,000	N/A
Credit Agricole Corporate and Investment Bank	$144,500,000	N/A
SunTrust Bank	$144,500,000	N/A
PNC Bank, National Association	$144,500,000	N/A
Societe Generale	$144,500,000	N/A
The Toronto-Dominion Bank, New York Branch	$144,500,000	N/A
Morgan Stanley Senior Funding, Inc.	$46,500,000	N/A
Morgan Stanley Bank, N.A.	$70,000,000	N/A
Compass Bank	$116,500,000	N/A
ING Capital LLC	$116,500,000	N/A
Regions Bank	$116,500,000	N/A
Intesa Sanpaolo S.p.A.-New York Branch	$116,500,000	N/A
National Bank of Canada	$116,500,000	N/A
Total	**$4,000,000,000**	**$500,000,000**

SCHEDULE 1.01A
Excluded Subsidiaries

ANR Real Estate Corporation
Calnev Pipeline LLC
Coastal Eagle Point Oil Company
Coastal Oil New England, Inc.
Colton Processing Facility
Coscol Petroleum Corporation
El Paso CGP Company, L.L.C.
El Paso Energy Argentina Service Company
El Paso Energy Capital Trust I
El Paso Energy E.S.T. Company
El Paso Energy International Company
El Paso Marketing Company, L.L.C.
El Paso Merchant Energy North America Company, L.L.C.
El Paso Merchant Energy-Petroleum Company
El Paso Reata Energy Company, L.L.C.
El Paso Remediation Company
El Paso Services Holding Company
EPC Building, LLC
EPC Property Holdings, Inc.
EPEC Corporation
EPEC Oil Company Liquidating Trust
EPEC Polymers, Inc.
EPEC Realty, Inc.
EPED Holding Company
I.M.T Land Corp.
International Marine Terminals Partnership
Kinder Morgan Foundation
Kinder Morgan G.P., Inc.
Kinder Morgan Mexico LLC
Kinder Morgan Services International LLC
Kinder Morgan Tejas Pipeline GP LLC
Kinder Morgan Urban Renewal, L.L.C.
Kinder Morgan Urban Renewal II, LLC
KM Express LLC
KM Insurance Texas Inc.
KN Capital Trust I
KN Capital Trust III
Mesquite Investors, L.L.C.
SFPP, L.P.

Note the Excluded Subsidiaries listed on this Schedule 1.01A may also be Excluded Subsidiaries pursuant to other exceptions set forth in the definition of “Excluded Subsidiary”.

SCHEDULE 1.01B
Existing Letters of Credit

Letters of Credit issued under the Existing Credit Agreement (as of September 15, 2014):

Letter of Credit #	Beneficiary	Amount
	JP Morgan	
P-367925	Insurance Company of North America	30,650.00
TPTS-211032	TCEQ	8,000,000.00
P-381222	SCA Services, Inc.	282,000.00
TPTS-390077	U.S. Environmental Protection Agency	3,700,000.00
TPTS-330400	RBC/BC Maritime	399,018.00
		4,381,018.00
	Wells Fargo	
SM215665W	TCEQ	7,000,000.00
SM230084W	Bank of New York Mellon	22,750,000.00
SM230086W	Bank of New York Mellon	22,750,000.00
S113181	Bank of New York	24,128,548.00
SM238154W	Port of Houston Authority	25,000.00
SM231529W	Port Authority of NY & NJ	375,000.00
SM235293W	Port of Portland	300,000.00
IS0012983	Guadalupe Valley Electric Coop	320,000.00
IS0011480	U.S. Environmental Protection Agency	489,652.00
IS0021875U	Twin County Electric Power Assoc	1,000,000.00
IS0024221U	Medina Electric Cooperative	536,433.63
IS0178750U	Karnes Electric Cooperative	875,329.00
IS0194687U	New Jersey Department of Environmental Protection (NJDEP)	423,972.00
IS0213588U	Guadalupe Valley Electric Coop	265,000.00
IS0255620U	California Department of Fish and Wildlife	685,795.72
		81,924,730.35
	Citigroup, N.A.	
61663921	Terasen Inc.	522,365.00
63656702	KANSAS H&E	2,000,000.00
63660191	SELF INS CA	836,631.00
63668640	New Jersey Dept of Environmental Protection Site Remediation Program	172,920.00
69605543	Philadelphia Gas Works	97,384.00
69606341	BP Products, NA	807,872.00
		4,437,172.00
	Total LCs under KMI Revolver	**90,742,920.35**

SCHEDULE 6.01
Existing Non-Guarantor Indebtedness

- Certificate of Designations of Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock due 2057 of Kinder Morgan G.P., Inc.
- EPC Building, LLC, promissory note, 3.967%, due 2013 through 2035
- K N Capital Trust I 8.56% capital trust securities due 2027
- K N Capital Trust III 7.63% capital trust securities due 2028
- El Paso Energy Capital Trust I 4.75% preferred securities due 2028
- International Marine Terminals Partnership 2002 floating rate notes due 2025

SCHEDULE 6.05
Existing Transactions with Affiliates

None.

SCHEDULE 6.06
Existing Restrictive Agreements

- Certificate of Designations of Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock due 2057 of Kinder Morgan G.P., Inc.
- Constituent documents of Kinder Morgan Canada Limited and its subsidiaries, each as amended to date, setting forth terms related to Kinder Morgan Canada Limited's (i) Cumulative Redeemable Minimum Rate Reset Preferred Shares, Series 1; and (ii) Cumulative Redeemable Minimum Rate Reset Preferred Shares, Series 3:
    - Certificate and Articles of Incorporation of Kinder Morgan Canada Limited
    - Certificate and Articles of Incorporation of Kinder Morgan Canada GP Inc.
    - Certificate of Limited Partnership of Kinder Morgan Canada Limited Partnership
    - Second Amended and Restated Limited Partnership Agreement of Kinder Morgan Canada Limited Partnership
    - Articles of Association of Kinder Morgan Cochin ULC
- Credit Agreement, dated August 31, 2018, by and among Kinder Morgan Cochin ULC, Royal Bank of Canada and the lenders party thereto

EXHIBIT 1.01-A

FORM OF ASSIGNMENT AND ASSUMPTION

This Assignment and Assumption (the "Assignment and Assumption") is dated as of the Effective Date set forth below and is entered into by and between [the][each][1] Assignor identified in item 1 below ([the][each, an] "Assignor") and [the][each][2] Assignee identified in item 2 below ([the][each, an] "Assignee"). [It is understood and agreed that the rights and obligations of [the Assignors][the Assignees][3] hereunder are several and not joint.][4] Capitalized terms used but not defined herein shall have the meanings given to them in the 5-Year Credit Agreement identified below (as further restated, amended, modified, supplemented and in effect, the "5-Year Credit Agreement"), receipt of a copy of which is hereby acknowledged by [the][each] Assignee. The Standard Terms and Conditions set forth in Annex 1 attached hereto are hereby agreed to and incorporated herein by reference and made a part of this Assignment and Assumption as if set forth herein in full.

For an agreed consideration, [the][each] Assignor hereby irrevocably sells and assigns to [the Assignee][the respective Assignees], and [the][each] Assignee hereby irrevocably purchases and assumes from [the Assignor][the respective Assignors], subject to and in accordance with the Standard Terms and Conditions and the 5-Year Credit Agreement, as of the Effective Date inserted by the Administrative Agent as contemplated below (i) all of [the Assignor's][the respective Assignors'] rights and obligations in [its capacity as a Lender][their respective capacities as Lenders] under the 5-Year Credit Agreement and any other documents or instruments delivered pursuant thereto to the extent related to the amount and percentage interest identified below of all of such outstanding rights and obligations of [the Assignor][the respective Assignors] under the revolving credit facility identified below (including, without limitation, the Letters of Credit and the Swingline Loans included in such facility), and (ii) to the extent permitted to be assigned under applicable law, all claims, suits, causes of action and any other right of [the Assignor (in its capacity as a Lender)][the respective Assignors (in their respective capacities as Lenders)] against any Person, whether known or unknown, arising under or in connection with the 5-Year Credit Agreement, any other documents or instruments delivered pursuant thereto or the loan transactions governed thereby or in any way based on or related to any of the foregoing, including, but not limited to, contract claims, tort claims, malpractice claims, statutory claims and all other claims at law or in equity related to the rights and obligations sold and assigned pursuant to clause (i) above (the rights and obligations sold and assigned by [the][any] Assignor to [the][any] Assignee pursuant to clauses (i) and (ii) above being referred to herein collectively as [the][an] "Assigned Interest"). Each such sale and assignment is without recourse to [the][any] Assignor and, except as expressly provided in this Assignment and Assumption, without representation or warranty by [the][any] Assignor.

---

1 For bracketed language here and elsewhere in this form relating to the Assignor(s), if the assignment is from a single Assignor, choose the first bracketed language. If the assignment is from multiple Assignors, choose the second bracketed language.

2 For bracketed language here and elsewhere in this form relating to the Assignee(s), if the assignment is to a single Assignee, choose the first bracketed language. If the assignment is to multiple Assignees, choose the second bracketed language.

3 Select as appropriate.

4 Include bracketed language if there are either multiple Assignors or multiple Assignees.

1. Assignor[s]: _____

_____

[Assignor [is] [is not] a Defaulting Lender]

2. Assignee[s]: _____

_____

[for each Assignee, indicate [Affiliate][Approved Fund] of [identify Lender]

3. Borrower: Kinder Morgan, Inc.

4. Administrative Agent: _____, as the administrative agent under the 5-Year Credit Agreement

5. 5-Year Credit Agreement: The Revolving Credit Agreement dated as of November 16, 2018 among Kinder Morgan, Inc., the Lenders parties thereto, Barclays Bank PLC, as Administrative Agent, and the other agents parties thereto

6. Assigned Interest[s]:

Assignor[s][5]	Assignee[s][6]	Aggregate Amount of Commitment/Loans for all Lenders[7]	Amount of Commitment/Loans Assigned[8]	Percentage Assigned of Commitment/ Loans[8]	CUSIP Number
		$	$	%	
		$	$	%	
		$	$	%	

[7. Trade Date: _____][9]

Effective Date: _____ ___, 20___ [TO BE INSERTED BY ADMINISTRATIVE AGENT AND WHICH SHALL BE THE EFFECTIVE DATE OF RECORDATION OF TRANSFER IN THE REGISTER THEREFOR.]

The terms set forth in this Assignment and Assumption are hereby agreed to:

---

5 List each Assignor, as appropriate.

6 List each Assignee, as appropriate.

7 Amount to be adjusted by the counterparties to take into account any payments or prepayments made between the Trade Date and the Effective Date.

8 Set forth, to at least 9 decimals, as a percentage of the Commitment/Loans of all Lenders thereunder.

[9] To be completed if the Assignor(s) and the Assignee(s) intend that the minimum assignment amount is to be determined as of the Trade Date.

ASSIGNOR[S][10]
[NAME OF ASSIGNOR]

By:_____
Title:

[NAME OF ASSIGNOR]

By:_____
Title:

ASSIGNEE[S][11]
[NAME OF ASSIGNEE]

By:_____
Title:

[NAME OF ASSIGNEE]

By:_____
Title:

[10] Add additional signature blocks as needed. Include both Fund/Pension Plan and manager making the trade (if applicable).

[11] Add additional signature blocks as needed. Include both Fund/Pension Plan and manager making the trade (if applicable).

[Consented to and][12] Accepted:

[NAME OF ADMINISTRATIVE AGENT], as
Administrative Agent

By: _____
Title:

[Consented to:][13]

[NAME OF THE RELEVANT PARTY]

By: _____
Title:

[12] To be added only if the consent of the Administrative Agent is required by the terms of the 5-Year Credit Agreement.

[13] To be added only if the consent of the Borrower and/or other parties (e.g. Swingline Lender or Issuing Bank) is required by the terms of the 5-Year Credit Agreement.

ANNEX 1 TO ASSIGNMENT AND ASSUMPTION

STANDARD TERMS AND CONDITIONS FOR

ASSIGNMENT AND ASSUMPTION

1. Representations and Warranties.

1.1. Assignor. [The][Each] Assignor (a) represents and warrants that (i) it is the legal and beneficial owner of [the][[the relevant] Assigned Interest, (ii) [the][such] Assigned Interest is free and clear of any lien, encumbrance or other adverse claim and (iii) it has full power and authority, and has taken all action necessary, to execute and deliver this Assignment and Assumption and to consummate the transactions contemplated hereby; and (b) assumes no responsibility with respect to (i) any statements, warranties or representations made in or in connection with the 5-Year Credit Agreement or any other Loan Document, (ii) the execution, legality, validity, enforceability, genuineness, sufficiency or value of the Loan Documents or any collateral thereunder, (iii) the financial condition of the Borrower, any of its Subsidiaries or Affiliates or any other Person obligated in respect of any Loan Document or (iv) the performance or observance by the Borrower, any of its Subsidiaries or Affiliates or any other Person of any of their respective obligations under any Loan Document.

1.2. Assignee. [The][Each] Assignee (a) represents and warrants that (i) it has full power and authority, and has taken all action necessary, to execute and deliver this Assignment and Assumption and to consummate the transactions contemplated hereby and to become a Lender under the 5-Year Credit Agreement, (ii) it meets all the requirements to be an assignee under the paragraph following Section 9.05(a)(vii) and Section 9.05(b) of the 5-Year Credit Agreement (subject to such consents, if any, as may be required under Section 9.05(a)(iii) of the 5-Year Credit Agreement), (iii) from and after the Effective Date, it shall be bound by the provisions of the 5-Year Credit Agreement as a Lender thereunder and, to the extent of [the][the relevant] Assigned Interest, shall have the obligations of a Lender thereunder, (iv) it is sophisticated with respect to decisions to acquire assets of the type represented by [the][such] Assigned Interest and either it, or the Person exercising discretion in making its decision to acquire [the][such] Assigned Interest, is experienced in acquiring assets of such type, (v) it has received a copy of the 5-Year Credit Agreement, and has received or has been accorded the opportunity to receive copies of the most recent financial statements delivered pursuant to Section 5.01 of the 5-Year Credit Agreement, as applicable, and such other documents and information as it deems appropriate to make its own credit analysis and decision to enter into this Assignment and Assumption and to purchase [the][such] Assigned Interest, (vi) it has, independently and without reliance upon the Administrative Agent or any other Lender and based on such documents and information as it has deemed appropriate, made its own credit analysis and decision to enter into this Assignment and Assumption and to purchase [the][such] Assigned Interest and (vii) attached to this Assignment and Assumption is any documentation required to be delivered by it pursuant to Section 2.16 of the 5-Year Credit Agreement; and (b) agrees that (i) it will, independently and without reliance upon the Administrative Agent, [the][any] Assignor or any other Lender, and based on such documents and information as it shall deem appropriate at the time, continue to make its own credit decisions in taking or not taking action under the Loan Documents, and (ii) it will perform in accordance with their terms all of the obligations which by the terms of the Loan Documents are required to be performed by it as a Lender.

2. Payments. From and after the Effective Date, the Administrative Agent shall make all payments in respect of [the][each] Assigned Interest (including payments of principal, interest, fees and other

amounts) to [the][the relevant] Assignor for amounts which have accrued to but excluding the Effective Date and to [the][the relevant] Assignee for amounts which have accrued from and after the Effective Date.

3. General Provisions.

3.1. In accordance with Sections 9.04 and 9.05 of the 5-Year Credit Agreement, upon execution, delivery, acceptance and recording of this Assignment and Assumption, from and after the Effective Date, (a) the Assignee shall be a party to the 5-Year Credit Agreement and, to the extent provided in this Assignment and Assumption, have the rights and obligations of a Lender under the 5-Year Credit Agreement with a Commitment as set forth herein and (b) the Assignor shall, to the extent of the Assigned Interest assigned pursuant to this Assignment and Assumption, be released from its obligations under the 5-Year Credit Agreement (and, in the case of this Assignment and Assumption covers all of the Assignor's rights and obligations under the 5-Year Credit Agreement, the Assignor shall cease to be a party to the 5-Year Credit Agreement but shall continue to be entitled to the benefits of Sections 2.14, 2.15, 2.16 and 9.03 thereof).

3.2. This Assignment and Assumption shall be binding upon, and inure to the benefit of, the parties hereto and their respective successors and assigns. This Assignment and Assumption may be executed in any number of counterparts, which together shall constitute one instrument. Delivery of an executed counterpart of a signature page of this Assignment and Assumption by telecopy shall be effective as delivery of a manually executed counterpart of this Assignment and Assumption. This Assignment and Assumption shall be governed by, and construed in accordance with, the laws of the State of New York.

EXHIBIT 1.01-B

FORM OF GUARANTY AGREEMENT

[See attached.]

EXHIBIT 1.01-C

FORM OF COMMITTED NOTE

_____, _____

FOR VALUE RECEIVED, the undersigned, KINDER MORGAN, INC., a Delaware corporation (the "Borrower"), HEREBY PROMISES TO PAY to the order of _____ (the "Lender"), the lesser of (i) such Lender's Commitment and (ii) the aggregate amount of Committed Loans made by the Lender and outstanding on the Maturity Date. The principal amount of the Committed Loans made by the Lender to the Borrower shall be due and payable on the dates and in the amounts as are specified in that certain Revolving Credit Agreement, dated as of November 16, 2018 (as further restated, amended, modified, supplemented and in effect from time to time, the "5-Year Credit Agreement"), among the Borrower, the Lender, certain other lenders that are party thereto, Barclays Bank PLC, as Administrative Agent for the Lender and such other lenders, and the other agents named therein. All capitalized terms used herein and not otherwise defined shall have the meanings as defined in the 5-Year Credit Agreement.

The Borrower promises to pay interest on the unpaid principal amount of each Committed Loan outstanding from time to time from the date thereof until such principal amount is paid in full, at such interest rates and payable on such dates as are specified in the 5-Year Credit Agreement. Principal and interest are payable in same day funds in lawful money of the United States of America to the Administrative Agent at its Principal Office, or at such other place as the Administrative Agent shall designate in writing to the Borrower.

This Note is one of the Committed Notes referred to in, and this Note and all provisions herein are entitled to the benefits of, the 5-Year Credit Agreement. The 5-Year Credit Agreement, among other things (a) provides for the making of Committed Loans by the Lender and the other lenders to the Borrower from time to time, and (b) contains provisions for acceleration of the maturity hereof upon the happening of certain stated events, for prepayments on account of principal hereof prior to the maturity hereof upon the terms and conditions therein specified, and for limitations on the amount of interest paid such that no provision of the 5-Year Credit Agreement or this Note shall require the payment or permit the collection of interest in excess of the Maximum Rate.

This Note may be held by the Lender for the account of its applicable lending office and may be transferred from one lending office to another lending office from time to time as the Lender may determine.

The Borrower and any and all endorsers, guarantors and sureties severally waive grace, demand, presentment for payment, notice of dishonor, default or intent to accelerate, protest and notice of protest and diligence in collecting and bringing of suit against any party hereto, and agree to all renewals, extensions or partial payments hereon and to any release or substitution of security herefor, in whole or in part, with or without notice, before or after maturity.

This Note shall be governed by and construed under the laws of the State of New York and the applicable laws of the United States of America.

KINDER MORGAN, INC.,
as the Borrower

By:_____
Name:_____
Title:_____

EXHIBIT 1.01-D

FORM OF SWINGLINE NOTE

$_____ _____, _____

FOR VALUE RECEIVED, the undersigned, KINDER MORGAN, INC., a Delaware corporation (the "Borrower"), HEREBY PROMISES TO PAY to the order of _____ (the "Swingline Lender"), the lesser of (i) $_____ and (ii) the aggregate amount of Swingline Loans made by the Swingline Lender and outstanding on the Maturity Date. The principal amount of the Swingline Loans made by the Swingline Lender to the Borrower shall be due and payable on the dates and in the amounts as are specified in that certain Revolving Credit Agreement dated as of November 16, 2018 (as further restated, amended, modified, supplemented and in effect from time to time, the "5-Year Credit Agreement") among the Borrower, the Swingline Lender, certain other lenders that are party thereto, Barclays Bank PLC, as Administrative Agent for the Swingline Lender and such other lenders, and the other agents named therein. All capitalized terms used herein and not otherwise defined shall have the meanings as defined in the 5-Year Credit Agreement.

The Borrower promises to pay interest on the unpaid principal amount of each Swingline Loan outstanding from time to time from the date thereof until such principal amount is paid in full, at such interest rates and payable on such dates as are specified in the 5-Year Credit Agreement. Both principal and interest are payable in same day funds in lawful money of the United States of America to the Swingline Lender at its Principal Office or such other place as the Swingline Lender shall designate in writing to the Borrower.

This Note is the Swingline Note referred to in, and this Note and all provisions herein are entitled to the benefits of, the 5-Year Credit Agreement. The 5-Year Credit Agreement, among other things (a) provides for the making of Swingline Loans by the Swingline Lender to the Borrower from time to time, and (b) contains provisions for acceleration of the maturity hereof upon the happening of certain stated events, for prepayments on account of principal hereof prior to the maturity hereof upon the terms and conditions therein specified, and for limitations on the amount of interest paid such that no provision of the 5-Year Credit Agreement or this Note shall require the payment or permit the collection of interest in excess of the Maximum Rate.

The Borrower and any and all endorsers, guarantors and sureties severally waive grace, demand, presentment for payment, notice of dishonor, default or intent to accelerate, protest and notice of protest and diligence in collecting and bringing of suit against any party hereto, and agree to all renewals, extensions or partial payments hereon and to any release or substitution of security herefor, in whole or in part, with or without notice, before or after maturity.

This Note shall be governed by and construed under the laws of the State of New York and the applicable laws of the United States of America.

KINDER MORGAN, INC.,
as the Borrower

By:_____
Name:_____
Title:_____

EXHIBIT 2.03

FORM OF BORROWING REQUEST

Dated _____

Barclays Bank PLC,
1301 Sixth Avenue
New York, NY 10019
Attn: Bobby Fitzpatrick
Phone: 201-499-5043
E-mail: bobby.fitzpatrick@barclays.com and 12145455230@tls.ldsprod.com

Ladies and Gentlemen:

This Borrowing Request is delivered to you by Kinder Morgan, Inc. (the "Borrower"), a Delaware corporation, under Section 2.03 of the Revolving Credit Agreement, dated as of November 16, 2018 (as further restated, amended, modified, supplemented and in effect, the "5-Year Credit Agreement"), by and among the Borrower, the Lenders party thereto, Barclays Bank PLC, as Administrative Agent, and the other agents named therein.

1. The Borrower hereby requests that the Lenders make a [Committed] [Swingline][1] Loan or Loans in the aggregate principal amount of $_____.[2]

2. The Borrower hereby requests that the [Committed] [Swingline] Loan or Loans be made on the following Business Day: _____.[3]

3. The Borrower hereby requests that the Borrowing be [an ABR Borrowing] [a Eurodollar Borrowing].[4]

4. In the case of a Eurodollar Borrowing, the initial Interest Period shall be [one week] [one month] [two months] [three months] [six months].

5. The Borrower hereby requests that the funds from the requested Loan or Loans be disbursed to the following bank account: _____.

6. After giving effect to the requested Loan or Loans, the aggregate Credit Exposures outstanding as of the date hereof (including the requested Loans) does not exceed the maximum amount permitted to be outstanding pursuant to the terms of the 5-Year Credit Agreement.

---

[1] Items 3 and 4 are not completed for Swingline Loans.

[2] Complete with an amount in accordance with Section 2.03 of the 5-Year Credit Agreement.

[3] Complete with a Business Day in accordance with Section 2.03 of the 5-Year Credit Agreement.

[4] If no election as to Type of Borrowing is made for a Committed Loan, the Requested Borrowing shall be an ABR Borrowing.

7. The representations and warranties set forth in the 5-Year Credit Agreement and the other Loan Documents are true and correct in all material respects on and as of the date hereof (unless such representation and warranty expressly relates to an earlier date).

8. No Default or Event of Default has occurred and is continuing on the date hereof or would result after giving effect to the Loans requested hereby.

9. All capitalized undefined terms used herein have the meanings assigned thereto in the 5-Year Credit Agreement.

IN WITNESS WHEREOF, the undersigned have executed this Borrowing Request this _____ day of _____, _____.

KINDER MORGAN, INC.,
as the Borrower

By:_____
Name:_____
Title:_____

EXHIBIT 2.05

FORM OF LETTER OF CREDIT REQUEST

Dated _____

Barclays Bank PLC,
1301 Sixth Avenue
New York, NY 10019
Attn: Patrick Shields
Phone: 212-526-9531
E-mail: xraletterofcredit@barclays.com and Patrick.shields@barclays.com

and

**[Name and address of Issuing Bank,
if the Issuing Bank is not Barclays Bank PLC]**

Ladies and Gentlemen:

This Letter of Credit Request is delivered to you by Kinder Morgan, Inc., (the "Borrower"), a Delaware corporation, under Section 2.05 of the Revolving Credit Agreement, dated as of November 16, 2018 (as further restated, amended, modified, supplemented, and in effect from time to time, the "5-Year Credit Agreement"), by and among the Borrower, the Lenders party thereto, Barclays Bank PLC, as Administrative Agent, and the other parties named therein.

The Borrower hereby requests the issuance of a Letter of Credit under the 5-Year Credit Agreement, and in that connection sets forth below the information relating to such Letter of Credit (the "Proposed Letter of Credit") as required by Section 2.05(e) of the 5-Year Credit Agreement. The Proposed Letter of Credit must be issued:

on or before _____, _____[1]

for the benefit of _____ whose address is _____

In the amount of $_____

having an expiry date of _____, ____[2]

attached hereto is any special language to be incorporated into the Proposed Letter of Credit.

or

The Borrower hereby refers to Letter of Credit Number _____ (the "Existing Letter of Credit") which has an existing expiry date of _____. The Borrower hereby requests

---

[1] Must be a date not earlier than five Business Days after notice is given to the Issuing Bank.

[2] May include requirement for automatic extension provision but, in any event must comply with Section 2.05(f) of the 5-Year Credit Agreement.

that [the expiry date of the Expiring Letter of Credit be extended to _____.[2]] [the Existing Letter of Credit be amended.] [the Existing Letter of Credit be renewed.[3]]

1. After giving effect to the Proposed Letter of Credit, (i) the LC Exposure for all Committed Letters of Credit issued by such Issuing Bank does not exceed such Issuing Bank's Letter of Credit Commitment at such time, (ii) the total LC Exposure does not exceed the LC Sublimit and (iii) the total Credit Exposure does not exceed the Total Commitment.

2. All capitalized undefined terms used herein have the meanings assigned thereto in the 5-Year Credit Agreement.

The undersigned hereby certifies that:

1.The representations and warranties set forth in the 5-Year Credit Agreement and the other Loan Documents are true and correct in all material respects on and as of the date hereof (unless such representation and warranty expressly relates to an earlier date); and

2.No Default or Event of Default has occurred and is continuing on the date hereof or would result from the issuance of the Letter of Credit requested hereby.

[Remainder of page intentionally left blank]

[3] If an amendment, describe the proposed amendment.

IN WITNESS WHEREOF, the undersigned have executed this Letter of Credit Request this _____ day of _____, _____.

KINDER MORGAN, INC.,
as the Borrower

By:_____
Name:_____
Title:_____

EXHIBIT 2.07

FORM OF INTEREST ELECTION REQUEST

Date: **[_____]**, 20**[__]**

Barclays Bank PLC,
1301 Sixth Avenue
New York, NY 10019
Attn: Bobby Fitzpatrick
Phone: 201-499-5043
E-mail: bobby.fitzpatrick@barclays.com and 12145455230@tls.ldsprod.com

Re: Kinder Morgan, Inc. – Interest Election Request

Ladies and Gentlemen:

Reference is made to the Revolving Credit Agreement, dated as of November 16, 2018 (as amended, amended and restated, supplemented or otherwise modified from time to time, the "5-Year Credit Agreement"), among Kinder Morgan, Inc., a Delaware corporation (the "Borrower"), the Lenders party thereto from time to time, Barclays Bank PLC as Administrative Agent, and the other parties thereto from time to time. Capitalized terms used but not otherwise defined in this Interest Election Request shall have the meanings assigned to such terms in the 5-Year Credit Agreement.

1. Interest Election Request. This Interest Election Request relates to the Borrower's election to (i) continue a Eurodollar Borrowing, (ii) convert a Eurodollar Borrowing or (iii) convert a Base Rate Borrowing on _____ (the "Interest Election Date"), as indicated below (*check each that applies*):

☐ **Continuation of Eurodollar Borrowing**.

Pursuant to Section 2.07 of the 5-Year Credit Agreement, this Interest Election Request confirms our written election on the date hereof to continue the following outstanding Borrowing comprised of Eurodollar Loans on the Interest Election Date, as follows:

(A) Expiration date of current Interest Period: _____

(B) Aggregate amount of outstanding Borrowing: _____

(C) Aggregate amount to be continued as Eurodollar Loans: _____

(D) Elected Interest Period: _____

☐ **Conversion of Eurodollar Borrowing**.

Pursuant to Section 2.07 of the 5-Year Credit Agreement, this Interest Election Request confirms our written election on the date hereof to convert the following outstanding Borrowing

comprised of Eurodollar Loans to Borrowing(s) comprised of ABR Loans on the Interest Election Date, as follows:

(A) Expiration date of current Interest Period: _____

(B) Aggregate amount of outstanding Borrowing: _____

(C) Aggregate amount to be converted to ABR Loans: _____

☐ **Conversion of Base Rate Borrowing**.

Pursuant to Section 2.07 of the 5-Year Credit Agreement, this Interest Election Request confirms our written election on the date hereof that the following outstanding Borrowing comprised of ABR Loans be converted to a Borrowing comprised of Eurodollar Loans on the Interest Election Date, as follows:

(A) Date of Conversion: _____

(B) Aggregate amount of outstanding Borrowing: _____

(C) Aggregate amount to be converted to Eurodollar Loans: _____

(D) Elected Interest Period: _____

2. Certifications. The Borrower hereby represents and warrants to the Lenders that, as of the date of this Interest Election Request and after giving effect to the continuations or conversions being requested under Section 1 hereof, no Default or Event of Default has occurred and is continuing.

[*Signature page follows*]

IN WITNESS WHEREOF, the undersigned has executed this Interest Election Request this _____ day of _____, ____.

KINDER MORGAN, INC.,
as the Borrower

By:_____
Name:_____
Title:_____

EXHIBIT 2.10

FORM OF NOTICE OF PREPAYMENT

Date: _____, ____

To: Barclays Bank PLC,
1301 Sixth Avenue
New York, NY 10019
Attn: Patrick Shields
Phone: 212-526-9531
E-mail: bobby.fitzpatrick@barclays.com, 12145455230@tls.ldsprod.com and Patrick.shields@barclays.com

Ladies and Gentlemen:

Reference is made to that certain Revolving Credit Agreement, dated as of November 16, 2018 (as may be amended, restated, amended and restated, extended, supplemented or otherwise modified in writing from time to time in accordance with its terms, the "5-Year Credit Agreement"; the terms defined therein being used herein as therein defined), among Kinder Morgan, Inc., a Delaware corporation (the "Borrower"), the Lenders party thereto from time to time, Barclays Bank PLC, as Administrative Agent, and the other parties thereto. All capitalized terms used but not defined herein have the meanings assigned in the 5-Year Credit Agreement.

This Prepayment Notice is delivered to you pursuant to Section 2.10 of the Agreement. The Borrower hereby gives notice of a prepayment of Loans as follows:

1. (select Class of Loans)

☐ Committed Loans

☐ Swingline Loans

2. (select Type(s) of Loans)

☐ ABR Loans in the aggregate principal amount of $_____.

☐ Eurodollar Loans with an Interest Period ending _____, 201_ in the aggregate principal amount of $_____.

3. On _____, 201_ (a Business Day).

IN WITNESS WHEREOF, the undersigned have executed this Prepayment Notice this _____ day of _____, _____.

KINDER MORGAN, INC.,
as the Borrower

By: _____
Name:_____
Title:_____

EXHIBIT 2.16-A

[FORM OF]
U.S. TAX COMPLIANCE CERTIFICATE
(For Foreign Lenders That Are Not Partnerships For U.S. Federal Income Tax Purposes)

Reference is hereby made to the Revolving Credit Agreement, dated as of November 16, 2018 (as further amended, supplemented or otherwise modified from time to time, the "5-Year Credit Agreement"), among Kinder Morgan, Inc. (the "Borrower"), Barclays Bank PLC, as administrative agent for the lenders party thereto (the "Lenders") and such Lenders.

Pursuant to the provisions of Section 2.16(g) of the 5-Year Credit Agreement, the undersigned hereby certifies that (i) it is the sole record and beneficial owner of the Loan(s) (as well as any Note(s) evidencing such Loan(s)) in respect of which it is providing this certificate, (ii) it is not a bank within the meaning of Section 881(c)(3)(A) of the Code, (iii) it is not a ten percent shareholder of the Borrower within the meaning of Section 881(c)(3)(B) of the Code and (iv) it is not a controlled foreign corporation related to the Borrower as described in Section 881(c)(3)(C) of the Code.

The undersigned has furnished the Administrative Agent and the Borrower with a certificate of its non-U.S. Person status on IRS Form W-8BEN or IRS Form W-8BEN-E, as applicable. By executing this certificate, the undersigned agrees that (1) if the information provided on this certificate changes, the undersigned shall promptly so inform the Borrower and the Administrative Agent, and (2) the undersigned shall have at all times furnished the Borrower and the Administrative Agent with a properly completed and currently effective certificate in either the calendar year in which each payment is to be made to the undersigned, or in either of the two calendar years preceding such payments.

Unless otherwise defined herein, terms defined in the 5-Year Credit Agreement and used herein shall have the meanings given to them in the 5-Year Credit Agreement.

[NAME OF LENDER]

By:
Name:
Title:

Date: _____ __, 20[ ]

EXHIBIT 2.16-B

[FORM OF]
U.S. TAX COMPLIANCE CERTIFICATE
(For Foreign Participants That Are Not Partnerships For U.S. Federal Income Tax Purposes)

Reference is hereby made to the Revolving Credit Agreement, dated as of November 16, 2018 (as further amended, supplemented or otherwise modified from time to time, the "5-Year Credit Agreement"), among Kinder Morgan, Inc. (the "Borrower"), Barclays Bank PLC, as administrative agent for the lenders party thereto (the "Lenders") and such Lenders.

Pursuant to the provisions of Section 2.16(g) of the 5-Year Credit Agreement, the undersigned hereby certifies that (i) it is the sole record and beneficial owner of the participation in respect of which it is providing this certificate, (ii) it is not a bank within the meaning of Section 881(c)(3)(A) of the Code, (iii) it is not a ten percent shareholder of the Borrower within the meaning of Section 881(c)(3)(B) of the Code, and (iv) it is not a controlled foreign corporation related to the Borrower as described in Section 881(c)(3)(C) of the Code.

The undersigned has furnished its participating Lender with a certificate of its non-U.S. Person status on IRS Form W-8BEN or IRS Form W-8BEN-E, as applicable. By executing this certificate, the undersigned agrees that (1) if the information provided on this certificate changes, the undersigned shall promptly so inform such Lender in writing, and (2) the undersigned shall have at all times furnished such Lender with a properly completed and currently effective certificate in either the calendar year in which each payment is to be made to the undersigned, or in either of the two calendar years preceding such payments.

Unless otherwise defined herein, terms defined in the 5-Year Credit Agreement and used herein shall have the meanings given to them in the 5-Year Credit Agreement.

[NAME OF PARTICIPANT]

By:
Name:
Title:

Date: _____ __, 20[ ]

EXHIBIT 2.16-C

[FORM OF]
U.S. TAX COMPLIANCE CERTIFICATE
(For Foreign Participants That Are Partnerships For U.S. Federal Income Tax Purposes)

Reference is hereby made to the Revolving Credit Agreement, dated as of November 16, 2018 (as further amended, supplemented or otherwise modified from time to time, the "5-Year Credit Agreement"), among Kinder Morgan, Inc. (the "Borrower), Barclays Bank PLC, as administrative agent for the lenders party thereto (the "Lenders") and such Lenders.

Pursuant to the provisions of Section 2.16(g) of the 5-Year Credit Agreement, the undersigned hereby certifies that (i) it is the sole record owner of the participation in respect of which it is providing this certificate, (ii) its direct or indirect partners/members are the sole beneficial owners of such participation, (iii) with respect such participation, neither the undersigned nor any of its direct or indirect partners/members is a bank extending credit pursuant to a loan agreement entered into in the ordinary course of its trade or business within the meaning of Section 881(c)(3)(A) of the Code, (iv) none of its direct or indirect partners/members is a ten percent shareholder of the Borrower within the meaning of Section 881(c)(3)(B) of the Code and (v) none of its direct or indirect partners/members is a controlled foreign corporation related to the Borrower as described in Section 881(c)(3)(C) of the Code.

The undersigned has furnished its participating Lender with IRS Form W-8IMY accompanied by one of the following forms from each of its partners/members that is claiming the portfolio interest exemption: (i) an IRS Form W-8BEN or IRS Form W-8BEN-E, as applicable, or (ii) an IRS Form W-8IMY accompanied by an IRS Form W-8BEN or IRS Form W-8BEN-E, as applicable, from each of such partner's/member's beneficial owners that is claiming the portfolio interest exemption. By executing this certificate, the undersigned agrees that (1) if the information provided on this certificate changes, the undersigned shall promptly so inform such Lender and (2) the undersigned shall have at all times furnished such Lender with a properly completed and currently effective certificate in either the calendar year in which each payment is to be made to the undersigned, or in either of the two calendar years preceding such payments.

Unless otherwise defined herein, terms defined in the 5-Year Credit Agreement and used herein shall have the meanings given to them in the 5-Year Credit Agreement.

[NAME OF PARTICIPANT]

By:
Name:
Title:

Date: _____ __, 20[ ]

EXHIBIT 2.16-D

[FORM OF]
U.S. TAX COMPLIANCE CERTIFICATE
(For Foreign Lenders That Are Partnerships For U.S. Federal Income Tax Purposes)

Reference is hereby made to the Revolving Credit Agreement, dated as of November 16, 2018 (as further amended, supplemented or otherwise modified from time to time, the "5-Year Credit Agreement"), among Kinder Morgan, Inc. (the "Borrower"), Barclays Bank PLC, as administrative agent for the lenders party thereto (the "Lenders") and such Lenders.

Pursuant to the provisions of Section 2.16(g) of the 5-Year Credit Agreement, the undersigned hereby certifies that (i) it is the sole record owner of the Loan(s) (as well as any Note(s) evidencing such Loan(s)) in respect of which it is providing this certificate, (ii) its direct or indirect partners/members are the sole beneficial owners of such Loan(s) (as well as any Note(s) evidencing such Loan(s)), (iii) with respect to the extension of credit pursuant to this 5-Year Credit Agreement or any other Loan Document, neither the undersigned nor any of its direct or indirect partners/members is a bank extending credit pursuant to a loan agreement entered into in the ordinary course of its trade or business within the meaning of Section 881(c)(3)(A) of the Code, (iv) none of its direct or indirect partners/members is a ten percent shareholder of the Borrower within the meaning of Section 881(c)(3)(B) of the Code and (v) none of its direct or indirect partners/members is a controlled foreign corporation related to the Borrower as described in Section 881(c)(3)(C) of the Code.

The undersigned has furnished the Administrative Agent and the Borrower with IRS Form W-8IMY accompanied by one of the following forms from each of its partners/members that is claiming the portfolio interest exemption: (i) an IRS Form W-8BEN or IRS Form W-8BEN-E, as applicable, or (ii) an IRS Form W-8IMY accompanied by an IRS Form W-8BEN or IRS Form W-8BEN-E, as applicable, from each of such partner's/member's beneficial owners that is claiming the portfolio interest exemption. By executing this certificate, the undersigned agrees that (1) if the information provided on this certificate changes, the undersigned shall promptly so inform the Borrower and the Administrative Agent, and (2) the undersigned shall have at all times furnished the Borrower and the Administrative Agent with a properly completed and currently effective certificate in either the calendar year in which each payment is to be made to the undersigned, or in either of the two calendar years preceding such payments.

Unless otherwise defined herein, terms defined in the 5-Year Credit Agreement and used herein shall have the meanings given to them in the 5-Year Credit Agreement.

[NAME OF LENDER]

By:
Name:
Title:

Date: _____ __, 20[ ]

EXHIBIT 2.21

FORM OF NEW LOAN INCREASE JOINDER

NEW LOAN INCREASE JOINDER, dated as of [_____], 201[_] (this "Agreement"), by and among [NEW LENDERS] (each, a "New Lender" and, collectively, the "New Lenders"), Kinder Morgan, Inc., a Delaware corporation (the "Borrower") and Barclays Bank PLC, as Administrative Agent in such capacity (the "Administrative Agent").

R E C I T A L S

WHEREAS, reference is hereby made to the Revolving Credit Agreement, dated as of November 16, 2018 (as amended, restated, supplemented or otherwise modified, refinanced or replaced from time to time, the "5-Year Credit Agreement"), among the Borrower, the Lenders party thereto, Barclays Bank PLC as Administrative Agent, and the other parties thereto (capitalized terms used but not defined herein having the meaning provided in the 5-Year Credit Agreement); and

WHEREAS, subject to the terms and conditions of the 5-Year Credit Agreement, the Borrower may establish New Commitments by, among other things, entering into one or more New Loan Increase Joinders with New Lenders;

NOW, THEREFORE, in consideration of the premises and agreements, provisions and covenants herein contained, the parties hereto agree as follows:

Each New Lender party hereto hereby agrees to commit to provide its respective New Commitment, as set forth opposite its name on Schedule A annexed hereto, on the terms and subject to the conditions set forth below.

Each New Lender (i) confirms that it has received a copy of the 5-Year Credit Agreement and the other Loan Documents and the exhibits thereto, together with copies of the financial statements referred to therein and such other documents and information as it has deemed appropriate to make its own credit analysis and decision to enter into this Agreement; (ii) agrees that it will, independently and without reliance upon the Administrative Agent, the Syndication Agent, any Documentation Agent, any other New Lender or any other Lender and based on such documents and information as it shall deem appropriate at the time, continue to make its own credit decisions in taking or not taking action under the 5-Year Credit Agreement; (iii) appoints and authorizes the Administrative Agent to take such action as agent on its behalf and to exercise such powers under the 5-Year Credit Agreement and the other Loan Documents as are delegated to the Administrative Agent by the terms thereof, together with such powers as are reasonably incidental thereto; and (iv) agrees that it will perform in accordance with their terms all of the obligations which by the terms of the 5-Year Credit Agreement are required to be performed by it as a New Lender.

Each New Lender hereby agrees to make its respective Commitment on the following terms and conditions:

1. Proposed Increase to Revolving Facility. This Agreement represents the Borrower's request to increase the Total Commitment pursuant to Section 2.21 of the 5-Year Credit Agreement through New Commitments from the New Lenders as follows (the "Proposed Commitment Increase"):

(a) Business Day of Proposed Revolving Credit Commitment Increase: _____, ____ (the "Increased Amount Date")

(b) Amount of Proposed Commitment Increase: $_____[1]

2. [Acknowledgment and Agreement. Each New Lender acknowledges and agrees that upon its execution of this Agreement and the making of New Loans that such New Lender shall become a "Lender" under, and for all purposes of, the 5-Year Credit Agreement and the other Loan Documents, and shall be subject to and bound by the terms thereof, and shall perform all the obligations of and shall have all rights of a Lender thereunder.][2]

3. 5-Year Credit Agreement Governs. Except as set forth in this Agreement, the New Commitments shall otherwise be subject to the provisions of the 5-Year Credit Agreement and the other Loan Documents.

4. Borrower's Certifications. By its execution of this Agreement, the undersigned officer of the Borrower, to the best of his or her knowledge, hereby certifies that:

i. The representations and warranties set forth in the 5-Year Credit Agreement and the other Loan Documents are true and correct in all material respects on and as of the date hereof (unless such representation and warranty expressly relates to an earlier date); and

ii. No Event of Default exists on such Increased Amount Date before or after giving effect to such New Commitments.

5. Borrower Covenants. By its execution of this Agreement, Borrower hereby covenants that:

i. Borrower shall make any payments required pursuant the 5-Year Credit Agreement (including Section 2.15 thereof) to the Administrative Agent and the Lenders (other than any Defaulting Lender), in connection with the New Commitments;

ii. Borrower shall deliver or cause to be delivered the following legal opinions and documents: [_____], together with all other legal opinions and other documents reasonably requested by the Administrative Agent in connection with this Agreement; and

iii. Set forth on the attached Officers' Certificate are the calculations (in reasonable detail) demonstrating compliance on a pro forma basis with the financial tests described in Section 6.07 of the 5-Year Credit Agreement as of the Increased Amount Date and as of the Most Recent Financial Statement Date, after giving effect to such New Commitments (assuming for the purposes of such calculation that any New Commitments are fully drawn) and other customary and appropriate pro forma adjustments, including any acquisitions or dispositions

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[1] Amount not to exceed $1,000,000,000 in the aggregate with all other New Commitments.

[2] Insert bracketed language if the lending institution is not already a Lender.

after the beginning of the relevant determination period and prior to or simultaneous with the effectiveness of such New Commitments.

7. Consents. The Administrative Agent, the Swingline Lender and the Issuing Banks have consented to each New Lender on or prior to the date hereof.

8. Notice. For purposes of the 5-Year Credit Agreement, the initial notice address of each New Lender that is not a Lender under the 5-Year Credit Agreement shall be as set forth below its signature below.

9. Tax Forms. For each relevant New Lender, delivered herewith to the Administrative Agent are such forms, certificates or other evidence with respect to United States federal income tax withholding matters as such New Lender may be required to deliver to the Administrative Agent pursuant to Section 2.16(g) of the 5-Year Credit Agreement.

10. Recordation of the New Revolving Credit Commitments. Upon execution and delivery hereof, the Administrative Agent will record the New Commitments made by each New Lender in the Register.

11. Amendment, Modification and Waiver. This Agreement may not be amended, modified or waived except by an instrument or instruments in writing signed and delivered on behalf of each of the parties hereto.

12. Entire Agreement. This Agreement, the 5-Year Credit Agreement and the other Loan Documents constitute the entire agreement among the parties with respect to the subject matter hereof and thereof and supersede all other prior agreements and understandings, both written and verbal, among the parties or any of them with respect to the subject matter hereof.

13. GOVERNING LAW. THIS AGREEMENT AND THE RIGHTS AND OBLIGATIONS OF THE PARTIES HEREUNDER SHALL BE GOVERNED BY, AND CONSTRUED AND INTERPRETED IN ACCORDANCE WITH, THE LAW OF THE STATE OF NEW YORK.

14. Severability. Any term or provision of this Agreement which is invalid or unenforceable in any jurisdiction shall, as to that jurisdiction, be ineffective to the extent of such invalidity or unenforceability without rendering invalid or unenforceable the remaining terms and provisions of this Agreement or affecting the validity or enforceability of any of the terms or provisions of this Agreement in any other jurisdiction. If any provision of this Agreement is so broad as to be unenforceable, the provision shall be interpreted to be only so broad as would be enforceable.

15. Counterparts. This Agreement may be executed in counterparts, each of which shall be deemed to be an original, but all of which shall constitute one and the same agreement.

IN WITNESS WHEREOF, each of the undersigned has caused its duly authorized officer to execute and deliver this New Loan Increase Joinder as of _____, _____.

[NEW REVOLVING LOAN LENDER]

By:
Name:
Title:

[Notice Address:
Attention:
Telephone:
Facsimile:][3]

KINDER MORGAN, INC., as Borrower

By:
Name:
Title:

[NAME OF ADMINISTRATIVE AGENT], as Administrative Agent

By:
Name:
Title:

[3] Insert notice information if such New Revolving Loan Lender is not a Revolving Credit Lender under the 5-Year Credit Agreement.

Consented to:

[NAME OF ADMINISTRATIVE AGENT], as
Administrative Agent

By: _____
Name:
Title:

[NAME OF EACH RELEVANT PARTY][4]

By: _____
Name:
Title:

[4] Requires consent of the Administrative Agent, each Swingline Lender and each Issuing Bank.

EXHIBIT 5.01

FORM OF COMPLIANCE CERTIFICATE

The undersigned hereby certifies that he is the _____ of KINDER MORGAN, INC., a Delaware corporation (the "Borrower"), and that as such he is authorized to execute this certificate on behalf of the Borrower. With reference to the Revolving Credit Agreement dated as of November 16, 2018 (as further restated, amended, modified, supplemented and in effect from time to time, the "5-Year Credit Agreement") among the Borrower, Barclays Bank PLC, as Administrative Agent, for the lenders (the "Lenders") and such Lenders, the undersigned represents and warrants as follows (each capitalized term used herein having the same meaning given to it in the 5-Year Credit Agreement unless otherwise specified);

Attached hereto as Annex I are the detailed computations necessary to determine whether the Borrower is in compliance with Section 6.07 of the 5-Year Credit Agreement as of the end of the [fiscal quarter][fiscal year] ending _____.

[Attached hereto as Annex II is a list of the Material Subsidiaries.][1]

[There has been no change in the list of Material Subsidiaries since [ ], the date of the last Compliance Certificate delivered prior to the date hereof.] [Attached hereto as Annex II is an update to the list of Material Subsidiaries to reflect changes in such list since [ ], the date of the last Compliance Certificate delivered prior to the date hereof.][2]

There does not exist any Default or Event of Default under the 5-Year Credit Agreement as of the date of this Compliance Certificate, except as set forth in a separate attachment, if any, to this Compliance Certificate, setting forth the details thereof and the action taken or proposed to be taken by the Borrower with respect thereto.

EXECUTED AND DELIVERED this _____ day of _____, _____.

KINDER MORGAN, INC.,
as the Borrower

By: _____
Name:_____
Title:_____

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[1] To be included in the compliance certificate delivered simultaneously with the first set of financial statements delivered following the Closing Date.

[2] Select the appropriate option for each Compliance Certificate delivered simultaneously with the second set of financial statements delivered following the Closing Date and each set of financial statements delivered thereafter.

$500,000,000

REVOLVING CREDIT AGREEMENT

dated as of
November 16, 2018

among

KINDER MORGAN, INC.,
as the Borrower,

THE LENDERS PARTY HERETO

and

BARCLAYS BANK PLC,
as the Administrative Agent

JPMORGAN CHASE BANK, N.A.,
as the Syndication Agent,

and

BARCLAYS BANK PLC,
JPMORGAN CHASE BANK, N.A.,
BANK OF AMERICA, N.A.,
BMO HARRIS BANK N.A.,
CITIGROUP GLOBAL MARKETS INC.,
CREDIT SUISSE AG, CAYMAN ISLANDS BRANCH,
MIZUHO BANK, LTD.,
MUFG BANK, LTD.,
ROYAL BANK OF CANADA,
THE BANK OF NOVA SCOTIA, HOUSTON BRANCH and
WELLS FARGO BANK, NATIONAL ASSOCIATION,
as the Documentation Agents,

BARCLAYS BANK PLC,
JPMORGAN SECURITIES LLC,
BMO CAPITAL MARKETS CORP.,
CITIGROUP GLOBAL MARKETS INC.,
CREDIT SUISSE SECURITIES (USA) LLC,
MERRILL LYNCH, PIERCE, FENNER & SMITH INCORPORATED,
MIZUHO BANK, LTD.,
MUFG BANK, LTD.,
RBC CAPITAL MARKETS,
THE BANK OF NOVA SCOTIA, HOUSTON BRANCH and
WELLS FARGO SECURITIES, LLC,

as the Joint Lead Arrangers and the Joint Book Runners

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SCHEDULES:

EXHIBITS:

REVOLVING CREDIT AGREEMENT

THIS REVOLVING CREDIT AGREEMENT, dated as of November 16, 2018 (this "Agreement") is among:

(a) Kinder Morgan, Inc., a Delaware corporation (the "Borrower");

(b) the banks, financial institutions and other lenders listed on the signature pages hereof under the caption "Lenders" (the "Lenders" and together with each other Person that becomes a Lender pursuant to Section 9.05, collectively, the "Lenders"); and

(c) Barclays Bank PLC, individually as a Lender and as the administrative agent for the Lenders (in such latter capacity together with any other Person that becomes Administrative Agent pursuant to Section 8.08, the "Administrative Agent").

PRELIMINARY STATEMENTS

The Borrower has requested that the Lenders extend credit to the Borrower in the form of Loans (as defined below) in an aggregate principal amount of $500,000,000 (the "Transactions") to be used by Borrower and its subsidiaries for working capital and general corporate purposes, and the Lenders have indicated their willingness to lend on the terms and subject to the conditions set forth herein.

NOW, THEREFORE, the parties hereto agree as follows:

ARTICLE I
DEFINITIONS

SECTION 1.01 Defined Terms. As used in this Agreement, the following terms have the meanings specified below:

"ABR", when used in reference to any Loan or Borrowing, refers to whether such Loan, or the Loans comprising such Borrowing, bear interest at a rate determined by reference to the Alternate Base Rate.

"Adjusted LIBO Rate" means, with respect to any Eurodollar Loan for any Interest Period for such Loan, a rate per annum (rounded upwards, if necessary, to the nearest 1/100 of 1%) determined by the Administrative Agent to be equal to the product of (i) the Eurodollar Rate for such Loan for such Interest Period multiplied by (ii) the Reserve Requirement for such Loan for such Interest Period. In no case shall the Adjusted LIBO Rate be less than zero.

"Administrative Agent" has the meaning specified in the introduction to this Agreement.

"Administrative Agent Fee Letter" has the meaning specified in Section 2.11(c).

"Administrative Questionnaire" means an Administrative Questionnaire in the form supplied by the Administrative Agent.

"Affiliate" of any Person means (i) any Person directly or indirectly controlled by, controlling or under common control with such first Person, (ii) any director or officer of such first Person or of any Person referred to in clause (i) above and (iii) if any Person in clause (i) above is an individual, any member of the immediate family (including parents, siblings, spouse and children) of such individual and any trust

whose principal beneficiary is such individual or one or more members of such immediate family and any Person who is controlled by any such member or trust. For purposes of this definition, any Person that owns directly or indirectly 25% or more of the securities having ordinary voting power for the election of directors or other governing body of a corporation or 25% or more of the partnership or other ownership interests of any other Person (other than as a limited partner of such other Person) will be deemed to *"control"* (including, with its correlative meanings, *"controlled by"* and *"under common control with"*) such corporation or other Person. In no event shall the Administrative Agent or any Lender be deemed to an Affiliate of the Borrower of any of its Subsidiaries.

"Affiliated Entities" means unconsolidated Subsidiaries of the Borrower and Persons not otherwise constituting Subsidiaries of the Borrower in which the Borrower has an equity investment.

"Agreement" has the meaning specified in the introduction to this Agreement (*subject, however*, to Section 1.04(e) hereof).

"Alternate Base Rate" means, for any day, a fluctuating rate per annum equal to the greatest of (a) the Federal Funds Effective Rate in effect on such day *plus* ½ of 1%, (b) the Prime Rate in effect for such day, and (c) the Adjusted LIBO Rate for a Eurodollar Loan with a one month Interest Period that begins on such day (and if such day is not a Business Day, the immediately preceding Business Day) *plus* 1%. Any change in the Alternate Base Rate due to a change in the Prime Rate, the Federal Funds Effective Rate or the Adjusted LIBO Rate shall be effective from the effective date of such change in the Prime Rate, the Federal Funds Effective Rate or the Adjusted LIBO Rate, respectively.

"Anti-Corruption Laws" means all laws, rules, and regulations of any jurisdiction applicable to the Borrower or any of its Subsidiaries from time to time concerning or relating to bribery or corruption.

"Applicable Commitment Fee Rate" means, at any time and from time to time, the percentage per annum equal to the applicable percentage set forth below for the corresponding Performance Level at such time:

Performance Level	Applicable Commitment Fee Rate
I	0.090%
II	0.100%
III	0.125%
IV	0.175%
V	0.225%
VI	0.275%

The Applicable Commitment Fee Rate shall be determined by reference to the Performance Level in effect from time to time and any change in the Applicable Commitment Fee Rate shall be effective from the effective date of the change in the applicable Performance Level giving rise thereto.

"Applicable Margin" means, as to any ABR Borrowing or any Eurodollar Borrowing, as the case may be, at any time and from time to time, a percentage per annum equal to the applicable percentage set forth below for the corresponding Performance Level at such time:

Performance Level	Eurodollar Borrowings Applicable Margin Percentage	ABR Borrowings Applicable Margin Percentage
I	1.000%	0.100%
II	1.125%	0.125%
III	1.250%	0.250%
IV	1.500%	0.500%
V	1.750%	0.750%
VI	2.000%	1.000%

The Applicable Margin shall be determined by reference to the Performance Level in effect from time to time, and any change in the Applicable Margin shall be effective from the effective date of any change in the applicable Performance Level giving rise thereto.

"Applicable Percentage" means at any time, for each Lender, the percentage obtained by dividing (a) such Lender's Commitment by (b) the amount of the Total Commitment, *provided* that at any time when the Total Commitment shall have been terminated, each Lender's Applicable Percentage shall be the percentage obtained by dividing (a) such Lender's Credit Exposure by (b) the aggregate Credit Exposure of all Lenders.

"Approved Fund" means any Fund that is administered or managed by (a) a Lender, (b) an Affiliate of a Lender or (c) an entity or an Affiliate of an entity that administers or manages a Lender.

"Arrangers" means Barclays Bank PLC, J.P. Morgan Securities LLC., Merrill Lynch, Pierce, Fenner & Smith Incorporated (or any other registered broker-dealer wholly-owned by Bank of America Corporation to which all or substantially all of Bank of America Corporation's or any of its subsidiaries' investment banking, commercial lending services or related businesses may be transferred following the date of this Agreement), BMO Capital Markets Corp., Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC, Mizuho Bank, Ltd., MUFG Bank, Ltd., RBC Capital Markets, The Bank of Nova Scotia, Houston Branch and Wells Fargo Securities LLC, as joint lead arrangers and joint book runners.

"Assignment and Acceptance" means an assignment and acceptance entered into by a Lender and an assignee (with the consent of any party whose consent is required by Section 9.05), and accepted by the Administrative Agent, in the form of Exhibit 1.01-A or any other form approved by the Administrative Agent.

"Availability Period" means the period from the Closing Date to the earlier of (i) the Maturity Date or (ii) the date of termination of the Total Commitment.

"Bail-In Action" means the exercise of any Write-Down and Conversion Powers by the applicable EEA Resolution Authority in respect of any liability of an EEA Financial Institution.

"Bail-In Legislation" means, with respect to any EEA Member Country implementing Article 55 of Directive 2014/59/EU of the European Parliament and of the Council of the European Union, the implementing law for such EEA Member Country from time to time which is described in the EU Bail-In Legislation Schedule.

"Beneficial Ownership Certification" means a certification regarding beneficial ownership or control as required by the Beneficial Ownership Regulation, which certification shall be substantially similar in form and substance to the form of Certification Regarding Beneficial Owners of Legal Entity Customers published jointly, in May 2018, by the Loan Syndications and Trading Association and Securities Industry and Financial Markets Association.

"Beneficial Ownership Regulation" means 31 C.F.R. § 1010.230.

"Benefit Arrangement" means at any time an employee benefit plan within the meaning of Section 3(3) of ERISA which is not a Plan or a Multiemployer Plan and which is maintained or otherwise contributed to by any member of the ERISA Group.

"Benefit Plan" means any of (a) an "employee benefit plan" (as defined in Section 3(3) of ERISA) that is subject to Title I of ERISA, (b) a "plan" as defined in Section 4975 of the Code to which Section 4975 of the Code applies, and (c) any Person whose assets include (for purposes of the Plan Asset Regulations or otherwise for purposes of Title I of ERISA or Section 4975 of the Code) the assets of any such "employee benefit plan" or "plan".

"Board" means the Board of Governors of the Federal Reserve System of the United States of America.

"Board of Directors" means, with respect to any Person, the Board of Directors of such Person or any committee of the Board of Directors of such Person duly authorized to act on behalf of the Board of Directors of such Person.

"Bonds" means the Port Facility Refunding Revenue Bonds (Enron Transportation Services, L.P. Project) Series 1994 in the original aggregate principal amount of $23,700,000, as issued by the Jackson-Union Regional Port District.

"Borrower" has the meaning specified in the introduction to this Agreement.

"Borrower Debt Rating" means, with respect to the Borrower as of any date of determination, the rating that has been most recently announced by each of S&P or Moody's for any non-credit enhanced, unsecured long-term senior debt issued or to be issued by the Borrower. For purposes of the foregoing:

(a) if, at any time, neither S&P nor Moody's shall have in effect a Borrower Debt Rating, the Applicable Margin or the Applicable Commitment Fee Rate, as the case may be, shall be set in accordance with Performance Level VI under the definition of "*Applicable Margin*" or "*Applicable Commitment Fee Rate*", as the case may be;

(b) if the ratings established by S&P and Moody's shall fall within different Performance Levels, the Applicable Margin or the Applicable Commitment Fee Rate, as the case may be,

shall be based upon the higher rating; *provided, however*, that, if the lower of such ratings is two or more Performance Levels below the higher of such ratings, the Applicable Margin or the Applicable Commitment Fee Rate, as the case may be, shall be based upon the rating that is one Performance Level higher than the lower rating;

(c) if any rating established by S&P or Moody's shall be changed, such change shall be effective as of the date on which such change is announced publicly by the rating agency making such change;

(d) if S&P or Moody's shall change the basis on which ratings are established by it, each reference to the Borrower Debt Rating announced by S&P or Moody's shall refer to the then equivalent rating by S&P or Moody's, as the case may be.

"Borrowing" means a borrowing comprised of Committed Loans of the same Type, made, converted or continued on the same date and, in the case of Eurodollar Loans, as to which a single Interest Period is in effect.

"Borrowing Date" means the Business Day upon which any Loans are to be made available to the Borrower.

"Borrowing Request" has the meaning specified in Section 2.03.

"Business Day" means any day that is not a Saturday, Sunday or other day on which commercial banks in Houston, Texas or New York, New York are authorized or required by law to remain closed; *provided* that, when used in connection with a rate of interest determined by reference to the Eurodollar Rate, the term *"Business Day"* shall also exclude any day on which banks are not open for dealings in dollar deposits in the London interbank market.

"Capital Lease Obligations" of any Person means the obligations of such Person to pay rent or other amounts under any lease of (or other arrangement conveying the right to use) real or personal property, or a combination thereof, which obligations are required to be classified and accounted for as capital leases on a balance sheet of such Person under GAAP, and the amount of such obligations shall be the capitalized amount thereof determined in accordance with GAAP.

"Capital Stock" means, with respect to any Person, any and all shares, interests, rights to purchase, warrants, options, participations or other equivalents (however designated) of such Person's equity, including (a) all common stock and preferred stock, any limited or general partnership interest and any limited liability company member interest, (b) beneficial interests in trusts, and (c) any other interest or participation that confers upon a Person the right to receive a share of the profits and losses of, or distribution of assets of, the issuing Person.

"Cash Equivalents" means (a) securities issued or unconditionally guaranteed by the United States government or any agency or instrumentality thereof, in each case having maturities of not more than 24 months from the date of acquisition thereof; (b) securities issued by any state of the United States of America or any political subdivision of any such state or any public instrumentality thereof or any political subdivision of any such state or any public instrumentality thereof having maturities of not more than 24 months from the date of acquisition thereof and, at the time of acquisition, having an investment grade rating generally obtainable from either S&P or Moody's (or, if at any time neither S&P nor Moody's shall be rating such obligations, then from another nationally recognized rating service); (c) commercial paper issued by any Lender or any bank holding company owning any Lender; (d) commercial paper maturing no more than

12 months after the date of creation thereof and, at the time of acquisition, having a rating of at least A-2 or P-2 from either S&P or Moody's (or, if at any time neither S&P nor Moody's shall be rating such obligations, an equivalent rating from another nationally recognized rating service); (e) domestic and Eurodollar Rate certificates of deposit or bankers' acceptances maturing no more than two years after the date of acquisition thereof issued by any Lender or any other bank having combined capital and surplus of not less than $250,000,000 in the case of domestic banks and $100,000,000 (or the equivalent in dollars thereof) in the case of foreign banks; (f) repurchase agreements with a term of not more than 30 days for underlying securities of the type described in clauses (a), (b) and (e) above entered into with any bank meeting the qualifications specified in clause (e) above or securities dealers of recognized national standing; (g) marketable short-term money market and similar funds (i) either having assets in excess of $250,000,000 or (ii) having a rating of at least A-2 or P-2 from either S&P or Moody's (or, if at any time neither S&P nor Moody's shall be rating such obligations, an equivalent rating from another nationally recognized rating service); (h) shares of investment companies that are registered under the Investment Company Act of 1940 and substantially all the investments of which are one or more of the types of securities described in clauses (a) through (g) above; and (i) in the case of investments by any Foreign Subsidiary, other customarily utilized high-quality investments in the country where such Foreign Subsidiary is located.

"Certain Items" means such items that are required to be included in the calculation of Net Income in accordance with GAAP that either (i) are non-cash or (ii) by their nature are separately identifiable from the Borrower and the Subsidiaries' normal business operations and are likely to occur only sporadically, and are reflected as such in the Annual Report on Form 10-K of the Borrower or in the Quarterly Report on Form 10-Q of the Borrower, in each case filed with the SEC. For the avoidance of doubt, Certain Items will be unadjusted for noncontrolling interests related thereto.

"CFC" means a Person that is a "controlled foreign corporation" within the meaning of Section 957 of the Code.

"Change in Control" means and will be deemed to have occurred if (a) any person, entity or "group" (within the meaning of Section 13(d) or 14(d) of the Securities Exchange Act of 1934, as amended) shall at any time have acquired direct or indirect beneficial ownership of a percentage of the voting power of the outstanding Voting Stock of the Borrower that exceeds 50% of the voting power of all the outstanding Voting Stock of the Borrower; or (b) Continuing Directors shall not constitute at least a majority of the board of directors of the Borrower.

"Change in Law" means the occurrence, after the date of this Agreement, of any of the following: (a) the adoption or taking effect of any law, rule, regulation or treaty, (b) any change in any law, rule, regulation or treaty or in the administration, interpretation, implementation or application thereof by any Governmental Authority or (c) the making or issuance of any request, rule, guideline or directive (whether or not having the force of law) by any Governmental Authority; *provided* that notwithstanding anything herein to the contrary, (x) the Dodd-Frank Wall Street Reform and Consumer Protection Act and all requests, rules, guidelines or directives thereunder or issued in connection therewith and (y) all requests, rules, guidelines or directives promulgated by the Bank for International Settlements, the Basel Committee on Banking Supervision (or any successor or similar authority) or the United States or foreign regulatory authorities, in each case pursuant to Basel III, shall in each case be deemed to be a "Change in Law", regardless of the date enacted, adopted or issued.

"Charges" has the meaning specified in Section 9.13.

"Closing Date" means the date on which the conditions specified in Section 3.01 are satisfied (or waived in accordance with Section 9.02).

"Code" means the Internal Revenue Code of 1986, as amended from time to time.

"Commitment" means, with respect to each Lender, the commitment of such Lender to make Committed Loans pursuant to Section 2.01, expressed as an amount representing the maximum aggregate amount of such Lender's Credit Exposure hereunder, as such commitment may be reduced or increased from time to time pursuant to the terms hereof. The initial amount of each Lender's Commitment as of the Closing Date is set forth on Schedule 1.01, or in the Register maintained by the Administrative Agent pursuant to Section 9.05.

"Commitment Fee" has the meaning specified in Section 2.11(a).

"Committed Loan" means a Loan made pursuant to Section 2.03.

"Committed Note" means a promissory note of the Borrower payable to the order of each Lender, in substantially the form of Exhibit 1.01-C, together with all modifications, extensions, renewals and rearrangements thereof.

"Communications" has the meaning specified in Section 9.01(a).

"Connection Income Taxes" means Other Connection Taxes that are imposed on or measured by net income (however denominated) or that are franchise Taxes or branch profits Taxes.

"Consolidated Assets" means, at the date of any determination thereof, the total assets of the Borrower and the Subsidiaries as set forth on a consolidated balance sheet of the Borrower and the Subsidiaries for their most recently completed fiscal quarter, prepared in accordance with GAAP.

"Consolidated EBITDA" means, for any period (without duplication), the Net Income of the Borrower and the Subsidiaries for such period determined on a consolidated basis in accordance with GAAP, increased (a) (to the extent deducted in determining Net Income for such period) by the sum of (i) all book taxes of the Borrower and the Subsidiaries paid or accrued and reflected in the Annual Report on Form 10-K of the Borrower or in the Quarterly Report on Form 10-Q of the Borrower, in each case filed with the SEC, and the pro rata portion of book taxes attributable to Affiliated Entities (net of (x) the noncontrolling interest's portion of such book taxes of KML and (y) the consolidating joint venture partners' share of such book taxes of such consolidating joint venture), for such period; (ii) Consolidated Interest Expense for such period, (iii) all DD&A of the Borrower and the Subsidiaries and the pro rata portion of DD&A attributable to Affiliated Entities (net of (x) the noncontrolling interest's portion of such DD&A of KML and (y) the consolidating joint venture partners' share of such DD&A of such consolidating joint venture), for such period; (iv) Certain Items charges or losses, and (v) amortization, write-off or write-down of debt discount, capitalized interest and debt issuance costs and commissions, discounts and other fees, charges and expenses associated with any letters of credit or Indebtedness, including in connection with the repurchase or repayment thereof, including any premium and acceleration of fees or discounts and other expenses, minus (b) Certain Items of income or gain which were included in determining such consolidated Net Income for such period; provided, that Consolidated EBITDA shall be calculated after giving pro forma effect to acquisitions of any Person, property, business or asset (to the extent not subsequently sold, transferred, abandoned or otherwise disposed) and any sale, transfer, abandonment or other disposition of any Person, property, business or asset made by the Borrower or any Subsidiary during such period, as if the acquisition, sale, transfer, abandonment or other disposition had been effected on the first date of such period.

"Consolidated Interest Expense" means, for any period, the Interest Expense of the Borrower and the Subsidiaries for such period determined on a consolidated basis in accordance with GAAP.

"Consolidated Net Indebtedness" means, at the date of any determination thereof, (a) Indebtedness of the Borrower and the Subsidiaries determined on a consolidated basis in accordance with GAAP minus (b) (i) the aggregate cash included in the cash accounts listed on the consolidated balance sheet of the Borrower and the Subsidiaries as at such date and (ii) Cash Equivalents of the Borrower and the Subsidiaries as at such date, in the case of each of clauses (i) and (ii), to the extent the use thereof for application to payment of Indebtedness is not prohibited by any Requirement of Law or any contract to which the Borrower or any of the Subsidiaries is a party.

"Consolidated Net Tangible Assets" means, at the date of any determination thereof, Consolidated Tangible Assets after deducting therefrom all current liabilities, excluding (i) any current liabilities that by their terms are extendable or renewable at the option of the obligor thereon to a time more than 12 months after the time as of which the amount thereof is being computed; and (ii) current maturities of long-term debt, all as set forth, or on a *pro forma* basis would be set forth, on a consolidated balance sheet of the Borrower and the Subsidiaries for their most recently completed fiscal quarter, prepared in accordance with GAAP.

"Consolidated Tangible Assets" means, at the date of any determination thereof, Consolidated Assets after deducting therefrom the value, net of any applicable reserves and accumulated amortization, of all goodwill, trade names, trademarks, patents and other like intangible assets, all as set forth, or on a pro forma basis would be set forth, on a consolidated balance sheet of the Borrower and the Subsidiaries for their most recently completed fiscal quarter, prepared in accordance with GAAP.

"Continuing Director" means, at any date, an individual (a) who is a member of the board of directors of the Borrower on the Closing Date, (b) who, as at such date, has been a member of such board of directors for at least the twelve preceding months, or (c) who has been nominated to be a member of such board of directors by, or elected to such board of directors with the approval of, a majority of the other Continuing Directors then in office.

"Credit Event" means the making of any Loan.

"Credit Exposure" means, with respect to any Lender at any time, the outstanding principal amount of such Lender's Committed Loans.

"DD&A" means depreciation, depletion and amortization (including amortization of goodwill) and the amortization of excess costs of equity investments, determined in accordance with GAAP.

"Debtor Relief Laws" means the Bankruptcy Code of the United States of America, and all other liquidation, conservatorship, bankruptcy, assignment for the benefit of creditors, moratorium, rearrangement, receivership, insolvency, reorganization, or similar debtor relief Laws of the United States or other applicable jurisdictions from time to time in effect.

"Default" means any event or condition which upon notice, lapse of time or both would, unless cured or waived, become an Event of Default.

"Defaulting Lender" means, subject to Section 2.19(b), any Lender that (a) has failed to (i) fund all or any portion of its Loans within three Business Days of the date such Loans were required to

be funded hereunder unless such Lender notifies the Administrative Agent and the Borrower in writing that such failure is the result of such Lender's determination that one or more conditions precedent to funding (each of which conditions precedent, together with any applicable default, shall be specifically identified in such writing) has not been satisfied, or (ii) pay to the Administrative Agent or any Lender any other amount required to be paid by it hereunder within two Business Days of the date when due, (b) has notified the Borrower or the Administrative Agent in writing that it does not intend to comply with its funding obligations hereunder, or has made a public statement to that effect (unless such writing or public statement relates to such Lender's obligation to fund a Loan hereunder and states that such position is based on such Lender's determination that a condition precedent to funding (which condition precedent, together with any applicable default, shall be specifically identified in such writing or public statement) cannot be satisfied), (c) has failed, within three Business Days after written request by the Administrative Agent or the Borrower, to confirm in writing to the Administrative Agent and the Borrower that it will comply with its prospective funding obligations hereunder (*provided* that such Lender shall cease to be a Defaulting Lender pursuant to this clause (c) upon receipt of such written confirmation by the Administrative Agent and the Borrower), or (d) has, or has a direct or indirect parent company that has, (i) become the subject of a proceeding under any Debtor Relief Law, (ii) become subject of a Bail-In Action, or (iii) had appointed for it a receiver, custodian, conservator, trustee, administrator, assignee for the benefit of creditors or similar Person charged with reorganization or liquidation of its business or assets, including the Federal Deposit Insurance Corporation or any other state or federal regulatory authority acting in such a capacity; *provided* that, for the avoidance of doubt, a Lender shall not be a Defaulting Lender solely by virtue of (i) the ownership or acquisition of any equity interest in that Lender or any direct or indirect parent company thereof by a Governmental Authority, or (ii), in the case of a solvent Person, the precautionary appointment of an administrator, guardian, custodian or other similar official by a Governmental Authority under or based on the law of the country where such Person is subject to home jurisdiction supervision if applicable law requires that such appointment not be publicly disclosed, in each of such cases, so long as such ownership interest or such appointment does not result in or provide such Lender with immunity from the jurisdiction of courts within the United States or from the enforcement of judgments or writs of attachment on its assets or permit such Lender (or such Governmental Authority) to reject, repudiate, disavow or disaffirm any contracts or agreements made with such Lender. Any determination by the Administrative Agent that a Lender is a Defaulting Lender under any one or more of clauses (a) through (d) above shall be conclusive and binding absent manifest error, and such Lender shall be deemed to be a Defaulting Lender (subject to Section 2.19(b)) upon delivery of written notice of such determination to the Borrower and each Lender.

"Dividing Person" has the meaning assigned to such term in the definition of "Division".

"Division" means the division of the assets, liabilities and/or obligations of a Person (the "Dividing Person") among two or more Persons (whether pursuant to a "plan of division" or similar arrangement), which may or may not include the Dividing Person and pursuant to which the Dividing Person may or may not survive.

"Division Successor" means any Person that, upon the consummation of a Division of a Dividing Person, holds all or any portion of the assets, liabilities and/or obligations previously held by such Dividing Person immediately prior to the consummation of such Division. A Dividing Person which retains any of its assets, liabilities and/or obligations after a Division shall be deemed a Division Successor upon the occurrence of such Division.

"Documentation Agents" means Barclays Bank PLC, JPMorgan Chase Bank, N.A., Bank of America, N.A., BMO Harris Bank N.A., Citigroup Global Markets Inc., Credit Suisse AG, Cayman Islands Branch, Mizuho Bank, Ltd., MUFG Bank, Ltd., Royal Bank of Canada, The Bank of Nova Scotia, Houston Branch and Wells Fargo Bank, National Association, as documentation agents.

"dollars" or "$" refers to lawful money of the United States of America.

"Domestic Subsidiary" means any Subsidiary of the Borrower organized under the laws of any jurisdiction within the United States.

"EEA Financial Institution" means (a) any credit institution or investment firm established in any EEA Member Country which is subject to the supervision of an EEA Resolution Authority, (b) any entity established in an EEA Member Country which is a parent of an institution described in clause (a) of this definition, or (c) any financial institution established in an EEA Member Country which is a subsidiary of an institution described in clauses (a) or (b) of this definition and is subject to consolidated supervision with its parent.

"EEA Member Country" means any of the member states of the European Union, Iceland, Liechtenstein, and Norway.

"EEA Resolution Authority" means any public administrative authority or any person entrusted with public administrative authority of any EEA Member Country (including any delegee) having responsibility for the resolution of any EEA Financial Institution.

"Eligible Assignee" means any Person that meets the requirements to be an assignee under Section 9.05(a)(iii), (v) and (vi) (subject to such consents, if any, as may be required under Section 9.05(a)(iii)).

"Environmental Laws" means all laws, rules, regulations, codes, ordinances, orders, decrees, judgments, injunctions, notices or binding agreements issued, promulgated or entered into by any Governmental Authority, relating in any way to the environment, preservation or reclamation of natural resources, the management, release or threatened release of any Hazardous Material or to health and safety matters.

"Environmental Liability" means any liability, contingent or otherwise (including any liability for damages, costs of environmental remediation, fines, penalties or indemnities), of the Borrower or any Subsidiary directly or indirectly resulting from or based upon (a) violation of any Environmental Law, (b) the generation, use, handling, transportation, storage, treatment or disposal of any Hazardous Materials, (c) exposure to any Hazardous Materials, (d) the release of any Hazardous Materials into the environment, or (e) any contract, agreement or other consensual arrangement pursuant to which liability is assumed or imposed with respect to any of the foregoing.

"ERISA" means the Employee Retirement Income Security Act of 1974, as amended from time to time.

"ERISA Group" means the Borrower and all members of a controlled group of corporations and all trades or businesses (whether or not incorporated) under common control which, together with the Borrower, are treated as a single employer under Section 414 of the Code or Section 4001(a)(14) of ERISA.

"EU Bail-In Legislation Schedule" means the EU Bail-In Legislation Schedule published by the Loan Market Association (or any successor person), as in effect from time to time.

"Eurodollar", when used in reference to any Loan or Borrowing, refers to whether such Loan, or the Loans comprising such Borrowing, bear interest at a rate determined by reference to the Adjusted LIBO Rate.

"Eurodollar Rate" means for any Interest Period as to any Eurodollar Loan, (i) the rate per annum determined by the Administrative Agent to be the offered rate which appears on the page of the Reuters Screen which displays the London interbank offered rate administered by ICE Benchmark Administration Limited (such page currently being the LIBOR01 page) (the "LIBO Rate") for deposits (for delivery on the first day of such Interest Period) with a term equivalent to such Interest Period in Dollars, determined as of approximately 11:00 a.m. (London, England time), two Business Days prior to the commencement of such Interest Period, or (ii) in the event the rate referenced in the preceding clause (i) does not appear on such page or service or if such page or service shall cease to be available, the rate determined by the Administrative Agent to be the offered rate on such other page or other service which displays the LIBO Rate for deposits (for delivery on the first day of such Interest Period) with a term equivalent to such Interest Period in Dollars, determined as of approximately 11:00 a.m. (London, England time) two Business Days prior to the commencement of such Interest Period; provided that if LIBO Rates are quoted under either of the preceding clauses (i) or (ii), but there is no such quotation for the Interest Period elected, the LIBO Rate shall be equal to the Interpolated Rate; and provided, further, that if any such rate determined pursuant to the preceding clauses (i) or (ii) is less than zero, the Eurodollar Rate will be deemed to be zero.

"Event of Default" has the meaning specified in Section 7.01.

"Exchange Act" means the Securities Exchange Act of 1934, as amended.

"Excluded Subsidiary" means (i) any Subsidiary that is not a Wholly-owned Domestic Operating Subsidiary, (ii) any Domestic Subsidiary that is a Subsidiary of a CFC or any Domestic Subsidiary (including a disregarded entity for U.S. federal income Tax purposes) substantially all of whose assets (held directly or through Subsidiaries) consist of Capital Stock of one or more CFCs or Indebtedness of such CFCs, (iii) any Immaterial Subsidiary, (iv) any Subsidiary listed on Schedule 1.01A, (v) any other Subsidiary with respect to which, in the reasonable judgment of the Administrative Agent (confirmed in writing by notice to the Borrower), the cost or other consequences (including any adverse Tax consequences) of providing a Guaranty shall be excessive in view of the benefits to be obtained by the Lenders therefrom, (vi) any not-for-profit Subsidiary, (vii) any Subsidiary that is prohibited by a Requirement of Law from providing a Guaranty of the Obligations, and (ix) any Subsidiary acquired by the Borrower and its Subsidiaries after the Closing Date to the extent, and so long as, the financing documentation governing any existing Indebtedness of such Subsidiary (other than Indebtedness created or incurred in anticipation of, or with the intent to circumvent the terms of, this Agreement) that is permitted to survive pursuant to Section 6.01 (and does survive) prohibits such Subsidiary from guaranteeing the Obligations; provided, that notwithstanding the foregoing, any Subsidiary that Guarantees any senior notes or senior debt securities issued by the Borrower shall not constitute an Excluded Subsidiary for so long as such Guarantee is in effect.

"Excluded Taxes" means any of the following Taxes imposed on or with respect to a Recipient or required to be withheld or deducted from a payment to a Recipient, (a) Taxes imposed on or measured by net income (however denominated), franchise Taxes and branch profits Taxes, in each case, (i) imposed as a result of such Recipient being organized under the laws of, or having its principal office or, in the case of any Lender, its applicable lending office located in, the jurisdiction imposing such Tax (or any political subdivision thereof) or (ii) that are Other Connection Taxes, (b) in the case of a Lender, U.S. federal withholding Taxes imposed on amounts payable to or for the account of such Lender with respect to an applicable interest in a Loan or Commitment pursuant to a law in effect on the date on which (i) such Lender acquires such interest in the Loan or Commitment or becomes a party to this Agreement (other than pursuant to an assignment request by the Borrower under Section 2.18(b) or (ii) such Lender changes its lending office, except in each case to the extent that, pursuant to Section 2.16, amounts with respect to such Taxes were payable either to such Lender's assignor immediately before such Lender

became a party hereto or to such Lender immediately before it changed its lending office, (c) Taxes attributable to such Recipient's failure to comply with Section 2.16(g) and (d) any U.S. federal withholding Taxes imposed under FATCA.

"Executive Summary" means the Confidential Information Memorandum relating to this Agreement and the Transactions dated October 2018.

"Existing Credit Agreement" means the Revolving Credit Agreement, dated as of September 19, 2014 (as amended, restated or otherwise modified), among the Borrower, the banks and other financial institutions party thereto as lenders and Barclays Bank, PLC as administrative agent.

"FATCA" means Sections 1471 through 1474 of the Code, as of the date of this Agreement (or any amended or successor version that is substantively comparable and not materially more onerous to comply with), any current or future regulations or official interpretations thereof, any agreements entered into pursuant to Section 1471(b)(1) of the Code, and any law, regulation, rule, promulgation, guidance notes, practices or official agreement implementing an intergovernmental agreement, treaty or convention with respect to the foregoing.

"Federal Funds Effective Rate" means, for any day, the rate calculated by the Federal Reserve Bank of New York based on such day's federal funds transactions by depository institutions (as determined in such manner as the Federal Reserve Bank of New York shall set forth on its public website from time to time) and published on the next succeeding Business Day by the Federal Reserve Bank of New York as the federal funds effective rate; provided, that if the Federal Funds Effective Rate for any day is less than zero, the Federal Funds Effective Rate for such day will be deemed to be zero.

"Fee Letter" has the meaning specified in Section 2.11(c).

"Fee Letters" means, collectively, the Administrative Agent Fee Letter and the Fee Letter.

"Foreign Lender" means any Lender that is not a U.S. Person.

"Foreign Subsidiary" means any Subsidiary of the Borrower that is not a Domestic Subsidiary.

"Fund" means any Person (other than a natural person) that is (or will be) engaged in making, purchasing, holding or otherwise investing in commercial loans and similar extensions of credit in the ordinary course of its business.

"GAAP" means generally accepted accounting principles in the United States of America from time to time, including as set forth in the opinions, statements and pronouncements of the Accounting Principles Board of the American Institute of Certified Public Accountants and the Financing Accounting Standards Board.

"Governmental Authority" means the government of the United States of America or any other nation, or of any political subdivision thereof, whether state or local, and any agency, authority, instrumentality, regulatory body, court, central bank or other entity exercising executive, legislative, judicial, taxing, regulatory or administrative powers or functions of or pertaining to government (including any supra national bodies such as the European Union or the European Central Bank).

"Guarantee" of or by any Person (the "*guarantor*") means any obligation, contingent or otherwise, of the guarantor guaranteeing or having the economic effect of guaranteeing any Indebtedness or other obligation of any other Person (the "*primary obligor*") in any manner, whether directly or indirectly, and including any obligation of the guarantor, direct or indirect, (a) to purchase or pay (or advance or supply funds for the purchase or payment of) such Indebtedness or other obligation or to purchase (or to advance or supply funds for the purchase of) any security for the payment thereof, (b) to purchase or lease property, securities or services for the purpose of assuring the owner of such Indebtedness or other obligation of the payment thereof, (c) to maintain working capital, equity capital or any other financial statement condition or liquidity of the primary obligor so as to enable the primary obligor to pay such Indebtedness or other obligation or (d) as an account party in respect of any letter of credit or letter of guaranty issued to support such Indebtedness or obligation; *provided* that the term Guarantee shall not include endorsements for collection or deposit in the ordinary course of business.

"Guarantors" means each Person that guarantees the Obligations pursuant to the Guaranty.

"Guaranty" means the Guaranty Agreement substantially in the form of Exhibit 1.01-B hereto.

"Hazardous Materials" means all explosive or radioactive substances or wastes and all hazardous or toxic substances, wastes or other pollutants, including petroleum or petroleum distillates, asbestos or asbestos containing materials, polychlorinated biphenyls, radon gas, infectious or medical wastes and all other substances or wastes of any nature regulated pursuant to any Environmental Law.

"Hedging Agreement" means a financial instrument or security which is used as a cash flow or fair value hedge to manage the risk associated with a change in interest rates, foreign currency exchange rates or commodity prices.

"Hybrid Securities" means any trust preferred securities, or deferrable interest subordinated debt with a maturity of at least 20 years, which provides for the optional or mandatory deferral of interest or distributions, issued by the Borrower, or any business trusts, limited liability companies, limited partnerships or similar entities (i) substantially all of the common equity, general partner or similar interests of which are owned (either directly or indirectly through one or more Wholly-owned Subsidiaries) at all times by the Borrower or any of the Subsidiaries, (ii) that have been formed for the purpose of issuing trust preferred securities or deferrable interest subordinated debt, and (iii) substantially all the assets of which consist of (A) subordinated debt of the Borrower or a Subsidiary, and (B) payments made from time to time on the subordinated debt.

"Immaterial Subsidiary" means any Subsidiary that is not a Material Subsidiary.

"Indebtedness" of any Person means, without duplication, (a) all obligations of such Person for borrowed money, (b) all obligations of such Person evidenced by bonds, debentures, notes or similar instruments (other than surety, performance and guaranty bonds), (c) all obligations of such Person under conditional sale or other title retention agreements relating to property acquired by such Person, (d) all obligations of such Person in respect of the deferred purchase price of property or services (excluding trade accounts payable incurred in the ordinary course of business), (e) all Indebtedness of others secured by (or for which the holder of such Indebtedness has an existing right, contingent or otherwise, to be secured by) any Lien on property owned or acquired by such Person, whether or not the Indebtedness secured thereby has been assumed (determined as the lesser of the amount of the Indebtedness so secured and such property's fair market value), (f) all Guarantees by such Person of Indebtedness of others (*provided* that in the event that any Indebtedness of the Borrower or any Subsidiary shall be the subject of a Guarantee by one or more

Subsidiaries or by the Borrower, as the case may be, the aggregate amount of the outstanding Indebtedness of the Borrower and the Subsidiaries in respect thereof shall be determined by reference to the primary Indebtedness so guaranteed, and without duplication by reason of the existence of any such guarantee), (g) all Capital Lease Obligations of such Person, (h) all obligations of such Person as an account party in respect of (i) the full face amount of all letters of credit (drawn or undrawn) supporting the exposure of such Person under Hedging Agreements and (ii) the drawn portion of all other letters of credit and letters of guaranty, (i) all obligations, contingent or otherwise, of such Person in respect of funded bankers' acceptances and (j) Hybrid Securities. The Indebtedness of any Person shall include the Indebtedness of any other Person (including any partnership in which such Person is a general partner) to the extent such Person is liable therefor as a result of such Person's ownership interest in or other relationship with such entity, except to the extent the terms of such Indebtedness provide that such Person is not liable therefor: *provided* that Indebtedness shall not include (1) non-recourse debt, (2) performance guaranties, (3) monetary obligations or guaranties of monetary obligations of Person as lessees under leases that are in accordance with GAAP, recorded as operating leases (and giving effect to the proviso in Section 1.03), and (4) guarantees by such Person of obligations of others which are not obligations described in clauses (a) through (j) of this definition, and *provided further*, that where any such indebtedness or obligation of such Person is made jointly, or jointly and severally, with any third party or parties other than any Subsidiary of such Person, the amount thereof for the purpose of this definition only shall be the *pro rata* portion thereof payable by such Person, so long as such third party or parties have not defaulted on its or their joint and several portions thereof and can reasonably be expected to perform its or their obligations thereunder. For the avoidance of doubt, except as expressly provided in clause (h)(i) above, "Indebtedness" of a Person in respect of such letters of credit shall include, without duplication, only the principal amount of the unreimbursed obligations of such Person in respect of such letters of credit that have been drawn upon by the beneficiaries to the extent of the amount drawn, and shall include no other obligations in respect of such letters of credit.

"Indemnified Parties" has the meaning specified in Section 9.03(b).

"Indemnified Taxes" means (a) Taxes, other than Excluded Taxes, imposed on or with respect to any payment made by or on account of any Obligation and (b) to the extent not otherwise described in (a), Other Taxes.

"Indemnity Matters" means, with respect to any Indemnified Party, all losses, liabilities, claims and damages (including reasonable legal fees and expenses).

"Interest Election Request" has the meaning specified in Section 2.07(b).

"Interest Expense" means (without duplication), with respect to any period for any Person (a) the aggregate amount of interest, whether expensed or capitalized, paid, accrued or scheduled to be paid during such period in respect of the Indebtedness of such Person including (i) the interest portion of any deferred payment obligation; (ii) the portion of any rental obligation in respect of Capital Lease Obligations allocable to interest expenses; and (iii) any non-cash interest payments or accruals, all determined in accordance with GAAP, less (b) Interest Income of such Person for such period.

"Interest Income" means, with respect to any period for any Person, interest actually received by such Person during such period.

"Interest Payment Date" means (a) with respect to any ABR Loan, the last Business Day of each March, June, September and December, and (b) with respect to any Eurodollar Loan, the last Business Day of the Interest Period applicable to the Borrowing of which such Loan is a part and, in the case of a Eurodollar Borrowing with an Interest Period of more than three months' duration, each day prior to the last

day of such Interest Period that occurs at intervals of three months' duration after the first day of such Interest Period.

"Interest Period" means with respect to any Eurodollar Borrowing, the period commencing on the date of such Borrowing and ending (a) on the date that is one week thereafter or (b) on the numerically corresponding day in the calendar month that is one, two, three or six months thereafter, in each case as the Borrower may elect; *provided* (i) if any Interest Period would end on a day other than a Business Day, such Interest Period shall be extended to the next succeeding Business Day unless, in the case of any Eurodollar Borrowing, such next succeeding Business Day would fall in the next calendar month, in which case such Interest Period shall end on the next preceding Business Day, (ii) any Interest Period that commences on the last Business Day of a calendar month (or on a day for which there is no numerically corresponding day in the last calendar month of such Interest Period) shall end on the last Business Day of the last calendar month of such Interest Period and (iii) no Interest Period shall end after the Stated Maturity Date. For purposes hereof, the date of a Borrowing initially shall be the date on which such Borrowing is made and, in the case of a Eurodollar Borrowing, thereafter shall be the effective date of the most recent conversion or continuation of such Borrowing.

"Interpolated Rate" means, in relation to the LIBO Rate, the rate which results from interpolating on a linear basis between:

(a) the applicable LIBO Rate for the longest period (for which that LIBO Rate is available) which is less than the Interest Period of that Loan; and

(b) the applicable LIBO Rate for the shortest period (for which that LIBO Rate is available) which exceeds the Interest Period of that Loan,

each as of approximately 11:00 a.m. (London, England time) two Business Days prior to the commencement of such Interest Period of that Loan.

"IRS" means the United States Internal Revenue Service.

"KML" means Kinder Morgan Canada Limited and its consolidated subsidiaries.

"Laws" means, collectively, all international, foreign, federal, state and local statutes, treaties, rules, guidelines, regulations, ordinances, codes and administrative or judicial precedents or authorities, including the interpretation or administration thereof by any Governmental Authority charged with the enforcement, interpretation or administration thereof, and all applicable administrative orders, directed duties, requests, licenses, authorizations and permits of, and agreements with, any Governmental Authority.

"Lenders" has the meaning specified in the introduction to this Agreement.

"LIBO Rate" shall have the meaning ascribed thereto in the definition of "Eurodollar Rate".

"Lien" means, with respect to any asset (a) any mortgage, deed of trust, lien, pledge, hypothecation, encumbrance, charge or security interest in, on or of such asset, and (b) the interest of a vendor or a lessor under any conditional sale agreement, capital lease or title retention agreement (or any financing lease having substantially the same economic effect as any of the foregoing) relating to such asset.

"Loan Documents" mean, collectively, this Agreement, the Guaranty, the Notes, if any, the Fee Letters and all other instruments and documents from time to time executed and delivered by the Borrower or the Guarantors in connection herewith and therewith.

"Loan Party" means the Borrower and each Guarantor.

"Loans" means advances made by the Lenders to the Borrower pursuant to this Agreement.

"Material Adverse Effect" means, relative to any occurrence of whatever nature, a material adverse effect on (a) the business assets, liabilities or financial condition of the Borrower and the Subsidiaries taken as a whole, (b) the ability of the Borrower and the Guarantors, taken as a whole, to perform the Obligations or (c) the rights and remedies of the Administrative Agent or any Lender against the Borrower or, taken as a whole, the Guarantors, under any material provision of this Agreement or any other Loan Document.

"Material Subsidiary" means, as at any date of determination, any Subsidiary of the Borrower whose total tangible assets (for purposes of the below, when combined with the tangible assets of such Subsidiary's Subsidiaries, after eliminating intercompany obligations) as at such date of determination are greater than or equal to 5% of Consolidated Tangible Assets as of the last day of the fiscal quarter most recently ended for which financial statements have been delivered pursuant to Section 5.01(a) or (b) (the "Most Recent Financial Statement Date"), as the case may be; provided that if the aggregate total tangible assets of all Material Subsidiaries is less than 85% of Consolidated Tangible Assets as of the Most Recent Financial Statement Date, the Borrower shall designate Subsidiaries as "Material Subsidiaries" in writing to the Administrative Agent along with the delivery of the applicable financial statements pursuant to Section 5.01(a) or (b) such that the deficit described in this proviso ceases to exist; provided further that KML shall not be eligible to be considered as a Material Subsidiary (if applicable) until June 30, 2019.

"Maturity Date" means the earlier of (a) the Stated Maturity Date and (b) the acceleration of the Obligations pursuant to Section 7.01.

"Maximum Rate" has the meaning specified in Section 9.13.

"Moody's" means Moody's Investors Service, Inc.

"Most Recent Financial Statement Date" has the meaning specified in the definition of Material Subsidiary.

"Multiemployer Plan" means a multiemployer plan as defined in Section 4001(a)(3) of ERISA.

"Net Income" means with respect to any Person for any period that net income of such Person for such period determined in accordance with GAAP; *provided* that there shall be excluded, without duplication, from such net income (to the extent otherwise included therein).

(a) net extraordinary gains and losses (other than, in the case of losses, losses resulting from charges against net income to establish or increase reserves for potential environmental liabilities and reserves for exposure of such Person under rate cases);

(b) net gains or losses in respect of dispositions of assets other than in the ordinary course of business;

(c) any gains or losses attributable to write-ups or write-downs of assets; and

(d) proceeds of any key man insurance, or any insurance on property, plant or equipment.

"Net Worth" means, as to the Borrower at any date, the sum of the amount of shareholders' equity of the Borrower determined as of such date in accordance with GAAP, *provided* there shall be excluded, without duplication, from such determination (to the extent otherwise included therein) the amount of accumulated other comprehensive gain or loss as of such date.

"Non-Consenting Lender" means any Lender that does not approve any consent, waiver or amendment that (i) requires the approval of all Lenders or all affected Lenders in accordance with the terms of Section 9.02 and (ii) has been approved by the Required Lenders.

"Non-Defaulting Lender" means, at any time, each Lender that is not a Defaulting Lender at such time.

"Non-Guarantor Subsidiary" has the meaning specified in Section 6.01.

"Non-Wholly-owned Subsidiary" means any Subsidiary that is not a Wholly-owned Subsidiary.

"Note" means a Committed Note.

"Notice of Default" has the meaning specified in Section 7.01.

"Notice of Prepayment" has the meaning specified in Section 2.10(b).

"Obligations" means collectively:

(a) the payment of all indebtedness and liabilities by, and performance of all other obligations of, the Borrower in respect of the Loans;

(b) [reserved];

(c) the payment of all other indebtedness and liabilities by and performance of all other obligations of the Borrower to the Administrative Agent and the Lenders under, with respect to, and arising in connection with, the Loan Documents, and the payment of all indebtedness and liabilities of the Borrower to the Administrative Agent and the Lenders for fees, costs, indemnification and expenses (including reasonable attorneys' fees and expenses) under the Loan Documents;

(d) the reimbursement of all sums advanced and costs and expenses incurred by the Administrative Agent under any Loan Document (whether directly or indirectly) in connection with the Obligations or any part thereof or any renewal, extension or change of or substitution for the Obligations or, any part thereof, whether such advances, costs and expenses were made or incurred at the request of the Borrower or the Administrative Agent; and

(e) all renewals, extensions, amendments and changes of, or substitutions or replacements for, all or any part of the items described under clauses (a) through (d) above.

"OLP "B"" means Kinder Morgan Operating L.P. "B", a Delaware limited partnership.

"Operating Subsidiary" means any operating company that is a Subsidiary of the Borrower.

"Other Connection Taxes" means, with respect to any Recipient, Taxes imposed as a result of a present or former connection between such Recipient and the jurisdiction imposing such Tax (other than connections arising from such Recipient having executed, delivered, become a party to, performed its obligations under, received payments under, received or perfected a security interest under, engaged in any other transaction pursuant to or enforced any Loan Document, or sold or assigned an interest in any Loan or any Loan Document).

"Other Taxes" means all present or future stamp, court or documentary, intangible, recording, filing or similar Taxes that arise from any payment made under, from the execution, delivery, performance, enforcement or registration of, from the receipt or perfection of a security interest under, or otherwise with respect to, any Loan Document, except any such Taxes that are Other Connection Taxes imposed with respect to an assignment (other than an assignment made pursuant to Section 2.18(b)).

"Participant" has the meaning assigned to such term in Section 9.05(c).

"Participant Register" has the meaning specified in Section 9.05(c).

"Patriot Act" has the meaning specified in Section 9.15.

"PBGC" means the Pension Benefit Guaranty Corporation referred to and defined in ERISA and any successor entity performing similar functions.

"Performance Level" means a reference to one of Performance Level I, Performance Level II, Performance Level III, Performance Level IV, Performance Level V or Performance Level VI.

"Performance Level I" means, at any date of determination, that the Borrower shall have a Borrower Debt Rating in effect on such date of at least A- by S&P or at least A3 by Moody's.

"Performance Level II" means, at any date of determination, (a) that the Performance Level does not meet the requirements of Performance Level I and (b) that the Borrower shall have a Borrower Debt Rating in effect on such date of at least BBB+ by S&P or at least Baa1 by Moody's.

"Performance Level III" means, at any date of determination, (a) that the Performance Level does not meet the requirements of Performance Level I or Performance Level II and (b) that the Borrower shall have a Borrower Debt Rating in effect on such date of at least BBB by S&P, or at least Baa2 by Moody's.

"Performance Level IV" means, at any date of determination, (a) that the Performance Level does not meet the requirements of Performance Level I, Performance Level II or Performance Level III and (b) that the Borrower shall have a Borrower Debt Rating in effect on such date of at least BBB- by S&P, or at least Baa3 by Moody's.

"Performance Level V" means, at any date of determination, (a) that the Performance Level does not meet the requirements of Performance Level I, Performance Level II, Performance Level III or Performance Level IV and (b) that the Borrower shall have a Borrower Debt Rating in effect on such date of at least BB+ by S&P, or at least Ba1 by Moody's.

"Performance Level VI" means, at any date of determination, that the Performance Level does not meet the requirements of Performance Level I, Performance Level II, Performance Level III, Performance Level IV or Performance Level V.

"Person" means any natural person, corporation, limited liability company, trust, joint venture, association, company, partnership, Governmental Authority or other entity.

"Plan" means any employee pension benefit plan (other than a Multiemployer Plan) subject to the provisions of Title IV of ERISA or Section 412 of the Code or Section 302 of ERISA, and in respect of which the Borrower or any member of its ERISA Group is (or, if such plan were terminated, would under Section 4069 of ERISA be deemed to be) an *"employer"* as defined in Section 3(5) of ERISA.

"Plan Asset Regulations" means 29 CFR § 2510.3-101 et seq., as modified by Section 3(42) of ERISA, as amended from time to time.

"Prime Rate" means the rate of interest last quoted by The Wall Street Journal as the "Prime Rate" in the U.S. or, if The Wall Street Journal ceases to quote such rate, the highest per annum interest rate published by the Federal Reserve Board in Federal Reserve Statistical Release H.15 (519) (Selected Interest Rates) as the "bank prime loan" rate or, if such rate is no longer quoted therein, any similar rate quoted therein (as determined by the Administrative Agent) or any similar release by the Federal Reserve Board (as determined by the Administrative Agent).

"Principal Office" means the principal office of the Administrative Agent, presently located in New York, New York, or such other location as designated by the Administrative Agent from time to time.

"Recipient" means (a) the Administrative Agent and (b) any Lender, as applicable.

"Register" has the meaning specified in Section 9.05(b).

"Regulation D" means Regulation D of the Board, as the same is from time to time in effect, and all official rulings and interpretations thereunder or thereof.

"Regulation T" means Regulation T of the Board, as the same is from time to time in effect, and all official rulings and interpretations thereunder or thereof.

"Regulation U" means Regulation U of the Board, as the same is from time to time in effect, and all official rulings and interpretations thereunder or thereof.

"Regulation X" means Regulation X of the Board, as the same is from time to time in effect, and all official rulings and interpretations thereunder or thereof.

"Related Parties" means, with respect to any Person, such Person's Affiliates and the partners, directors, officers, employees, agents, trustees, administrators, managers, advisors and representatives of such Person and of such Person's Affiliates.

"Required Lenders" means, at any time, subject to the provisions of Section 9.02(b), Lenders having Credit Exposure and unused Commitments representing more than 50% of the sum of the total Credit Exposures and unused Commitments at such time.

"Requirement of Law" means any law, statute, code, ordinance, order, determination, rule, regulation, judgment, decree, injunction, franchise, permit, certificate, license, authorization or other directive or requirement (whether or not having the force of law), including Environmental Laws, energy regulations and occupational, safety and health standards or controls, of any Governmental Authority.

"Reserve Requirement" means, for any day a fraction (expressed as a decimal), the numerator of which is the number one and the denominator of which is the number one minus the aggregate of the maximum reserve percentage (including any marginal, special, emergency or supplemental reserves) expressed as a decimal established by the Board or other Governmental Authority to which the Administrative Agent is subject with respect to the Adjusted LIBO Rate, for eurocurrency funding (currently referred to as "*Eurocurrency Liabilities*" in Regulation D of the Board). Such reserve percentage shall include those imposed pursuant to such Regulation D. Eurodollar Loans shall be deemed to constitute eurocurrency funding and to be subject to such reserve requirements without benefit of or credit for proration, exemptions or offsets that may be available from time to time to any Lender under such Regulation D or any comparable regulations. The Reserve Requirement shall be adjusted automatically on and as of the effective date of any change in any such reserve percentage.

"Responsible Officer" means, as used with respect to the Borrower, the Chairman, Vice Chairman, President, any Vice President, Chief Executive Officer, Chief Financial Officer, Controller or Treasurer of the Borrower.

"Restricted Payment" means any distribution (whether in cash, securities or other property) with respect to any Capital Stock in the Borrower, or any payment (whether in cash, securities or other property), including any deposit, on account of the purchase, redemption, retirement, acquisition, cancellation or termination of any such Capital Stock or any option or other right to acquire any such Capital Stock.

"S&P" means Standard & Poor's Ratings Group, a division of The McGraw-Hill Companies, Inc.

"Sanctioned Country" means, at any time, a country, region or territory which is itself the subject or target of any Sanctions (at the time of this Agreement, Crimea, Cuba, Iran, North Korea, and Syria).

"Sanctioned Person" means, at any time, (a) any Person listed in any Sanctions-related list of designated Persons maintained by the Office of Foreign Assets Control of the U.S. Department of the Treasury, the U.S. Department of State, (b) any Person operating, organized or resident in a Sanctioned Country or (c) any Person owned or controlled by any such Person or Persons described in the foregoing clauses (a) or (b).

"Sanctions" has the meaning specified in Section 4.14(a).

"SEC" means the Securities and Exchange Commission or any Governmental Authority succeeding to its function.

"Solvent" means, with respect to any Person as of any date, that as of such date, (a)(i) the sum of such Person's indebtedness (including contingent liabilities) does not exceed the present fair saleable value of such Person's present assets; (ii) such Person's capital is not unreasonably small in relation to its business as contemplated on such date; and (iii) such Person has not incurred, and does not intend to incur, or believe that it will incur indebtedness (including current obligations) beyond its ability to pay principal and interest on such indebtedness as it becomes due (whether at maturity or otherwise); and (b) such Person

is "solvent" within the meaning given that term and similar terms under applicable laws relating to fraudulent transfers and conveyances. For the purposes of this definition, the amount of any contingent liability at any time shall be computed as the amount that, in light of all the facts and circumstances existing at such time, represents the amount that can reasonably be expected to become an actual or matured liability (irrespective of whether such contingent liabilities meet the criteria for accrual under Statement of Financial Accounting Standard No. 5).

"Stated Maturity Date" means, for any Lender, the date that is 364 days following the Closing Date or, if such date is not a Business Day, the immediately preceding Business Day.

"Subsidiary" means, with respect to any Person (the "parent") at any date, any corporation, limited liability company, partnership, association or other entity the accounts of which would be consolidated with those of the parent in the parent's consolidated financial statements if such financial statements were prepared in accordance with GAAP as of such date, as well as any other corporation, limited liability company, partnership, association or other entity that is, as of such date, otherwise controlled, by the parent or one or more subsidiaries of the parent or by the parent and one or more subsidiaries of the parent. Unless the context otherwise clearly requires, references in this Agreement to a "Subsidiary" or the "Subsidiaries" refer to a Subsidiary or the Subsidiaries of the Borrower.

"Syndication Agent" means JPMorgan Chase Bank, N.A.

"Taxes" means all present or future taxes, levies, imposts, duties, deductions, or withholdings (including backup withholding) assets, fees or other charges imposed by any Governmental Authority including any interest, additions to tax or penalties applicable thereto.

"Total Capitalization" means, as to the Borrower at any date, the sum of Consolidated Net Indebtedness (determined at such date) and the Net Worth (determined as at the end of the most recent fiscal quarter of the Borrower for which financial statements pursuant to Section 5.01(a) or Section 5.01(b), as applicable, have been delivered).

"Total Commitment" means the sum of the Commitments of the Lenders.

"Transactions" has the meaning specified in the Preliminary Statements.

"Type", when used in reference to any Loan or Borrowing, refers to whether the rate of interest on such Loan, or on the Loans comprising such Borrowing, is determined by reference to the Adjusted LIBO Rate or the Alternate Base Rate.

"United States" and "U.S." each means United States of America.

"U.S. Person" means any Person that is a "*United States Person*" as defined in Section 7701(a)(30) of the Code.

"U.S. Tax Compliance Certificate" has the meaning specified in Section 2.16(g)(ii)(B)(3).

"Voting Stock" means, with respect to any Person, securities of any class or classes of Capital Stock in such Person entitling holders thereof (whether at all times or only so long as no senior class of stock has voting power by reason of any contingency) to vote in the election of members of the

Board of Directors or other governing body of such Person or its managing member or its general partner (or its managing general partner if there is more than one general partner).

"Wholly-owned Domestic Operating Subsidiary" means any Wholly-owned Subsidiary that constitutes (i) a Domestic Subsidiary and (ii) an Operating Subsidiary.

"Wholly-owned Subsidiary" means a Subsidiary of which all issued and outstanding Capital Stock (excluding in the case of a corporation, directors' qualifying shares) is directly or indirectly owned by the Borrower.

"Withdrawal Liability" means liability to a Multiemployer Plan as a result of a complete or partial withdrawal from such Multiemployer Plan, as such terms are defined in Part I of Subtitle E of Title IV of ERISA.

"Withholding Agent" means the Administrative Agent and the Borrower.

"Write-Down and Conversion Powers" means, with respect to any EEA Resolution Authority, the write-down and conversion powers of such EEA Resolution Authority from time to time under the Bail-In Legislation for the applicable EEA Member Country, which write-down and conversion powers are described in the EU Bail-In Legislation Schedule.

SECTION 1.02 Classification of Loans and Borrowings. For purposes of this Agreement, Loans and Borrowings may be classified and referred to by Type (*e.g.*, a "*Eurodollar Loan*" or "*Eurodollar Borrowing*" or an "*ABR Loan*" or "*ABR Borrowing*").

SECTION 1.03 Accounting Terms; Changes in GAAP. All accounting and financial terms used herein and not otherwise defined herein and the compliance with each covenant contained herein which relates to financial matters shall be determined in accordance with GAAP applied by the Borrower on a consistent basis, except to the extent that a deviation therefrom is expressly stated. Should there be a change in GAAP from that in effect on the Closing Date, such that any of the defined terms set forth in Section 1.01 and/or compliance with the covenants set forth in Article VI would then be calculated in a different manner or with different components or any of such covenants and/or defined terms used therein would no longer constitute meaningful criteria for evaluating the matters addressed thereby prior to such change in GAAP (a) the Borrower and the Required Lenders agree, within the 60-day period following any such change, to negotiate in good faith and enter into an amendment to this Agreement in order to modify the defined terms set forth in Section 1.01 or the covenants set forth in Article VI, or both, in such respects as shall reasonably be deemed necessary by the Required Lenders that the criteria for evaluating the matters addressed by such covenants are substantially the same criteria as were effective prior to any such change in GAAP, and (b) the Borrower shall be deemed to be in compliance with such covenants during the 60-day period following any such change, or until the earlier date of execution of such amendment, if and to the extent that the Borrower would have been in compliance therewith under GAAP as in effect immediately prior to such change; provided, however, that for the avoidance of doubt, any lease that was accounted for by the Borrower or the Subsidiaries as an operating lease as of the Closing Date and any other lease entered into after the Closing Date by the Borrower or any Subsidiary shall be accounted for as an operating lease and not a capital lease to the extent that such lease would have been characterized as an operating lease as of the Closing Date.

SECTION 1.04 Interpretation. In this Agreement, unless a clear contrary intention appears:

(a) the singular number includes the plural number and vice versa;

(b) reference to any gender includes each other gender;

(c) the words "*herein*", "*hereof*" and "*hereunder*" and other words of similar import refer to this Agreement as a whole and not to any particular Article, Section or other subdivision;

(d) reference to any Person includes such Person's successors and assigns but, if applicable, only if such successors and assigns are permitted by this Agreement, and reference to a Person in a particular capacity excludes such Person in any other capacity or individually; *provided* that nothing in this clause (d) is intended to authorize any assignment not otherwise permitted by this Agreement;

(e) except as expressly provided to the contrary herein, reference to any agreement, document or instrument (including this Agreement) means such agreement, document or instrument as amended, supplemented or modified, or extended, renewed, refunded, substituted or replaced, and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof, and reference to any Note or other note or Indebtedness or other indebtedness includes any note or indebtedness issued pursuant hereto in extension or renewal or refunding thereof or in substitution or replacement therefor;

(f) unless the context indicates otherwise, reference to any Article, Section, Schedule or Exhibit means such Article or Section hereof or such Schedule or Exhibit hereto;

(g) the word "*including*" (and with correlative meaning "*include*") means including, without limiting the generality of any description preceding such term;

(h) with respect to the determination of any period of time, except as expressly provided to the contrary, the word "*from*" means "*from and including*" and the word "*to*" means "*to but excluding*";

(i) reference to any law, rule or regulation means such as amended, modified, codified or reenacted, in whole or in part, and in effect from time to time; and

(j) the words "*asset*" and "*property*" shall be construed to have the same meaning and effect and refer to any and all tangible and intangible assets and properties.

ARTICLE II
THE CREDITS

SECTION 2.01 Commitments.

Subject to the terms and conditions set forth herein, each Lender agrees to make Committed Loans in U.S. dollars to the Borrower from time to time during the Availability Period in an aggregate principal amount that will not result in (i) such Lender's Credit Exposure exceeding such Lender's Commitment or (ii) the sum of the total Credit Exposures exceeding the Total Commitment. Within the foregoing limits and subject to the terms and conditions set forth herein, the Borrower may borrow, prepay and reborrow Committed Loans.

SECTION 2.02 Loans and Borrowings.

(a) Each Committed Loan shall be made as part of a Borrowing consisting of Committed Loans denominated in U.S. dollars made by the Lenders, ratably in accordance with their Applicable Percentage of the Total Commitment on the date such Loan is made hereunder. The failure of

any Lender to make any Loan required to be made by it shall not relieve any other Lender of its obligations hereunder; *provided* that the Commitments of the Lenders are several and no Lender shall be responsible for any other Lender's failure to make Loans as required.

(b) Subject to Section 2.13, each Borrowing shall be comprised entirely of ABR Loans or Eurodollar Loans as the Borrower may request in accordance herewith. Each Lender at its option may make any Eurodollar Loan by causing any domestic or foreign branch or Affiliate of such Lender to make such Loan; *provided* that any exercise of such option shall not affect the obligation of the Borrower to repay such Loan in accordance with the terms of this Agreement.

(c) At the commencement of each Interest Period for any Eurodollar Borrowing, such Borrowing shall be in an aggregate amount that is an integral multiple of $1,000,000 and not less than $3,000,000. At the time that each ABR Borrowing is made, such Borrowing shall be in an aggregate amount that is an integral multiple of $1,000,000 and not less than $1,000,000; *provided* that an ABR Borrowing may be in an aggregate amount that is equal to the entire unused balance of the Total Commitment.

(d) There shall not at any time be more than a total of twelve Eurodollar Borrowings outstanding.

(e) Notwithstanding any other provision of this Agreement, the Borrower shall not be entitled to request, or to elect to convert or continue, any Borrowing if the Interest Period requested with respect thereto would end after the Stated Maturity Date.

SECTION 2.03 Requests for Borrowings.

To request a Borrowing, the Borrower shall notify the Administrative Agent of such request (which request shall be in writing unless otherwise agreed to by the Administrative Agent) (a) in the case of a Eurodollar Borrowing, not later than 11:00 a.m., New York, New York time, three Business Days before the date of the proposed Borrowing and (b) in the case of an ABR Borrowing, not later than 10:00 a.m., New York, New York, time, on the date of the proposed Borrowing. Each such Borrowing Request shall be irrevocable and shall be made by hand delivery, telecopy or electronic communication (e-mail) to the Administrative Agent of a written Borrowing Request in a form of Exhibit 2.03 (a "Borrowing Request") and signed by the Borrower. Each such Borrowing Request shall specify the following information in compliance with Section 2.02:

(i) the aggregate amount of the requested Borrowing;

(ii) the date of such Borrowing, which shall be a Business Day;

(iii) whether such Borrowing is to be an ABR Borrowing or a Eurodollar Borrowing;

(iv) in the case of a Eurodollar Borrowing, the initial Interest Period to be applicable thereto, which shall be a period contemplated by the definition of the term *"Interest Period"*; and

(v) the location and number of the Borrower's account to which funds are to be disbursed, which shall comply with the requirements of Section 2.06;

If no election as to the Type of Borrowing is specified, then the requested Borrowing shall be an ABR Borrowing. If no Interest Period is specified with respect to any requested Eurodollar Borrowing, then the Borrower shall be deemed to have selected an Interest Period of one month's duration. Promptly following receipt of a Borrowing Request in accordance with this Section 2.03, the Administrative Agent shall advise each Lender in writing of the details thereof and of the amount of such Lender's Loan to be made as part of the requested Borrowing.

SECTION 2.04 [Reserved].

SECTION 2.05 [Reserved].

SECTION 2.06 Funding of Borrowings.

(a) Each Lender shall make each Loan to be made by it hereunder on the proposed date thereof by wire transfer of immediately available funds by 2:00 p.m., New York, New York time, to the account of the Administrative Agent most recently designated by it for such purpose by notice to the Lenders. The Borrower hereby irrevocably authorizes the Administrative Agent to disburse the proceeds of each Borrowing requested pursuant to Section 2.03 in immediately available funds by crediting or wiring such proceeds to the deposit account of the Borrower identified in the Borrowing Request or otherwise agreed upon by the Borrower and the Administrative Agent from time to time.

(b) Unless the Administrative Agent shall have received notice from a Lender prior to the proposed date of any Borrowing (or prior to 11:00 a.m., New York, New York, time, on such date in the case of an ABR Borrowing) that such Lender will not make available to the Administrative Agent such Lender's Applicable Percentage of such Borrowing, the Administrative Agent may assume that such Lender has made such Applicable Percentage of such Borrowing available on such date in accordance with Section 2.06(a) and may, in reliance upon such assumption, make available to the Borrower a corresponding amount. In such event, if a Lender has not in fact made its Applicable Percentage of the applicable Borrowing available to the Administrative Agent, then the applicable Lender and the Borrower severally agree to pay to the Administrative Agent forthwith on demand such corresponding amount with interest thereon, for each day from the date such amount is made available to the Borrower to the date of payment to the Administrative Agent, at (i) in the case of such Lender, the greater of the Federal Funds Effective Rate and a rate determined by the Administrative Agent in accordance with banking industry rules on interbank compensation, or (ii) in the case of the Borrower, the interest rate applicable to ABR Loans. If the Borrower and such Lender shall pay such interest to the Administrative Agent for the same or an overlapping period, the Administrative Agent shall promptly remit to the Borrower the amount of such interest paid by the Borrower for such period. If such Lender pays its share of the applicable Borrowing to the Administrative Agent, then the amount so paid shall constitute such Lender's Loan included in such Borrowing. Any payment by the Borrower shall be without prejudice to any claim the Borrower may have against a Lender that shall have failed to make such payment to the Administrative Agent.

SECTION 2.07 Interest Elections.

(a) Subject to Section 2.13, each Borrowing initially shall be of the Type specified in the applicable Borrowing Request and, in the case of a Eurodollar Borrowing, shall have an initial Interest Period as specified in such Borrowing Request. Thereafter, subject to Section 2.13, the Borrower may elect to convert such Borrowing to a different Type or to continue such Borrowing and, in the case of a Eurodollar Borrowing, may elect Interest Periods therefor, all as provided in this Section 2.07. The Borrower may elect different options with respect to different portions of the affected Borrowing, in which case each such portion

shall be allocated ratably among the Lenders holding the Loans comprising such Borrowing, and the Loans comprising each such portion shall be considered a separate Borrowing.

(b) To make an election pursuant to this Section 2.07, the Borrower shall notify the Administrative Agent of such election (which notification shall be in writing unless otherwise agreed to by the Administrative Agent) by the time that a Borrowing Request would be required under Section 2.03 if the Borrower were requesting a Borrowing of the Type resulting from such election to be made on the effective date of such election. Each such Interest Election Request shall be irrevocable and shall be made by hand delivery or telecopy or by electronic communication (e-mail) to the Administrative Agent of an Interest Election Request in the form of Exhibit 2.07 (an "Interest Election Request").

(c) Each Interest Election Request shall specify the following information in compliance with Section 2.02:

(i) the Borrowing to which such Interest Election Request applies and, if different options are being elected with respect to different portions thereof, the portions thereof to be allocated to each resulting Borrowing (in which case the information to be specified pursuant to clauses (iii) and (iv) below shall be specified for each resulting Borrowing);

(ii) the effective date of the election made pursuant to such Interest Election Request, which shall be a Business Day;

(iii) whether the resulting Borrowing is to be an ABR Borrowing or a Eurodollar Borrowing; and

(iv) if the resulting Borrowing is a Eurodollar Borrowing, the Interest Period to be applicable thereto after giving effect to such election, which shall be a period contemplated by the definition of the term "*Interest Period*".

If any such Interest Election Request requests a Eurodollar Borrowing but does not specify an Interest Period, then the Borrower shall be deemed to have selected an Interest Period of one month's duration.

(d) Promptly following receipt of an Interest Election Request, the Administrative Agent shall advise each Lender in writing of the details thereof and of such Lender's portion of each resulting Borrowing.

(e) If the Borrower fails to deliver a timely Interest Election Request with respect to a Eurodollar Borrowing prior to the end of the Interest Period applicable thereto, then, unless such Borrowing is repaid as provided herein, at the end of such Interest Period such Borrowing shall be converted to an ABR Borrowing. Notwithstanding any contrary provision hereof, if and so long as an Event of Default is continuing and the Administrative Agent, at the request of the Required Lenders, so notifies the Borrower, then so long as an Event of Default has occurred and is continuing (i) no outstanding Borrowing may be converted to or continued as a Eurodollar Borrowing, and (ii) unless repaid, each Eurodollar Borrowing shall be converted to an ABR Borrowing at the end of the Interest Period applicable thereto.

SECTION 2.08 Termination and Reduction of Commitments; Mandatory Prepayments.

(a) Unless previously terminated, the Total Commitment shall terminate on the Maturity Date.

(b) The Borrower may at any time terminate, or from time to time reduce, the Total Commitment, in whole or in part; *provided* that (i) each partial reduction of the Total Commitment shall be in an amount that is an integral multiple of $1,000,000 and not less than $5,000,000 and (ii) the Borrower shall not terminate or reduce the Commitments if, after giving effect to any concurrent prepayment of the Loans in accordance with Section 2.10, the total Credit Exposures would exceed the Total Commitment.

(c) The Borrower shall notify the Administrative Agent of any election to terminate or reduce the Total Commitment under Section 2.08(a) at least three Business Days prior to the effective date of such termination or reduction, specifying such election and the effective date thereof. Promptly following receipt of any notice, the Administrative Agent shall advise the Lenders of the contents thereof. Each notice delivered by the Borrower pursuant to this Section 2.08 shall be irrevocable; *provided* that a notice of termination of the Total Commitment delivered by the Borrower may state that such notice is conditioned upon the effectiveness of other credit facilities or other event, in which case such notice may be revoked by the Borrower (by notice to the Administrative Agent on or prior to the specified effective date) if such condition is not satisfied. Any termination or reduction of the Total Commitment shall be permanent. Except as expressly provided in Section 2.19, each reduction of the Total Commitment shall be made ratably among the Lenders in accordance with their Applicable Percentages.

SECTION 2.09 Repayment of Loans; Evidence of Debt.

(a) The Borrower hereby unconditionally promises to pay to the Administrative Agent for the account of each Lender the then unpaid principal amount of each Committed Loan on the Maturity Date. In addition, if the total Credit Exposures exceeds the Total Commitment, the Borrower shall pay to the Administrative Agent for the account of each Lender an aggregate principal amount of Committed Loans sufficient to cause the total Credit Exposures not to exceed the Total Commitment; *provided*, *however*, if the repayment of the outstanding Committed Loans does not cause the total Credit Exposures, to be equal to or less than the Total Commitment, the Borrower shall deposit in an account with the Administrative Agent in the name of the Administrative Agent and for the benefit of the Lenders, an amount in cash equal to the amount by which the total Credit Exposures exceeds the Total Commitment, which cash deposit shall be held by the Administrative Agent for the payment of the Obligations of the Borrower under this Agreement and the other Loan Documents. The Administrative Agent shall have exclusive dominion and control, including the exclusive right of withdrawal, over such account other than any interest earned on the investment of such deposit (which investments shall be made at the option and sole discretion of the Administrative Agent, but only in investments rated at least AA (or equivalent) by at least one nationally recognized rating agency, unless an Event of Default shall have occurred and be continuing, and in any event at the Borrower's risk and expense). Interest or profits, if any, on such investments shall accumulate in such account. Moneys in such account shall be applied to satisfy other obligations of the Borrower under this Agreement and the other Loan Documents. At any time when the sum of the total Credit Exposures does not exceed the Total Commitment and so long as no Default under Section 7.01(b) or Event of Default shall then exist, upon the request of the Borrower the amount of such deposit (to the extent not applied as aforesaid) shall be returned to the Borrower within three Business Days after receipt of such request.

(b) Each Lender shall maintain in accordance with its usual practice an account or accounts evidencing the indebtedness of the Borrower to such Lender resulting from each Loan made by such Lender, including the amounts of principal and interest payable and paid to such Lender from time to time hereunder.

(c) The Administrative Agent shall maintain accounts in which it shall record (i) the amount of each Loan made hereunder, the Type thereof and the Interest Period applicable thereto, (ii) the amount of any principal or interest due and payable or to become due and payable from the Borrower to each Lender hereunder and (iii) the amount of any sum received by the Administrative Agent hereunder for the account of the Lenders and each Lender's share thereof.

(d) The entries made in the accounts maintained pursuant to Section 2.09(b) or (c) shall be prima facie evidence of the existence and amounts of the obligations recorded therein; *provided* that the failure of any Lender or the Administrative Agent to maintain such accounts or any error or conflict therein shall not in any manner affect the obligation of the Borrower to repay the Loans in accordance with the terms of this Agreement.

(e) Any Lender may request that Loans made by it be evidenced by a Committed Note. In such event, the Borrower shall prepare, execute and deliver to such Lender a Committed Note. Thereafter, the Loans evidenced by such Committed Note and interest thereon shall at all times (including after assignment pursuant to Section 9.05) be represented by one or more Committed Notes in such forms payable to the payee named therein.

SECTION 2.10 Voluntary Prepayment of Loans.

(a) The Borrower shall have the right at any time and from time to time to prepay any Borrowing in whole or in part, subject to prior notice in accordance with Section 2.10(b).

(b) The Borrower shall notify the Administrative Agent (which notice shall be made in writing by telecopy or electronic communication (e-mail) in the form of Exhibit 2.10 (a "Notice of Prepayment")) of any prepayment hereunder (i) in the case of prepayment of a Eurodollar Borrowing, not later than 11:00 a.m., New York, New York time, three Business Days before the date of prepayment or (ii) in the case of prepayment of an ABR Borrowing, not later than 11:00 a.m., New York, New York time, one Business Day prior to the date of prepayment. Each such notice shall be irrevocable and shall specify the prepayment date, Type and the principal amount of each Borrowing or portion thereof to be prepaid; *provided* that, if a notice of prepayment is given in connection with a conditional notice of termination of the Total Commitment as contemplated by Section 2.08, then such notice of prepayment may be revoked if such notice of termination of the Total Commitment is revoked in accordance with Section 2.08. Each partial prepayment shall be in an aggregate amount not less than, and shall be an integral multiple of, the amounts shown below with respect to the applicable Type of Loan or Borrowing:

Type of Loan/Borrowing	Integral Multiple of	Minimum Aggregate Amount
Eurodollar Borrowing	$1,000,000	$3,000,000
ABR Borrowing	$1,000,000	$1,000,000

Promptly following receipt of any such notice relating to a Borrowing, the Administrative Agent shall advise the Lenders in writing of the contents thereof. If the Borrower fails to designate the Type of Borrowings to be prepaid, partial prepayments shall be applied first to the outstanding ABR Borrowings until the outstanding principal amount of all ABR Borrowings is repaid in full, and then to the outstanding principal amount of Eurodollar Borrowings. Each partial prepayment of any Borrowing shall be in an amount that would be permitted in the case of an advance of a Borrowing of the same Type as provided in Section 2.02. Each prepayment of a Borrowing shall be applied to the Loans included in the prepaid Borrowing in accordance

with the Lenders' Applicable Percentage of such Borrowing. Prepayments shall be accompanied by accrued interest to the extent required by Section 2.12.

SECTION 2.11 Fees.

(a) The Borrower agrees to pay to the Administrative Agent for the account of each Lender (other than a Defaulting Lender) a commitment fee (the "Commitment Fee"), which shall be equal to (a) the Applicable Commitment Fee Rate times (b) the daily average undrawn portion of the such Lender's Commitment, during the period from the Closing Date to the later of (i) the date on which such Commitment terminates and (ii) the date on which the Loans are paid in full; *provided* that, if such Lender continues to have any Credit Exposure after its Commitment terminates, then such Commitment Fee shall continue to accrue on the daily amount of such Lender's Credit Exposure from the date on which its Commitment terminates to the date on which such Lender ceases to have any Credit Exposure. Accrued Commitment Fees shall be payable in arrears on the last Business Day of March, June, September and December of each year and on the date on which the Commitments terminate and the date the Loans are paid in full, commencing on the first such date to occur after the Closing Date. All Commitment Fees shall be computed on the basis of a year of 365 or 366 days, as the case may be, and shall be payable for the actual number of days elapsed (including the first day but excluding the last day).

(b) [Reserved].

(c) The Borrower agrees to pay, without duplication, to (i) the Administrative Agent and the Lenders, for their own accounts (or that of their applicable Affiliate), fees payable in the amounts and at the times specified in that letter agreement dated October 23, 2018 among the Borrower, Barclays Bank PLC and JPMorgan Chase Bank, N.A. (as from time to time amended, the "Fee Letter") and (ii) the Administrative Agent, for its own account (or that of its applicable Affiliate), fees payable in amounts and at the times specified in that letter agreement dated October 23, 2018 among the Borrower and Barclays Bank PLC (the "Administrative Agent Fee Letter").

(d) All fees payable hereunder shall be paid on the dates due, in immediately available funds, to the Administrative Agent (for distribution, in the case of Commitment Fees and participation fees, to the Lenders). Except as required by law, fees paid shall not be refundable under any circumstance.

SECTION 2.12 Interest.

(a) The Loans comprising each ABR Borrowing shall bear interest at a rate per annum equal to the *sum* of Alternate Base Rate *plus* the Applicable Margin.

(b) The Loans comprising each Eurodollar Borrowing shall bear interest at the Adjusted LIBO Rate for the Interest Period in effect for such Borrowing *plus* the Applicable Margin.

(c) Notwithstanding the foregoing, if any principal of or interest on any Loan or any fee or other amount payable by the Borrower hereunder is not paid when due, whether at stated maturity, upon acceleration or otherwise, such overdue amount shall bear interest, after as well as before judgment, at a rate per annum equal to (i) in the case of overdue principal of any Loan, 2% *plus* the rate otherwise applicable to such Loan as provided above or (ii) in the case of any other amount, 2% *plus* the Alternate Base Rate.

(d) Accrued interest on each Loan shall be payable in arrears on each Interest Payment Date for such Loan; *provided* that (i) interest accrued pursuant to Section 2.12(c) shall be payable on demand,

(ii) in the event of any repayment or prepayment of any Loan (other than a prepayment of an ABR Committed Loan prior to the end of the Availability Period), accrued interest on the principal amount repaid or prepaid shall be payable on the date of such repayment or prepayment, (iii) in the event of any conversion of any Eurodollar Committed Loan prior to the end of the current Interest Period therefor, accrued interest on such Loan shall be payable on the effective date of such conversion and (iv) all accrued interest shall be payable upon termination of the Total Commitment.

(e) All interest hereunder shall be computed on the basis of a year of 360-day year, except that interest computed by reference to the Alternate Base Rate at times when the Alternate Base Rate is based on the Prime Rate shall be computed on the basis of a year of 365 days (or 366 days in a leap year), and in each case shall be payable for the actual number of days elapsed (including the first day but excluding the last day). The applicable Alternate Base Rate, Adjusted LIBO Rate or LIBO Rate shall be determined by the Administrative Agent, and such determination shall be conclusive absent manifest error.

SECTION 2.13 Alternate Rate of Interest.

(a) If prior to the commencement of any Interest Period for a Eurodollar Borrowing:

(i) the Administrative Agent determines (which determination shall be conclusive absent manifest error) that adequate and reasonable means do not exist for ascertaining the Adjusted LIBO Rate or the LIBO Rate for such Interest Period; or

(ii) the Administrative Agent is advised by the Required Lenders that the Adjusted LIBO Rate or the LIBO Rate, as applicable, for such Interest Period will not adequately and fairly reflect the cost to such Lenders of making or maintaining their Loans included in such Borrowing for such Interest Period;

then the Administrative Agent shall give notice thereof to the Borrower and the Lenders in writing as promptly as practicable thereafter and, until the Administrative Agent notifies the Borrower and the Lenders in writing that the circumstances giving rise to such notice no longer exist, (i) any Interest Election Request that requests the conversion of any Borrowing to, or continuation of any Borrowing as, a Eurodollar Borrowing shall be ineffective, and (ii) if any Borrowing Request requests a Eurodollar Borrowing, such Borrowing shall be made as an ABR Borrowing.

(b) If at any time the Administrative Agent determines (which determination shall be conclusive absent manifest error) that (i) the circumstances set forth in clause (a)(i) have arisen and such circumstances are unlikely to be temporary or (ii) the circumstances set forth in clause (a)(i) have not arisen but the supervisor for the administrator of the LIBO Rate or a Governmental Authority having jurisdiction over the Administrative Agent has made a public statement identifying a specific date after which the LIBO Rate shall no longer be used for determining interest rates for loans, then the Administrative Agent and the Borrower shall endeavor to establish an alternate rate of interest to the LIBO Rate that gives due consideration to the then prevailing market convention for determining a rate of interest for syndicated loans in the United States at such time, and shall enter into an amendment to this Agreement to reflect such alternate rate of interest and such other related changes to this Agreement as may be applicable (but for the avoidance of doubt, such related changes shall not include a reduction of the Applicable Margin). Notwithstanding anything to the contrary in Section 9.02, such amendment shall become effective without any further action or consent of any other party to this Agreement so long as the Administrative Agent shall not have received, within five Business Days of the date notice of such alternate rate of interest is provided to the Lenders, a written notice from the Required Lenders stating that such Required Lenders object to such amendment. Until an alternate rate of interest shall be

determined in accordance with this clause (b) (but, in the case of the circumstances described in clause (ii) of the first sentence of this Section 2.13(b), only to the extent the LIBO Rate for such Interest Period is not available or published at such time on a current basis), (x) any Interest Election Request that requests the conversion of any Borrowing to, or continuation of any Borrowing as, a Eurodollar Borrowing shall be ineffective and (y) if any Borrowing Request requests a Eurodollar Borrowing, such Borrowing shall be made as an ABR Borrowing; provided that, if such alternate rate of interest shall be less than zero, such rate shall be deemed to be zero for the purposes of this Agreement.

SECTION 2.14 Increased Costs.

(a) If any Change in Law shall:

(i) impose, modify or deem applicable any reserve, special deposit or similar requirement against assets of, deposits with or for the account of, or credit extended by, any Lender (except any such reserve requirement reflected in the Adjusted LIBO Rate);

(ii) subject any Recipient to any Taxes (other than (A) Indemnified Taxes, (B) Taxes described in clauses (b) through (d) of the definition of Excluded Taxes and (C) Connection Income Taxes) on its Loans, loan principal, Commitments, or other Obligations, or its deposits, reserves, other liabilities or capital attributable thereto; or

(iii) impose on any Lender or the London interbank market any other condition, cost or expense (other than Taxes) affecting this Agreement or Eurodollar Loans made by such Lender;

and the result of any of the foregoing shall be to increase the cost to such Lender or such other Recipient of making, converting to, continuing or maintaining any Loan or of maintaining its obligation to make any such Loan, or to reduce the amount of any sum received or receivable by such Lender or other Recipient hereunder (whether of principal, interest or any other amount) then, upon request of such Lender or other Recipient, the Borrower will pay to such Lender or other Recipient, as the case may be, such additional amount or amounts as will compensate such Lender or other Recipient, as the case may be, for such additional costs incurred or reduction suffered.

(b) If any Lender determines that any Change in Law affecting such Lender or any lending office of such Lender or such Lender's holding company, if any, regarding capital or liquidity requirements, has or would have the effect of reducing the rate of return on such Lender's capital or on the capital of such Lender's holding company, if any, as a consequence of this Agreement, the Commitment of such Lender or the Loans made by such Lender, to a level below that which such Lender or such Lender's holding company could have achieved but for such Change in Law (taking into consideration such Lender's policies and the policies of such Lender's holding company with respect to capital adequacy and/or liquidity requirements), then from time to time the Borrower will pay to such Lender such additional amount or amounts as will compensate such Lender or such Lender's holding company for any such reduction suffered.

(c) A certificate of a Lender setting forth the amount or amounts necessary to compensate such Lender or its holding company, as the case may be, as specified in paragraph (a) or (b) of this Section 2.14 and delivered to the Borrower, shall be conclusive absent manifest error. The Borrower shall pay such Lender the amount shown as due on any such certificate within 10 Business Days after receipt thereof.

(d) Failure or delay on the part of any Lender to demand compensation pursuant to this Section 2.14 shall not constitute a waiver of such Lender's right to demand such compensation; *provided* that the Borrower shall not be required to compensate a Lender pursuant to this Section 2.14 for any increased costs or reductions incurred more than six months prior to the date that such Lender notifies the Borrower of the Change in Law giving rise to such increased costs or reductions and of such Lender's intention to claim compensation therefor (except that, if the Change in Law giving rise to such increased costs or reductions is retroactive, then the six-month period referred to above shall be extended to include the period of retroactive effect thereof).

SECTION 2.15 Break Funding Payments. In the event of (a) the payment of any principal of any Eurodollar Loan other than on the last day of an Interest Period applicable thereto (including as a result of an Event of Default), (b) the conversion of any Eurodollar Loan other than on the last day of the Interest Period applicable thereto, (c) the failure to borrow (unless such failure was caused by the failure of a Lender to make such Loan), convert, continue or prepay any Eurodollar Loan, or the failure to convert an ABR Loan to a Eurodollar Loan, on the date specified in any notice delivered pursuant hereto (regardless of whether such notice is permitted to be revocable under Section 2.08 and is revoked in accordance herewith), or (d) the assignment of any Eurodollar Loan other than on the last day of the Interest Period applicable thereto as a result of a request by the Borrower pursuant to Section 2.18, then, in any such event, the Borrower shall compensate each Lender for the loss, cost and expense attributable to such event. In the case of a Eurodollar Loan, the loss to any Lender attributable to any such event shall be deemed to include an amount determined by such Lender to be equal to the excess, if any, of (i) the amount of interest that such Lender would pay for a deposit equal to the principal amount of such Loan for the period from the date of such payment, conversion, failure or assignment to the last day of the then current Interest Period for such Loan (or, in the case of a failure to borrow, convert or continue, the duration of the Interest Period that would have resulted from such borrowing, conversion or continuation) if the interest rate payable on such deposit were equal to the Adjusted LIBO Rate for such Interest Period, over (ii) the amount of interest that such Lender would earn on such principal amount for such period if such Lender were to invest such principal amount for such period at the interest rate that would be bid by such Lender (or an affiliate of such Lender) for dollar deposits from other banks in the Eurodollar market at the commencement of such period. A certificate of any Lender setting forth any amount or amounts that such Lender is entitled to receive pursuant to this Section 2.15 shall be delivered to the Borrower and shall be conclusive absent manifest error. The Borrower shall pay such Lender the amount shown as due on any such certificate within 10 Business Days after receipt thereof.

SECTION 2.16 Taxes.

(a) Defined Terms. For purposes of this Section 2.16, the term "Requirement of Law" includes FATCA.

(b) Payments Free of Taxes. Any and all payments by or on account of any obligation of the Borrower under any Loan Document shall be made without deduction or withholding for any Taxes, except as required by a Requirement of Law. If any Requirement of Law (as determined in the good faith discretion of the Withholding Agent) requires the deduction or withholding of any Tax from any such payment by the Withholding Agent, then the Withholding Agent shall be entitled to make such deduction or withholding and shall timely pay the full amount deducted or withheld to the relevant Governmental Authority in accordance with applicable Requirement of Law and, if such Tax is an Indemnified Tax, then the sum payable by the Borrower shall be increased as necessary so that after such deduction or withholding has been made (including such deductions and withholdings applicable to additional sums payable under this Section 2.16) the applicable Recipient receives an amount equal to the sum it would have received had no such deduction or withholding been made.

(c) Payment of Other Taxes by the Borrower. Without duplication of any obligation under this Section 2.16, the Borrower shall timely pay to the relevant Governmental Authority in accordance with applicable Requirement of Law, or at the option of the Administrative Agent timely reimburse it for the payment of, any Other Taxes.

(d) Indemnification by the Borrower. Without duplication of any obligation under this Section 2.16, the Borrower shall indemnify each Recipient, within 10 days after demand therefor, for the full amount of any Indemnified Taxes (including Indemnified Taxes imposed or asserted on or attributable to amounts payable under this Section) payable or paid by such Recipient or required to be withheld or deducted from a payment to such Recipient and any reasonable expenses arising therefrom or with respect thereto, whether or not such Indemnified Taxes were correctly or legally imposed or asserted by the relevant Governmental Authority; *provided, however*, the Borrower shall not be required to indemnify a Recipient pursuant to this Section 2.16(d) for any Indemnified Taxes unless such Recipient makes written demand on the Borrower for indemnification for such Indemnified Taxes no later than six months after the earlier of (i) the date on which such Recipient receives written demand from the relevant Governmental Authority for payment of such Indemnified Taxes or (ii) the date on which such Recipient has made payment of such Indemnified Taxes. A certificate as to the amount of such payment or liability delivered to the Borrower by a Lender (with a copy to the Administrative Agent), or by the Administrative Agent on its own behalf or on behalf of a Lender, shall be conclusive absent manifest error.

(e) Indemnification by the Lenders. Each Lender shall severally indemnify the Administrative Agent, within 10 days after demand therefor, for (i) any Taxes attributable to such Lender (but only to the extent that the Borrower has not already indemnified the Administrative Agent for such Taxes and without limiting the obligation of the Borrower to do so), (ii) any Taxes attributable to such Lender's failure to comply with the provisions of Section 9.05(c) relating to the maintenance of a Participant Register and (iii) any Excluded Taxes attributable to such Lender, in each case, that are payable or paid by the Administrative Agent in connection with any Loan Document, and any reasonable expenses arising therefrom or with respect thereto, whether or not such Taxes were correctly or legally imposed or asserted by the relevant Governmental Authority. A certificate as to the amount of such payment or liability delivered to any Lender by the Administrative Agent shall be conclusive absent manifest error. Each Lender hereby authorizes the Administrative Agent to set off and apply any and all amounts at any time owing to such Lender under any Loan Document or otherwise payable by the Administrative Agent to the Lender from any other source against any amount due to the Administrative Agent under this paragraph (e).

(f) Evidence of Payments. As soon as practicable after any payment of Taxes by the Borrower to a Governmental Authority pursuant to this Section 2.16, the Borrower shall deliver to the Administrative Agent the original or a certified copy of a receipt issued by such Governmental Authority evidencing such payment, a copy of the return reporting such payment or other evidence of such payment reasonably satisfactory to the Administrative Agent.

(g) Status of Lenders. (i) Any Lender that is entitled to an exemption from or reduction of withholding Tax with respect to payments made under any Loan Document shall deliver to the Borrower and the Administrative Agent, at the time or times reasonably requested by the Borrower or the Administrative Agent, such properly completed and executed documentation reasonably requested by the Borrower or the Administrative Agent as will permit such payments to be made without withholding or at a reduced rate of withholding. In addition, any Lender, if reasonably requested by the Borrower or the Administrative Agent, shall deliver such other documentation prescribed by applicable Requirement of Law or reasonably requested by the Borrower or the Administrative Agent as will enable the Borrower or the Administrative Agent to determine whether or not such Lender is subject to backup withholding or

information reporting requirements. Notwithstanding anything to the contrary in the preceding two sentences, the completion, execution and submission of such documentation (other than such documentation set forth in subsections (ii)(A), (ii)(B) and (ii)(D) below) shall not be required if in the Lender's reasonable judgment such completion, execution or submission would subject such Lender to any material unreimbursed cost or expense or would materially prejudice the legal or commercial position of such Lender.

(ii) Without limiting the generality of the foregoing, in the event that the Borrower is a U.S. Borrower,

(A) any Lender that is a U.S. Person shall deliver to the Borrower and the Administrative Agent on or prior to the date on which such Lender becomes a Lender under this Agreement (and from time to time thereafter upon the reasonable request of the Borrower or the Administrative Agent), executed originals of IRS Form W-9 certifying that such Lender is exempt from U.S. federal backup withholding Tax;

(B) any Foreign Lender shall, to the extent it is legally entitled to do so, deliver to the Borrower and the Administrative Agent (in such number of copies as shall be requested by the recipient) on or prior to the date on which such Foreign Lender becomes a Lender under this Agreement (and from time to time thereafter upon the reasonable request of the Borrower or the Administrative Agent), whichever of the following is applicable:

(1) in the case of a Foreign Lender claiming the benefits of an income Tax treaty to which the United States is a party (x) executed originals of IRS Form W-8BEN or IRS Form W-8BEN-E establishing an exemption from, or reduction of, U.S. federal withholding Tax pursuant to the "interest" article of such Tax treaty and (y) IRS Form W-8BEN or IRS Form W-8BEN-E establishing an exemption from, or reduction of, U.S. federal withholding Tax pursuant to the "business profits" or "other income" article of such Tax treaty;

(2) executed originals of IRS Form W-8ECI;

(3) in the case of a Foreign Lender claiming the benefits of the exemption for portfolio interest under Section 881(c) of the Code, (x) a certificate substantially in the form of Exhibit 2.16-A to the effect that such Foreign Lender is not a "bank" within the meaning of Section 881(c)(3)(A) of the Code, a "10 percent shareholder" of the Borrower within the meaning of Section 881(c)(3)(B) of the Code, or a "controlled foreign corporation" described in Section 881(c)(3)(C) of the Code (a "U.S. Tax Compliance Certificate") and (y) executed originals of IRS Form W-8BEN or IRS Form W-8BEN-E; or

(4) to the extent a Foreign Lender is not the beneficial owner, executed originals of IRS Form W-8IMY, accompanied by IRS Form W-8ECI, IRS Form W-8BEN or IRS Form W-8BEN-E, a U.S. Tax Compliance Certificate substantially in the form of Exhibit 2.16-B or Exhibit 2.16-C, IRS Form W-9, and/or other certification documents from each beneficial owner, as applicable; *provided* that if the Foreign Lender is a partnership and one or more direct or indirect partners of such Foreign Lender are claiming the portfolio interest exemption, such Foreign Lender may provide a U.S. Tax Compliance Certificate substantially in the form of Exhibit 2.16-D on behalf of each such direct and indirect partner;

(C) any Foreign Lender shall, to the extent it is legally entitled to do so, deliver to the Borrower and the Administrative Agent (in such number of copies as shall be requested by the recipient) on or prior to the date on which such Foreign Lender becomes a Lender under this Agreement (and from time to time thereafter upon the reasonable request of the Borrower or the Administrative Agent), executed originals of any other form prescribed by applicable Requirement of Law as a basis for claiming exemption from or a reduction in U.S. federal withholding Tax, duly completed and executed, together with such supplementary documentation as may be prescribed by applicable Requirement of Law to permit the Borrower or the Administrative Agent to determine the withholding or deduction required to be made; and

(D) if a payment made to a Lender under any Loan Document would be subject to U.S. federal withholding Tax imposed by FATCA if such Lender were to fail to comply with the applicable reporting requirements of FATCA (including those contained in Section 1471(b) or 1472(b) of the Code, as applicable), such Lender shall deliver to the Borrower and the Administrative Agent at the time or times prescribed by Requirement of Law and at such time or times reasonably requested by the Borrower or the Administrative Agent such documentation prescribed by applicable Requirement of Law (including as prescribed by Section 1471(b)(3)(C)(i) of the Code) and such additional documentation reasonably requested by the Borrower or the Administrative Agent as may be necessary for the Borrower and the Administrative Agent to comply with their obligations under FATCA and to determine that such Lender has complied with such Lender's obligations under FATCA or to determine the amount to deduct and withhold from such payment. Solely for purposes of this clause (D), "*FATCA*" shall include any amendments made to FATCA after the date of this Agreement.

Each Lender agrees that if any form or certification it previously delivered expires or becomes obsolete or inaccurate in any respect, it shall update such form or certification or promptly notify the Borrower and the Administrative Agent in writing of its legal inability to do so.

(h) Treatment of Certain Refunds. If any party determines, in its sole discretion exercised in good faith, that it has received a refund of any Taxes as to which it has been indemnified pursuant to this Section 2.16 (including by the payment of additional amounts pursuant to this Section 2.16), it shall pay to the indemnifying party an amount equal to such refund (but only to the extent of indemnity payments made under this Section with respect to the Taxes giving rise to such refund), net of all out-of-pocket expenses (including Taxes) of such indemnified party and without interest (other than any interest paid by the relevant Governmental Authority with respect to such refund). Such indemnifying party, upon the request of such indemnified party, shall repay to such indemnified party the amount paid over pursuant to this paragraph (h) (plus any penalties, interest or other charges imposed by the relevant Governmental Authority) in the event that such indemnified party is required to repay such refund to such Governmental Authority. Notwithstanding anything to the contrary in this paragraph (h), in no event will the indemnified party be required to pay any amount to an indemnifying party pursuant to this paragraph (h) the payment of which would place the indemnified party in a less favorable net after-Tax position than the indemnified party would have been in if the Tax subject to indemnification and giving rise to such refund had not been deducted, withheld or otherwise imposed and the indemnification payments or additional amounts with respect to such Tax had never been paid. This paragraph shall not be construed to require any indemnified party to make available its Tax returns (or any other information relating to its Taxes that it deems confidential) to the indemnifying party or any other Person.

(i) On or before the date that Barclays Bank PLC (or any successor or replacement Administrative Agent) becomes the Administrative Agent hereunder, it shall deliver to the Borrower two duly executed originals of either (i) IRS Form W-9 (or any applicable successor form) certifying that the Administrative Agent is not subject to backup withholding, or (ii) IRS Form W-8IMY (or any applicable successor form) establishing that the Administrative Agent will act as a withholding agent for any U.S. federal withholding tax imposed with respect to any payments made to Lenders under any Loan Document.

(j) Survival. Each party's obligations under this Section 2.16 shall survive the resignation or replacement of the Administrative Agent or any assignment of rights by, or the replacement of, a Lender, the termination of the Commitments and the repayment, satisfaction or discharge of all obligations under any Loan Document.

SECTION 2.17 Payments Generally; Pro Rata Treatment; Sharing of Set-offs.

(a) The Borrower shall make each payment required to be made by the Borrower hereunder (whether of principal, interest or fees, or under Section 2.14, 2.15 or 2.16, or otherwise) prior to 12:00 noon, New York, New York time, on the date when due, in immediately available funds, without set-off or counterclaim. Any amounts received after such time on any date may, in the discretion of the Administrative Agent, be deemed to have been received on the next succeeding Business Day for purposes of calculating interest thereon. All such payments shall be made to the Administrative Agent at its Principal Office, except that payments pursuant to Sections 2.14, 2.15, 2.16 and 9.03 shall be made directly to the Persons entitled thereto. The Administrative Agent shall distribute any such payments received by it for the account of any other Person to the appropriate recipient promptly following receipt thereof. If any payment hereunder shall be due on a day that is not a Business Day, the date for payment shall be extended to the next succeeding Business Day, and, in the case of any payment accruing interest, interest thereon shall be payable for the period of such extension. All payments hereunder shall be made in dollars.

(b) If at any time insufficient funds are received by and available to the Administrative Agent to pay fully all amounts of principal, interest and fees then due hereunder, such funds shall be applied to pay interest and fees then due hereunder, ratably among the parties entitled thereto in accordance with the amounts of interest and fees then due to such parties.

(c) If any Lender shall, by exercising any right of setoff or counterclaim or otherwise, obtain payment in respect of any principal of or interest on any of its Loans or other obligations hereunder resulting in such Lender receiving payment of a proportion of the aggregate amount of its Loans and accrued interest thereon or other such obligations greater than its *pro rata* share thereof as provided herein, then the Lender receiving such greater proportion shall (a) notify the Administrative Agent of such fact, and (b) purchase (for cash at face value) participations in the Loans and such other obligations of the other Lenders, or make such other adjustments as shall be equitable, so that the benefit of all such payments shall be shared by the Lenders ratably in accordance with the aggregate amount of principal of and accrued interest on their respective Loans and other amounts owing them*; provided* that:

(i) if any such participations are purchased and all or any portion of the payment giving rise thereto is recovered, such participations shall be rescinded and the purchase price restored to the extent of such recovery, without interest; and

(ii) the provisions of this paragraph shall not be construed to apply to (x) any payment made by the Borrower pursuant to and in accordance with the express terms of this Agreement (including the application of funds arising from the existence of a Defaulting Lender), or (y) any payment obtained by a Lender as consideration for the assignment of or sale of a

participation in any of its Loans to any assignee or participant, other than to the Borrower or any Subsidiary thereof (as to which the provisions of this paragraph shall apply).

The Borrower consents to the foregoing and agrees, to the extent it may effectively do so under applicable law, that any Lender acquiring a participation pursuant to the foregoing arrangements may exercise against the Borrower rights of setoff and counterclaim with respect to such participation as fully as if such Lender were a direct creditor of the Borrower in the amount of such participation.

(d) Unless the Administrative Agent shall have received notice from the Borrower prior to the date on which any payment is due to the Administrative Agent for the account of the Lenders hereunder that the Borrower will not make such payment, the Administrative Agent may assume that the Borrower has made such payment on such date in accordance herewith and may, in reliance upon such assumption, distribute to the Lenders the amount due. In such event, if the Borrower has not in fact made such payment, then each of the Lenders severally agrees to repay to the Administrative Agent forthwith on demand the amount so distributed to such Lender with interest thereon, for each day from the date such amount is distributed to it to the date of payment to the Administrative Agent, at the greater of the Federal Funds Effective Rate and a rate determined by the Administrative Agent in accordance with banking industry rules or interbank compensation.

(e) If any Lender shall fail to make any payment required to be made by it pursuant to Section 2.06(b), 2.17(d) or 8.08, then the Administrative Agent may, in its discretion (notwithstanding any contrary provision hereof), (i) apply any amounts thereafter received by the Administrative Agent for the account of such Lender to satisfy such Lender's obligations under such Sections until all such unsatisfied obligations are fully paid and/or (ii) hold any such amounts in a segregated account as cash collateral for, and application to, any future funding obligations of such Lender under such Sections; in the case of each of (i) and (ii) above, in any order as determined by the Administrative Agent in its discretion.

SECTION 2.18 Mitigation of Obligations; Replacement of Lenders.

(a) Designation of a Different Lending Office. If any Lender requests compensation under Section 2.14, or requires the Borrower to pay any Indemnified Taxes or additional amounts to any Lender or any Governmental Authority for the account of any Lender pursuant to Section 2.16, then such Lender shall (at the request of the Borrower) use reasonable efforts to designate a different lending office for funding or booking its Loans hereunder or to assign its rights and obligations hereunder to another of its offices, branches or affiliates, if, in the judgment of such Lender, such designation or assignment (i) would eliminate or reduce amounts payable pursuant to Section 2.14 or 2.16, as the case may be, in the future, and (ii) would not subject such Lender to any unreimbursed cost or expense and would not otherwise be disadvantageous to such Lender. The Borrower hereby agrees to pay all reasonable costs and expenses incurred by any Lender in connection with any such designation or assignment.

(b) Replacement of Lenders. If any Lender requests compensation under Section 2.14, or if the Borrower is required to pay any Indemnified Taxes or additional amounts to any Lender or any Governmental Authority for the account of any Lender pursuant to Section 2.16 and, in each case, such Lender has declined or is unable to designate a different lending office in accordance with Section 2.18(a), or if any Lender is a Defaulting Lender or a Non-Consenting Lender, then the Borrower may, at its sole expense and effort, upon notice to such Lender and the Administrative Agent, require such Lender to assign and delegate, without recourse (in accordance with and subject to the restrictions contained in, and consents required by, Section 9.05), all of its interests, rights (other than its existing rights to payments pursuant to Section 2.14 or Section 2.16) and obligations under this Agreement and the related Loan Documents to an

Eligible Assignee that shall assume such obligations (which assignee may be another Lender, if a Lender accepts such assignment); *provided* that:

(i) the Borrower shall have paid to the Administrative Agent the assignment fee (if any) specified in Section 9.05;

(ii) such Lender shall have received payment of an amount equal to the outstanding principal of its Loans, accrued interest thereon, accrued fees and all other amounts payable to it hereunder and under the other Loan Documents (including any amounts under Section 2.15) from the assignee (to the extent of such outstanding principal and accrued interest and fees) or the Borrower (in the case of all other amounts);

(iii) in the case of any such assignment resulting from a claim for compensation under Section 2.14 or payments required to be made pursuant to Section 2.16, such assignment will result in a reduction in such compensation or payments thereafter;

(iv) such assignment does not conflict with applicable law; and

(v) in the case of any assignment resulting from a Lender becoming a Non-Consenting Lender, the applicable assignee shall have consented to the applicable amendment, waiver or consent.

A Lender shall not be required to make any such assignment or delegation if, prior thereto, as a result of a waiver by such Lender or otherwise, the circumstances entitling the Borrower to require such assignment and delegation cease to apply.

SECTION 2.19 Defaulting Lenders. (a) Notwithstanding anything to the contrary contained in this Agreement, if any Lender becomes a Defaulting Lender, then, until such time as such Lender is no longer a Defaulting Lender, to the extent permitted by applicable law:

(i) Such Defaulting Lender's right to approve or disapprove any amendment, waiver or consent with respect to this Agreement shall be restricted as set forth in Section 9.02.

(ii) Any payment of principal, interest, fees or other amounts received by the Administrative Agent for the account of such Defaulting Lender (whether voluntary or mandatory, at maturity, pursuant to Article VII or otherwise) or received by the Administrative Agent from a Defaulting Lender pursuant to Section 9.09 shall be applied at such time or times as may be determined by the Administrative Agent as follows: *first*, to the payment of any amounts owing by such Defaulting Lender to the Administrative Agent hereunder; *second*, as the Company may request (so long as no Default or Event of Default exists), to the funding of any Loan in respect of which such Defaulting Lender has failed to fund its portion thereof as required by this Agreement, as determined by the Administrative Agent; *third*, if so determined by the Administrative Agent and the Borrower, to be held in a deposit account and released *pro rata* in order to satisfy such Defaulting Lender's potential future funding obligations with respect to Loans under this Agreement; *fourth*, to the payment of any amounts owing to the Lenders as a result of any judgment of a court of competent jurisdiction obtained by any Lender against such Defaulting Lender as a result of such Defaulting Lender's breach of its obligations under this Agreement; *fifth,* so long as no Default or Event of Default exists, to the payment of any amounts owing to the Borrower as a result of any judgment of a court of competent jurisdiction obtained by the Borrower against such Defaulting Lender as a result of such Defaulting Lender's breach of its obligations under this Agreement; and

sixth, to such Defaulting Lender or as otherwise directed by a court of competent jurisdiction; *provided* that if (x) such payment is a payment of the principal amount of any Loans in respect of which such Defaulting Lender has not fully funded its appropriate share, and (y) such Loans were made at a time when the conditions set forth in Section 3.02 were satisfied or waived, such payment shall be applied solely to pay the Loans of all Non-Defaulting Lenders on a *pro rata* basis prior to being applied to the payment of any Loans of such Defaulting Lender until such time as all Loans are held by the Lenders *pro rata* in accordance with the Commitments. Any payments, prepayments or other amounts paid or payable to a Defaulting Lender that are applied (or held) to pay amounts owed by a Defaulting Lender shall be deemed paid to and redirected by such Defaulting Lender, and each Lender irrevocably consents hereto.

(iii) (A) Each Defaulting Lender shall be entitled to receive a Commitment Fee for any period during which that Lender is a Defaulting Lender only to extent allocable to the outstanding principal amount of the Loans funded by it.

(B) With respect to any Commitment Fee under Section 2.11(b) not required to be paid to any Defaulting Lender pursuant to clause (A) above, the Borrower shall not be required to pay the remaining amount of any such fee.

(b) If the Borrower and the Administrative Agent agree in writing that a Lender is no longer a Defaulting Lender, the Administrative Agent will so notify the parties hereto, whereupon as of the effective date specified in such notice and subject to any conditions set forth therein, that Lender will, to the extent applicable, purchase at par that portion of outstanding Loans of the other Lenders or take such other actions as the Administrative Agent may determine to be necessary to cause the Loans to be held *pro rata* by the Lenders in accordance with their respective Commitments, whereupon, that Lender will cease to be a Defaulting Lender; *provided* that no adjustments will be made retroactively with respect to fees accrued or payments made by or on behalf of the Borrower while that Lender was a Defaulting Lender; and *provided*, *further*, that except to the extent otherwise expressly agreed by the affected parties, no change hereunder from Defaulting Lender to Lender will constitute a waiver or release of any claim of any party hereunder arising from that Lender's having been a Defaulting Lender.

ARTICLE III
CONDITIONS PRECEDENT

SECTION 3.01 Conditions Precedent to the Closing Date. The obligations of the Lenders to make Loans hereunder shall not become effective until the date on which each of the following conditions is satisfied or waived in accordance with Section 9.02:

(a) The Administrative Agent shall have received the following, each dated as of the Closing Date:

(i) this Agreement executed by each party hereto;

(ii) the Guaranty executed by each party thereto;

(iii) a certificate of an officer and of the secretary or an assistant secretary of the Borrower and each Guarantor, certifying, *inter alia* (A) true and complete copies of each of the certificate of incorporation or other appropriate organizational document, as amended and in effect, of such Person, the bylaws or similar organizational document, as amended and in effect, of such Person and the resolutions adopted by the Board of Directors or similar governing body of such Person (1) authorizing the execution, delivery and performance by such Person of each Loan

Document to which such Person is or will be a party, (2) approving the Loan Documents to which such Person is or will be a party and (3) authorizing officers of such Person to execute and deliver the Loan Documents to which such Person is or will be a party and any related documents and (B) the incumbency and specimen signatures of the officers of such Person executing any documents on its behalf; provided, that there shall be no requirement to deliver such certificates for any Guarantor that is not a Material Subsidiary;

(iv) a certificate of a Responsible Officer of the Borrower certifying as to the satisfaction of the conditions in Sections 3.01(c) and (e); and

(v) signed opinions addressed to the Administrative Agent and the Lenders from legal counsel to the Borrower and the Guarantors covering the matters reasonably requested by the Administrative Agent; provided, that there shall be no requirement to deliver opinions of legal counsel for any Guarantor that is not a Material Subsidiary.

(b) The Administrative Agent shall have received a certificate of appropriate officials as to the existence and good standing of the Borrower and each Guarantor.

(c) There shall not have occurred any change, effect, event or occurrence since December 31, 2017 that, individually or in the aggregate, has had, or would reasonably be expected to have, a Material Adverse Effect.

(d) The Administrative Agent shall have received evidence that the Existing Credit Agreement has been, or substantially concurrently with the Closing Date will be, terminated and the obligations outstanding thereunder repaid in full pursuant to customary payoff documentation, including evidence of the release of Liens, if any, granted in connection therewith.

(e) The conditions precedent set forth in Sections 3.02(b) and (d) shall have theretofore been satisfied or waived in accordance with Section 9.02.

(f) (i) The Administrative Agent shall have received (for distribution to the Lenders so requesting) at least three business days prior to the Closing Date all documentation and other information about the Borrower and Guarantors as required by regulatory authorities under applicable "know your customer" and anti-money laundering rules and regulations, including without limitation the Patriot Act, to the extent reasonably requested by any Lender to the Administrative Agent and conveyed by the Administrative Agent to the Borrower in writing at least 10 days prior to the Closing Date and (ii) to the extent the Borrower qualifies as a "legal entity customer" under the Beneficial Ownership Regulation, at least five days prior to the Closing Date, any Lender that has requested, in a written notice to the Borrower at least 10 days prior to the Closing Date, a Beneficial Ownership Certification in relation to the Borrower shall have received such Beneficial Ownership Certification (provided that, upon the execution and delivery by such Lender of its signature page to this Agreement, the condition set forth in this clause (ii) shall be deemed to be satisfied).

(g) All fees required to be paid on the Closing Date pursuant to the Fee Letters referenced in Section 2.11(c) and all reasonable out-of-pocket expenses required to be paid on the Closing Date, to the extent invoiced at least two Business Days prior to the Closing Date shall have been paid.

The Administrative Agent shall notify the Borrower and the Lenders of the Closing Date in writing promptly upon such conditions precedent being satisfied (or waived in accordance with Section 9.02), and such notice shall be conclusive and binding.

SECTION 3.02 Conditions Precedent to Each Credit Event. The obligations of the Lenders to make Loans hereunder is subject to the satisfaction or waiver in accordance with Section 9.02 of the following conditions precedent:

(a) The conditions precedent set forth in Section 3.01 shall have theretofore been satisfied or waived in accordance with Section 9.02;

(b) The representations and warranties set forth in Article IV and in the other Loan Documents shall be true and correct in all material respects as of, and as if such representations and warranties were made on, the Borrowing Date of the proposed Loan (unless such representation and warranty expressly relates to an earlier date), and by the Borrower's delivery of a Borrowing Request, the Borrower shall be deemed to have certified to the Administrative Agent and the Lenders that such representations and warranties are true and correct in all material respects;

(c) The Company shall have complied with the provisions of Section 2.03;

(d) No Default or Event of Default shall have occurred and be continuing or would result from such Credit Event; and

(e) A Borrowing Request shall have been delivered in accordance with the terms of Section 2.03.

The acceptance by the Borrower of the benefits of each Credit Event shall constitute a representation and warranty by the Borrower to each of the Lenders that all of the conditions specified in this Section 3.02 above exist as of that time.

ARTICLE IV
REPRESENTATIONS AND WARRANTIES

On the Closing Date and on each Borrowing Date, the Borrower makes the following representations and warranties to the Administrative Agent and the Lenders:

SECTION 4.01 Organization and Qualification. The Borrower and each of the Material Subsidiaries (a) is a corporation, partnership or limited liability company duly organized or formed, validly existing and in good standing under the laws of the state of its incorporation, organization or formation, (b) has all requisite corporate, partnership, limited liability company or other power and all material governmental licenses, authorizations, consents and approvals required to carry on its business as now conducted and (c) is duly qualified to do business and is in good standing in every jurisdiction in which the failure to be so qualified would, individually or together with all such other failures of the Borrower and the Subsidiaries, have a Material Adverse Effect.

SECTION 4.02 Authorization, Validity, Etc. The Borrower and each Guarantor has all requisite corporate (or other organizational) power and authority to execute and deliver, and to incur and perform its obligations under this Agreement and under the other Loan Documents to which it is a party and, in the case of the Borrower, to make the Borrowings hereunder, and all such actions have been duly authorized by all necessary proceedings on its behalf. This Agreement and the other Loan Documents have been duly and validly executed and delivered by or on behalf of the Borrower (and, on the Closing Date, with respect to the Guaranty, each Guarantor) party thereto and constitute valid and legally binding agreements of the Borrower and each Guarantor, as applicable, enforceable against the Borrower or the Guarantor in accordance with the respective terms thereof, except (a) as may be limited by bankruptcy, insolvency, reorganization,

moratorium, fraudulent transfer, fraudulent conveyance or other similar laws relating to or affecting the enforcement of creditors' rights generally, and by general principles of equity (including principles of good faith, reasonableness, materiality and fair dealing) which may, among other things, limit the right to obtain equitable remedies (regardless of whether considered in a proceeding in equity or at law) and (b) as to the enforceability of provisions for indemnification for violation of applicable securities laws, limitations thereon arising as a matter of law or public policy.

SECTION 4.03 Governmental Consents, Etc. No authorization, consent, approval, license or exemption of or registration, declaration or filing with any Governmental Authority, is necessary for the valid execution and delivery of, or the incurrence and performance by the Borrower or each Guarantor of its obligations under, any Loan Document to which it is a party, except those that have been obtained and such matters relating to performance as would ordinarily be done in the ordinary course of business after the Closing Date.

SECTION 4.04 No Breach or Violation of Agreements or Restrictions, Etc. Neither the execution and delivery of, nor the incurrence and performance by any Loan Party of its obligations under, the Loan Documents to which it is a party, nor the extensions of credit contemplated by the Loan Documents, will (a) breach or violate any applicable Requirement of Law, (b) result in any breach or violation of any of the terms, covenants, conditions or provisions of, or constitute a default under, or result in the creation or imposition of (or the obligation to create or impose) any Lien upon any of its property or assets (other than Liens created or contemplated by this Agreement) pursuant to the terms of, any indenture, mortgage, deed of trust, agreement or other instrument to which it or any of the Subsidiaries is party or by which any of its properties or assets, or those of any of the Subsidiaries is bound or to which it is subject, except for breaches, violations and defaults under clauses (a) and (b) that neither individually nor in the aggregate could reasonably be expected to result in a Material Adverse Effect, or (c) violate any provision of the organizational documents of such Loan Party.

SECTION 4.05 Properties. Each of the Borrower and the Material Subsidiaries has good title to, or valid leasehold or other interests in, all its real and personal property material to its business free of all Liens securing Indebtedness except for such Liens permitted under Section 6.02.

SECTION 4.06 Litigation and Environmental Matters. (a) Except as disclosed in the most recent Annual Report on Form 10-K delivered by the Borrower to the Lenders, there is no action, suit or proceeding by or before any arbitrator or Governmental Authority pending against or, to the knowledge of the Borrower, threatened against or affecting the Borrower or any of the Material Subsidiaries as to which there is a reasonable possibility of an adverse determination and that, if adversely determined, could reasonably be expected to result in a Material Adverse Effect.

(b) Except as disclosed in the most recent Annual Report on Form 10-K delivered by the Borrower to the Lenders, the associated liabilities and costs of the Borrower's compliance with Environmental Laws (including any capital or operating expenditures required for clean-up or closure of properties currently or previously owned, any capital or operating expenditures required to achieve or maintain compliance with environmental protection standards imposed by Environmental Laws or as a condition of any license, permit or contract, any related constraints on operating activities, including any periodic or permanent shutdown of any facility or reduction in the level of or change in the nature of operations conducted thereat, any costs or liabilities in connection with off-site disposal of wastes or Hazardous Materials, and any actual or potential liabilities to third parties, including employees, and any related costs and expenses) are unlikely to result in a Material Adverse Effect.

SECTION 4.07 Financial Statements.

(a) The consolidated balance sheet of the Borrower and the Subsidiaries as at December 31, 2017 and the related consolidated statements of income, comprehensive income, shareholders' equity and cash flows of the Borrower and the Subsidiaries for the fiscal year ended on said date, with the opinion thereon of PricewaterhouseCoopers LLP and set forth in the Borrower's 2017 Annual Report on Form 10-K, as filed with the SEC, fairly present, in all material respects, the consolidated financial position of the Borrower and the Subsidiaries as of such date and their consolidated results of operations and cash flows for such fiscal year in accordance with GAAP.

(b) The unaudited consolidated balance sheets of the Borrower and the Subsidiaries as at March 31, 2018, June 30, 2018 and September 30, 2018 and the related consolidated statements of income and cash flows of the Borrower and the Subsidiaries for the three month period ended on such date and set forth in the Borrower's Quarterly Report on Form 10-Q for its fiscal quarter then ended, as filed with the SEC, fairly present, in all material respects, the consolidated financial position of the Borrower and the Subsidiaries as of such date and their consolidated results of their operations cash flows for the applicable time period ended on said date (subject to the absence of footnotes and to normal year-end and audit adjustments), in accordance with GAAP applied on a basis consistent with the financial statements referred to in Section 4.07(a).

(c) On the Closing Date and since the date of the Annual Report on Form 10-K delivered by the Borrower to the Lenders with respect to the fiscal year ended December 31, 2017, there has been no material adverse change in the business, assets, liabilities or financial condition of the Borrower and the Subsidiaries, taken as a whole.

SECTION 4.08 Disclosure.

(a) As of the Closing Date only, information heretofore furnished by the Borrower to the Administrative Agent or any Lender for purposes of or in connection with this Agreement or any transaction contemplated hereby, together with the Executive Summary is, when taken as a whole, true and accurate in all material respects on the date as of which such information is stated or certified. The Executive Summary and the reports, financial statements, certificates or other written information furnished by or on behalf of the Borrower to the Administrative Agent or any Lender in connection with the syndication or negotiation of this Agreement or delivered hereunder (as modified or supplemented by other information so furnished) on or prior to the Closing Date, when taken as a whole, do not contain any material misstatement of fact or omits to state any material fact necessary to make the statements therein, in the light of the circumstances under which they were made, not misleading; *provided* that, with respect to any projected financial information, the Borrower represents only that such information was prepared in good faith based upon assumptions believed by the Borrower to be reasonable at the time (it being recognized, however, that projections as to future events are not to be viewed as facts and that the actual results during the period or periods covered by any projects may materially different from the projected results).

(b) As of the Closing Date, to the knowledge of the Borrower, the information included in the Beneficial Ownership Certification provided on or prior to the Closing Date to any Lender in connection with this Agreement is true and correct in all respects.

SECTION 4.09 Investment Company Act. The Borrower is not, and no Loan Party is required to register as, an "*investment company*," as such term is defined in the Investment Company Act of 1940, as amended.

SECTION 4.10 ERISA. Each member of the ERISA Group has fulfilled its obligations under the minimum funding standards of ERISA and the Code with respect to each Plan and is in compliance

in all material respects with the presently applicable provisions of ERISA and the Code with respect to each Plan, except where the failure to so fulfill such obligations and such noncompliance individually, or together with all such failures to fulfill such obligations and all such noncompliance, could not reasonably be expected to result in a Material Adverse Effect. No member of the ERISA Group has (i) sought a waiver of the minimum funding standard under Section 412 of the Code in respect of any Plan, (ii) failed to make any contribution or payment to any Plan or Multiemployer Plan or in respect of any Benefit Arrangement, or made any amendment to any Plan or Benefit Arrangement, which has resulted or could result in the imposition of a Lien or the posting of a bond or other security under ERISA or the Code or (iii) incurred any liability under Title IV of ERISA other than a liability to the PBGC for premiums under Section 4007 of ERISA, which waiver, failure, amendment or liability individually, or collectively with all such waivers, failures, amendments or liabilities, could reasonably be expected to result in a Material Adverse Effect. Except where the failure to so fulfill such obligations and such noncompliance could individually, or together with all such failures to fulfill such obligations and all such noncompliance could reasonably be expected to result in a Material Adverse Effect, (i) no "reportable event", as defined in Section 4043 of ERISA or the regulations issued thereunder, has occurred with respect to a Plan (other than an event for which the 30 day notice period is waived),. (ii) neither the Borrower nor any member of its ERISA Group has received any notice from the PBGC or a plan administrator relating to an intention to terminate any Plan or Plans or to appoint a trustee to administer any Plan and (iii) neither the Borrower or any members of its ERISA Group has any liability with respect to the withdrawal or partial withdrawal from any Plan or Multiemployer Plan, nor has the Borrower, any members of its ERISA Group, or any Multiemployer Plan from the Borrower or member of its ERISA Group received any notice concerning the imposition of Withdrawal Liability or a determination that a Multiemployer Plan is, or is expected to be, insolvent within the meaning of Title IV of ERISA.

SECTION 4.11 Tax Returns and Payments. The Borrower and the Material Subsidiaries have caused to be filed all federal income Tax returns and other material Tax returns, statements and reports (or obtained extensions with respect thereto) which are required to be filed and have paid or deposited or made adequate provision in accordance with GAAP for the payment of all Taxes (including estimated Taxes shown on such returns, statements and reports) which are shown to be due pursuant to such returns, except for Taxes being contested in good faith by appropriate proceedings for which adequate reserves in accordance with GAAP have been created on the books of the Borrower and the Subsidiaries and where the failure to pay such Taxes (individually or in the aggregate for the Borrower and the Subsidiaries) would not have a Material Adverse Effect.

SECTION 4.12 Compliance with Laws and Agreements. Each of the Borrower and the Material Subsidiaries is in compliance with all laws, regulations and orders of any Governmental Authority applicable to it or its property and all indentures, agreements and other instruments binding upon it or its property, except where the failure to do so, individually or in the aggregate for the Borrower and the Material Subsidiaries, could not reasonably be expected to result in a Material Adverse Effect.

SECTION 4.13 Purpose of Loans.

(a) All proceeds of the Loans will be used for the purposes set forth in Section 5.07.

(b) Neither the Borrower nor any agent acting on its behalf has taken or will take any action which might cause this Agreement or any other Loan Document to violate Regulation T, Regulation U, Regulation X, or any other regulation of the Board or to violate the Exchange Act. Margin stock does not constitute more than 25% of the assets of the Borrower, or of the Borrower and the Subsidiaries on a consolidated basis, and the Borrower does not intend or foresee that it will ever do so.

SECTION 4.14 Foreign Assets Control Regulations, etc. (a) To the extent applicable, no part of the proceeds of the Loans will (i) be used to violate in any material respect the Trading with the Enemy Act, as amended, or (ii) be used, directly or indirectly or made available to any subsidiary, joint venture partner or any other Person to fund or support any activities or business of or with any Person, or in any country or territory, that, at the time of such funding or extension, is, or whose government is, at the time of making such Loans, the subject of any economic or financial sanctions or trade embargoes administered or enforced by the U.S. Government, including any enforced by the U.S. Department of Treasury's Office of Foreign Assets Control or the U.S. Department of State (collectively, "Sanctions").

(b) Neither the Borrower nor any Subsidiary, nor, to the knowledge of the Borrower, any director, officer, employee, agent, affiliate or representative of the Borrower or any Subsidiary is a Person that is, or is owned or controlled by, a Sanctioned Person. The Borrower and the Subsidiaries are in compliance, in all material respects, with the Patriot Act.

(c) No part of the proceeds of the Loans will be used, directly or indirectly, for any payments to any person in violation of any Anti-Corruption Laws, to the extent the Anti-Corruption Laws apply to the Borrower or one of the Subsidiaries.

SECTION 4.15 Solvency. On the Closing Date, after giving effect to the Transactions, the Borrower and its Subsidiaries, on a consolidated basis, are Solvent.

ARTICLE V
AFFIRMATIVE COVENANTS

From the Closing Date until the Commitments have expired or been terminated and principal of and interest on each Loan and all fees payable hereunder shall have been paid in full, the Borrower covenants and agrees with the Lenders that:

SECTION 5.01 Financial Statements and Other Information. The Borrower will furnish to the Administrative Agent:

(a) within ten days after the date in each fiscal year on which the Borrower is required to file its Annual Report on Form 10-K with the SEC or, if earlier, 100 days after the end of each fiscal year (i) such Annual Report, and (ii) its audited consolidated balance sheet and the related consolidated statements of income, comprehensive income, operations, shareholders' equity and cash flows as of the end of and for such year, setting forth in each case in comparative form the figures as of the end of and for the previous fiscal year, all reported on by, and accompanied by an opinion (without a "*going concern*" or like qualification or exception and without any qualification or exception as to the scope of their audit) of, PricewaterhouseCoopers LLP, or other independent public accountants of recognized national standing to the effect that such consolidated financial statements present fairly in all material respects the financial position, results of operations and cash flows of the Borrower and the Subsidiaries on a consolidated basis in accordance with GAAP; *provided*, *however*, that (x) the Borrower shall be deemed to have furnished said Annual Report on Form 10-K for purposes of clause (i) if it shall have timely made the same available on "EDGAR" and/or on its home page on the worldwide web (at the date of this Agreement located at http://www.kindermorgan.com) and complied with the last grammatical paragraph of this Section 5.01 in respect thereof, and (y) if said Annual Report contains such consolidated balance sheet and such consolidated statements of results of income, comprehensive income, shareholders' equity and cash flows, and the report thereon of such independent public accountants (without qualification or exception, and to the effect, as specified above), the Borrower shall not be required to comply with clause (ii);

(b) within five days after each date in each fiscal year on which the Borrower is required to file a Quarterly Report on Form 10-Q with the SEC or, if earlier, 50 days after the end of each fiscal quarter (i) such Quarterly Report, and (ii) its consolidated balance sheet and the related consolidated statements of income and cash flows as of the end of and for the fiscal quarter to which said Quarterly Report relates and the then elapsed portion of the fiscal year, setting forth in each case in comparative form the figures as of the end and for the corresponding period or periods of the previous fiscal year, all certified by a Responsible Officer as presenting fairly in all material respects the financial condition and results of operations of the Borrower and the Subsidiaries on a consolidated basis in accordance with GAAP, subject to normal year-end audit adjustments and the absence of footnotes; *provided*, *however*, that (x) the Borrower shall be deemed to have furnished said Quarterly Report for purposes of clause (i) if it shall have timely made the same available on "EDGAR" and/or on its home page on the worldwide web (at the date of this Agreement located at http://www.kindermorgan.com) and complied with the last grammatical paragraph of this Section 5.01 in respect thereof, and (y) if said Quarterly Report contains such consolidated balance sheet and consolidated statements of income and cash flows, and such certifications, the Borrower shall not be required to comply with clause (ii);

(c) simultaneously with the delivery of each set of financial statements referred to in clauses (a) and (b) above, a certificate in substantially the form of Exhibit 5.01 signed by an authorized financial or accounting officer of the Borrower (i) setting forth in reasonable detail the calculations required to establish whether the Borrower was in compliance with the requirements of Section 6.07, (ii) (A) in the case of the first set of financial statements delivered following the Closing Date, setting forth a list of the Material Subsidiaries, and (B) in the case of each set of financial statements delivered thereafter, an update of any change in the list of the Material Subsidiaries or stating that there has been no such change, and (iii) stating whether any Default or Event of Default exists on the date of such certificate and, if any Default or Event of Default then exists, setting forth the details thereof and the action which the Borrower is taking or proposes to take with respect thereto;

(d) prompt written notice of the following:

(i) the occurrence of any Default or Event of Default;

(ii) any other development that results in, or could reasonably be expected to result in, a Material Adverse Effect; and

(iii) any change in the information provided in the Beneficial Ownership Certification delivered to such Lender that would result in a change to the list of beneficial owners identified in such certification;

(each notice delivered under this Section 5.01(d) to be accompanied by a statement of a Responsible Officer setting forth the details of the event or development requiring such notice and any action taken or proposed to be taken with respect thereto);

(e) without duplication of any other requirement of this Section 5.01, promptly upon the mailing thereof to the public shareholders of the Borrower generally, copies of all financial statements, reports and proxy statements so mailed;

(f) promptly upon the filing thereof with the SEC, copies of all registration statements (other than the exhibits thereto and any registration statements on Form S-8 or its equivalent) and reports on Form 8-K which the Borrower shall have filed with the SEC;

(g) if and when any member of the ERISA Group (i) gives or is required to give notice to the PBGC of any "*reportable event*" (as defined in Section 4043 of ERISA) (other than such event as to which the 30-day notice requirement is waived) with respect to any Plan which would reasonably be expected to constitute grounds for a termination of such Plan under Title IV of ERISA, or knows that the plan administrator of any Plan has given or is required to give notice of any such reportable event, a copy of the notice of such reportable event given or required to be given to the PBGC; (ii) receives notice of complete or partial material Withdrawal Liability under Title IV of ERISA or notice that any Multiemployer Plan is insolvent, is in "endangered" or "critical" status (within the meaning of Section 432 of the Code or Section 305 of ERISA) or has been terminated, a copy of such notice; (iii) receives notice from the PBGC under Title IV of ERISA of an intent to terminate, impose liability (other than for premiums under Section 4007 of ERISA) in respect of, or appoint a trustee to administer any Plan, a copy of such notice; (iv) fails to satisfy, or applies for a waiver of, the minimum funding standard under Section 412 of the Code, a copy of such application; (v) gives notice of intent to terminate any Plan under Section 4041(c) of ERISA, a copy of such notice and other information filed with the PBGC; (vi) gives notice of withdrawal from any Plan pursuant to Section 4063 of ERISA, a copy of such notice; or (vii) fails to make any payment or contribution to any Plan or Multiemployer Plan or in respect of any Benefit Arrangement or makes any amendment to any Plan or Benefit Arrangement which has resulted or could result in the imposition of a Lien or the posting of a bond or other security, a certificate of the chief financial officer or the chief accounting officer of the Borrower setting forth details as to such occurrence and action, if any, which the Borrower or applicable member of the ERISA Group is required or proposes to take; and

(h) (x) from time to time such other information (other than projections) regarding the business, affairs or financial condition of the Borrower or any Subsidiary as the Required Lenders or the Administrative Agent may reasonably request and (y) promptly following any request therefor, information and documentation reasonably requested by the Administrative Agent for distribution to the Lenders so requesting for purposes of compliance with applicable "know your customer" and anti-money laundering rules and regulations, including the Patriot Act and the Beneficial Ownership Regulation.

Information required to be delivered pursuant to Section 5.01(a), 5.01(b) or 5.01(f) above shall be deemed to have been delivered on the date on which the Borrower provides notice to the Administrative Agent and the Lenders that such information has been posted on "EDGAR" or the Borrower's website or another website identified in such notice and accessible by the Administrative Agent and the Lenders without charge (and the Borrower hereby agrees to provide such notice); *provided* that such notice may be included in a certificate delivered pursuant to Section 5.01(c).

SECTION 5.02 Existence, Conduct of Business. The Borrower will, and will cause each of the Material Subsidiaries to, do or cause to be done all things necessary to preserve, renew and keep in full force and effect its legal existence and the rights, licenses, permits, privileges and franchises material to the conduct of its business, except where the failure to do so (individually or collectively with all such failures) could not reasonably expected to have a Material Adverse Effect; *provided* that the foregoing shall not prohibit any merger, consolidation, liquidation or dissolution permitted under Section 6.03.

SECTION 5.03 Payment of Obligations. The Borrower will, and will cause each of the Material Subsidiaries to, pay, before the same shall become delinquent or in default, its Indebtedness and Tax liabilities but excluding Indebtedness (other than the Obligations) that is not in excess of $150,000,000, except where (a) the validity or amount thereof is being contested in good faith by appropriate proceedings, (b) the Borrower or such Material Subsidiary has set aside on its books adequate reserves with respect thereto in accordance with GAAP or (c) the failure to make payment pending such contest could not reasonably be expected to result in a Material Adverse Effect.

SECTION 5.04 Maintenance of Properties; Insurance.

(a) The Borrower will keep, and will cause each Material Subsidiary to keep, all property material to the conduct its business (taken as a whole) in good working order and condition, ordinary wear and tear excepted, in the reasonable judgment of the Borrower.

(b) The Borrower will maintain or cause to be maintained with, in the good faith judgment of the Borrower, financially sound and reputable insurers, or through self-insurance, insurance with respect to its properties and business and the properties and businesses of the Subsidiaries against loss or damage of the kinds customarily insured against by business enterprises of established reputation engaged in the same or similar business and similarly situated, of such types and in such amounts as are customarily carried under similar circumstances by such other corporations. Such insurance may include self-insurance or be subject to co-insurance, deductibility or similar clauses which, in effect, result in self-insurance of certain losses, *provided* that such self-insurance is in accord with the approved practices of business enterprises of established reputation similarly situated and adequate insurance reserves are maintained in connection with such self-insurance, and, notwithstanding the foregoing provisions of this Section 5.04 the Borrower or any Subsidiary may effect workers' compensation or similar insurance in respect of operations in any state or other jurisdiction any through an insurance fund operated by such state or other jurisdiction or by causing to be maintained a system or systems of self-insurance in accord with applicable laws.

SECTION 5.05 Books and Records; Inspection Rights. The Borrower will, and will cause each of the Material Subsidiaries to, keep, in accordance with GAAP, books of record and account. The Borrower will, and will cause each of the Material Subsidiaries to, permit any representatives designated by the Administrative Agent or any Lender, upon reasonable prior notice during normal business hours, and, if the Borrower shall so request, in the presence of a Responsible Officer or an appointee of a Responsible Officer, at the expense of the Administrative Agent or such Lender (unless an Event of Default exists, in which event the expense shall be that of the Borrower) to visit and inspect its properties, to examine and make extracts from its books and records (subject to compliance with confidentiality agreements and applicable copyright law), and to discuss its affairs, finances and condition with its officers, all at such times, and as often, as reasonably requested, but unless an Event of Default exists, no more frequently than once during each calendar year.

SECTION 5.06 Compliance with Laws. The Borrower will, and will cause each of the Material Subsidiaries to, comply with all Requirements of Law applicable to it or its property, except where the failure to do so, individually or in the aggregate, could not reasonably be expected to result in a Material Adverse Effect. The Borrower will maintain in effect and enforce policies and procedures designed to ensure compliance by the Borrower, its Subsidiaries and their respective directors, officers, employees and agents with Anti-Corruption Laws and applicable Sanctions.

SECTION 5.07 Use of Proceeds. The proceeds of the Loans will be used for working capital and other general corporate purposes.

SECTION 5.08 Additional Guarantors. The Borrower shall cause each Subsidiary (including, without limitation, any Division Successor) (other than any Excluded Subsidiary) formed or otherwise purchased or acquired after the Closing Date (including each Subsidiary that ceases to constitute an Excluded Subsidiary after the Closing Date) to execute a supplement to the Guaranty and become a Guarantor within 45 days of the occurrence of the applicable event specified in this Section 5.08 (or such longer period of time as the Administrative Agent shall reasonably agree).

ARTICLE VI
NEGATIVE COVENANTS

From the Closing Date until the Commitments have expired or terminated and principal of and interest on each Loan and all fees payable hereunder have been paid in full, the Borrower covenants and agrees with the Lenders that:

SECTION 6.01 Indebtedness of Non-Guarantor Subsidiaries. The Borrower will not permit any Subsidiary that is not a Guarantor (each a "Non-Guarantor Subsidiary") to create, incur or assume Indebtedness other than the following:

(a) Indebtedness existing as of the Closing Date and set forth on Schedule 6.01 and any Indebtedness incurred to refund, extend, refinance or otherwise replace such Indebtedness; provided that the principal amount of such Indebtedness does not exceed the principal amount of Indebtedness refinanced (plus the amount of penalties, premiums, fees, accrued interest and reasonable expenses and other obligations incurred therewith) at the time of the refinancing;

(b) Indebtedness owing to the Borrower or its Subsidiaries;

(c) Indebtedness that is (or was) secured by Liens permitted pursuant to Section 6.02(b) or (c) and any Indebtedness incurred to refund, extend, refinance or otherwise replace such Indebtedness; provided, that the principal amount of such Indebtedness does not exceed the principal amount of Indebtedness refinanced (plus the amount of penalties, premiums, fees, accrued interest and reasonable expenses and other obligations incurred therewith) at the time of refinancing;

(d) (i) Indebtedness attaching to any property or asset prior to the acquisition thereof by any Non-Guarantor Subsidiary or of, or attaching to any property or asset of, any Person that becomes a Non-Guarantor Subsidiary after the date hereof prior to the time such Person becomes a Non-Guarantor Subsidiary, in each case, outstanding prior to the acquisition of such property or asset or such Person becoming a Non-Guarantor Subsidiary; *provided* that such Indebtedness was not incurred in contemplation of or in connection with such acquisition or such Person becoming a Non-Guarantor Subsidiary, as the case may be and (ii) and any Indebtedness incurred to refund, extend, refinance or otherwise replace such Indebtedness (plus the amount of penalties, premiums, fees, accrued interest and reasonable expenses and other obligations incurred therewith);

(e) Indebtedness of Foreign Subsidiaries; and

(f) Indebtedness of Non-Wholly-owned Subsidiaries.

SECTION 6.02 Liens. The Borrower will not, and will not permit any Subsidiary to, create, incur, assume or permit to exist any Lien securing Indebtedness on any property or asset now owned or hereafter acquired by it except:

(a) Liens existing as of the Closing Date (including any replacement, extension or renewal of any such Lien permitted upon or in the same assets (other than after acquired property that is affixed or incorporated into the property covered by such Lien) theretofore subject to such Lien or the replacement, extension or renewal (without increase in the amount or change in any direct or contingent obligor except to the extent otherwise permitted hereunder) of the Indebtedness secured thereby);

(b) Liens securing (A) Capital Lease Obligations, or (B) Indebtedness incurred to finance the acquisition, construction, expansion or improvement of any fixed or capital assets of the Borrower

or its Subsidiaries; *provided* that (x) such Liens attach at all times only to the assets so financed except for accessions to such property, improvements thereof and general intangibles relating thereto, and the proceeds and the products thereof and (y) individual financings of equipment provided by one lender may be cross collateralized to other financings of equipment provided by such lender;

(c) Liens existing on any property or asset prior to the acquisition thereof by the Borrower or any Subsidiary or existing on any property or asset of any Person that becomes a Subsidiary after the date hereof prior to the time such Person becomes a Subsidiary, in each case, pursuant to security documents in effect prior to the acquisition of such property or asset or such Person becoming a Subsidiary ("Existing Security Documents"), and securing Indebtedness whose incurrence, for purposes of this Agreement, by virtue of acquisition of such property or asset, or by virtue of such Person so becoming a Subsidiary, would not result in a violation of Section 6.07; *provided* that (i) such Lien is not created in contemplation of or in connection with such acquisition or such Person becoming a Subsidiary, as the case may be, (ii) such Lien shall not apply to any other property or assets of the Borrower or any Subsidiary except to the extent such Lien attaches to such property or assets pursuant to Existing Security Documents, (iii) such Lien shall secure only those obligations which it secures on the date of such acquisition or the date such Person becomes a Subsidiary, as the case may be, and extensions, renewals and replacements thereof that do not increase the outstanding principal amount thereof. For purposes of this Section 6.02(c), the Indebtedness so secured shall be deemed to have been incurred on the last day of the fiscal quarter then most recently ended; and

(d) Liens, not otherwise permitted by the foregoing clauses (a) and (b), securing Indebtedness in an aggregate amount not exceeding 15% of Consolidated Net Tangible Assets.

SECTION 6.03 Fundamental Changes. The Borrower will not, and will not permit any Material Subsidiary to, merge into or consolidate with any other Person, or permit any other Person to merge into or consolidate with it, or sell, transfer, lease or otherwise dispose of (including pursuant to a Division and whether in one transaction or in a series of transactions) all (or substantially all) of its assets, or all or substantially all of the stock of or other equity interest in any of the Material Subsidiaries (in each case, whether now owned or hereafter acquired), or liquidate or dissolve, unless: (a) at the time thereof and immediately after giving effect thereto no Event of Default or Default shall have occurred and be continuing; and (b) (i) the Borrower or a Material Subsidiary is the surviving entity or the recipient of the assets so sold, transferred, leased or otherwise disposed of in any such sale, transfer, lease or other disposition of assets, *provided,* that no such merger, consolidation, sale, transfer, lease or other disposition shall have the effect of releasing the Borrower from any of the Obligations or (ii) such merger, consolidation, sale, transfer, lease or other disposition, when taken together with all other consolidations, mergers or sales of assets by the Borrower or any Material Subsidiary since the Closing Date, shall not result in the disposition by the Borrower and the Material Subsidiaries of assets in an amount that would constitute all or substantially all of the consolidated assets of the Borrower and the Material Subsidiaries.

SECTION 6.04 Restricted Payments. The Borrower will not declare or make, or agree to pay or make, directly or indirectly, any Restricted Payment except (a) distributions with respect to the Capital Stock of the Borrower, so long as both before and after the making of such distribution, no Event of Default shall have occurred and be continuing, (b) any Capital Stock split, Capital Stock reverse split, dividend of Borrower Capital Stock or similar transaction will not constitute a Restricted Payment, and (c) acquisitions by officers, directors and employees of the Borrower of equity interests in the Borrower through cashless exercise of options pursuant to, and in accordance with the terms of, management and/or employee stock plans, stock subscription agreements or shareholder agreements.

SECTION 6.05 Transactions with Affiliates. The Borrower will conduct, and cause each of the Subsidiaries to conduct, all transactions with any of its Affiliates (other than the Borrower or the

Subsidiaries) on terms that are substantially as favorable to the Borrower or such Subsidiary as it would obtain in a comparable arm's-length transaction with a Person that is not an Affiliate, provided that the foregoing shall be deemed to be satisfied with respect to any transaction that is approved by a majority of the independent members of the Borrower's board of directors, or of a committee thereof consisting solely of independent directors, and provided, further that the foregoing restrictions shall not apply to:

(a) the payment of customary fees for management, consulting and financial services rendered to the Borrower and the Subsidiaries and (ii) customary investment banking fees paid for services rendered to the Borrower and the Subsidiaries in connection with divestitures, acquisitions, financings and other transactions;

(b) transactions permitted by Section 6.04;

(c) the payment of any fees or expenses incurred or paid by the Borrower or any of its Subsidiaries in connection with the Transactions, this Agreement and the other Loan Documents and the transactions contemplated hereby and thereby;

(d) the issuance of Capital Stock of the Borrower to the management of the Borrower or any of its Subsidiaries in connection with the Transactions or pursuant to arrangements described in clause (f) of this Section 6.05;

(e) loans, advances, provision of credit support and other investments by (or to) the Borrower and the Subsidiaries;

(f) employment and severance arrangements among the Borrower and the Subsidiaries and their respective officers and employees in the ordinary course of business;

(g) payments by the Borrower and the Subsidiaries pursuant to tax sharing agreements among the Borrower and the Subsidiaries on customary terms to the extent attributable to the ownership or operation of the Borrower and the Subsidiaries;

(h) the payment of customary fees and reasonable out of pocket costs to, and indemnities provided on behalf of, directors, managers, consultants, officers and employees of the Borrower and the Subsidiaries in the ordinary course of business to the extent attributable to the ownership or operation of the Borrower and the Subsidiaries; and

(i) transactions pursuant to agreements set forth on Schedule 6.05 or any amendment thereto to the extent such an amendment is not adverse, taken as a whole, to the Lenders in any material respect.

SECTION 6.06 Restrictive Agreements. The Borrower will not, and will not permit any of the Material Subsidiaries that are not Guarantors to, directly or indirectly, enter into, incur or permit to exist any agreement or other arrangement that prohibits, restricts or imposes any condition upon the ability of any non-Guarantor Material Subsidiary to pay dividends or other distributions with respect to any shares of its Capital Stock or to make or repay loans (including subordinate loans) or advances to the Borrower or any Guarantor, *provided* that the foregoing shall not apply to (a) restrictions and conditions imposed by law or by this Agreement, (b) customary restrictions and conditions contained in agreements relating to the sale of all or substantially all of the Capital Stock or assets of a Subsidiary pending such sale, *provided* such restrictions and conditions apply only to the Subsidiary that is to be sold and such sale is permitted hereunder, (c) restrictions and conditions existing on the date hereof identified on Schedule 6.06 (but shall apply to any extension or renewal of, or any amendment or modification expanding the scope of, any such restriction

or condition) and (d) restrictions or conditions contained in, or existing by reason of, any agreement or instrument relating to any Subsidiary at the time such Subsidiary was merged or consolidated with or into, or acquired by, the Borrower or a Subsidiary or became a Subsidiary and not created in contemplation thereof.

SECTION 6.07 Ratio of Consolidated Net Indebtedness to Consolidated EBITDA. Commencing with the last day of the first full fiscal quarter following the Closing Date and on the last day of each fiscal quarter ended thereafter, the Borrower will not permit the ratio of Consolidated Net Indebtedness to Consolidated EBITDA for the most recent four full fiscal quarters ended as of the last day of such applicable fiscal quarter, to exceed 5.50:1.00.

In addition, for purposes of this Section 6.07, Hybrid Securities up to an aggregate amount of 5% of Total Capitalization (after giving effect to the following exclusion) shall be excluded from Consolidated Net Indebtedness.

SECTION 6.08 Use of Proceeds. The Borrower will not request any Borrowing, and the Borrower shall not use, and shall procure that its Subsidiaries and its or their respective directors, officers, employees and agents shall not use, the proceeds of any Borrowing (A) in furtherance of an offer, payment, promise to pay, or authorization of the payment or giving of money, or anything else of value, to any Person in violation of any Anti-Corruption Laws, (B) for the purpose of funding, financing or facilitating any activities, business or transaction of or with any Sanctioned Person, or in any Sanctioned Country, or (C) in any manner that would result in the violation of any Sanctions applicable to any party hereto.

ARTICLE VII
EVENTS OF DEFAULT

SECTION 7.01 Events of Default and Remedies. If any of the following events ("Events of Default") shall occur and be continuing:

(a) the principal of any Loan shall not be paid when and as the same shall become due and payable, whether at the due date thereof or at a date fixed for prepayment thereof or otherwise;

(b) any interest on any Loan or any fee or any other amount (other than an amount referred to in clause (a) of this Article) payable by a Loan Party under this Agreement or any other Loan Document shall not be paid, when and as the same shall become due and payable, and such failure shall continue unremedied for a period of five Business Days;

(c) any representation or warranty made or, for purposes of Article III, deemed made by or on behalf of the Borrower herein, at the direction of the Borrower or by any Loan Party in any other Loan Document or in any document, certificate or financial statement delivered in connection with this Agreement or any other Loan Document shall prove to have been incorrect in any material respect when made or deemed made or reaffirmed, as the case may be;

(d) the Borrower shall fail to observe or perform any covenant, condition or agreement contained in Section 5.01(d)(i), 5.02 (with respect to the Borrower's existence) or 5.07 or in Article VI;

(e) any Loan Party shall fail to perform or observe any other term, covenant or agreement contained in this Agreement (other than those specified in Section 7.01(a), Section 7.01(b) or Section 7.01(d)) or any other Loan Document to which it is a party and, in any event, such failure shall

remain unremedied for 30 calendar days after the earlier of (i) written notice of such failure shall have been given to the Borrower by the Administrative Agent or any Lender or, (ii) a Responsible Officer of the Borrower becomes aware of such failure;

(f) other than as specified in Section 7.01(a) or (b), (i) the Borrower or any Subsidiary fails to make (whether as primary obligor or as guarantor or other surety) any payment of principal of, or interest or premium, if any, on any item or items of Indebtedness (other than as specified in Section 7.01(a) or Section 7.01(b)) or any payment in respect of any Hedging Agreement, in each case when the same becomes due and payable (whether by scheduled maturity, required payment or prepayment, acceleration, demand or otherwise), beyond any period of grace provided with respect thereto (not to exceed 30 days); *provided* that the aggregate outstanding principal amount of all Indebtedness or payment obligations in respect of all Hedging Agreements as to which such a payment default shall occur and be continuing is equal to or exceeds $150,000,000, or (ii) the Borrower or any Subsidiary fails to duly observe, perform or comply with any agreement with any Person or any term or condition of any instrument, if such failure, either individually or in the aggregate, shall have resulted in the acceleration of the payment of Indebtedness with an aggregate face amount which is equal to or exceeds $150,000,000; *provided* that this Section 7.01(f) shall not apply to secured Indebtedness that becomes due as a result of the voluntary sale or transfer of the property or assets securing such Indebtedness, so long as such Indebtedness is paid in full when due;

(g) an involuntary case shall be commenced or an involuntary petition shall be filed seeking (i) liquidation, reorganization or other relief in respect of the Borrower or any Material Subsidiary or its debts, or of a substantial part of its assets, under any Debtor Relief Laws or (ii) the appointment of a receiver, trustee, custodian, sequestrator, conservator or similar official for the Borrower or any Material Subsidiary or for a substantial part of its assets, and, in any such case, such proceeding or petition shall continue undismissed for 60 days or an order or decree approving or ordering any of the foregoing shall be entered;

(h) the Borrower or any Material Subsidiary shall (i) voluntarily commence any proceeding or file any petition seeking liquidation, winding-up, reorganization or other relief under any Debtor Relief Laws, (ii) consent to the institution of, or fail to contest in a timely and appropriate manner, any proceeding or petition described in Section 7.01(g), (iii) apply for or consent to the appointment of a receiver, trustee, custodian, sequestrator, conservator or similar official for the Borrower or any Material Subsidiary or for a substantial part of its assets, (iv) file an answer admitting the material allegations of a petition filed against it in any such proceeding, (v) make a general assignment for the benefit of creditors or (vi) take any action for the purpose of effecting any of the foregoing;

(i) the Borrower or any Material Subsidiary shall become unable, admit in writing or fail generally to pay its debts as they become due;

(j) one or more judgments for the payment of money in an aggregate amount in excess of $150,000,000 shall be rendered against the Borrower, any Subsidiary or any combination thereof and the same shall (x) not be covered by insurance and (y) remain undischarged for a period of 60 consecutive days during which execution shall not be effectively stayed, or any action shall be legally taken by a judgment creditor to attach or levy upon any assets of the Borrower or any Subsidiary to enforce any such judgment;

(k) a Change in Control shall occur;

(l) any member of the ERISA Group shall fail to pay when due an amount which it shall have become liable to pay under Title IV of ERISA; or notice of intent to terminate a Plan shall be filed under Title IV of ERISA by any member of the ERISA Group, any plan administrator or any combination

of the foregoing; or the PBGC shall institute proceedings under Title IV of ERISA to terminate, to impose liability (other than for premiums under Section 4007 of ERISA) in respect of, or to cause a trustee to be appointed to administer any Plan; or a condition shall exist by reason of which the PBGC would be entitled to obtain a decree adjudicating that any Plan must be terminated; or there shall occur a complete or partial withdrawal from, or a default, within the meaning of Section 4219(c)(5) of ERISA, with respect to, one or more Multiemployer Plans which could cause one or more members of the ERISA Group to incur a current payment obligation; and in each of the foregoing instances such condition could reasonably be expected to result in a Material Adverse Effect;

then, and in any such event, and at any time thereafter (but for the avoidance of doubt, in each case, not prior to the Closing Date) if any Event of Default shall then be continuing, the Administrative Agent, may, and upon the written request of the Required Lenders shall, by written notice (including notice sent by telecopy or electronic mail) to the Borrower (a "Notice of Default") take any or all of the following actions, without prejudice to the rights of the Administrative Agent, any Lender or other holder of any of the Obligations to enforce its claims against the Borrower (*provided* that, if an Event of Default specified in Section 7.01(g) or Section 7.01(h) shall occur with respect to the Borrower or any Material Subsidiary, the actions described in clauses (i), (ii) and (v) below shall occur automatically without the giving of any Notice of Default): (i) declare the Total Commitment terminated, whereupon the Commitments of the Lenders shall forthwith terminate immediately and any accrued Commitment Fees shall forthwith become due and payable without any other notice of any kind; (ii) declare the principal of and any accrued interest in respect of all Loans, and all the other Obligations owing hereunder and under the other Loan Documents, to be, whereupon the same shall become, forthwith due and payable without presentment, demand, notice of demand or of dishonor and nonpayment, protest, notice of protest, notice of intent to accelerate, declaration or notice of acceleration or any other notice of any kind, all of which are hereby waived by the Borrower; and (iii) exercise any rights or remedies under the Loan Documents.

ARTICLE VIII
THE ADMINISTRATIVE AGENT

SECTION 8.01 Appointment and Authority. Each of the Lenders hereby irrevocably appoints Barclays Bank PLC to act on its behalf as the Administrative Agent hereunder and under the other Loan Documents and authorizes the Administrative Agent to take such actions on its behalf and to exercise such powers as are delegated to the Administrative Agent by the terms hereof or thereof, together with such actions and powers as are reasonably incidental thereto. The provisions of this Article are solely for the benefit of the Administrative Agent, the Lenders and, except as specifically provided in Section 8.06(a) and (b), the Borrower shall not have rights as a third-party beneficiary of any of such provisions. It is understood and agreed that the use of the term "agent" herein or in any other Loan Documents (or any other similar term) with reference to the Administrative Agent is not intended to connote any fiduciary or other implied (or express) obligations arising under agency doctrine of any applicable law. Instead such term is used as a matter of market custom, and is intended to create or reflect only an administrative relationship between contracting parties.

SECTION 8.02 Rights as a Lender. The Person serving as the Administrative Agent hereunder shall have the same rights and powers in its capacity as a Lender as any other Lender and may exercise the same as though it were not the Administrative Agent, and the term *"Lender"* or *"Lenders"* shall, unless otherwise expressly indicated or unless the context otherwise requires, include the Person serving as the Administrative Agent hereunder in its individual capacity. Such Person and its Affiliates may accept deposits from, lend money to, own securities of, act as the financial advisor or in any other advisory capacity for, and generally engage in any kind of business with, the Borrower or any Subsidiary or other Affiliate

thereof as if such Person were not the Administrative Agent hereunder and without any duty to account therefor to the Lenders.

SECTION 8.03 Exculpatory Provisions.

(a) The Administrative Agent shall not have any duties or obligations except those expressly set forth herein and in the other Loan Documents, and its duties hereunder shall be administrative in nature. Without limiting the generality of the foregoing, the Administrative Agent:

(i) shall not be subject to any fiduciary or other implied duties, regardless of whether a Default or an Event of Default has occurred and is continuing;

(ii) shall not have any duty to take any discretionary action or exercise any discretionary powers, except discretionary rights and powers expressly contemplated hereby or by the other Loan Documents that the Administrative Agent is required to exercise as directed in writing by the Required Lenders (or such other number or percentage of the Lenders as shall be expressly provided for herein or in the other Loan Documents); *provided* that the Administrative Agent shall not be required to take any action that, in its opinion or the opinion of its counsel, may expose the Administrative Agent to liability or that is contrary to any Loan Document or applicable law, including for the avoidance of doubt any action that may be in violation of the automatic stay under any Debtor Relief Law or that may effect a forfeiture, modification or termination of property of a Defaulting Lender in violation of any Debtor Relief Law; and

(iii) shall not, except as expressly set forth herein and in the other Loan Documents, have any duty to disclose, and shall not be liable for the failure to disclose, any information relating to the Borrower or any of its Affiliates that is communicated to or obtained by the Person serving as the Administrative Agent or any of its Affiliates in any capacity.

(b) The Administrative Agent shall not be liable for any action taken or not taken by it (i) with the consent or at the request of the Required Lenders (or such other number or percentage of the Lenders as shall be necessary, or as the Administrative Agent shall believe in good faith shall be necessary, under the circumstances as provided in Sections 9.02 and 9.03) or (ii) in the absence of its own gross negligence or willful misconduct as determined by a court of competent jurisdiction by final and nonappealable judgment. The Administrative Agent shall be deemed not to have knowledge of any Default or Event of Default unless and until notice describing such Default is given to the Administrative Agent in writing by the Borrower or a Lender.

(c) The Administrative Agent shall not be responsible for or have any duty to ascertain or inquire into (i) any statement, warranty or representation made in or in connection with this Agreement or any other Loan Document, (ii) the contents of any certificate, report or other document delivered hereunder or thereunder or in connection herewith or therewith, (iii) the performance or observance of any of the covenants, agreements or other terms or conditions set forth herein or therein or the occurrence of any Default or Event of Default or the enforceability, effectiveness or genuineness of this Agreement, any other Loan Document or any other agreement, instrument or document, or (v) the satisfaction of any condition set forth in Article III or elsewhere herein, other than to confirm receipt of items expressly required to be delivered to the Administrative Agent.

SECTION 8.04 Reliance by Administrative Agent. The Administrative Agent shall be entitled to rely upon, and shall not incur any liability for relying upon, any notice, request, certificate, consent, statement, instrument, document or other writing (including any electronic message, Internet or intranet

website posting or other distribution) believed by it to be genuine and to have been signed, sent or otherwise authenticated by the proper Person. The Administrative Agent also may rely upon any statement made to it orally or by telephone and believed by it to have been made by the proper Person, and shall not incur any liability for relying thereon. In determining compliance with any condition hereunder to the making or extension of a Loan that by its terms must be fulfilled to the satisfaction of a Lender, the Administrative Agent may presume that such condition is satisfactory to such Lender unless the Administrative Agent shall have received notice to the contrary from such Lender prior to the making or extension of such Loan. The Administrative Agent may consult with legal counsel (who may be counsel for the Borrower), independent accountants and other experts selected by it, and shall not be liable for any action taken or not taken by it in accordance with the advice of any such counsel, accountants or experts.

SECTION 8.05 Delegation of Duties. The Administrative Agent may perform any and all of its duties and exercise its rights and powers hereunder or under any other Loan Document by or through any one or more sub agents appointed by the Administrative Agent. The Administrative Agent and any such sub agent may perform any and all of its duties and exercise its rights and powers by or through their respective Related Parties. The exculpatory provisions of this Article shall apply to any such sub agent and to the Related Parties of the Administrative Agent and any such sub agent, and shall apply to their respective activities in connection with the syndication of the revolving credit facility provided for herein as well as activities as Administrative Agent. The Administrative Agent shall not be responsible for the negligence or misconduct of any sub-agents except to the extent that a court of competent jurisdiction determines in a final and nonappealable judgment that the Administrative Agent acted with gross negligence or willful misconduct in the selection of such sub agents.

SECTION 8.06 Resignation of Administrative Agent.

(a) The Administrative Agent may at any time give notice of its resignation to the Lenders and the Borrower. Upon receipt of any such notice of resignation, the Required Lenders shall have the right to appoint a successor, subject to (so long as no Default or Event of Default exists) the prior written consent of the Borrower (which consent will not be unreasonably withheld or delayed), which shall be a bank with an office in the United States, or an Affiliate of any such bank with an office in the United States. If no such successor shall have been so appointed by the Required Lenders and shall have accepted such appointment within 30 days after the retiring Administrative Agent gives notice of its resignation (or such earlier day as shall be agreed by the Required Lenders) (the "Resignation Effective Date"), then the retiring Administrative Agent may (but shall not be obligated to), subject to (so long as no Default or Event of Default exists) the prior written consent of the Borrower (which consent will not be unreasonably withheld), on behalf of the Lenders, appoint a successor Administrative Agent meeting the qualifications set forth above. Whether or not a successor has been appointed, such resignation shall become effective in accordance with such notice on the Resignation Effective Date.

(b) If the Person serving as Administrative Agent is a Defaulting Lender pursuant to clause (d) of the definition thereof, the Required Lenders may, to the extent permitted by applicable law, by notice in writing to the Borrower and such Person remove such Person as Administrative Agent and, subject to (so long as no Default or Event of Default exists) the prior written consent of the Borrower (which consent will not be unreasonably withheld or delayed), appoint a successor. If no such successor shall have been so appointed by the Required Lenders and shall have accepted such appointment within 30 days (or such earlier day as shall be agreed by the Required Lenders) (the "Removal Effective Date"), then such removal shall nonetheless become effective in accordance with such notice on the Removal Effective Date.

(c) With effect from the Resignation Effective Date or the Removal Effective Date (as applicable) (1) the retiring or removed Administrative Agent shall be discharged from its duties and

obligations hereunder and under the other Loan Documents (except that in the case of any collateral security held by the Administrative Agent on behalf of the Lenders under any of the Loan Documents, the retiring or removed Administrative Agent shall continue to hold such collateral security until such time as a successor Administrative Agent is appointed) and (2) except for any indemnity payments owed to the retiring or removed Administrative Agent, all payments, communications and determinations provided to be made by, to or through the Administrative Agent shall instead be made by or to each Lender directly, until such time, if any, as the Required Lenders appoint a successor Administrative Agent as provided for above. Upon the acceptance of a successor's appointment as Administrative Agent hereunder, such successor shall succeed to and become vested with all of the rights, powers, privileges and duties of the retiring or removed Administrative Agent (other than any rights to indemnity payments owed to the retiring or removed Administrative Agent), and the retiring or removed Administrative Agent shall be discharged from all of its duties and obligations hereunder or under the other Loan Documents. The fees payable by the Borrower to a successor Administrative Agent shall be the same as those payable to its predecessor unless otherwise agreed between the Borrower and such successor. After the retiring or removed Administrative Agent's resignation or removal hereunder and under the other Loan Documents, the provisions of this Article and Section 9.03 shall continue in effect for the benefit of such retiring or removed Administrative Agent, its sub agents and their respective Related Parties in respect of any actions taken or omitted to be taken by any of them while the retiring or removed Administrative Agent was acting as Administrative Agent.

SECTION 8.07 Non-Reliance on Administrative Agent and Other Lenders.

(a) Each Lender acknowledges that it has, independently and without reliance upon the Administrative Agent or any other Lender or any of their Related Parties and based on such documents and information as it has deemed appropriate, made its own credit analysis and decision to enter into this Agreement. Each Lender also acknowledges that it will, independently and without reliance upon the Administrative Agent or any other Lender or any of their Related Parties and based on such documents and information as it shall from time to time deem appropriate, continue to make its own decisions in taking or not taking action under or based upon this Agreement, any other Loan Document or any related agreement or any document furnished hereunder or thereunder.

(b) Each Lender acknowledges that Simpson Thacher & Bartlett LLP is acting in this transaction as special legal counsel to the Administrative Agent only. Each Lender will consult with its own legal counsel to the extent it deems necessary with this Agreement and the other Loan Documents and the matters contemplated herein and therein.

SECTION 8.08 INDEMNIFICATION. **THE LENDERS AGREE TO INDEMNIFY THE ADMINISTRATIVE AGENT, THE ARRANGERS, THE SYNDICATION AGENT AND THE DOCUMENTATION AGENTS RATABLY IN ACCORDANCE WITH THEIR APPLICABLE PERCENTAGES FOR THE INDEMNITY MATTERS AS DESCRIBED IN SECTION 9.03 TO THE EXTENT NOT INDEMNIFIED OR REIMBURSED BY THE BORROWER UNDER SECTION 9.03, BUT WITHOUT LIMITING THE OBLIGATIONS OF THE BORROWER UNDER SAID SECTION 9.03 AND FOR ANY AND ALL OTHER LIABILITIES, OBLIGATIONS, LOSSES, DAMAGES, PENALTIES, ACTIONS, JUDGMENTS, SUITS, COSTS, EXPENSES OR DISBURSEMENTS OF ANY KIND AND NATURE WHATSOEVER WHICH MAY BE IMPOSED ON, INCURRED BY OR ASSERTED AGAINST THE ADMINISTRATIVE AGENT, ANY ARRANGER, THE SYNDICATION AGENT OR ANY DOCUMENTATION AGENT IN ANY WAY RELATING TO OR ARISING OUT OF: (A) THIS AGREEMENT OR ANY OTHER LOAN DOCUMENT CONTEMPLATED BY OR REFERRED TO HEREIN OR THE TRANSACTIONS CONTEMPLATED HEREBY, BUT EXCLUDING, UNLESS A DEFAULT OR AN EVENT OF DEFAULT HAS OCCURRED AND IS CONTINUING, NORMAL ADMINISTRATIVE COSTS AND**

EXPENSES INCIDENT TO THE PERFORMANCE OF ITS AGENCY DUTIES, IF ANY, HEREUNDER OR UNDER ANY SUCH OTHER LOAN DOCUMENT OR (B) THE ENFORCEMENT OF ANY OF THE TERMS OF THIS AGREEMENT OR OF ANY OTHER LOAN DOCUMENT; WHETHER OR NOT ANY OF THE FOREGOING SPECIFIED IN THIS SECTION 8.08 ARISES FROM THE SOLE OR CONCURRENT NEGLIGENCE OF THE ADMINISTRATIVE AGENT, ANY ARRANGER, THE SYNDICATION AGENT OR ANY DOCUMENTATION AGENT, AS THE CASE MAY BE; *PROVIDED* THAT NO LENDER SHALL BE LIABLE FOR ANY OF THE FOREGOING TO THE EXTENT THEY ARISE FROM THE GROSS NEGLIGENCE, WILLFUL MISCONDUCT OR UNLAWFUL CONDUCT OF THE ADMINISTRATIVE AGENT, ANY ARRANGER, THE SYNDICATION AGENT OR ANY DOCUMENTATION AGENT AS DETERMINED BY A COURT OF COMPETENT JURISDICTION IN A FINAL AND NONAPPEALABLE JUDGMENT.

SECTION 8.09 No Reliance on Agents or other Lenders. Each Lender acknowledges and agrees that it has, independently and without reliance on the Administrative Agent, any Arranger, the Syndication Agent, any Documentation Agent or any other Lender, and based on such documents and information as it has deemed appropriate, made its own credit analysis of the Borrower and its Subsidiaries and its decision to enter into this Agreement, and that it will, independently and without reliance upon the Administrative Agent, any Arranger, the Syndication Agent, any Documentation Agent or any other Lender, and based on such documents and information as it shall deem appropriate at the time, continue to make its own analysis and decisions in taking or not taking action under this Agreement. None of the Administrative Agent, the Arrangers, the Syndication Agent or the Documentation Agents shall be required to keep itself informed as to the performance or observance by the Borrower of this Agreement, the other Loan Documents or any other document referred to or provided for herein or to inspect the properties or books of the Borrower. Except for notices, reports and other documents and information expressly required to be furnished to the Lenders by the Administrative Agent hereunder, none of the Administrative Agent, the Arrangers, the Syndication Agent or the Documentation Agents shall have any duty or responsibility to provide any Lender with any credit or other information concerning the affairs, financial condition or business of the Borrower (or any of its Affiliates) which may come into the possession of the Administrative Agent, any Arranger, the Syndication Agent, any Documentation Agent or any of their respective Affiliates. In this regard, each Lender acknowledges that Simpson Thacher & Bartlett LLP is acting in this transaction as special counsel to the Administrative Agent only. Each Lender will consult with its own legal counsel to the extent that it deems necessary in connection with this Agreement and other Loan Documents and the matters contemplated herein and therein.

SECTION 8.10 Duties of the Syndication Agent, Documentation Agents, Arrangers. Notwithstanding the indemnity of the Syndication Agent, the Documentation Agents and the Arrangers contained in Section 8.08 and in Section 9.03, nothing contained in this Agreement shall be construed to impose any obligation or duty whatsoever on any Person named on the cover of this Agreement or elsewhere in this Agreement as a Syndication Agent, a Documentation Agent, an Arranger, a "lead arranger" or a "bookrunner", other than those applicable to all Lenders as such.

SECTION 8.11 Certain ERISA Matters.

(a) Each Lender (x) represents and warrants, as of the date such Person became a Lender party hereto, to, and (y) covenants, from the date such Person became a Lender party hereto to the date such Person ceases being a Lender party hereto, for the benefit of, the Administrative Agent and the Joint Lead Arrangers and their respective Affiliates, and not, for the avoidance of doubt, to or for the benefit of the Borrower or any other Loan Party, that at least one of the following is and will be true:

(i) such Lender is not using "plan assets" (within the meaning of the Plan Asset Regulations) of one or more Benefit Plans in connection with the Loans or the Commitments,

(ii) the transaction exemption set forth in one or more PTEs, such as PTE 84-14 (a class exemption for certain transactions determined by independent qualified professional asset managers), PTE 95-60 (a class exemption for certain transactions involving insurance company general accounts), PTE 90-1 (a class exemption for certain transactions involving insurance company pooled separate accounts), PTE 91-38 (a class exemption for certain transactions involving bank collective investment funds) or PTE 96-23 (a class exemption for certain transactions determined by in-house asset managers), is applicable with respect to such Lender's entrance into, participation in, administration of and performance of the Loans, the Commitments and this Agreement, and the conditions for exemptive relief thereunder are and will continue to be satisfied in connection therewith,

(iii) (A) such Lender is an investment fund managed by a "Qualified Professional Asset Manager" (within the meaning of Part VI of PTE 84-14), (B) such Qualified Professional Asset Manager made the investment decision on behalf of such Lender to enter into, participate in, administer and perform the Loans, the Commitments and this Agreement, (C) the entrance into, participation in, administration of and performance of the Loans, the Commitments and this Agreement satisfies the requirements of sub-sections (b) through (g) of Part I of PTE 84-14 and (D) to the best knowledge of such Lender, the requirements of subsection (a) of Part I of PTE 84-14 are satisfied with respect to such Lender's entrance into, participation in, administration of and performance of the Loans, the Commitments and this Agreement, or

(iv) such other representation, warranty and covenant as may be agreed in writing between the Administrative Agent, in its sole discretion, and such Lender.

(b) In addition, unless sub-clause (i) in the immediately preceding clause (a) is true with respect to a Lender or such Lender has not provided another representation, warranty and covenant as provided in sub-clause (iv) in the immediately preceding clause (a), such Lender further (x) represents and warrants, as of the date such Person became a Lender party hereto, to, and (y) covenants, from the date such Person became a Lender party hereto to the date such Person ceases being a Lender party hereto, for the benefit of, the Administrative Agent and the Joint Lead Arrangers and their respective Affiliates, and not, for the avoidance of doubt, to or for the benefit of the Borrower or any other Loan Party, that none of the Administrative Agent or the Joint Leader Arrangers or any of their respective Affiliates is a fiduciary with respect to the assets of such Lender (including in connection with the reservation or exercise of any rights by the Administrative Agent under this Agreement, any Loan Document or any documents related to hereto or thereto),

(c) The Administrative Agent and the Joint Leader Arrangers hereby inform the Lenders that each such Person is not undertaking to provide impartial investment advice, or to give advice in a fiduciary capacity, in connection with the transactions contemplated hereby, and that such Person has a financial interest in the transactions contemplated hereby in that such Person or an Affiliate thereof (i) may receive interest or other payments with respect to the Loans, the Commitments and this Agreement, (ii) may recognize a gain if it extended the Loans or the Commitments for an amount less than the amount being paid for an interest in the Loans or the Commitments by such Lender or (iii) may receive fees or other payments in connection with the transactions contemplated hereby, the Loan Documents or otherwise, including structuring fees, commitment fees, arrangement fees, facility fees, upfront fees, underwriting fees, ticking fees, agency fees, administrative agent or collateral agent fees, utilization fees, minimum usage fees, letter of credit fees, fronting fees, deal-away or alternate transaction fees, amendment fees, processing fees, term

out premiums, banker's acceptance fees, breakage or other early termination fees or fees similar to the foregoing.

ARTICLE IX
MISCELLANEOUS

SECTION 9.01 Notices, Etc.

(a) All notices, consents, requests, approvals, demands and other communications (collectively "Communications") provided for herein shall be in writing (including facsimile Communications) and mailed, telecopied or delivered:

(i) if to the Borrower, to it at:

1001 Louisiana Street, Suite 1000
Houston, Texas 77002
Attention: Anthony Ashley
Telecopy No.: (713) 445-8302;

With a copy to:

1001 Louisiana Street, Suite 1000
Houston, Texas 77002
Attention: General Counsel
Telecopy No.: (713) 495-2877;

(ii) if to the Administrative Agent, to it at

c/o Barclays Bank PLC
745 Seventh Avenue
27th Floor
New York, NY 10019
Attention: Patrick Shields
Email: patrick.shields@barclays.com
Phone: 212-526-9531

(i) if to any other Lender, to it at its address (or telecopy number) set forth in the Administrative Questionnaire delivered by such Person to the Administrative Agent or in the Assignment and Acceptance executed by such Person;

or, in the case of any party hereto, such other address or telecopy number as such party may hereafter specify for such purpose by notice to the other parties.

(b) Communications to the Lenders hereunder may be delivered or furnished by electronic communications (including electronic mail and internet or intranet websites) pursuant to procedures approved by the Administrative Agent; *provided* that the foregoing shall not apply to notices pursuant to Article II unless otherwise agreed by the Administrative Agent and the applicable Lender. The Administrative Agent or the Borrower may, in its discretion, agree to accept notices and other communications to it hereunder by electronic communications pursuant to procedures approved by it; *provided* that approval of such procedures may be limited to particular notices or communications.

(c) Unless the Administrative Agent otherwise prescribes, (i) notices and other communications sent to an e-mail address shall be deemed received upon the sender's receipt of an acknowledgement from the intended recipient (such as by the "return receipt requested" function, as available, return e-mail or other written acknowledgement), and (ii) notices or communications posted to an Internet or intranet website shall be deemed received upon the deemed receipt by the intended recipient, at its e-mail address as described in the foregoing clause (i), of notification that such notice or communication is available and identifying the website address therefor; *provided* that, for both clauses (i) and (ii) above, if such notice, email or other communication is not sent during the normal business hours of the recipient, such notice or communication shall be deemed to have been sent at the opening of business on the next business day for the recipient.

(d) Any party hereto may change its address or telecopy number for notices and other communications hereunder by notice to the other parties hereto.

(e) Platform.

(i) The Borrower agrees that the Administrative Agent may, but shall not be obligated to, make the Communications available to the Lenders by posting the Communications on Debt Domain, Intralinks, Syndtrak or a substantially similar electronic transmission system (the "Platform").

The Platform is provided "*as is*" and "*as available*." The Agent Parties (as defined below) do not warrant the adequacy of the Platform and expressly disclaim liability for errors or omissions in the Electronic Communications (as defined below). No warranty of any kind, express, implied or statutory, including, without limitation, any warranty of merchantability, fitness for a particular purpose, non-infringement of third-party rights or freedom from viruses or other code defects, is made by any Agent Party in connection with the Communications or the Platform. In no event shall the Administrative Agent or any of its Related Parties (collectively, the "Agent Parties") have any liability to the Borrower, any Lender or any other Person or entity for damages of any kind, including, without limitation, direct or indirect, special, incidental or consequential damages, losses or expenses (whether in tort, contract or otherwise) arising out of the Borrower or the Administrative Agent's transmission of communications through the Platform. "Electronic Communications" means, collectively, any notice, demand, communication, information, document or other material provided by or on behalf of the Borrower pursuant to any Loan Document or the transactions contemplated therein which is distributed to the Administrative Agent or any Lender by means of electronic communications pursuant to this Section, including through the Platform.

SECTION 9.02 Waivers; Amendments; Releases.

(a) No failure or delay by the Administrative Agent or any Lender in exercising, and no course of dealing with respect to, any right or power hereunder shall operate as a waiver thereof, nor shall any single or partial exercise of any such right or power, or any abandonment or discontinuance of steps to enforce such a right or power, preclude any other or further exercise thereof or the exercise of any other right or power. No notice to or demand on the Borrower in any case shall entitle the Borrower to any other or further notice or demand in similar or other circumstances. No waiver of any provision of this Agreement or consent to any departure therefrom shall in any event be effective unless the same shall be permitted by Section 9.02(b), and then such waiver or consent shall be effective only in the specific instance and for the purpose for which given. Without limiting the generality of the foregoing, the making of a Loan shall not be construed as a waiver of any Default or Event of Default, regardless of whether the Administrative Agent or any Lender may have had notice or knowledge of such Default at the time.

(b) No provision of this Agreement or any other Loan Document (other than each Fee Letter, which may be amended by the parties thereto) provision may be waived, amended or modified except pursuant to an agreement or agreements in writing entered into by the Borrower (or to the extent another Loan Party and not the Borrower is party thereto, such Loan Party) and the Required Lenders or by the Borrower and the Administrative Agent with the consent of the Required Lenders; *provided* that no such agreement shall (i) increase the Commitment of any Lender without the written consent of such Lender, (ii) reduce the principal amount of any Loan or reduce the rate of interest thereon, or reduce any fees payable hereunder, without the written consent of each Lender affected thereby (for the avoidance of doubt, any amendment imposing an alternative interest rate basis in accordance with Section 2.13(b) shall become effective as provided in Section 2.13(b)), (iii) postpone the scheduled date of payment of the principal amount of any Loan, or any interest thereon, or any fees or other amounts payable hereunder, or reduce the amount of, waive or excuse any such payment, or postpone the scheduled date of expiration of any Commitment, without the written consent of each Lender affected thereby, (iv) change Section 2.17(b) or (c) in a manner that would alter the *pro rata* sharing of payments required thereby, without the written consent of each Lender, (v) amend Section 2.19 without the consent of the Administrative Agent, in addition to the consent of the Required Lenders, (vi) release all or substantially all of the value of the Guarantees under the Guaranty or change any of the provisions of this Section 9.02(b), or the definition of "*Required Lenders*" or any other provision hereof specifying the number or percentage of Lenders required to waive, amend or modify any rights hereunder or make any determination or grant any consent hereunder, without the written consent of each Lender; *provided*, *further*, that no such agreement shall amend, modify or otherwise affect the rights or duties of the Administrative Agent hereunder without the prior written consent of the Administrative Agent. Except as provided herein, during such period as a Lender is a Defaulting Lender, to the fullest extent permitted by applicable law, such Lender will not be entitled to vote in respect of amendments and waivers hereunder and the Commitment and the outstanding Loans or other extensions of credit of such Lender hereunder will not be taken into account in determining whether the Required Lenders or all of the Lenders, as required, have approved any such amendment or waiver (and the definition of "*Required Lenders*" will automatically be deemed modified accordingly for the duration of such period); *provided* that any such amendment or waiver referred to in clauses (i) through (vi) or the first of this Section 9.02(b) above or that would alter the terms set forth in such proviso shall require the consent of such Defaulting Lender.

Notwithstanding the foregoing, the Administrative Agent and the Borrower may amend any Loan Document to correct any obvious errors, mistakes, omissions, defects or inconsistencies and such amendment shall become effective without any further consent of any other party to such Loan Document other than the Administrative Agent and the Borrower.

(c) The Lenders hereby irrevocably agree that any Guarantor shall be automatically released from the Guarantee upon consummation of any transaction not prohibited hereunder resulting in such Subsidiary ceasing to constitute a Subsidiary or upon any Subsidiary becoming an Excluded Subsidiary, provided that with respect to any Excluded Subsidiary that is a Guarantor on the Closing Date or that has become a Guarantor after the Closing Date at the request of the Borrower, such Excluded Subsidiary shall be automatically released from the Guaranty upon written notice thereof from a Responsible Officer of the Borrower to the Administrative Agent certifying that (i) such Excluded Subsidiary is an Excluded Subsidiary and (ii) on such date, or concurrently with such release, such Excluded Subsidiary shall be automatically released as a guarantor under the Cross Guarantee Agreement, dated as of November 26, 2014 (as amended, restated, supplemented or otherwise modified from time to time) entered by the Borrower and the other signatories party thereto, and is not a guarantor of the Bonds or any other material Indebtedness of the Borrower or any Subsidiary. The Lenders hereby authorize the Administrative Agent to execute and deliver any instruments, documents, and agreements necessary or desirable to evidence and confirm the release of any Guarantor pursuant to the foregoing provisions of this paragraph, all without the further consent or joinder of any Lender.

SECTION 9.03 Payment of Expenses, Indemnities, etc. The Borrower agrees:

(a) to pay (i) all reasonable out-of-pocket expenses incurred by the Administrative Agent and its Affiliates, including the reasonable fees, charges and disbursements of counsel for the Administrative Agent, in connection with the syndication of the credit facility provided for herein, the preparation and administration of this Agreement or any amendments, modifications or waivers of the provisions hereof and (ii) all out-of-pocket expenses incurred by the Administrative Agent or any Lender, including the fees, charges and disbursements of any counsel for the Administrative Agent or any Lender, in connection with the enforcement or protection of its rights in connection with this Agreement, including its rights under this Section, or in connection with the Loans made hereunder, including all such out-of-pocket expenses incurred during any workout, restructuring or negotiations in respect of such Loans.

(b) TO INDEMNIFY THE ADMINISTRATIVE AGENT, EACH ARRANGER, THE SYNDICATION AGENT, EACH DOCUMENTATION AGENT AND EACH LENDER AND EACH OF THEIR AFFILIATES AND EACH OF THEIR OFFICERS, DIRECTORS, EMPLOYEES, REPRESENTATIVES, AGENTS, ATTORNEYS, ACCOUNTANTS AND EXPERTS ("INDEMNIFIED PARTIES") FROM, HOLD EACH OF THEM HARMLESS AGAINST AND PROMPTLY UPON DEMAND PAY OR REIMBURSE EACH OF THEM FOR, THE INDEMNITY MATTERS WHICH MAY BE REASONABLY INCURRED BY OR ASSERTED AGAINST OR INVOLVE ANY OF THEM (WHETHER OR NOT ANY OF THEM IS DESIGNATED A PARTY THERETO AND WHETHER OR NOT THE CLAIM IS BROUGHT BY THE BORROWER OR A THIRD PARTY) AS A RESULT OF, ARISING OUT OF OR IN ANY WAY RELATED TO (I) ANY ACTUAL OR PROPOSED USE BY THE BORROWER OF THE PROCEEDS OF ANY OF THE LOANS, (II) THE EXECUTION, DELIVERY AND PERFORMANCE OF THE LOAN DOCUMENTS, (III) THE OPERATIONS OF THE BUSINESS OF THE BORROWER AND THE SUBSIDIARIES, (IV) THE FAILURE OF THE BORROWER OR ANY SUBSIDIARY TO COMPLY WITH THE TERMS OF THIS AGREEMENT, OR WITH ANY REQUIREMENT OF LAW, (V) ANY INACCURACY OF ANY REPRESENTATION OR ANY BREACH OF ANY WARRANTY OF THE BORROWER SET FORTH IN ANY OF THE LOAN DOCUMENTS OR (VI) ANY OTHER ASPECT OF THE LOAN DOCUMENTS, INCLUDING THE REASONABLE FEES AND DISBURSEMENTS OF COUNSEL AND ALL OTHER EXPENSES INCURRED IN CONNECTION WITH INVESTIGATING, DEFENDING OR PREPARING TO DEFEND ANY SUCH ACTION, SUIT, PROCEEDING (INCLUDING ANY INVESTIGATIONS, LITIGATION OR INQUIRIES) OR CLAIM AND INCLUDING ALL INDEMNITY MATTERS ARISING BY REASON OF THE ORDINARY NEGLIGENCE OF ANY INDEMNIFIED PARTY, BUT EXCLUDING ALL INDEMNITY MATTERS ARISING SOLELY (I) BY REASON OF CLAIMS BETWEEN THE LENDERS OR ANY LENDER AND THE ADMINISTRATIVE AGENT, ANY ARRANGER, THE SYNDICATION AGENT, ANY DOCUMENTATION AGENT, OR A LENDER'S SHAREHOLDERS AGAINST THE ADMINISTRATIVE AGENT OR LENDER (OTHER THAN CLAIMS IN ITS ROLE AS AGENT OR ARRANGER) OR (II) BY REASON OF THE GROSS NEGLIGENCE, WILLFUL MISCONDUCT OR UNLAWFUL CONDUCT ON THE PART OF THE INDEMNIFIED PARTY SEEKING INDEMNIFICATION AS DETERMINED BY A COURT OF COMPETENT JURISDICTION IN A FINAL AND NONAPPEALABLE JUDGMENT. FOR THE AVOIDANCE OF DOUBT, THIS SECTION 9.03(B) SHALL NOT APPLY WITH RESPECT TO TAXES OTHER THAN ANY TAXES THAT REPRESENT LOSSES, CLAIMS, DAMAGES, ETC. ARISING FROM ANY NON-TAX CLAIM.

(c) TO INDEMNIFY AND HOLD HARMLESS FROM TIME TO TIME THE INDEMNIFIED PARTIES FROM AND AGAINST ANY AND ALL LOSSES, CLAIMS, COST RECOVERY ACTIONS, ADMINISTRATIVE ORDERS OR PROCEEDINGS, DAMAGES AND

LIABILITIES TO WHICH ANY SUCH PERSON MAY BECOME SUBJECT (I) UNDER ANY ENVIRONMENTAL LAW APPLICABLE TO THE BORROWER OR ANY SUBSIDIARY OR ANY OF THEIR PROPERTIES OR ASSETS, INCLUDING THE TREATMENT OR DISPOSAL OF HAZARDOUS MATERIALS ON ANY OF THEIR PROPERTIES OR ASSETS, (II) AS A RESULT OF THE BREACH OR NON-COMPLIANCE BY THE BORROWER OR ANY SUBSIDIARY WITH ANY ENVIRONMENTAL LAW APPLICABLE TO THE BORROWER OR ANY SUBSIDIARY, (III) DUE TO PAST OWNERSHIP BY THE BORROWER OR ANY SUBSIDIARY OF ANY OF THEIR PROPERTIES OR ASSETS OR PAST ACTIVITY ON ANY OF THEIR PROPERTIES OR ASSETS WHICH, THOUGH LAWFUL AND FULLY PERMISSIBLE AT THE TIME, COULD RESULT IN PRESENT LIABILITY, (IV) THE PRESENCE, USE, RELEASE, STORAGE, TREATMENT OR DISPOSAL OF HAZARDOUS MATERIALS ON OR AT ANY OF THE PROPERTIES OWNED OR OPERATED BY THE BORROWER OR ANY SUBSIDIARY, OR (V) ANY OTHER ENVIRONMENTAL, HEALTH OR SAFETY CONDITION IN CONNECTION WITH THE LOAN DOCUMENTS (EXPRESSLY INCLUDING ANY SUCH CLAIM, DAMAGE LOSS, LIABILITY, COST, PENALTY, FEE OR EXPENSE ATTRIBUTABLE TO THE ORDINARY, SOLE OR CONTRIBUTORY NEGLIGENCE OF SUCH INDEMNIFIED PARTY, BUT EXCLUDING ANY SUCH CLAIM, DAMAGE, LOSS, LIABILITY, COST, PENALTY, FEE OR EXPENSE RESULTING FROM THE GROSS NEGLIGENCE OR WILLFUL MISCONDUCT OF SUCH INDEMNIFIED PARTY AS DETERMINED BY A COURT OF COMPETENT JURISDICTION IN A FINAL AND NONAPPEALABLE JUDGMENT). FOR THE AVOIDANCE OF DOUBT, THIS SECTION 9.03(C) SHALL NOT APPLY WITH RESPECT TO TAXES OTHER THAN ANY TAXES THAT REPRESENT LOSSES, CLAIMS, DAMAGES, ETC. ARISING FROM ANY NON-TAX CLAIM.

(d) No Indemnified Party may settle any claim to be indemnified without the consent of the indemnitor, such consent not to be unreasonably withheld; *provided* that the indemnitor may not reasonably withhold consent to any settlement that an Indemnified Party proposes, if the indemnitor does not have the financial ability to pay all its obligations outstanding and asserted against the indemnitor at that time, including the maximum potential claims against the Indemnified Party to be indemnified pursuant to this Section 9.03.

(e) In the case of any indemnification hereunder, the Indemnified Party, as appropriate, shall give notice to the Borrower of any such claim or demand being made against the Indemnified Party and the Borrower shall have the non-exclusive right to join in the defense against any such claim or demand; *provided* that if the Borrower provides a defense, the Indemnified Party shall bear its own cost of defense unless there is a conflict between the Borrower and such Indemnified Party.

(f) THE FOREGOING INDEMNITIES SHALL EXTEND TO THE INDEMNIFIED PARTIES NOTWITHSTANDING THE SOLE OR CONCURRENT NEGLIGENCE OF EVERY KIND OR CHARACTER WHATSOEVER, WHETHER ACTIVE OR PASSIVE, WHETHER AN AFFIRMATIVE ACT OR AN OMISSION, INCLUDING, ALL TYPES OF NEGLIGENT CONDUCT IDENTIFIED IN THE RESTATEMENT (SECOND) OF TORTS OF ONE OR MORE OF THE INDEMNIFIED PARTIES OR BY REASON OF STRICT LIABILITY IMPOSED WITHOUT FAULT ON ANY ONE OR MORE OF THE INDEMNIFIED PARTIES. TO THE EXTENT THAT AN INDEMNIFIED PARTY IS FOUND TO HAVE COMMITTED AN ACT OF GROSS NEGLIGENCE OR WILLFUL MISCONDUCT OR ENGAGED IN UNLAWFUL CONDUCT (AS DETERMINED BY A COURT OF COMPETENT JURISDICTION IN A FINAL AND NONAPPEALABLE JUDGMENT), THIS CONTRACTUAL OBLIGATION OF INDEMNIFICATION SHALL CONTINUE BUT SHALL ONLY EXTEND TO THE PORTION OF THE CLAIM THAT IS DEEMED TO HAVE OCCURRED BY REASON OF EVENTS OTHER THAN THE GROSS NEGLIGENCE, WILLFUL MISCONDUCT OR UNLAWFUL CONDUCT OF THE INDEMNIFIED

PARTY (AS DETERMINED BY A COURT OF COMPETENT JURISDICTION IN A FINAL AND NONAPPEALABLE JUDGMENT).

(g) The Borrower's obligations under this Section 9.03 shall survive any termination of this Agreement, the payment of the Loans and shall continue thereafter in full force and effect.

(h) To the extent that the Borrower fails to pay any amount required to be paid by it to the Administrative Agent under this Section 9.03, each Lender severally agrees to pay to the Administrative Agent such Lender's Applicable Percentage (determined as of the time that the applicable unreimbursed expense or indemnity payment is sought) of such unpaid amount; *provided* that the unreimbursed expense or indemnified loss, claim, damage, liability or related expense, as the case may be, was incurred by or asserted against the Administrative Agent in its capacity as such.

(i) The Borrower shall pay any amounts due under this Section 9.03 within 30 days of the receipt by the Borrower of notice of the amount due.

(j) To the fullest extent permitted by applicable law, no party shall assert, and each party hereby waives, any claim against any other party, on any theory of liability, for special, indirect, consequential or punitive damages (as opposed to direct or actual damages) arising out of, in connection with, or as a result of this Agreement, any other Loan Document or any agreement or instrument contemplated hereby, the transactions contemplated hereby or thereby, any Loan or the use of the proceeds thereof; *provided, howev*er, that the foregoing limitation shall not be deemed to impair or affect the indemnification obligations of the Borrower under the Loan Documents. No Indemnified Party referred to in paragraph (b) above shall be liable for any damages arising from the use by unintended recipients of any information or other materials distributed by it through telecommunications, electronic or other information transmission systems in connection with this Agreement or the other Loan Documents or the transactions contemplated hereby or thereby.

SECTION 9.04 Successors and Assigns Generally. The provisions of this Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective successors and assigns permitted hereby, except that the Borrower may not assign or otherwise transfer any of its rights or obligations hereunder without the prior written consent of the Administrative Agent and each Lender, and no Lender may assign or otherwise transfer any of its rights or obligations hereunder except (i) to an assignee in accordance with the provisions of Section 9.05(a), (ii) by way of participation in accordance with the provisions of Section 9.05(c), or (iii) by way of pledge or assignment of a security interest subject to the restrictions of Section 9.05(d) (and any other attempted assignment or transfer by any party hereto shall be null and void). Nothing in this Agreement, expressed or implied, shall be construed to confer upon any Person (other than the parties hereto, their respective successors and assigns permitted hereby, Participants to the extent provided in Section 9.05(c) and, to the extent expressly contemplated hereby, the Related Parties of each of the Administrative Agent and the Lenders) any legal or equitable right, remedy or claim under or by reason of this Agreement.

SECTION 9.05 Assignments by Lenders.

(a) Any Lender may at any time assign to one or more assignees all or a portion of its rights and obligations under this Agreement (including all or a portion of its Commitment and the Loans at the time owing to it); *provided* that any such assignment shall be subject to the following conditions:

(i) (A) in the case of an assignment of the entire remaining amount of the assigning Lender's Commitment and/or the Loans at the time owing to it or contemporaneous

assignments to related Approved Funds that equal at least the amount specified in paragraph (a)(i)(B) of this Section; and

(B) in any case not described in the proviso to paragraph (a)(i)(A) of this Section, the aggregate amount of the Commitment (which for this purpose includes Loans outstanding thereunder) or, if the applicable Commitment is not then in effect, the principal outstanding balance of the Loans of the assigning Lender subject to each such assignment (determined as of the date the Assignment and Acceptance with respect to such assignment is delivered to the Administrative Agent or, if "Trade Date" is specified in the Assignment and Acceptance, as of the Trade Date) shall not be less than $5,000,000, unless each of the Administrative Agent and, so long as no Event of Default has occurred and is continuing, the Borrower otherwise consents (each such consent not to be unreasonably withheld or delayed); *provided*, however, in the case of an assignment to a Lender, an Affiliate of a Lender or an Approved Fund, no minimum amount need be assigned.

(ii) Each partial assignment shall be made as an assignment of a proportionate part of all the assigning Lender's rights and obligations under this Agreement with respect to the Loans or the Commitment assigned.

(iii) No consent shall be required for any assignment except to the extent required by paragraph (a)(i)(B) of this Section and, in addition:

(A) the consent of the Borrower (such consent not to be unreasonably withheld or delayed) shall be required unless (x) an Event of Default has occurred and is continuing at the time of such assignment or (y) such assignment is to a Lender, an Affiliate of a Lender or an Approved Fund, *provided* that the Borrower's consent shall not be required during the primary syndication of the credit facility evidenced by this Agreement; and

(B) the consent of the Administrative Agent (such consent not to be unreasonably withheld or delayed) shall be required for assignments if such assignment is to a Person that is not a Lender, an Affiliate of such Lender or an Approved Fund with respect to such Lender.

(iv) The parties to each assignment shall execute and deliver to the Administrative Agent an Assignment and Acceptance, together with a processing and recordation fee of $3,500; *provided* that the Administrative Agent may, in its sole discretion, elect to waive such processing and recordation fee in the case of any assignment. The assignee, if it is not a Lender, shall deliver to the Administrative Agent an Administrative Questionnaire.

(v) No such assignment shall be made to (A) the Borrower or any of the Borrower's Affiliates or Subsidiaries or (B) to any Defaulting Lender or any of its Subsidiaries, or any Person who, upon becoming a Lender hereunder, would constitute any of the foregoing Persons described in this clause (B).

(vi) No such assignment shall be made to a natural Person.

(vii) In connection with any assignment of rights and obligations of any Defaulting Lender hereunder, no such assignment shall be effective unless and until, in addition to the other conditions thereto set forth herein, the parties to the assignment shall make such additional payments to the Administrative Agent in an aggregate amount sufficient, upon distribution thereof

as appropriate (which may be outright payment, purchases by the assignee of participations or subparticipations, or other compensating actions, including funding, with the consent of the Borrower and the Administrative Agent, the applicable *pro rata* share of Loans previously requested but not funded by the Defaulting Lender, to each of which the applicable assignee and assignor hereby irrevocably consent), to (x) pay and satisfy in full all payment liabilities then owed by such Defaulting Lender to the Administrative Agent and each other Lender hereunder (and interest and fees accrued thereon), and (y) acquire (and fund as appropriate) its full *pro rata* share of all Loans in accordance with its Applicable Percentage. Notwithstanding the foregoing, in the event that any assignment of rights and obligations of any Defaulting Lender hereunder shall become effective under applicable law without compliance with the provisions of this paragraph, then the assignee of such interest shall be deemed to be a Defaulting Lender for all purposes of this Agreement until such compliance occurs.

Subject to acceptance and recording thereof by the Administrative Agent pursuant to paragraph (b) of this Section, from and after the effective date specified in each Assignment and Acceptance, the assignee thereunder shall be a party to this Agreement and, to the extent of the interest assigned by such Assignment and Acceptance, have the rights and obligations of a Lender under this Agreement, and the assigning Lender thereunder shall, to the extent of the interest assigned by such Assignment and Acceptance, be released from its obligations under this Agreement (and, in the case of an Assignment and Acceptance covering all of the assigning Lender's rights and obligations under this Agreement, such Lender shall cease to be a party hereto) but shall continue to be entitled to the benefits of Sections 2.14, 2.15 and 9.03 and with respect to facts and circumstances occurring prior to the effective date of such assignment; *provided*, that except to the extent otherwise expressly agreed by the affected parties, no assignment by a Defaulting Lender will constitute a waiver or release of any claim of any party hereunder arising from that Lender's having been a Defaulting Lender. Any assignment or transfer by a Lender of rights or obligations under this Agreement that does not comply with this paragraph shall be treated for purposes of this Agreement as a sale by such Lender of a participation in such rights and obligations in accordance with paragraph (c) of this Section.

(b) Upon its receipt of a duly completed Assignment and Acceptance executed by an assigning Lender and an assignee, the assignee's completed Administrative Questionnaire (unless the assignee shall already be a Lender hereunder), the processing and recordation fee, if any, referred to in Section 9.05(a) and any written consent to such assignment required by Section 9.05(a), the Administrative Agent shall accept such Assignment and Acceptance and record the information contained therein in the Register (as defined below). No assignment shall be effective for purposes of this Agreement unless it has been recorded in the Register as provided in this paragraph. The Administrative Agent, acting solely for this purpose as a non-fiduciary agent of the Borrower, shall maintain at one of its offices in New York, New York a copy of each Assignment and Acceptance delivered to it and a register for the recordation of the names and addresses of the Lenders, and the Commitments of, and principal amounts (and stated interest) of the Loans owing to, each Lender pursuant to the terms hereof from time to time (the "Register"). The entries in the Register shall be conclusive absent manifest error, and the Borrower, the Administrative Agent and the Lenders shall treat each Person whose name is recorded in the Register pursuant to the terms hereof as a Lender hereunder for all purposes of this Agreement. The Register shall be available for inspection by the Borrower and any Lender (with respect to its own interest only), at any reasonable time and from time to time upon reasonable prior notice.

(c) Any Lender may at any time, without the consent of, or notice to, the Borrower or the Administrative Agent, sell participations to any Person (other than a natural Person or the Borrower or any of the Borrower's Affiliates or Subsidiaries) (each, a "Participant") in all or a portion of such Lender's rights and/or obligations under this Agreement (including all or a portion of its Commitment

and/or the Loans owing to it); *provided* that (i) such Lender's obligations under this Agreement shall remain unchanged, (ii) such Lender shall remain solely responsible to the other parties hereto for the performance of such obligations, and (iii) the Borrower, the Administrative Agent and the Lenders shall continue to deal solely and directly with such Lender in connection with such Lender's rights and obligations under this Agreement. For the avoidance of doubt, each Lender shall be responsible for the indemnity under Section 8.08 with respect to any payments made by such Lender to its Participant(s).

Any agreement or instrument pursuant to which a Lender sells such a participation shall provide that such Lender shall retain the sole right to enforce this Agreement and to approve any amendment, modification or waiver of any provision of this Agreement; *provided* that such agreement or instrument may provide that such Lender will not, without the consent of the Participant, agree to any amendment, modification or waiver described in the first proviso Section 9.02(b) that affects such Participant. The Borrower agrees that each Participant shall be entitled to the benefits of Sections 2.14, 2.15 and 2.16 (subject to the requirements and limitations therein, including the requirements under Section 2.16 (it being understood that the documentation required under Section 2.16 shall be delivered to the participating Lender)) to the same extent as if it were a Lender and had acquired its interest by assignment pursuant to paragraph (a) of this Section; *provided* that such Participant (A) agrees to be subject to the provisions of Sections 2.18 as if it were an assignee under paragraph (a) of this Section; and (B) shall not be entitled to receive any greater payment under Sections 2.14 and 2.16, with respect to any participation, than its participating Lender would have been entitled to receive, except to the extent such entitlement to receive a greater payment results from a Change in Law that occurs after the Participant acquired the applicable participation. Each Lender that sells a participation agrees, at the Borrower's request and expense, to use reasonable efforts to cooperate with the Borrower to effectuate the provisions of Section 2.18 with respect to any Participant. To the extent permitted by law, each Participant also shall be entitled to the benefits of Section 9.09 as though it were a Lender; *provided* that such Participant agrees to be subject to Section 2.17 as though it were a Lender. Each Lender that sells a participation shall, acting solely for this purpose as a non-fiduciary agent of the Borrower, maintain a register on which it enters the name and address of each Participant and the principal amounts (and stated interest) of each Participant's interest in the Loans or other obligations under the Loan Documents (the "Participant Register"); *provided* that no Lender shall have any obligation to disclose all or any portion of the Participant Register (including the identity of any Participant or any information relating to a Participant's interest in any commitments, loans, letters of credit or its other obligations under any Loan Document) to any Person except to the extent that such disclosure is necessary to establish that such commitment, loan, letter of credit or other obligation is in registered form under Section 5f.103-1(c) of the United States Treasury Regulations. The entries in the Participant Register shall be conclusive absent manifest error, and such Lender shall treat each Person whose name is recorded in the Participant Register as the owner of such participation for all purposes of this Agreement notwithstanding any notice to the contrary. For the avoidance of doubt, the Administrative Agent (in its capacity as Administrative Agent) shall have no responsibility for maintaining a Participant Register.

(d) Any Lender may at any time pledge or assign a security interest in all or any portion of its rights under this Agreement to secure obligations of such Lender, including any pledge or assignment to secure obligations to a Federal Reserve Bank or any central bank having jurisdiction over such Lender; *provided* that no such pledge or assignment shall release such Lender from any of its obligations hereunder or substitute any such pledgee or assignee for such Lender as a party hereto.

SECTION 9.06 Survival; Reinstatement.

(a) All covenants, agreements, representations and warranties made by the Borrower herein and in the certificates or other instruments delivered in connection with or pursuant to this Agreement shall be considered to have been relied upon by the other parties hereto and shall survive the execution and

delivery of this Agreement and the making of any Loans, regardless of any investigation made by any such other party or on its behalf and notwithstanding that the Administrative Agent or any Lender may have had notice or knowledge of any Default or Event of Default or incorrect representation or warranty at the time any credit is extended hereunder, and shall continue in full force and effect as long as the principal of or any accrued interest on any Loan or any fee or any other amount payable under this Agreement is outstanding and unpaid. The provisions of Sections 2.14, 2.15, 2.16 and 9.03 and Article VIII shall survive and remain in full force and effect regardless of the consummation of the transactions contemplated hereby, the repayment of the Loans, the expiration or termination of the Commitments or the termination of this Agreement or any provision hereof.

(b) To the extent that any payments on the Obligations are subsequently invalidated, declared to be fraudulent or preferential, set aside or required to be repaid to a trustee, debtor in possession, receiver or other Person under any bankruptcy law, common law or equitable cause, then to such extent, the Obligations so satisfied shall be revived and continue as if such payment or proceeds had not been received.

SECTION 9.07 Counterparts; Integration; Effectiveness; Electronic Execution.

(a) This Agreement may be executed in counterparts (and by different parties hereto on different counterparts), each of which shall constitute an original, but all of which when taken together shall constitute a single contract. This Agreement, the other Loan Documents and the Fee Letters constitute the entire contract among the parties hereto relating to the subject matter hereof and supersede any and all previous agreements and understandings, oral or written, relating to the subject matter hereof (including the Executive Summary). Except as provided in Section 3.01, this Agreement shall become effective when it shall have been executed by the Administrative Agent and when the Administrative Agent shall have received counterparts hereof which, when taken together, bear the signatures of each of the other parties hereto, and thereafter shall be binding upon and inure to the benefit of the parties hereto and their respective successors and assigns. Delivery of an executed counterpart of a signature page of this Agreement by facsimile or electronic (*i.e.*, "*pdf*" or "*tif*") format shall be effective as delivery of a manually executed counterpart of this Agreement.

(b) The words "execution," "signed," "signature," and words of like import in any Assignment and Acceptance shall be deemed to include electronic signatures or the keeping of records in electronic form, each of which shall be of the same legal effect, validity or enforceability as a manually executed signature or the use of a paper-based recordkeeping system, as the case may be, to the extent and as provided for in any applicable law, including the Federal Electronic Signatures in Global and National Commerce Act, the New York State Electronic Signatures and Records Act, or any other similar state laws based on the Uniform Electronic Transactions Act.

SECTION 9.08 Severability. Any provision of this Agreement held to be invalid, illegal or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such invalidity, illegality or unenforceability without affecting the validity, legality and enforceability of the remaining provisions hereof; and the invalidity of a particular provision in a particular jurisdiction shall not invalidate such provision in any other jurisdiction.

SECTION 9.09 Right of Setoff. If an Event of Default shall have occurred and be continuing, each Lender and each of its respective Affiliates is hereby authorized at any time and from time to time, to the fullest extent permitted by applicable law, to set off and apply any and all deposits (general or special, time or demand, provisional or final, in whatever currency) at any time held, and other obligations (in whatever currency) at any time owing, by such Lender or any such Affiliate, to or for the credit or the account of a Loan Party against any and all of the obligations of a Loan Party now or hereafter existing under

this Agreement or any other Loan Document to such Lender or its respective Affiliates, irrespective of whether or not such Lender or Affiliate shall have made any demand under this Agreement or any other Loan Document and although such obligations of the Loan Parties may be contingent or unmatured or are owed to a branch, office or Affiliate of such Lender different from the branch, office or Affiliate holding such deposit or obligated on such indebtedness; *provided* that in the event that any Defaulting Lender shall exercise any such right of setoff, (x) all amounts so set off shall be paid over immediately to the Administrative Agent for further application in accordance with the provisions of Section 2.19 pending such payment, shall be segregated by such Defaulting Lender from its other funds and deemed held in trust for the benefit of the Administrative Agent and the Lenders, and (y) the Defaulting Lender shall provide promptly to the Administrative Agent a statement describing in reasonable detail the Obligations owing to such Defaulting Lender as to which it exercised such right of setoff. The rights of each Lender and its respective Affiliates under this Section are in addition to other rights and remedies (including other rights of setoff) that such Lender or its respective Affiliates may have. Each Lender agrees to notify the Borrower and the Administrative Agent promptly after any such setoff and application; *provided* that the failure to give such notice shall not affect the validity of such setoff and application. The rights of each Lender under this Section 9.09 are in addition to other rights and remedies (including other rights of setoff) which such Lender may have.

SECTION 9.10 Governing Law; Jurisdiction; Consent to Service of Process. (a) This Agreement and the other Loan Documents shall be construed in accordance with and governed by the laws of the State of New York.

(b) **ANY LEGAL ACTION OR PROCEEDING WITH RESPECT TO THIS AGREEMENT AND THE OTHER LOAN DOCUMENTS SHALL BE BROUGHT IN THE COURTS OF THE STATE OF NEW YORK SITTING IN THE BOROUGH OF MANHATTAN OR OF THE UNITED STATES FOR THE SOUTHERN DISTRICT OF NEW YORK AND, BY EXECUTION AND DELIVERY OF THIS AGREEMENT, EACH OF THE PARTIES HERETO HEREBY IRREVOCABLY ACCEPTS FOR ITSELF AND IN RESPECT OF ITS PROPERTY AND ASSETS, UNCONDITIONALLY, THE EXCLUSIVE JURISDICTION OF THE AFORESAID COURTS WITH RESPECT TO ANY SUCH ACTION OR PROCEEDING. THE BORROWER HEREBY IRREVOCABLY DESIGNATES, APPOINTS AND EMPOWERS C T CORPORATION SYSTEM, WITH OFFICES ON THE DATE HEREOF AT 111 8TH AVENUE, NEW YORK, NEW YORK 10011, AS ITS DESIGNEE, APPOINTEE AND AGENT TO RECEIVE AND ACCEPT FOR AND ON ITS BEHALF, AND IN RESPECT OF ITS PROPERTY, SERVICE OF ANY AND ALL LEGAL PROCESS, SUMMONS, NOTICES AND DOCUMENTS WHICH MAY BE SERVED IN ANY SUCH ACTION OR PROCEEDING. IF FOR ANY REASON SUCH DESIGNEE, APPOINTEE AND AGENT SHALL CEASE TO BE AVAILABLE TO ACT AS SUCH, THE BORROWER AGREES TO DESIGNATE A NEW DESIGNEE, APPOINTEE AND AGENT IN NEW YORK, NEW YORK ON THE TERMS AND FOR THE PURPOSES OF THIS PROVISION SATISFACTORY TO THE ADMINISTRATIVE AGENT. THE BORROWER FURTHER IRREVOCABLY CONSENTS TO THE SERVICE OF PROCESS OUT OF ANY OF THE AFOREMENTIONED COURTS IN ANY SUCH ACTION OR PROCEEDING BY THE MAILING OF COPIES THEREOF BY REGISTERED OR CERTIFIED MAIL, POSTAGE PREPAID, TO IT AT ITS ADDRESS PROVIDED IN SECTION 9.01, SUCH SERVICE TO BECOME EFFECTIVE THIRTY DAYS AFTER SUCH MAILING. NOTHING HEREIN SHALL AFFECT THE RIGHT OF THE ADMINISTRATIVE AGENT OR ANY LENDER TO SERVE PROCESS IN ANY OTHER MANNER PERMITTED BY LAW.**

(c) **THE BORROWER HEREBY IRREVOCABLY WAIVES ANY OBJECTION WHICH IT MAY NOW OR HEREAFTER HAVE TO THE LAYING OF VENUE OF ANY OF THE AFORESAID ACTIONS OR PROCEEDINGS ARISING OUT OF OR IN**

CONNECTION WITH THIS AGREEMENT BROUGHT IN THE COURTS REFERRED TO IN CLAUSE (b) ABOVE AND HEREBY FURTHER IRREVOCABLY WAIVES, TO THE MAXIMUM EXTENT PERMITTED BY APPLICABLE LAW, THE RIGHT TO PLEAD OR CLAIM, AND AGREES NOT TO PLEAD OR CLAIM, THAT ANY SUCH ACTION OR PROCEEDING BROUGHT IN ANY SUCH COURT HAS BEEN BROUGHT IN AN INCONVENIENT FORUM.

(d) **EACH PARTY HERETO HEREBY (i) IRREVOCABLY WAIVES, TO THE MAXIMUM EXTENT PERMITTED BY LAW, ANY RIGHT IT MAY HAVE TO CLAIM OR RECOVER IN ANY SUCH LITIGATION ANY SPECIAL, EXEMPLARY, PUNITIVE OR CONSEQUENTIAL DAMAGES, OR DAMAGES OTHER THAN, OR IN ADDITION TO, ACTUAL DAMAGES; (ii) CERTIFIES THAT NO PARTY HERETO NOR ANY REPRESENTATIVE OR AGENT OR COUNSEL FOR ANY PARTY HERETO HAS REPRESENTED, EXPRESSLY OR OTHERWISE, OR IMPLIED THAT SUCH PARTY WOULD NOT, IN THE EVENT OF LITIGATION, SEEK TO ENFORCE THE FOREGOING WAIVERS, AND (iii) ACKNOWLEDGES THAT IT HAS BEEN INDUCED TO ENTER INTO THIS AGREEMENT AND THE TRANSACTIONS CONTEMPLATED HEREBY AND THEREBY BY, AMONG OTHER THINGS, THE MUTUAL WAIVERS AND CERTIFICATIONS CONTAINED IN THIS SECTION 9.10.**

SECTION 9.11 **WAIVER OF JURY TRIAL. EACH PARTY HERETO HEREBY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN ANY LEGAL PROCEEDING DIRECTLY OR INDIRECTLY ARISING OUT OF OR RELATING TO THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY (WHETHER BASED ON CONTRACT, TORT OR ANY OTHER THEORY). EACH PARTY HERETO (A) CERTIFIES THAT NO REPRESENTATIVE, AGENT OR ATTORNEY OF ANY OTHER PARTY HAS REPRESENTED, EXPRESSLY OR OTHERWISE, THAT SUCH OTHER PARTY WOULD NOT, IN THE EVENT OF LITIGATION, SEEK TO ENFORCE THE FOREGOING WAIVER AND (B) ACKNOWLEDGES THAT IT AND THE OTHER PARTIES HERETO HAVE BEEN INDUCED TO ENTER INTO THIS AGREEMENT BY, AMONG OTHER THINGS, THE MUTUAL WAIVERS AND CERTIFICATIONS IN THIS SECTION 9.11.**

SECTION 9.12 Confidentiality. Each of the Administrative Agent and the Lenders agrees to maintain the confidentiality of the Information (as defined below), except that Information may be disclosed (a) to their Affiliates, to their and their Affiliates' directors, officers and employees and agents, including accountants, legal counsel and other advisors who have been informed of the confidential nature of the information provided, (b) disclosures in connection with any pledge or assignment permitted under Section 9.05(d) and, to the extent requested by any regulatory authority, including any self-regulatory authority such as the National Association of Insurance Commissioners or any similar organization, or any nationally recognized rating agency that requires access to information about a Lender's investment portfolio, (c) to the extent a Lender reasonably believes it is required by applicable laws or regulations or by any subpoena or similar legal process (and, to the extent not prohibited under applicable law), such Lender will provide prompt notice thereof to the Borrower), (d) to any other party to this Agreement, (e) in connection with the exercise of any remedies hereunder or any suit, action or proceeding relating to this Agreement or any other Loan Document or the enforcement of rights hereunder or thereunder, (f) subject to an understanding with such Person that such Person will comply with this Section 9.12, to (i) any assignee of or Participant in, or any prospective assignee of or Participant in, any of its rights or obligations under this Agreement or (ii) any actual or prospective party (or its Related Parties) to any swap, derivative, or other transaction under which payments are to be made by reference to the Borrower, and its obligations under this Agreement or the payments hereunder, (g) with the consent of the Borrower or (h) to the extent such Information (i) becomes publicly available other than as a result of a breach of this Section 9.12 or (ii) becomes available to the Administrative Agent or any Lender from a source other than the Borrower (unless such source is actually

known by the individual providing the information to be bound by a confidentiality agreement or other legal or contractual obligation of confidentiality with respect to such information). In addition, the Administrative Agent and the Lenders may disclose the existence of this Agreement and information about this Agreement to market data collectors, similar service providers to the lending industry and service providers to the Administrative Agent and the Lenders in connection with the administration of this Agreement, the other Loan Documents, and the Commitments. For the purposes of this Section 9.12, "Information" means all information received from the Borrower relating to the Borrower or its business, other than any such information that is known to a Lender, publicly known or otherwise available to the Administrative Agent or any Lender other than through disclosure (a) by the Borrower, or (b) from a source actually known to a Lender to be bound by a confidentiality agreement or other legal or contractual obligation of confidentiality with respect to such information. Any Person required to maintain the confidentiality of Information as provided in this Section 9.12 shall be considered to have complied with its obligation to do so if such Person maintains the confidentiality of such Information in accordance with procedures adopted in good faith to protect confidential Information of third parties delivered to a lender.

SECTION 9.13 Interest Rate Limitation. Notwithstanding anything herein to the contrary, if at any time the interest rate applicable to any Loan, together with all fees, charges and other amounts which are treated as interest on such Loan under applicable law (collectively the "Charges"), shall exceed the maximum lawful rate (the "Maximum Rate") which may be contracted for, charged, taken, received or reserved by the Lender holding such Loan in accordance with applicable law, the rate of interest payable in respect of such Loan hereunder, together with all Charges payable in respect thereof, shall be limited to the Maximum Rate and, to the extent lawful, the interest and Charges that would have been payable in respect of such Loan but were not payable as a result of the operation of this Section 9.13 shall be cumulated and the interest and Charges payable to such Lender in respect of other Loans or periods shall be increased (but not above the Maximum Rate therefor) until such cumulated amount, together with interest thereon at the Federal Funds Effective Rate to the date of repayment, shall have been received by such Lender.

SECTION 9.14 **EXCULPATION PROVISIONS**. EACH OF THE PARTIES HERETO SPECIFICALLY AGREES THAT IT HAS A DUTY TO READ THIS AGREEMENT, THE NOTES AND (IN THE CASE OF THE BORROWER AND THE ADMINISTRATIVE AGENT) THE FEE LETTERS AND AGREES THAT IT IS CHARGED WITH NOTICE AND KNOWLEDGE OF THE TERMS OF THIS AGREEMENT AND THE OTHER LOAN DOCUMENTS; THAT IT HAS IN FACT READ THIS AGREEMENT AND IS FULLY INFORMED AND HAS FULL NOTICE AND KNOWLEDGE OF THE TERMS, CONDITIONS AND EFFECTS OF THIS AGREEMENT AND THE OTHER LOAN DOCUMENTS; THAT IT HAS BEEN REPRESENTED BY INDEPENDENT LEGAL COUNSEL OF ITS CHOICE THROUGHOUT THE NEGOTIATIONS PRECEDING ITS EXECUTION OF THIS AGREEMENT AND THE OTHER LOAN DOCUMENTS; AND HAS RECEIVED THE ADVICE OF ITS ATTORNEY IN ENTERING INTO THIS AGREEMENT AND THE OTHER LOAN DOCUMENTS; AND THAT IT RECOGNIZES THAT CERTAIN OF THE TERMS OF THIS AGREEMENT AND THE OTHER LOAN DOCUMENTS RESULT IN ONE PARTY ASSUMING THE LIABILITY INHERENT IN SOME ASPECTS OF THE TRANSACTION AND RELIEVING THE OTHER PARTY OF ITS RESPONSIBILITY FOR SUCH LIABILITY. EACH PARTY HERETO AGREES AND COVENANTS THAT IT WILL NOT CONTEST THE VALIDITY OR ENFORCEABILITY OF ANY EXCULPATORY PROVISION OF THIS AGREEMENT ON THE BASIS THAT THE PARTY HAD NO NOTICE OR KNOWLEDGE OF SUCH PROVISION OR THAT THE PROVISION IS NOT *"CONSPICUOUS."*

SECTION 9.15 U.S. Patriot Act. Each Lender that is subject to the requirements of the USA PATRIOT ACT (Title III of Pub. L. 107-56 (signed into law October 26, 2001)) (the "Patriot Act") and the Beneficial Ownership Regulation hereby notifies the Loan Parties that pursuant to the requirements of the Patriot Act and the Beneficial Ownership Regulation, it is required to obtain, verify, and record information that identifies the Loan Parties, which information includes the name and address of the Loan Parties and other information that will allow such Lender to identify the Loan Parties in accordance with the Patriot Act and the Beneficial Ownership Regulation.

SECTION 9.16 No Advisory or Fiduciary Responsibility. In connection with all aspects of each transaction contemplated hereby, the Borrower acknowledges and agrees, and acknowledges its Affiliates' understanding, that: (i) the credit facility provided for hereunder and any related arranging or other services in connection therewith (including in connection with any amendment, waiver or other modification hereof or of any other Loan Document) are an arm's-length commercial transaction between the Borrower, on the one hand, and the Administrative Agent, the Arrangers, the Syndication Agent, the Documentation Agents and the Lenders, on the other hand, and the Borrower is capable of evaluating and understanding and understands and accepts the terms, risks and conditions of the transactions contemplated hereby and by the other Loan Documents (including any amendments, waiver or other modification hereof or thereof); (ii) in connection with the process leading to such transaction, the Administrative Agent, the Arrangers, the Syndication Agent, the Documentation Agents and the Lenders are and have been acting solely as principals and are not the financial advisors, agents or fiduciaries, for the Borrower or any of its Affiliates, stockholders, creditors or employees or any other Person; (iii) the Administrative Agent, the Arrangers, Syndication Agent, the Documentation Agents and the Lenders have not assumed and will not assume an advisory, agency or fiduciary responsibility in favor of the Borrower with respect to any of the transactions contemplated hereby or the process leading thereto, including with respect to any amendment, waiver or other modification hereof or of any other Loan Document (irrespective of whether the Administrative Agent, any Arranger, the Syndication Agent, any Documentation Agent or any Lender advised or is currently advising the Borrower or any of its Affiliates on other matters) and the Administrative Agent, the Arrangers, the Syndication Agent, the Documentation Agents and the Lenders have no obligation to the Borrower or any of its Affiliates with respect to the transactions contemplated hereby except those obligations expressly set forth herein and in the other Loan Documents; (iv) the Administrative Agent, the Arrangers, the Syndication Agent, the Documentation Agents, the Lenders and their respective Affiliates may be engaged in a broad range of transactions that involve interests that differ from those of the Borrower and its Affiliates, and the Administrative Agent, the Arrangers, the Syndication Agent, the Documentation Agents and the Lenders have no obligation to disclose any of such interests by virtue of any advisory, agency or fiduciary relationship; and (v) the Administrative Agent, the Arrangers, the Syndication Agent, the Documentation Agents and the Lenders have not provided and will not provide any legal, accounting, regulatory or Tax advice with respect to any of the transactions contemplated hereby (including any amendment, waiver or other modification hereof or of any other Loan Document) and the Loan Parties have consulted its own legal, accounting, regulatory and Tax advisors to the extent it has deemed appropriate. Each Loan Parties hereby waive and release, to the fullest extent permitted by law, any claims that it may have against the Administrative Agent, the Arrangers, the Syndication Agent, the Documentation Agents or the Lenders with respect to any breach or alleged breach of agency or fiduciary duty.

SECTION 9.17 Headings. Section headings herein are included herein for convenience of reference only and shall not constitute a part hereof for any other purpose or be given any substantive effect.

SECTION 9.18 Acknowledgement and Consent to Bail-In of EEA Financial Institutions. (a) Notwithstanding anything to the contrary in any Loan Document or in any other agreement, arrangement or understanding among any such parties, each party hereto acknowledges that any

liability of any EEA Financial Institution arising under any Loan Document, to the extent such liability is unsecured, may be subject to the write-down and conversion powers of an EEA Resolution Authority and agrees and consents to, and acknowledges and agrees to be bound by: (a) the application of any Write-Down and Conversion Powers by an EEA Resolution Authority to any such liabilities arising hereunder which may be payable to it by any party hereto that is an EEA Financial Institution; and

(b) the effects of any Bail-in Action on any such liability, including, if applicable:

(i) a reduction in full or in part or cancellation of any such liability;

(ii) a conversion of all, or a portion of, such liability into shares or other instruments of ownership in such EEA Financial Institution, its parent undertaking, or a bridge institution that may be issued to it or otherwise conferred on it, and that such shares or other instruments of ownership will be accepted by it in lieu of any rights with respect to any such liability under this Agreement or any other Loan Document; or

(iii) the variation of the terms of such liability in connection with the exercise of the write-down and conversion powers of any EEA Resolution Authority.

[The rest of this page intentionally left blank]

The parties hereto have caused this Agreement to be duly executed as of the date and year first above written.

KINDER MORGAN, INC.,
as the Borrower

By: /s/ Anthony B. Ashley /s/
Name: Anthony B. Ashley
Title: Treasurer

BARCLAYS BANK PLC,
as the Administrative Agent and as a Lender

By: /s/ Sydney G. Dennis /s/
Name: Sydney G. Dennis
Title: Director

JPMORGAN CHASE BANK, N.A.,
as a Lender

By: /s/ Stephanie Balette /s/
Name: Stephanie Balette
Title: Authorized Officer

Bank of America, N.A.,
as a Lender

By: /s/ Tyler Ellis /s/
Name: Tyler Ellis
Title: Director

BMO Harris Bank, N.A.,
as a Lender

By: /s/ Melissa Guzman /s/
Name: Melissa Guzman
Title: Director

CITIBANK, N.A.,
as a Lender

By: /s/ Maureen Maroney /s/
Name: Maureen Maroney
Title: Vice President

CREDIT SUISSE AG, CAYMAN ISLANDS BRANCH,
as a Lender

By: /s/ Nupur Kumar /s/
Name: Nupur Kumar
Title: Authorized Signatory

By: /s/ Christopher Zybrick /s/
Name: Christopher Zybrick
Title: Authorized Signatory

Mizuho Bank, Ltd.,
as a Lender

By: /s/ Donna DeMagistris /s/
Name: Donna DeMagistris
Title: Authorized Signatory

MUFG BANK, LTD.
as a Lender

By: /s/ Christopher Facenda /s/
Name: Christopher Facenda
Title: Director

ROYAL BANK OF CANADA,
as a Lender

By: /s/ Jason S. York /s/
Name: Jason S. York
Title: Authorized Signatory

The Bank of Nova Scotia, Houston Branch,
as a Lender

By: /s/ Alfredo Brahim /s/
Name: Alfredo Brahim
Title: Director

Wells Fargo Bank, N.A.,
as a Lender

By: /s/ Doug McDowell /s/
Name: Doug McDowell
Title: Managing Director

Commerzbank AG, New York Branch,
as a Lender

By: /s/ Barbara Stacks /s/
Name: Barbara Stacks
Title: Director

By: /s/ James Boyle /s/
Name: James Boyle
Title: Director

Sumitomo Mitsui Banking Corporation,
as a Lender

By: /s/ Katsuyuki Kubo /s/
Name: Katsuyuki Kubo
Title: Managing Director

CANADIAN IMPERIAL BANK OF COMMERCE,
New York Branch,
as a Lender

By: /s/ Donovan C. Broussard /s/
Name: Donovan C. Broussard
Title: Authorized Signatory

By: /s/ Trudy Nelson /s/
Name: Trudy Nelson
Title: Authorized Signatory

CREDIT AGRICOLE CORPORATE AND
INVESTMENT BANK,
as a Lender

By: /s/ Dixon Schultz /s/
Name: Dixon Schultz
Title: Managing Director

By: /s/ Michael Willis /s/
Name: Michael Willis
Title: Managing Director

SUNTRUST BANK,
as a Lender

By: /s/ Carmen Malizia /s/
Name: Carmen Malizia
Title: Director

PNC Bank, National Association,
as a Lender

By: /s/ Stephen Monto /s/
Name: Stephen Monto
Title: SVP

SOCIETE GENERALE,
as a Lender

By: /s/ Diego Medina /s/
Name: Diego Medina
Title: Director

THE TORONTO-DOMINION BANK, NEW YORK BRANCH
as a Lender

By: /s/ Annie Dorval /s/
Name: Annie Dorval
Title: Authorized Signatory

MORGAN STANLEY SENIOR FUNDING, INC.,
as a Lender

By: /s/ Michael King /s/
Name: Michael King
Title: Vice President

MORGAN STANLEY BANK, N.A.,
as a Lender

By: /s/ Michael King /s/
Name: Michael King
Title: Authorized Signatory

Compass Bank,
as a Lender

By: /s/ Mark H. Wolf /s/
Name: Mark H. Wolf
Title: Senior Vice President

ING Capital LLC,
as a Lender

By: /s/ Subha Pasumarti /s/
Name: Subha Pasumarti
Title: Managing Director

By: /s/ Tanja van der Woude /s/
Name: Tanja van der Woude
Title: Director

REGIONS BANK,
as a Lender

By: /s/ David Valentine /s/
Name: David Valentine
Title: Managing Director

Intesa Sanpaolo S.p.A. – New York Branch,
as a Lender

By: /s/ Christophe Hamonet /s/
Name: Christophe Hamonet
Title: Reginal Business Manager

By: /s/ Francesco Di Mario /s/
Name: Francesco Di Mario
Title: FVP – Head of Credit

NATIONAL BANK OF CANADA,
as a Lender

By: /s/ Rahul Rahul /s/
Name: Rahul Rahul
Title: Authorized Signatory

By: /s/ Mark Williamson /s/
Name: Mark Williamson
Title: Authorized Signatory

SCHEDULE 1.01
Commitments

Lender	Commitment
Barclays Bank PLC	$24,000,000
JPMorgan Chase Bank, N.A.	$24,000,000
Bank of America, N.A.	$24,000,000
BMO Harris Bank, N.A.	$24,000,000
Citibank, N.A.	$24,000,000
Credit Suisse AG, Cayman Islands Branch	$24,000,000
Mizuho Bank, Ltd.	$24,000,000
MUFG Bank, Ltd.	$24,000,000
Royal Bank of Canada	$24,000,000
The Bank of Nova Scotia, Houston Branch	$24,000,000
Wells Fargo Bank, N.A.	$24,000,000
Commerzbank AG, New York Branch	$17,500,000
Sumitomo Mitsui Banking Corporation	$17,500,000
Canadian Imperial Bank of Commerce, New York Branch	$17,500,000
Credit Agricole Corporate and Investment Bank	$17,500,000
SunTrust Bank	$17,500,000
PNC Bank, National Association	$17,500,000
Societe Generale	$17,500,000
The Toronto-Dominion Bank, New York Branch	$17,500,000
Morgan Stanley Senior Funding, Inc.	$16,000,000
Compass Bank	$16,000,000
ING Capital LLC	$16,000,000
Regions Bank	$16,000,000
Intesa Sanpaolo S.p.A.-New York Branch	$16,000,000
National Bank of Canada	$16,000,000
Total	**$500,000,000**

SCHEDULE 1.01A
Excluded Subsidiaries

ANR Real Estate Corporation
Calnev Pipeline LLC
Coastal Eagle Point Oil Company
Coastal Oil New England, Inc.
Colton Processing Facility
Coscol Petroleum Corporation
El Paso CGP Company, L.L.C.
El Paso Energy Argentina Service Company
El Paso Energy Capital Trust I
El Paso Energy E.S.T. Company
El Paso Energy International Company
El Paso Marketing Company, L.L.C.
El Paso Merchant Energy North America Company, L.L.C.
El Paso Merchant Energy-Petroleum Company
El Paso Reata Energy Company, L.L.C.
El Paso Remediation Company
El Paso Services Holding Company
EPC Building, LLC
EPC Property Holdings, Inc.
EPEC Corporation
EPEC Oil Company Liquidating Trust
EPEC Polymers, Inc.
EPEC Realty, Inc.
EPED Holding Company
I.M.T Land Corp.
International Marine Terminals Partnership
Kinder Morgan Foundation
Kinder Morgan G.P., Inc.
Kinder Morgan Mexico LLC
Kinder Morgan Services International LLC
Kinder Morgan Tejas Pipeline GP LLC
Kinder Morgan Urban Renewal, L.L.C.
Kinder Morgan Urban Renewal II, LLC
KM Express LLC
KM Insurance Texas Inc.
KN Capital Trust I
KN Capital Trust III
Mesquite Investors, L.L.C.
SFPP, L.P.

Note the Excluded Subsidiaries listed on this Schedule 1.01A may also be Excluded Subsidiaries pursuant to other exceptions set forth in the definition of “Excluded Subsidiary”.

SCHEDULE 6.01
Existing Non-Guarantor Indebtedness

- Certificate of Designations of Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock due 2057 of Kinder Morgan G.P., Inc.
- EPC Building, LLC, promissory note, 3.967%, due 2013 through 2035
- K N Capital Trust I 8.56% capital trust securities due 2027
- K N Capital Trust III 7.63% capital trust securities due 2028
- El Paso Energy Capital Trust I 4.75% preferred securities due 2028
- International Marine Terminals Partnership 2002 floating rate notes due 2025

SCHEDULE 6.05
Existing Transactions with Affiliates

None.

SCHEDULE 6.06
Existing Restrictive Agreements

- Certificate of Designations of Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock due 2057 of Kinder Morgan G.P., Inc.
- Constituent documents of Kinder Morgan Canada Limited and its subsidiaries, each as amended to date, setting forth terms related to Kinder Morgan Canada Limited's (i) Cumulative Redeemable Minimum Rate Reset Preferred Shares, Series 1; and (ii) Cumulative Redeemable Minimum Rate Reset Preferred Shares, Series 3:
    - Certificate and Articles of Incorporation of Kinder Morgan Canada Limited
    - Certificate and Articles of Incorporation of Kinder Morgan Canada GP Inc.
    - Certificate of Limited Partnership of Kinder Morgan Canada Limited Partnership
    - Second Amended and Restated Limited Partnership Agreement of Kinder Morgan Canada Limited Partnership
    - Articles of Association of Kinder Morgan Cochin ULC
- Credit Agreement, dated August 31, 2018, by and among Kinder Morgan Cochin ULC, Royal Bank of Canada and the lenders party thereto

EXHIBIT 1.01-A

FORM OF ASSIGNMENT AND ASSUMPTION

This Assignment and Assumption (the "Assignment and Assumption") is dated as of the Effective Date set forth below and is entered into by and between [the][each][1] Assignor identified in item 1 below ([the][each, an] "Assignor") and [the][each][2] Assignee identified in item 2 below ([the][each, an] "Assignee"). [It is understood and agreed that the rights and obligations of [the Assignors][the Assignees][3] hereunder are several and not joint.][4] Capitalized terms used but not defined herein shall have the meanings given to them in the 364-Day Credit Agreement identified below (as further restated, amended, modified, supplemented and in effect, the "364-Day Credit Agreement"), receipt of a copy of which is hereby acknowledged by [the][each] Assignee. The Standard Terms and Conditions set forth in Annex 1 attached hereto are hereby agreed to and incorporated herein by reference and made a part of this Assignment and Assumption as if set forth herein in full.

For an agreed consideration, [the][each] Assignor hereby irrevocably sells and assigns to [the Assignee][the respective Assignees], and [the][each] Assignee hereby irrevocably purchases and assumes from [the Assignor][the respective Assignors], subject to and in accordance with the Standard Terms and Conditions and the 364-Day Credit Agreement, as of the Effective Date inserted by the Administrative Agent as contemplated below (i) all of [the Assignor's][the respective Assignors'] rights and obligations in [its capacity as a Lender][their respective capacities as Lenders] under the 364-Day Credit Agreement and any other documents or instruments delivered pursuant thereto to the extent related to the amount and percentage interest identified below of all of such outstanding rights and obligations of [the Assignor][the respective Assignors] under the revolving credit facility identified below, and (ii) to the extent permitted to be assigned under applicable law, all claims, suits, causes of action and any other right of [the Assignor (in its capacity as a Lender)][the respective Assignors (in their respective capacities as Lenders)] against any Person, whether known or unknown, arising under or in connection with the 364-Day Credit Agreement, any other documents or instruments delivered pursuant thereto or the loan transactions governed thereby or in any way based on or related to any of the foregoing, including, but not limited to, contract claims, tort claims, malpractice claims, statutory claims and all other claims at law or in equity related to the rights and obligations sold and assigned pursuant to clause (i) above (the rights and obligations sold and assigned by [the][any] Assignor to [the][any] Assignee pursuant to clauses (i) and (ii) above being referred to herein collectively as [the][an] "Assigned Interest"). Each such sale and assignment is without recourse to [the][any] Assignor and, except as expressly provided in this Assignment and Assumption, without representation or warranty by [the][any] Assignor.

---

1 For bracketed language here and elsewhere in this form relating to the Assignor(s), if the assignment is from a single Assignor, choose the first bracketed language. If the assignment is from multiple Assignors, choose the second bracketed language.

2 For bracketed language here and elsewhere in this form relating to the Assignee(s), if the assignment is to a single Assignee, choose the first bracketed language. If the assignment is to multiple Assignees, choose the second bracketed language.

3 Select as appropriate.

4 Include bracketed language if there are either multiple Assignors or multiple Assignees.

1. Assignor[s]: _____

_____

[Assignor [is] [is not] a Defaulting Lender]

2. Assignee[s]: _____

_____

[for each Assignee, indicate [Affiliate][Approved Fund] of [identify Lender]

3. Borrower: Kinder Morgan, Inc.

4. Administrative Agent: _____, as the administrative agent under the 364-Day Credit Agreement

5. 364-Day Credit Agreement: The Revolving Credit Agreement dated as of November 16, 2018 among Kinder Morgan, Inc., the Lenders parties thereto, Barclays Bank PLC, as Administrative Agent, and the other agents parties thereto

6. Assigned Interest[s]:

Assignor[s][5]	Assignee[s][6]	Aggregate Amount of Commitment/Loans for all Lenders[7]	Amount of Commitment/Loans Assigned[8]	Percentage Assigned of Commitment/ Loans[8]	CUSIP Number
		$	$	%	
		$	$	%	
		$	$	%	

[7. Trade Date: _____][9]

Effective Date: _____ ___, 20___ [TO BE INSERTED BY ADMINISTRATIVE AGENT AND WHICH SHALL BE THE EFFECTIVE DATE OF RECORDATION OF TRANSFER IN THE REGISTER THEREFOR.]

The terms set forth in this Assignment and Assumption are hereby agreed to:

---

5 List each Assignor, as appropriate.

6 List each Assignee, as appropriate.

7 Amount to be adjusted by the counterparties to take into account any payments or prepayments made between the Trade Date and the Effective Date.

8 Set forth, to at least 9 decimals, as a percentage of the Commitment/Loans of all Lenders thereunder.

[9] To be completed if the Assignor(s) and the Assignee(s) intend that the minimum assignment amount is to be determined as of the Trade Date.

ASSIGNOR[S][10]
[NAME OF ASSIGNOR]

By:_____
Title:

[NAME OF ASSIGNOR]

By:_____
Title:

ASSIGNEE[S][11]
[NAME OF ASSIGNEE]

By:_____
Title:

[NAME OF ASSIGNEE]

By:_____
Title:

[10] Add additional signature blocks as needed. Include both Fund/Pension Plan and manager making the trade (if applicable).

[11] Add additional signature blocks as needed. Include both Fund/Pension Plan and manager making the trade (if applicable).

[Consented to and][12] Accepted:

[NAME OF ADMINISTRATIVE AGENT], as
Administrative Agent

By: _____
Title:

[Consented to:][13]

[NAME OF THE RELEVANT PARTY]

By: _____
Title:

[12] To be added only if the consent of the Administrative Agent is required by the terms of the 364-Day Credit Agreement.

[13] To be added only if the consent of the Borrower and/or other parties is required by the terms of the 364-Day Credit Agreement.

ANNEX 1 TO ASSIGNMENT AND ASSUMPTION

STANDARD TERMS AND CONDITIONS FOR

ASSIGNMENT AND ASSUMPTION

1. Representations and Warranties.

1.1. Assignor. [The][Each] Assignor (a) represents and warrants that (i) it is the legal and beneficial owner of [the][[the relevant] Assigned Interest, (ii) [the][such] Assigned Interest is free and clear of any lien, encumbrance or other adverse claim and (iii) it has full power and authority, and has taken all action necessary, to execute and deliver this Assignment and Assumption and to consummate the transactions contemplated hereby; and (b) assumes no responsibility with respect to (i) any statements, warranties or representations made in or in connection with the 364-Day Credit Agreement or any other Loan Document, (ii) the execution, legality, validity, enforceability, genuineness, sufficiency or value of the Loan Documents or any collateral thereunder, (iii) the financial condition of the Borrower, any of its Subsidiaries or Affiliates or any other Person obligated in respect of any Loan Document or (iv) the performance or observance by the Borrower, any of its Subsidiaries or Affiliates or any other Person of any of their respective obligations under any Loan Document.

1.2. Assignee. [The][Each] Assignee (a) represents and warrants that (i) it has full power and authority, and has taken all action necessary, to execute and deliver this Assignment and Assumption and to consummate the transactions contemplated hereby and to become a Lender under the 364-Day Credit Agreement, (ii) it meets all the requirements to be an assignee under the paragraph following Section 9.05(a)(vii) and Section 9.05(b) of the 364-Day Credit Agreement (subject to such consents, if any, as may be required under Section 9.05(a)(iii) of the 364-Day Credit Agreement), (iii) from and after the Effective Date, it shall be bound by the provisions of the 364-Day Credit Agreement as a Lender thereunder and, to the extent of [the][the relevant] Assigned Interest, shall have the obligations of a Lender thereunder, (iv) it is sophisticated with respect to decisions to acquire assets of the type represented by [the][such] Assigned Interest and either it, or the Person exercising discretion in making its decision to acquire [the][such] Assigned Interest, is experienced in acquiring assets of such type, (v) it has received a copy of the 364-Day Credit Agreement, and has received or has been accorded the opportunity to receive copies of the most recent financial statements delivered pursuant to Section 5.01 of the 364-Day Credit Agreement, as applicable, and such other documents and information as it deems appropriate to make its own credit analysis and decision to enter into this Assignment and Assumption and to purchase [the][such] Assigned Interest, (vi) it has, independently and without reliance upon the Administrative Agent or any other Lender and based on such documents and information as it has deemed appropriate, made its own credit analysis and decision to enter into this Assignment and Assumption and to purchase [the][such] Assigned Interest and (vii) attached to this Assignment and Assumption is any documentation required to be delivered by it pursuant to Section 2.16 of the 364-Day Credit Agreement; and (b) agrees that (i) it will, independently and without reliance upon the Administrative Agent, [the][any] Assignor or any other Lender, and based on such documents and information as it shall deem appropriate at the time, continue to make its own credit decisions in taking or not taking action under the Loan Documents, and (ii) it will perform in accordance with their terms all of the obligations which by the terms of the Loan Documents are required to be performed by it as a Lender.

2. Payments. From and after the Effective Date, the Administrative Agent shall make all payments in respect of [the][each] Assigned Interest (including payments of principal, interest, fees and other

amounts) to [the][the relevant] Assignor for amounts which have accrued to but excluding the Effective Date and to [the][the relevant] Assignee for amounts which have accrued from and after the Effective Date.

3. General Provisions.

3.1. In accordance with Sections 9.04 and 9.05 of the 364-Day Credit Agreement, upon execution, delivery, acceptance and recording of this Assignment and Assumption, from and after the Effective Date, (a) the Assignee shall be a party to the 364-Day Credit Agreement and, to the extent provided in this Assignment and Assumption, have the rights and obligations of a Lender under the 364-Day Credit Agreement with a Commitment as set forth herein and (b) the Assignor shall, to the extent of the Assigned Interest assigned pursuant to this Assignment and Assumption, be released from its obligations under the 364-Day Credit Agreement (and, in the case of this Assignment and Assumption covers all of the Assignor's rights and obligations under the 364-Day Credit Agreement, the Assignor shall cease to be a party to the 364-Day Credit Agreement but shall continue to be entitled to the benefits of Sections 2.14, 2.15, 2.16 and 9.03 thereof).

3.2. This Assignment and Assumption shall be binding upon, and inure to the benefit of, the parties hereto and their respective successors and assigns. This Assignment and Assumption may be executed in any number of counterparts, which together shall constitute one instrument. Delivery of an executed counterpart of a signature page of this Assignment and Assumption by telecopy shall be effective as delivery of a manually executed counterpart of this Assignment and Assumption. This Assignment and Assumption shall be governed by, and construed in accordance with, the laws of the State of New York.

EXHIBIT 1.01-B

FORM OF GUARANTY AGREEMENT

[See attached.]

EXHIBIT 1.01-C

FORM OF COMMITTED NOTE

_____, _____

FOR VALUE RECEIVED, the undersigned, KINDER MORGAN, INC., a Delaware corporation (the "Borrower"), HEREBY PROMISES TO PAY to the order of _____ (the "Lender"), the lesser of (i) such Lender's Commitment and (ii) the aggregate amount of Committed Loans made by the Lender and outstanding on the Maturity Date. The principal amount of the Committed Loans made by the Lender to the Borrower shall be due and payable on the dates and in the amounts as are specified in that certain Revolving Credit Agreement, dated as of November 16, 2018 (as further restated, amended, modified, supplemented and in effect from time to time, the "364-Day Credit Agreement"), among the Borrower, the Lender, certain other lenders that are party thereto, Barclays Bank PLC, as Administrative Agent for the Lender and such other lenders, and the other agents named therein. All capitalized terms used herein and not otherwise defined shall have the meanings as defined in the 364-Day Credit Agreement.

The Borrower promises to pay interest on the unpaid principal amount of each Committed Loan outstanding from time to time from the date thereof until such principal amount is paid in full, at such interest rates and payable on such dates as are specified in the 364-Day Credit Agreement. Principal and interest are payable in same day funds in lawful money of the United States of America to the Administrative Agent at its Principal Office, or at such other place as the Administrative Agent shall designate in writing to the Borrower.

This Note is one of the Committed Notes referred to in, and this Note and all provisions herein are entitled to the benefits of, the 364-Day Credit Agreement. The 364-Day Credit Agreement, among other things (a) provides for the making of Committed Loans by the Lender and the other lenders to the Borrower from time to time, and (b) contains provisions for acceleration of the maturity hereof upon the happening of certain stated events, for prepayments on account of principal hereof prior to the maturity hereof upon the terms and conditions therein specified, and for limitations on the amount of interest paid such that no provision of the 364-Day Credit Agreement or this Note shall require the payment or permit the collection of interest in excess of the Maximum Rate.

This Note may be held by the Lender for the account of its applicable lending office and may be transferred from one lending office to another lending office from time to time as the Lender may determine.

The Borrower and any and all endorsers, guarantors and sureties severally waive grace, demand, presentment for payment, notice of dishonor, default or intent to accelerate, protest and notice of protest and diligence in collecting and bringing of suit against any party hereto, and agree to all renewals, extensions or partial payments hereon and to any release or substitution of security herefor, in whole or in part, with or without notice, before or after maturity.

This Note shall be governed by and construed under the laws of the State of New York and the applicable laws of the United States of America.

KINDER MORGAN, INC.,
as the Borrower

By: _____
Name:_____
Title:_____

EXHIBIT 2.03

FORM OF BORROWING REQUEST

Dated _____

Barclays Bank PLC,
1301 Sixth Avenue
New York, NY 10019
Attn: Bobby Fitzpatrick
Phone: 201-499-5043
E-mail: bobby.fitzpatrick@barclays.com and 12145455230@tls.ldsprod.com

Ladies and Gentlemen:

This Borrowing Request is delivered to you by Kinder Morgan, Inc. (the "Borrower"), a Delaware corporation, under Section 2.03 of the Revolving Credit Agreement, dated as of November 16, 2018 (as further restated, amended, modified, supplemented and in effect, the "364-Day Credit Agreement"), by and among the Borrower, the Lenders party thereto, Barclays Bank PLC, as Administrative Agent, and the other agents named therein.

1. The Borrower hereby requests that the Lenders make a Committed Loan or Loans in the aggregate principal amount of $_____.[1]

2. The Borrower hereby requests that the Committed Loan or Loans be made on the following Business Day: _____.[2]

3. The Borrower hereby requests that the Borrowing be [an ABR Borrowing] [a Eurodollar Borrowing].[3]

4. In the case of a Eurodollar Borrowing, the initial Interest Period shall be [one week] [one month] [two months] [three months] [six months].

5. The Borrower hereby requests that the funds from the requested Loan or Loans be disbursed to the following bank account: _____.

6. After giving effect to the requested Loan or Loans, the aggregate Credit Exposures outstanding as of the date hereof (including the requested Loans) does not exceed the maximum amount permitted to be outstanding pursuant to the terms of the 364-Day Credit Agreement.

7. The representations and warranties set forth in the 364-Day Credit Agreement and the other Loan Documents are true and correct in all material respects on and as of the date hereof (unless such representation and warranty expressly relates to an earlier date).

---

[1] Complete with an amount in accordance with Section 2.03 of the 364-Day Credit Agreement.

[2] Complete with a Business Day in accordance with Section 2.03 of the 364-Day Credit Agreement.

[3] If no election as to Type of Borrowing is made for a Committed Loan, the Requested Borrowing shall be an ABR Borrowing.

8. No Default or Event of Default has occurred and is continuing on the date hereof or would result after giving effect to the Loans requested hereby.

9. All capitalized undefined terms used herein have the meanings assigned thereto in the 364-Day Credit Agreement.

IN WITNESS WHEREOF, the undersigned have executed this Borrowing Request this _____ day of _____, _____.

KINDER MORGAN, INC.,
as the Borrower

By: _____
Name:_____
Title:_____

EXHIBIT 2.07

FORM OF INTEREST ELECTION REQUEST

Date: **[_____]**, 20**[__]**

Barclays Bank PLC,
1301 Sixth Avenue
New York, NY 10019
Attn: Bobby Fitzpatrick
Phone: 201-499-5043
E-mail: bobby.fitzpatrick@barclays.com and 12145455230@tls.ldsprod.com

Re: Kinder Morgan, Inc. – Interest Election Request

Ladies and Gentlemen:

Reference is made to the Revolving Credit Agreement, dated as of November 16, 2018 (as amended, amended and restated, supplemented or otherwise modified from time to time, the "364-Day Credit Agreement"), among Kinder Morgan, Inc., a Delaware corporation (the "Borrower"), the Lenders party thereto from time to time, Barclays Bank PLC as Administrative Agent, and the other parties thereto from time to time. Capitalized terms used but not otherwise defined in this Interest Election Request shall have the meanings assigned to such terms in the 364-Day Credit Agreement.

1. Interest Election Request. This Interest Election Request relates to the Borrower's election to (i) continue a Eurodollar Borrowing, (ii) convert a Eurodollar Borrowing or (iii) convert a Base Rate Borrowing on _____ (the "Interest Election Date"), as indicated below (*check each that applies*):

☐ **Continuation of Eurodollar Borrowing**.

Pursuant to Section 2.07 of the 364-Day Credit Agreement, this Interest Election Request confirms our written election on the date hereof to continue the following outstanding Borrowing comprised of Eurodollar Loans on the Interest Election Date, as follows:

(A) Expiration date of current Interest Period: _____

(B) Aggregate amount of outstanding Borrowing: _____

(C) Aggregate amount to be continued as Eurodollar Loans: _____

(D) Elected Interest Period: _____

☐ **Conversion of Eurodollar Borrowing**.

Pursuant to Section 2.07 of the 364-Day Credit Agreement, this Interest Election Request confirms our written election on the date hereof to convert the following outstanding Borrowing

comprised of Eurodollar Loans to Borrowing(s) comprised of ABR Loans on the Interest Election Date, as follows:

(A) Expiration date of current Interest Period: _____

(B) Aggregate amount of outstanding Borrowing: _____

(C) Aggregate amount to be converted to ABR Loans: _____

☐ **Conversion of Base Rate Borrowing**.

Pursuant to Section 2.07 of the 364-Day Credit Agreement, this Interest Election Request confirms our written election on the date hereof that the following outstanding Borrowing comprised of ABR Loans be converted to a Borrowing comprised of Eurodollar Loans on the Interest Election Date, as follows:

(A) Date of Conversion: _____

(B) Aggregate amount of outstanding Borrowing: _____

(C) Aggregate amount to be converted to Eurodollar Loans: _____

(D) Elected Interest Period: _____

2. Certifications. The Borrower hereby represents and warrants to the Lenders that, as of the date of this Interest Election Request and after giving effect to the continuations or conversions being requested under Section 1 hereof, no Default or Event of Default has occurred and is continuing.

[*Signature page follows*]

IN WITNESS WHEREOF, the undersigned has executed this Interest Election Request this _____ day of _____, ____.

KINDER MORGAN, INC.,
as the Borrower

By: _____
Name:_____
Title:_____

EXHIBIT 2.10

FORM OF NOTICE OF PREPAYMENT

Date: _____, ____

To: Barclays Bank PLC,
1301 Sixth Avenue
New York, NY 10019
Attn: Patrick Shields
Phone: 212-526-9531
E-mail: bobby.fitzpatrick@barclays.com, 12145455230@tls.ldsprod.com and Patrick.shields@barclays.com

Ladies and Gentlemen:

Reference is made to that certain Revolving Credit Agreement, dated as of November 16, 2018 (as may be amended, restated, amended and restated, extended, supplemented or otherwise modified in writing from time to time in accordance with its terms, the "364-Day Credit Agreement"; the terms defined therein being used herein as therein defined), among Kinder Morgan, Inc., a Delaware corporation (the "Borrower"), the Lenders party thereto from time to time, Barclays Bank PLC, as Administrative Agent, and the other parties thereto. All capitalized terms used but not defined herein have the meanings assigned in the 364-Day Credit Agreement.

This Prepayment Notice is delivered to you pursuant to Section 2.10 of the Agreement. The Borrower hereby gives notice of a prepayment of Committed Loans as follows:

1. (select Type(s) of Loans)

☐ ABR Loans in the aggregate principal amount of $_____.

☐ Eurodollar Loans with an Interest Period ending _____, 201_ in the aggregate principal amount of $_____.

2. On _____, 201_ (a Business Day).

IN WITNESS WHEREOF, the undersigned have executed this Prepayment Notice this _____ day of _____, _____.

KINDER MORGAN, INC.,
as the Borrower

By: _____
Name:_____
Title:_____

EXHIBIT 2.16-A

[FORM OF]
U.S. TAX COMPLIANCE CERTIFICATE
(For Foreign Lenders That Are Not Partnerships For U.S. Federal Income Tax Purposes)

Reference is hereby made to the Revolving Credit Agreement, dated as of November 16, 2018 (as further amended, supplemented or otherwise modified from time to time, the "364-Day Credit Agreement"), among Kinder Morgan, Inc. (the "Borrower"), Barclays Bank PLC, as administrative agent for the lenders party thereto (the "Lenders") and such Lenders.

Pursuant to the provisions of Section 2.16(g) of the 364-Day Credit Agreement, the undersigned hereby certifies that (i) it is the sole record and beneficial owner of the Loan(s) (as well as any Note(s) evidencing such Loan(s)) in respect of which it is providing this certificate, (ii) it is not a bank within the meaning of Section 881(c)(3)(A) of the Code, (iii) it is not a ten percent shareholder of the Borrower within the meaning of Section 881(c)(3)(B) of the Code and (iv) it is not a controlled foreign corporation related to the Borrower as described in Section 881(c)(3)(C) of the Code.

The undersigned has furnished the Administrative Agent and the Borrower with a certificate of its non-U.S. Person status on IRS Form W-8BEN or IRS Form W-8BEN-E, as applicable. By executing this certificate, the undersigned agrees that (1) if the information provided on this certificate changes, the undersigned shall promptly so inform the Borrower and the Administrative Agent, and (2) the undersigned shall have at all times furnished the Borrower and the Administrative Agent with a properly completed and currently effective certificate in either the calendar year in which each payment is to be made to the undersigned, or in either of the two calendar years preceding such payments.

Unless otherwise defined herein, terms defined in the 364-Day Credit Agreement and used herein shall have the meanings given to them in the 364-Day Credit Agreement.

[NAME OF LENDER]

By:
Name:
Title:

Date: _____ __, 20[ ]

EXHIBIT 2.16-B

[FORM OF]
U.S. TAX COMPLIANCE CERTIFICATE
(For Foreign Participants That Are Not Partnerships For U.S. Federal Income Tax Purposes)

Reference is hereby made to the Revolving Credit Agreement, dated as of November 16, 2018 (as further amended, supplemented or otherwise modified from time to time, the "364-Day Credit Agreement"), among Kinder Morgan, Inc. (the "Borrower"), Barclays Bank PLC, as administrative agent for the lenders party thereto (the "Lenders") and such Lenders.

Pursuant to the provisions of Section 2.16(g) of the 364-Day Credit Agreement, the undersigned hereby certifies that (i) it is the sole record and beneficial owner of the participation in respect of which it is providing this certificate, (ii) it is not a bank within the meaning of Section 881(c)(3)(A) of the Code, (iii) it is not a ten percent shareholder of the Borrower within the meaning of Section 881(c)(3)(B) of the Code, and (iv) it is not a controlled foreign corporation related to the Borrower as described in Section 881(c)(3)(C) of the Code.

The undersigned has furnished its participating Lender with a certificate of its non-U.S. Person status on IRS Form W-8BEN or IRS Form W-8BEN-E, as applicable. By executing this certificate, the undersigned agrees that (1) if the information provided on this certificate changes, the undersigned shall promptly so inform such Lender in writing, and (2) the undersigned shall have at all times furnished such Lender with a properly completed and currently effective certificate in either the calendar year in which each payment is to be made to the undersigned, or in either of the two calendar years preceding such payments.

Unless otherwise defined herein, terms defined in the 364-Day Credit Agreement and used herein shall have the meanings given to them in the 364-Day Credit Agreement.

[NAME OF PARTICIPANT]

By:
Name:
Title:

Date: _____ __, 20[ ]

EXHIBIT 2.16-C

[FORM OF]
U.S. TAX COMPLIANCE CERTIFICATE
(For Foreign Participants That Are Partnerships For U.S. Federal Income Tax Purposes)

Reference is hereby made to the Revolving Credit Agreement, dated as of November 16, 2018 (as further amended, supplemented or otherwise modified from time to time, the "364-Day Credit Agreement"), among Kinder Morgan, Inc. (the "Borrower), Barclays Bank PLC, as administrative agent for the lenders party thereto (the "Lenders") and such Lenders.

Pursuant to the provisions of Section 2.16(g) of the 364-Day Credit Agreement, the undersigned hereby certifies that (i) it is the sole record owner of the participation in respect of which it is providing this certificate, (ii) its direct or indirect partners/members are the sole beneficial owners of such participation, (iii) with respect such participation, neither the undersigned nor any of its direct or indirect partners/members is a bank extending credit pursuant to a loan agreement entered into in the ordinary course of its trade or business within the meaning of Section 881(c)(3)(A) of the Code, (iv) none of its direct or indirect partners/members is a ten percent shareholder of the Borrower within the meaning of Section 881(c)(3)(B) of the Code and (v) none of its direct or indirect partners/members is a controlled foreign corporation related to the Borrower as described in Section 881(c)(3)(C) of the Code.

The undersigned has furnished its participating Lender with IRS Form W-8IMY accompanied by one of the following forms from each of its partners/members that is claiming the portfolio interest exemption: (i) an IRS Form W-8BEN or IRS Form W-8BEN-E, as applicable, or (ii) an IRS Form W-8IMY accompanied by an IRS Form W-8BEN or IRS Form W-8BEN-E, as applicable, from each of such partner's/member's beneficial owners that is claiming the portfolio interest exemption. By executing this certificate, the undersigned agrees that (1) if the information provided on this certificate changes, the undersigned shall promptly so inform such Lender and (2) the undersigned shall have at all times furnished such Lender with a properly completed and currently effective certificate in either the calendar year in which each payment is to be made to the undersigned, or in either of the two calendar years preceding such payments.

Unless otherwise defined herein, terms defined in the 364-Day Credit Agreement and used herein shall have the meanings given to them in the 364-Day Credit Agreement.

[NAME OF PARTICIPANT]

By:
Name:
Title:

Date: _____ __, 20[ ]

EXHIBIT 2.16-D

[FORM OF]
U.S. TAX COMPLIANCE CERTIFICATE
(For Foreign Lenders That Are Partnerships For U.S. Federal Income Tax Purposes)

Reference is hereby made to the Revolving Credit Agreement, dated as of November 16, 2018 (as further amended, supplemented or otherwise modified from time to time, the "364-Day Credit Agreement"), among Kinder Morgan, Inc. (the "Borrower"), Barclays Bank PLC, as administrative agent for the lenders party thereto (the "Lenders") and such Lenders.

Pursuant to the provisions of Section 2.16(g) of the 364-Day Credit Agreement, the undersigned hereby certifies that (i) it is the sole record owner of the Loan(s) (as well as any Note(s) evidencing such Loan(s)) in respect of which it is providing this certificate, (ii) its direct or indirect partners/members are the sole beneficial owners of such Loan(s) (as well as any Note(s) evidencing such Loan(s)), (iii) with respect to the extension of credit pursuant to this 364-Day Credit Agreement or any other Loan Document, neither the undersigned nor any of its direct or indirect partners/members is a bank extending credit pursuant to a loan agreement entered into in the ordinary course of its trade or business within the meaning of Section 881(c)(3)(A) of the Code, (iv) none of its direct or indirect partners/members is a ten percent shareholder of the Borrower within the meaning of Section 881(c)(3)(B) of the Code and (v) none of its direct or indirect partners/members is a controlled foreign corporation related to the Borrower as described in Section 881(c)(3)(C) of the Code.

The undersigned has furnished the Administrative Agent and the Borrower with IRS Form W-8IMY accompanied by one of the following forms from each of its partners/members that is claiming the portfolio interest exemption: (i) an IRS Form W-8BEN or IRS Form W-8BEN-E, as applicable, or (ii) an IRS Form W-8IMY accompanied by an IRS Form W-8BEN or IRS Form W-8BEN-E, as applicable, from each of such partner's/member's beneficial owners that is claiming the portfolio interest exemption. By executing this certificate, the undersigned agrees that (1) if the information provided on this certificate changes, the undersigned shall promptly so inform the Borrower and the Administrative Agent, and (2) the undersigned shall have at all times furnished the Borrower and the Administrative Agent with a properly completed and currently effective certificate in either the calendar year in which each payment is to be made to the undersigned, or in either of the two calendar years preceding such payments.

Unless otherwise defined herein, terms defined in the 364-Day Credit Agreement and used herein shall have the meanings given to them in the 364-Day Credit Agreement.

[NAME OF LENDER]

By:
Name:
Title:

Date: _____ __, 20[ ]

EXHIBIT 5.01

FORM OF COMPLIANCE CERTIFICATE

The undersigned hereby certifies that he is the _____ of KINDER MORGAN, INC., a Delaware corporation (the "Borrower"), and that as such he is authorized to execute this certificate on behalf of the Borrower. With reference to the Revolving Credit Agreement dated as of November 16, 2018 (as further restated, amended, modified, supplemented and in effect from time to time, the "364-Day Credit Agreement") among the Borrower, Barclays Bank PLC, as Administrative Agent, for the lenders (the "Lenders") and such Lenders, the undersigned represents and warrants as follows (each capitalized term used herein having the same meaning given to it in the 364-Day Credit Agreement unless otherwise specified);

Attached hereto as Annex I are the detailed computations necessary to determine whether the Borrower is in compliance with Section 6.07 of the 364-Day Credit Agreement as of the end of the [fiscal quarter][fiscal year] ending _____.

[Attached hereto as Annex II is a list of the Material Subsidiaries.][1]

[There has been no change in the list of Material Subsidiaries since [ ], the date of the last Compliance Certificate delivered prior to the date hereof.] [Attached hereto as Annex II is an update to the list of Material Subsidiaries to reflect changes in such list since [ ], the date of the last Compliance Certificate delivered prior to the date hereof.][2]

There does not exist any Default or Event of Default under the 364-Day Credit Agreement as of the date of this Compliance Certificate, except as set forth in a separate attachment, if any, to this Compliance Certificate, setting forth the details thereof and the action taken or proposed to be taken by the Borrower with respect thereto.

EXECUTED AND DELIVERED this _____ day of _____, _____.

KINDER MORGAN, INC.,
as the Borrower

By: _____
Name:_____
Title:_____

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[1] To be included in the compliance certificate delivered simultaneously with the first set of financial statements delivered following the Closing Date.

[2] Select the appropriate option for each Compliance Certificate delivered simultaneously with the second set of financial statements delivered following the Closing Date and each set of financial statements delivered thereafter.

CROSS GUARANTEE AGREEMENT

This CROSS GUARANTEE AGREEMENT is dated as of November 26, 2014 (as amended, restated, supplemented or otherwise modified from time to time, this "Agreement"), by each of the signatories listed on the signature pages hereto and each of the other entities that becomes a party hereto pursuant to Section 19 (the "Guarantors" and individually, a "Guarantor"), for the benefit of the Guaranteed Parties (as defined below).

W I T N E S S E T H:

WHEREAS, Kinder Morgan, Inc., a Delaware corporation ("KMI"), and certain of its direct and indirect Subsidiaries have outstanding senior, unsecured Indebtedness and may from time to time issue additional senior, unsecured Indebtedness;

WHEREAS, each Guarantor, other than KMI, is a direct or indirect Subsidiary of KMI;

WHEREAS, each Guarantor desires to provide the guarantee set forth herein with respect to the Indebtedness of such Guarantors that constitutes the Guaranteed Obligations; and

WHEREAS, each Guarantor acknowledges that it will derive substantial direct and indirect benefit from the making of the guarantees hereby;

NOW, THEREFORE, in consideration of the premises, the Guarantors hereby agree with each other for the benefit of the Guaranteed Parties as follows:

1. Defined Terms.

(a) As used in this Agreement, the following terms have the meanings specified below:

"Agreement" has the meaning provided in the preamble hereto.

"Bankruptcy Code" means Title 11 of the United States Code, as now or hereafter in effect, or any successor thereto.

"Capital Stock" means, with respect to any Person, any and all shares, interests, rights to purchase, warrants, options, participations or other equivalents (however designated) of such Person's equity, including (i) all common stock and preferred stock, any limited or general partnership interest and any limited liability company member interest, (ii) beneficial interests in trusts, and (iii) any other interest or participation that confers upon a Person the right to receive a share of the profits and losses of, or distribution of assets of, the issuing Person.

"CFC" means a Person that is a "controlled foreign corporation" within the meaning of Section 957 of the Internal Revenue Code of 1986, as amended.

"Commodity Exchange Act" means the Commodity Exchange Act (7 U.S.C. § 1 et seq.), as amended from time to time, and any successor statute.

"Consolidated Assets" means, at the date of any determination thereof, the total assets of KMI and its Subsidiaries as set forth on a consolidated balance sheet of KMI and its Subsidiaries for their most recently completed fiscal quarter, prepared in accordance with GAAP.

"Consolidated Tangible Assets" means, at the date of any determination thereof, Consolidated Assets after deducting therefrom the value, net of any applicable reserves and accumulated

amortization, of all goodwill, trade names, trademarks, patents and other like intangible assets, all as set forth, or on a pro forma basis would be set forth, on a consolidated balance sheet of KMI and its Subsidiaries for their most recently completed fiscal quarter, prepared in accordance with GAAP.

"Domestic Subsidiary" means any Subsidiary of KMI organized under the laws of any jurisdiction within the United States.

"Excluded Subsidiary" means (i) any Subsidiary that is not a Wholly-owned Domestic Operating Subsidiary, (ii) any Domestic Subsidiary that is a Subsidiary of a CFC or any Domestic Subsidiary (including a disregarded entity for U.S. federal income tax purposes) substantially all of whose assets (held directly or through Subsidiaries) consist of Capital Stock of one or more CFCs or Indebtedness of such CFCs, (iii) any Immaterial Subsidiary, (iv) any Subsidiary listed on Schedule III, (v) each of Calnev Pipe Line LLC, SFPP, L.P., Kinder Morgan G.P., Inc. and EPEC Realty, Inc. and each of its Subsidiaries, (vi) any other Subsidiary that is not a Guarantor under the Revolving Credit Agreement Guarantee, (vii) any not-for-profit Subsidiary, (viii) any Subsidiary that is prohibited by a Requirement of Law from guaranteeing the Guaranteed Obligations, and (ix) any Subsidiary acquired by KMI or its Subsidiaries after the date of this Agreement to the extent, and so long as, the financing documentation governing any existing Indebtedness of such Subsidiary that survives such acquisition prohibits such Subsidiary from guaranteeing the Guaranteed Obligations; *provided*, that notwithstanding the foregoing, any Subsidiary that is party to the Revolving Credit Agreement Guarantee or that Guarantees any senior notes or senior debt securities issued by KMI (other than pursuant to this Agreement) shall not constitute an Excluded Subsidiary for so long as such Guarantee is in effect.

"Excluded Swap Obligation" means, with respect to any Guarantor, any Swap Obligation if, and to the extent that, all or a portion of the Guarantee of such Guarantor of such Swap Obligation (or any Guarantee thereof) is or becomes illegal under the Commodity Exchange Act or any rule, regulation or order of the Commodity Futures Trading Commission (or the application or official interpretation of any thereof) by virtue of such Guarantor's failure for any reason to constitute an "eligible contract participant" as defined in the Commodity Exchange Act and the regulations thereunder at the time the Guarantee of such Guarantor becomes effective with respect to such Swap Obligation. If a Swap Obligation arises under a master agreement governing more than one swap, such exclusion shall apply only to the portion of such Swap Obligation that is attributable to swaps for which such Guarantee is or becomes illegal.

"GAAP" means generally accepted accounting principles in the United States of America from time to time, including as set forth in the opinions, statements and pronouncements of the Accounting Principles Board of the American Institute of Certified Public Accountants and the Financial Accounting Standards Board.

"Governmental Authority" means the government of the United States of America or any other nation, or of any political subdivision thereof, whether state or local, and any agency, authority, instrumentality, regulatory body, court, central bank or other entity exercising executive, legislative, judicial, taxing, regulatory or administrative powers or functions of or pertaining to government (including any supra national bodies such as the European Union or the European Central Bank).

"Guarantee" of or by any Person (the "guarantor") means any obligation, contingent or otherwise, of the guarantor guaranteeing or having the economic effect of guaranteeing any Indebtedness or other obligation of any other Person (the "primary obligor") in any manner, whether directly or indirectly, and including any obligation of the guarantor, direct or indirect, (i) to purchase or pay (or advance or supply funds for the purchase or payment of) such Indebtedness or other obligation or to purchase (or to advance or supply funds for the purchase of) any security for the payment thereof, (ii) to purchase or lease property, securities or services for the purpose of assuring the owner of such Indebtedness

or other obligation of the payment thereof, (iii) to maintain working capital, equity capital or any other financial statement condition or liquidity of the primary obligor so as to enable the primary obligor to pay such Indebtedness or other obligation or (iv) as an account party in respect of any letter of credit or letter of guaranty issued to support such Indebtedness or obligation; *provided* that the term Guarantee shall not include endorsements for collection or deposit in the ordinary course of business.

"Guarantee Termination Date" has the meaning set forth in Section 2(d).

"Guaranteed Obligations" means the Indebtedness set forth on Schedule I hereto, as such schedule may be amended from time to time in accordance with the terms of this Agreement; *provided* that the term "Guaranteed Obligations" shall exclude any Excluded Swap Obligations.

"Guaranteed Parties" means, collectively, (i) in the case of Guaranteed Obligations that are governed by trust indentures, the holders (as that term is defined in the applicable trust indenture) of such Guaranteed Obligations, (ii) in the case of Guaranteed Obligations that are governed by loan agreements, credit agreements, or similar agreements, the lenders providing such loans or credit, and (iii) in the case of Guaranteed Obligations with respect to Hedging Agreements, the counterparties under such agreements.

"Guarantor" has the meaning provided in the preamble hereto. Schedule II hereto, as such schedule may be amended from time to time in accordance with the terms of this Agreement, sets forth the name of each Guarantor.

"Hedging Agreement" means a financial instrument, agreement or security which hedges or is used to hedge or manage the risk associated with a change in interest rates, foreign currency exchange rates or commodity prices (but excluding any purchase, swap, derivative contract or similar agreement relating to power, electricity or any related commodity product).

"Immaterial Subsidiary" means any Subsidiary that is not a Material Subsidiary.

"Indebtedness" means, collectively, (i) any senior, unsecured obligation created or assumed by any Person for borrowed money, including all obligations of such Person evidenced by bonds, debentures, notes or similar instruments (other than surety, performance and guaranty bonds), and (ii) all payment obligations of any Person with respect to obligations under Hedging Agreements.

"Investment Grade Rating" means a rating equal to or higher than Baa3 by Moody's and BBB- by S&P; *provided, however,* that if (i) either of Moody's or S&P changes its rating system, such ratings shall be the equivalent ratings after such changes or (ii) Moody's or S&P shall not make a rating of a Guaranteed Obligation publicly available, the references above to Moody's or S&P or both of them, as the case may be, shall be to a nationally recognized U.S. rating agency or agencies, as the case may be, selected by KMI and the references to the ratings categories above shall be to the corresponding rating categories of such rating agency or rating agencies, as the case may be.

"Issuer" means the issuer, borrower, or other applicable primary obligor of a Guaranteed Obligation.

"KMI" has the meaning provided in the recitals hereto.

"Lien" means, with respect to any asset (i) any mortgage, deed of trust, lien, pledge, hypothecation, encumbrance, charge or security interest in, on or of such asset, and (ii) the interest of a vendor or a lessor under any conditional sale agreement, capital lease or title retention agreement (or any financing lease having substantially the same economic effect as any of the foregoing) relating to such asset.

"Material Subsidiary" means, as at any date of determination, any Subsidiary of KMI whose total tangible assets (for purposes of the below, when combined with the tangible assets of such Subsidiary's Subsidiaries, after eliminating intercompany obligations) as at such date of determination are greater than or equal to 5% of Consolidated Tangible Assets as of the last day of the fiscal quarter most recently ended for which financial statements of KMI have been filed with the SEC.

"Moody's" means Moody's Investors Service, Inc. and its successors.

"Operating Subsidiary" means any operating company that is a Subsidiary of KMI.

"Person" means any natural person, corporation, limited liability company, trust, joint venture, association, company, partnership, Governmental Authority or other entity.

"Qualified ECP Guarantor" means, in respect of any Swap Obligation, each Guarantor that has total assets exceeding $10,000,000 at the time the relevant Guarantee becomes effective with respect to such Swap Obligation or such other person as constitutes an "eligible contract participant" under the Commodity Exchange Act or any regulations promulgated thereunder and can cause another person to qualify as an "eligible contract participant" at such time by entering into a keepwell under Section 1a(18)(A)(v)(II) of the Commodity Exchange Act.

"Rating Agencies" means Moody's and S&P; *provided* that, if at the relevant time neither Moody's nor S&P shall be rating the relevant Guaranteed Obligation, then "Rating Agencies" shall mean another nationally recognized rating service that rates such Guaranteed Obligation.

"Rating Date" means the date immediately prior to the earlier of (i) the occurrence of a Release Event and (ii) public notice of the intention to effect a Release Event.

"Rating Decline" means, with respect to a Guaranteed Obligation, the occurrence of the following on, or within 90 days after, the date of the occurrence of a Release Event or of public notice of the intention to effect a Release Event (which period may be extended so long as the rating of such Guaranteed Obligation is under publicly announced consideration for possible downgrade by either of the Rating Agencies): (i) in the event such Guaranteed Obligation is assigned an Investment Grade Rating by both Rating Agencies on the Rating Date, the rating of such Guaranteed Obligation by one or both of the Rating Agencies shall be below an Investment Grade Rating; or (ii) in the event such Guaranteed Obligation is rated below an Investment Grade Rating by either of the Rating Agencies on the Rating Date, any such below-Investment Grade Rating of such Guaranteed Obligation shall be decreased by one or more gradations (including gradations within rating categories as well as between rating categories).

"Release Event" has the meaning set forth in Section 6(b).

"Requirement of Law" means any law, statute, code, ordinance, order, determination, rule, regulation, judgment, decree, injunction, franchise, permit, certificate, license, authorization or other directive or requirement (whether or not having the force of law), including environmental laws, energy regulations and occupational, safety and health standards or controls, of any Governmental Authority.

"Revolving Credit Agreement" means the Revolving Credit Agreement, dated as of September 19, 2014, among KMI, the lenders party thereto and Barclays Bank PLC, as administrative agent, as such credit agreement may be amended, modified, supplemented or restated from time to time, or refunded, refinanced, restructured, replaced, renewed, repaid or extended from time to time (whether with the original agents and lenders or other agents or lenders or trustee or otherwise, and whether provided under the original credit agreement or other credit agreements or note indentures or otherwise), including, without limitation, increasing the amount of available borrowings or other Indebtedness thereunder.

"Revolving Credit Agreement Guarantee" means the Guarantee Agreement, dated as of November 26, 2014, made by the Subsidiaries of KMI party thereto in favor of Barclays Bank PLC, as administrative agent, for the benefit of the lenders and the issuing banks under the Revolving Credit Agreement, as such guarantee agreement may be amended, modified, supplemented or restated from time to time, and as it may be replaced or renewed from time to time in connection with any amendment, modification, supplement, restatement, refunding, refinancing, restructuring, replacement, renewal, repayment, or extension of any Revolving Credit Agreement from time to time.

"S&P" means Standard & Poor's Rating Services, a division of The McGraw-Hill Companies, Inc., and its successors.

"SEC" means the United States Securities and Exchange Commission.

"Subsidiary" means, with respect to any Person (the "parent") at any date, any corporation, limited liability company, partnership, association or other entity the accounts of which would be consolidated with those of the parent in the parent's consolidated financial statements if such financial statements were prepared in accordance with GAAP as of such date, as well as any other corporation, limited liability company, partnership, association or other entity (a) of which securities or other ownership interests representing more than 50% of the equity or more than 50% of the ordinary voting power or, in the case of a partnership, more than 50% of the general partner interests are, as of such date, owned, controlled or held, or (b) that is, as of such date, otherwise controlled, by the parent or one or more Subsidiaries of the parent or by the parent and one or more Subsidiaries of the parent. Unless the context otherwise clearly requires, references in this Agreement to a "Subsidiary" or the "Subsidiaries" refer to a Subsidiary or the Subsidiaries of KMI. Notwithstanding the foregoing, Plantation Pipe Line Company, a Delaware and Virginia corporation, shall not be a Subsidiary of KMI until such time as its assets and liabilities, profit or loss and cash flow are required under GAAP to be consolidated with those of KMI.

"Swap Obligation" means, with respect to any Guarantor, any obligation to pay or perform under any agreement, contract or transaction that constitutes a "swap" within the meaning of Section 1a(47) of the Commodity Exchange Act.

"Wholly-owned Domestic Operating Subsidiary" means any Wholly-owned Subsidiary that constitutes (i) a Domestic Subsidiary and (ii) an Operating Subsidiary.

"Wholly-owned Subsidiary" means a Subsidiary of which all issued and outstanding Capital Stock (excluding in the case of a corporation, directors' qualifying shares) is directly or indirectly owned by KMI.

(b) The words "hereof", "herein" and "hereunder" and words of similar import when used in this Agreement shall refer to this Agreement as a whole and not to any particular provision of this

Agreement, and Section references are to Sections of this Agreement unless otherwise specified. The words "include", "includes" and "including" shall be deemed to be followed by the phrase "without limitation".

(c) The meanings given to terms defined herein shall be equally applicable to both the singular and plural forms of such terms.

2. Guarantee.

(a) Subject to the provisions of Section 2(b), each of the Guarantors hereby, jointly and severally, unconditionally and irrevocably, guarantees, as primary obligor and not merely as surety, for the benefit of the Guaranteed Parties, the prompt and complete payment when due (whether at the stated maturity, by acceleration or otherwise) of the Guaranteed Obligations; *provided* that each Guarantor shall be released from its respective guarantee obligations under this Agreement as provided in Section 6(b). Upon the failure of an Issuer to punctually pay any Guaranteed Obligation, each Guarantor shall, upon written demand by the applicable Guaranteed Party to such Guarantor, pay or cause to be paid such amounts.

(b) Anything herein to the contrary notwithstanding, the maximum liability of each Guarantor hereunder shall in no event exceed the amount that can be guaranteed by such Guarantor under the Bankruptcy Code or any applicable laws relating to fraudulent conveyances, fraudulent transfers or the insolvency of debtors after giving full effect to the liability under this Agreement and its related contribution rights set forth in this Section 2, but before taking into account any liabilities under any other Guarantees.

(c) Each Guarantor agrees that the Guaranteed Obligations may at any time and from time to time exceed the amount of the liability of such Guarantor hereunder (as a result of the limitations set forth in Section 2(b) or elsewhere in this Agreement) without impairing this Agreement or affecting the rights and remedies of any Guaranteed Party hereunder.

(d) No payment or payments made by any Issuer, any of the Guarantors, any other guarantor or any other Person or received or collected by any Guaranteed Party from any Issuer, any of the Guarantors, any other guarantor or any other Person by virtue of any action or proceeding or any set-off or appropriation or application at any time or from time to time in reduction of or in payment of any Guaranteed Obligation shall be deemed to modify, reduce, release or otherwise affect the liability of any Guarantor hereunder, which shall, notwithstanding any such payment or payments, other than payments made by such Guarantor in respect of such Guaranteed Obligation or payments received or collected from such Guarantor in respect of such Guaranteed Obligation, remain liable for the Guaranteed Obligations up to the maximum liability of such Guarantor hereunder until all Guaranteed Obligations (other than any contingent indemnity obligations not then due and any letters of credit that remain outstanding which have been fully cash collateralized or otherwise back-stopped to the reasonable satisfaction of the applicable issuing bank) shall have been discharged by payment in full or shall have been deemed paid and discharged by defeasance pursuant to the terms of the instruments governing such Guaranteed Obligations (the "Guarantee Termination Date").

(e) If and to the extent required in order for the obligations of any Guarantor hereunder to be enforceable under applicable federal, state and other laws relating to the insolvency of debtors, the maximum liability of such Guarantor hereunder shall be limited to the greatest amount which can lawfully be guaranteed by such Guarantor under such laws, after giving effect to any rights of contribution, reimbursement and subrogation arising hereunder. Each Guarantor acknowledges and agrees

that, to the extent not prohibited by applicable law, (i) such Guarantor (as opposed to its creditors, representatives of creditors or bankruptcy trustee, including such Guarantor in its capacity as debtor in possession exercising any powers of a bankruptcy trustee) has no personal right under such laws to reduce, or request any judicial relief that has the effect of reducing, the amount of its liability under this Agreement, (ii) such Guarantor (as opposed to its creditors, representatives of creditors or bankruptcy trustee, including such Guarantor in its capacity as debtor in possession exercising any powers of a bankruptcy trustee) has no personal right to enforce the limitation set forth in this Section 2(e) or to reduce, or request judicial relief reducing, the amount of its liability under this Agreement, and (iii) the limitation set forth in this Section 2(e) may be enforced only to the extent required under such laws in order for the obligations of such Guarantor under this Agreement to be enforceable under such laws and only by or for the benefit of a creditor, representative of creditors or bankruptcy trustee of such Guarantor or other Person entitled, under such laws, to enforce the provisions hereof.

3. Right of Contribution. Each Guarantor hereby agrees that to the extent that a Guarantor shall have paid more than its proportionate share of any payment made hereunder (including by way of set-off rights being exercised against it), such Guarantor shall be entitled to seek and receive contribution from and against any other Guarantor hereunder who has not paid its proportionate share of such payment as set forth in this Section 3. To the extent that any Guarantor shall be required hereunder to pay any portion of any Guaranteed Obligation guaranteed hereunder exceeding the greater of (a) the amount of the value actually received by such Guarantor and its Subsidiaries from such Guaranteed Obligation and (b) the amount such Guarantor would otherwise have paid if such Guarantor had paid the aggregate amount of such Guaranteed Obligation guaranteed hereunder (excluding the amount thereof repaid by the Issuer of such Guaranteed Obligation) in the same proportion as such Guarantor's net worth on the date enforcement is sought hereunder bears to the aggregate net worth of all the Guarantors on such date, then such Guarantor shall be reimbursed by such other Guarantors for the amount of such excess, pro rata, based on the respective net worth of such other Guarantors on such date; *provided* that any Guarantor's right of reimbursement shall be subject to the terms and conditions of Section 5 hereof. For purposes of determining the net worth of any Guarantor in connection with the foregoing, all Guarantees of such Guarantor other than pursuant to this Agreement will be deemed to be enforceable and payable after its obligations pursuant to this Agreement. The provisions of this Section 3 shall in no respect limit the obligations and liabilities of any Guarantor to the Guaranteed Parties, and each Guarantor shall remain liable to the Guaranteed Parties for the full amount guaranteed by such Guarantor hereunder.

4. No Right of Set-off. No Guaranteed Party shall have, as a result of this Agreement, any right of set-off against any amount owing by such Guaranteed Party to or for the credit or the account of a Guarantor.

5. No Subrogation. Notwithstanding any payment or payments made by any of the Guarantors hereunder, no Guarantor shall be entitled to be subrogated to any of the rights (or if subrogated by operation of law, such Guarantor hereby waives such rights to the extent permitted by applicable law) of any Guaranteed Party against any Issuer or any other Guarantor or any collateral security or guarantee or right of offset held by any Guaranteed Party for the payment of any Guaranteed Obligation, nor shall any Guarantor seek or be entitled to seek any contribution or reimbursement from any Issuer or any other Guarantor in respect of payments made by such Guarantor hereunder, until the Guarantee Termination Date. If any amount shall be paid to any Guarantor on account of such subrogation, contribution or reimbursement rights at any time prior to the Guarantee Termination Date, such amount shall be held by such Guarantor in trust for the applicable Guaranteed Parties, segregated from other funds of such Guarantor, and shall, forthwith upon receipt by such Guarantor, be turned over to the applicable Guaranteed Parties in the exact form received by such Guarantor (duly indorsed by such

Guarantor to the applicable Guaranteed Parties if required), to be applied against the applicable Guaranteed Obligation, whether due or to become due.

6. Amendments, etc. with Respect to the Guaranteed Obligations; Waiver of Rights; Release.

(a) Each Guarantor shall remain obligated hereunder notwithstanding that, without any reservation of rights against any Guarantor and without notice to or further assent by any Guarantor, (i) any demand for payment of any Guaranteed Obligation made by any Guaranteed Party may be rescinded by such party and any Guaranteed Obligation continued, (ii) a Guaranteed Obligation, or the liability of any other party upon or for any part thereof, or any collateral security or guarantee therefor or right of offset with respect thereto, may, from time to time, in whole or in part, be renewed, extended, amended, modified, accelerated, compromised, waived, allowed to lapse, surrendered or released by any Guaranteed Party, (iii) the instruments governing any Guaranteed Obligation may be amended, modified, supplemented or terminated, in whole or in part, and (iv) any collateral security, guarantee or right of offset at any time held by any Guaranteed Party for the payment of any Guaranteed Obligation may be sold, exchanged, waived, allowed to lapse, surrendered or released. No Guaranteed Party shall have any obligation to protect, secure, perfect or insure any Lien at any time held by it as security for the Guaranteed Obligations or for this Agreement or any property subject thereto. When making any demand hereunder against any Guarantor, a Guaranteed Party may, but shall be under no obligation to, make a similar demand on the Issuer of the applicable Guaranteed Obligation or any other Guarantor or any other person, and any failure by a Guaranteed Party to make any such demand or to collect any payments from such Issuer or any other Guarantor or any other person or any release of such Issuer or any other Guarantor or any other person shall not relieve any Guarantor in respect of which a demand or collection is not made or any Guarantor not so released of its several obligations or liabilities hereunder, and shall not impair or affect the rights and remedies, express or implied, or as a matter of law, of any Guaranteed Party against any Guarantor. For the purposes hereof "demand" shall include the commencement and continuance of any legal proceedings.

(b) A Guarantor shall be automatically released from its guarantee hereunder upon release of such Guarantor from the Revolving Credit Agreement Guarantee, including upon consummation of any transaction resulting in such Guarantor ceasing to constitute a Subsidiary or upon any Guarantor becoming an Excluded Subsidiary (such transaction or event, a "Release Event").

(c) Upon the occurrence of a Release Event, each Guaranteed Obligation for which such released Guarantor was the Issuer shall be automatically released from the provisions of this Agreement and shall cease to constitute a Guaranteed Obligation hereunder; *provided* that in the case of any Guaranteed Obligation that has been assigned an Investment Grade Rating by the Rating Agencies, such Guaranteed Obligation shall be so released, effective as of the 91st day after the occurrence of the Release Event, if and only if a Rating Decline with respect to such Guaranteed Obligation does not occur.

7. Guarantee Absolute and Unconditional.

(a) Each Guarantor waives any and all notice of the creation, contraction, incurrence, renewal, extension, amendment, waiver or accrual of any of the Guaranteed Obligations, and notice of or proof of reliance by any Guaranteed Party upon this Agreement or acceptance of this Agreement. To the fullest extent permitted by applicable law, each Guarantor waives diligence, promptness, presentment, protest and notice of protest, demand for payment or performance, notice of default or nonpayment, notice of acceptance and any other notice in respect of the Guaranteed Obligations or any part of them, and any defense arising by reason of any disability or other defense of any Issuer or any of the Guarantors

with respect to the Guaranteed Obligations. Each Guarantor understands and agrees that this Agreement shall be construed as a continuing, absolute and unconditional guarantee of payment without regard to (i) the validity, regularity or enforceability of any of the Guaranteed Obligations, the indenture, loan agreement, note or other instrument evidencing or governing any of the Guaranteed Obligations or any collateral security therefor or guarantee or right of offset with respect thereto at any time or from time to time held by any Guaranteed Party, (ii) any defense, set-off or counterclaim (other than a defense of payment or performance) that may at any time be available to or be asserted by any Issuer against any Guaranteed Party or (iii) any other circumstance whatsoever (with or without notice to or knowledge of any Issuer or such Guarantor) that constitutes, or might be construed to constitute, an equitable or legal discharge of any Issuer for any of the Guaranteed Obligations, or of such Guarantor under this Agreement, in bankruptcy or in any other instance. When pursuing its rights and remedies hereunder against any Guarantor, any Guaranteed Party may, but shall be under no obligation to, pursue such rights and remedies as it may have against the Issuer or any other Person or against any collateral security or guarantee for the Guaranteed Obligations or any right of offset with respect thereto, and any failure by any Guaranteed Party to pursue such other rights or remedies or to collect any payments from the Issuer or any such other Person or to realize upon any such collateral security or guarantee or to exercise any such right of offset, or any release of the Issuer or any such other Person or any such collateral security, guarantee or right of offset, shall not relieve such Guarantor of any liability hereunder, and shall not impair or affect the rights and remedies, whether express, implied or available as a matter of law, of the other Guaranteed Parties against such Guarantor.

(b) This Agreement shall remain in full force and effect and be binding in accordance with and to the extent of its terms upon each Guarantor and the successors and assigns thereof and shall inure to the benefit of the Guaranteed Parties and their respective successors, indorsees, transferees and assigns until the Guarantee Termination Date.

8. Reinstatement. This Agreement shall continue to be effective, or be reinstated, as the case may be, if at any time payment, or any part thereof, of any of the Guaranteed Obligations is rescinded or must otherwise be restored or returned by any Guaranteed Party upon the insolvency, bankruptcy, dissolution, liquidation or reorganization of any Issuer or any Guarantor, or upon or as a result of the appointment of a receiver, intervenor or conservator of, or trustee or similar officer for, any Issuer or any Guarantor or any substantial part of its property, or otherwise, all as though such payments had not been made.

9. Payments. Each Guarantor hereby guarantees that payments hereunder will be paid to the applicable Guaranteed Parties without set-off or counterclaim in dollars.

10. Representations and Warranties. Each Guarantor hereby represents and warrants to each Guaranteed Party that the following representations and warranties are true and correct in all material respects as of the date of this Agreement or as of the date such Guarantor became a party to this Agreement, as applicable:

(a) such Guarantor (i) is a corporation, partnership or limited liability company duly organized or formed, validly existing and in good standing under the laws of the state of its incorporation, organization or formation, (ii) has all requisite corporate, partnership, limited liability company or other power and all material governmental licenses, authorizations, consents and approvals required to carry on its business as now conducted and (iii) is duly qualified to do business and is in good standing in every jurisdiction in which the failure to be so qualified would have a material adverse effect on its ability to perform its obligations under this Agreement;

(b) such Guarantor has all requisite corporate (or other organizational) power and authority to execute and deliver and to perform its obligations under this Agreement, and all such actions have been duly authorized by all necessary proceedings on its behalf;

(c) this Agreement has been duly and validly executed and delivered by or on behalf of such Guarantor and constitutes the valid and legally binding agreement of such Guarantor, enforceable against such Guarantor in accordance with its terms, except (i) as may be limited by bankruptcy, insolvency, reorganization, moratorium, fraudulent transfer, fraudulent conveyance or other similar laws relating to or affecting the enforcement of creditors' rights generally, and by general principles of equity (including principles of good faith, reasonableness, materiality and fair dealing) which may, among other things, limit the right to obtain equitable remedies (regardless of whether considered in a proceeding in equity or at law) and (ii) as to the enforceability of provisions for indemnification for violation of applicable securities laws, limitations thereon arising as a matter of law or public policy;

(d) no authorization, consent, approval, license or exemption of or registration, declaration or filing with any Governmental Authority is necessary for the valid execution and delivery of, or the performance by such Guarantor of its obligations hereunder, except those that have been obtained and such matters relating to performance as would ordinarily be done in the ordinary course of business after the date of this Agreement or as of the date such Guarantor became a party to this Agreement, as applicable; and

(e) neither the execution and delivery of, nor the performance by such Guarantor of its obligations under, this Agreement will (i) breach or violate any applicable Requirement of Law, (ii) result in any breach or violation of any of the terms, covenants, conditions or provisions of, or constitute a default under, or result in the creation or imposition of (or the obligation to create or impose) any Lien upon any of its property or assets (other than Liens created or contemplated by this Agreement) pursuant to the terms of, any indenture, mortgage, deed of trust, agreement or other instrument to which it or any of its Subsidiaries is party or by which any of its properties or assets, or those of any of its Subsidiaries is bound or to which it is subject, except for breaches, violations and defaults under clauses (i) and (ii) that neither individually nor in the aggregate could reasonably be expected to result in a material adverse effect on its ability to perform its obligations under this Agreement, or (iii) violate any provision of the organizational documents of such Guarantor.

11. Rights of Guaranteed Parties. Each Guarantor acknowledges and agrees that any changes in the identity of the Persons from time to time comprising the Guaranteed Parties gives rise to an equivalent change in the Guaranteed Parties, without any further act. Upon such an occurrence, the persons then comprising the Guaranteed Parties are vested with the rights, remedies and discretions of the Guaranteed Parties under this Agreement.

12. Notices.

(a) All notices, requests, demands and other communications to any Guarantor pursuant hereto shall be in writing and mailed, telecopied or delivered to such Guarantor in care of KMI, 1001 Louisiana Street, Suite 1000, Houston, Texas 77002, Attention: Treasurer, Telecopy: (713) 445-8302.

(b) KMI will provide a copy of this Agreement, including the most recently amended schedules and supplements hereto, to any Guaranteed Party upon written request to the address set forth in Section 12(a); *provided, however*, that KMI's obligations under this Section 12(b) shall be deemed satisfied if KMI has filed a copy of this Agreement, including the most recently amended schedules and

supplements hereto, with the SEC within three months preceding the date on which KMI receives such written request.

13. Counterparts. This Agreement may be executed by one or more of the parties to this Agreement on any number of separate counterparts (including by facsimile or other electronic transmission), and all of said counterparts taken together shall be deemed to constitute one and the same instrument. A set of the copies of this Agreement signed by all the parties shall be lodged with KMI.

14. Severability. Any provision of this Agreement that is prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction. The parties hereto shall endeavor in good-faith negotiations to replace the invalid, illegal or unenforceable provisions with valid provisions the economic effect of which comes as close as possible to that of the invalid, illegal or unenforceable provisions.

15. Integration. This Agreement represents the agreement of each Guarantor with respect to the subject matter hereof, and there are no promises, undertakings, representations or warranties by any Guaranteed Party relative to the subject matter hereof not expressly set forth or referred to herein.

16. Amendments; No Waiver; Cumulative Remedies.

(a) None of the terms or provisions of this Agreement may be waived, amended, supplemented or otherwise modified except by a written instrument executed by the affected Guarantors and KMI.

(b) The Guarantors may amend or supplement this Agreement by a written instrument executed by all Guarantors:

(i) to cure any ambiguity, defect or inconsistency;

(ii) to reflect a change in the Guarantors or the Guaranteed Obligations made in accordance with this Agreement;

(iii) to make any change that would provide any additional rights or benefits to the Guaranteed Parties or that would not adversely affect the legal rights hereunder of any Guaranteed Party in any material respect; or

(iv) to conform this Agreement to any change made to the Revolving Credit Agreement or to the Revolving Credit Agreement Guarantee.

Except as set forth in this clause (b) or otherwise provided herein, the Guarantors may not amend, supplement or otherwise modify this Agreement prior to the Guarantee Termination Date without the prior written consent of the holders of the majority of the outstanding principal amount of the Guaranteed Obligations (excluding obligations with respect to Hedging Agreements). Notwithstanding the foregoing, in the case of an amendment that would reasonably be expected to adversely, materially and disproportionately affect Guaranteed Parties with Guaranteed Obligations existing under Hedging Agreements relative to the other Guaranteed Parties, the foregoing exclusion of obligations with respect to Hedging Agreements shall not apply, and the outstanding principal amount attributable to each such Guaranteed Party's Guaranteed Obligations shall be deemed to be equal to the termination payment that

would be due to such Guaranteed Party as if the valuation date were an "Early Termination Date" under and calculated in accordance with each applicable Hedging Agreement.

(c) No Guaranteed Party shall by any act, delay, indulgence, omission or otherwise be deemed to have waived any right or remedy hereunder or to have acquiesced in any breach of any of the terms and conditions hereof. No failure to exercise, nor any delay in exercising, on the part of any Guaranteed Party, any right, power or privilege hereunder shall operate as a waiver thereof. No single or partial exercise of any right, power or privilege hereunder shall preclude any other or further exercise thereof or the exercise of any other right, power or privilege. A waiver by a Guaranteed Party of any right or remedy hereunder on any one occasion shall not be construed as a bar to any right or remedy that such Guaranteed Party would otherwise have on any future occasion.

(d) The rights, remedies, powers and privileges herein provided are cumulative, may be exercised singly or concurrently and are not exclusive of any other rights or remedies provided by law.

17. Section Headings. The Section headings used in this Agreement are for convenience of reference only and are not to affect the construction hereof or be taken into consideration in the interpretation hereof.

18. Successors and Assigns. This Agreement shall be binding upon the successors and assigns of each Guarantor and shall inure to the benefit of the Guaranteed Parties and their respective successors and permitted assigns, except that no Guarantor may assign, transfer or delegate any of its rights or obligations under this Agreement except pursuant to a transaction permitted by the Revolving Credit Agreement and in connection with a corresponding assignment under the Revolving Credit Agreement Guarantee.

19. Additional Guarantors.

(a) KMI shall cause each Subsidiary (other than any Excluded Subsidiary) formed or otherwise purchased or acquired after the date of this Agreement (including each Subsidiary that ceases to constitute an Excluded Subsidiary after the date of this Agreement) to execute a supplement to this Agreement and become a Guarantor within 45 days of the occurrence of the applicable event specified in this Section 19(a).

(b) Each Subsidiary of KMI that becomes, at the request of KMI, or that is required pursuant to Section 19(a) to become, a party to this Agreement shall become a Guarantor, with the same force and effect as if originally named as a Guarantor herein, for all purposes of this Agreement upon execution and delivery by such Subsidiary of a written supplement substantially in the form of Annex A hereto. The execution and delivery of any instrument adding an additional Guarantor as a party to this Agreement shall not require the consent of any other Guarantor hereunder. The rights and obligations of each Guarantor hereunder shall remain in full force and effect notwithstanding the addition of any new Guarantor as a party to this Agreement.

20. Additional Guaranteed Obligations. Any Indebtedness issued by a Guarantor or for which a Guarantor otherwise becomes obligated after the date of this Agreement shall become a Guaranteed Obligation upon the execution by all Guarantors of a notation of guarantee substantially in the form of Annex B hereto, which shall be affixed to the instrument or instruments evidencing such Indebtedness. Each such notation of guarantee shall be signed on behalf of each Guarantor by a duly authorized officer prior to the authentication or issuance of such Indebtedness.

21. **GOVERNING LAW. THIS AGREEMENT AND THE RIGHTS AND OBLIGATIONS OF THE PARTIES HEREUNDER SHALL BE GOVERNED BY, AND CONSTRUED AND INTERPRETED IN ACCORDANCE WITH, THE LAW OF THE STATE OF NEW YORK.**

22. Keepwell. Each Qualified ECP Guarantor hereby jointly and severally absolutely, unconditionally and irrevocably undertakes to provide such funds or other support as may be needed from time to time by each other Guarantor to honor all of its obligations under this Agreement in respect of Swap Obligations (provided, however, that each Qualified ECP Guarantor shall only be liable under this Section 22 for the maximum amount of such liability that can be hereby incurred without rendering its obligations under this Section 22, or otherwise under this Agreement, voidable under applicable law relating to fraudulent conveyance or fraudulent transfer, and not for any greater amount). The obligations of each Qualified ECP Guarantor under this Section shall remain in full force and effect until the Guarantee Termination Date. Each Qualified ECP Guarantor intends that this Section 22 constitute, and this Section 22 shall be deemed to constitute, a "keepwell, support, or other agreement" for the benefit of each other Guarantor for all purposes of Section 1a(18)(A)(v)(II) of the Commodity Exchange Act.

[Signature pages follow]

IN WITNESS WHEREOF, each of the undersigned has caused this Agreement to be duly executed and delivered by its duly authorized officer or other representative as of the day and year first above written.

KINDER MORGAN, INC.

By: /s/ Anthony B. Ashley
Name: Anthony B. Ashley
Title: Treasurer

AGNES B CRANE, LLC
AMERICAN PETROLEUM TANKERS II LLC
AMERICAN PETROLEUM TANKERS III LLC
AMERICAN PETROLEUM TANKERS IV LLC
AMERICAN PETROLEUM TANKERS LLC
AMERICAN PETROLEUM TANKERS PARENT LLC
AMERICAN PETROLEUM TANKERS V LLC
AMERICAN PETROLEUM TANKERS VI LLC
AMERICAN PETROLEUM TANKERS VII LLC
APT FLORIDA LLC
APT INTERMEDIATE HOLDCO LLC
APT NEW INTERMEDIATE HOLDCO LLC
APT PENNSYLVANIA LLC
APT SUNSHINE STATE LLC
AUDREY TUG LLC
BEAR CREEK STORAGE COMPANY, L.L.C.
BETTY LOU LLC
CAMINO REAL GATHERING COMPANY, L.L.C.
CANTERA GAS COMPANY LLC
CDE PIPELINE LLC
CENTRAL FLORIDA PIPELINE LLC
CHEYENNE PLAINS GAS PIPELINE COMPANY, L.L.C.
CIG GAS STORAGE COMPANY LLC
CIG PIPELINE SERVICES COMPANY, L.L.C.
CIMMARRON GATHERING LLC
COLORADO INTERSTATE GAS COMPANY, L.L.C.
COLORADO INTERSTATE ISSUING CORPORATION
COPANO DOUBLE EAGLE LLC
COPANO ENERGY FINANCE CORPORATION
COPANO ENERGY, L.L.C.
COPANO ENERGY SERVICES/UPPER GULF COAST LLC
COPANO FIELD SERVICES GP, L.L.C.
COPANO FIELD SERVICES/NORTH TEXAS, L.L.C.
COPANO FIELD SERVICES/SOUTH TEXAS LLC
COPANO FIELD SERVICES/UPPER GULF COAST LLC
COPANO LIBERTY, LLC
COPANO NGL SERVICES (MARKHAM), L.L.C.
COPANO NGL SERVICES LLC
COPANO PIPELINES GROUP, L.L.C.

COPANO PIPELINES/NORTH TEXAS, L.L.C.
COPANO PIPELINES/ROCKY MOUNTAINS, LLC
COPANO PIPELINES/SOUTH TEXAS LLC
COPANO PIPELINES/UPPER GULF COAST LLC
COPANO PROCESSING LLC
COPANO RISK MANAGEMENT LLC
COPANO/WEBB-DUVAL PIPELINE LLC
CPNO SERVICES LLC
DAKOTA BULK TERMINAL, INC.
DELTA TERMINAL SERVICES LLC
EAGLE FORD GATHERING LLC
EL PASO CHEYENNE HOLDINGS, L.L.C.
EL PASO CITRUS HOLDINGS, INC.
EL PASO CNG COMPANY, L.L.C.
EL PASO ENERGY SERVICE COMPANY, L.L.C.
EL PASO LLC
EL PASO MIDSTREAM GROUP LLC
EL PASO NATURAL GAS COMPANY, L.L.C.
EL PASO NORIC INVESTMENTS III, L.L.C.
EL PASO PIPELINE CORPORATION
EL PASO PIPELINE GP COMPANY, L.L.C.
EL PASO PIPELINE HOLDING COMPANY, L.L.C.
EL PASO PIPELINE LP HOLDINGS, L.L.C.
EL PASO PIPELINE PARTNERS, L.P.
By El Paso Pipeline GP Company, L.L.C., its general partner
EL PASO PIPELINE PARTNERS OPERATING COMPANY, L.L.C.
EL PASO RUBY HOLDING COMPANY, L.L.C.
EL PASO TENNESSEE PIPELINE CO., L.L.C.
ELBA EXPRESS COMPANY, L.L.C.
ELIZABETH RIVER TERMINALS LLC
EMORY B CRANE, LLC
EPBGP CONTRACTING SERVICES LLC
EP ENERGY HOLDING COMPANY
EP RUBY LLC
EPTP ISSUING CORPORATION
FERNANDINA MARINE CONSTRUCTION MANAGEMENT LLC
FRANK L. CRANE, LLC
GENERAL STEVEDORES GP, LLC
GENERAL STEVEDORES HOLDINGS LLC
GLOBAL AMERICAN TERMINALS LLC
HAMPSHIRE LLC
HARRAH MIDSTREAM LLC
HBM ENVIRONMENTAL, INC.
ICPT, L.L.C
J.R. NICHOLLS LLC
JAVELINA TUG LLC
JEANNIE BREWER LLC
JV TANKER CHARTERER LLC
KINDER MORGAN (DELAWARE), INC.
KINDER MORGAN 2-MILE LLC
KINDER MORGAN ADMINISTRATIVE SERVICES TAMPA LLC
KINDER MORGAN ALTAMONT LLC

KINDER MORGAN AMORY LLC
KINDER MORGAN ARROW TERMINALS HOLDINGS, INC.
KINDER MORGAN ARROW TERMINALS, L.P.
By Kinder Morgan River Terminals, LLC, its general partner
KINDER MORGAN BALTIMORE TRANSLOAD TERMINAL LLC
KINDER MORGAN BATTLEGROUND OIL LLC
KINDER MORGAN BORDER PIPELINE LLC
KINDER MORGAN BULK TERMINALS, INC.
KINDER MORGAN CARBON DIOXIDE TRANSPORTATION COMPANY
KINDER MORGAN CO2 COMPANY, L.P.
By Kinder Morgan G.P., Inc., its general partner
KINDER MORGAN COCHIN LLC
KINDER MORGAN COLUMBUS LLC
KINDER MORGAN COMMERCIAL SERVICES LLC
KINDER MORGAN CRUDE & CONDENSATE LLC
KINDER MORGAN CRUDE OIL PIPELINES LLC
KINDER MORGAN CRUDE TO RAIL LLC
KINDER MORGAN CUSHING LLC
KINDER MORGAN DALLAS FORT WORTH RAIL TERMINAL LLC
KINDER MORGAN ENDEAVOR LLC
KINDER MORGAN ENERGY PARTNERS, L.P.
By Kinder Morgan G.P., Inc., its general partner
KINDER MORGAN EP MIDSTREAM LLC
KINDER MORGAN FINANCE COMPANY LLC
KINDER MORGAN FLEETING LLC
KINDER MORGAN FREEDOM PIPELINE LLC
KINDER MORGAN KEYSTONE GAS STORAGE LLC
KINDER MORGAN KMAP LLC
KINDER MORGAN LAS VEGAS LLC
KINDER MORGAN LINDEN TRANSLOAD TERMINAL LLC
KINDER MORGAN LIQUIDS TERMINALS LLC
KINDER MORGAN LIQUIDS TERMINALS ST. GABRIEL LLC
KINDER MORGAN MARINE SERVICES LLC
KINDER MORGAN MATERIALS SERVICES, LLC
KINDER MORGAN MID ATLANTIC MARINE SERVICES LLC
KINDER MORGAN NATGAS O&M LLC
KINDER MORGAN NORTH TEXAS PIPELINE LLC
KINDER MORGAN OPERATING L.P. “A”
By Kinder Morgan G.P., Inc., its general partner
KINDER MORGAN OPERATING L.P. “B”
By Kinder Morgan G.P., Inc., its general partner
KINDER MORGAN OPERATING L.P. “C”
By Kinder Morgan G.P., Inc., its general partner
KINDER MORGAN OPERATING L.P. “D”
By Kinder Morgan G.P., Inc., its general partner
KINDER MORGAN PECOS LLC
KINDER MORGAN PECOS VALLEY LLC
KINDER MORGAN PETCOKE GP LLC

KINDER MORGAN PETCOKE, L.P.
By Kinder Morgan Petcoke GP LLC, its general partner
KINDER MORGAN PETCOKE LP LLC
KINDER MORGAN PETROLEUM TANKERS LLC
KINDER MORGAN PIPELINE LLC
KINDER MORGAN PIPELINES (USA) INC.
KINDER MORGAN PORT MANATEE TERMINAL LLC
KINDER MORGAN PORT SUTTON TERMINAL LLC
KINDER MORGAN PORT TERMINALS USA LLC
KINDER MORGAN PRODUCTION COMPANY LLC
KINDER MORGAN RAIL SERVICES LLC
KINDER MORGAN RESOURCES II LLC
KINDER MORGAN RESOURCES III LLC
KINDER MORGAN RESOURCES LLC
KINDER MORGAN RIVER TERMINALS LLC
KINDER MORGAN SERVICES LLC
KINDER MORGAN SEVEN OAKS LLC
KINDER MORGAN SOUTHEAST TERMINALS LLC
KINDER MORGAN TANK STORAGE TERMINALS LLC
KINDER MORGAN TEJAS PIPELINE LLC
KINDER MORGAN TERMINALS, INC.
KINDER MORGAN TEXAS PIPELINE LLC
KINDER MORGAN TEXAS TERMINALS, L.P.
By General Stevedores GP, LLC, its general partner
KINDER MORGAN TRANSMIX COMPANY, LLC
KINDER MORGAN TREATING LP
By KM Treating GP LLC, its general partner
KINDER MORGAN URBAN RENEWAL, L.L.C.
KINDER MORGAN UTICA LLC
KINDER MORGAN VIRGINIA LIQUIDS TERMINALS LLC
KINDER MORGAN WINK PIPELINE LLC
KINDERHAWK FIELD SERVICES LLC
KM CRANE LLC
KM DECATUR, INC.
KM EAGLE GATHERING LLC
KM GATHERING LLC
KM KASKASKIA DOCK LLC
KM LIQUIDS TERMINALS LLC
KM NORTH CAHOKIA LAND LLC
KM NORTH CAHOKIA SPECIAL PROJECT LLC
KM NORTH CAHOKIA TERMINAL PROJECT LLC
KM SHIP CHANNEL SERVICES LLC
KM TREATING GP LLC
KM TREATING PRODUCTION LLC
KMBT LLC
KMGP CONTRACTING SERVICES LLC
KMGP SERVICES COMPANY, INC.
KN TELECOMMUNICATIONS, INC.
KNIGHT POWER COMPANY LLC
LOMITA RAIL TERMINAL LLC
MILWAUKEE BULK TERMINALS LLC
MJR OPERATING LLC
MOJAVE PIPELINE COMPANY, L.L.C.
MOJAVE PIPELINE OPERATING COMPANY, L.L.C.
MR. BENNETT LLC

[Signature Page to Cross Guarantee]

MR. VANCE LLC
NASSAU TERMINALS LLC
NGPL HOLDCO INC.
NS 307 HOLDINGS INC.
PADDY RYAN CRANE, LLC
PALMETTO PRODUCTS PIPE LINE LLC
PI 2 PELICAN STATE LLC
PINNEY DOCK & TRANSPORT LLC
QUEEN CITY TERMINALS LLC
RAHWAY RIVER LAND LLC
RAZORBACK TUG LLC
RCI HOLDINGS, INC.
RIVER TERMINALS PROPERTIES GP LLC
RIVER TERMINAL PROPERTIES, L.P.
By River Terminals Properties GP LLC, its general partner
SCISSORTAIL ENERGY, LLC
SNG PIPELINE SERVICES COMPANY, L.L.C.
SOUTHERN GULF LNG COMPANY, L.L.C.
SOUTHERN LIQUEFACTION COMPANY LLC
SOUTHERN LNG COMPANY, L.L.C.
SOUTHERN NATURAL GAS COMPANY, L.L.C.
SOUTHERN NATURAL ISSUING CORPORATION
SOUTHTEX TREATERS LLC
SOUTHWEST FLORIDA PIPELINE LLC
SRT VESSELS LLC
STEVEDORE HOLDINGS, L.P.
By Kinder Morgan Petcoke GP LLC, its general partner
TAJON HOLDINGS, INC.
TEJAS GAS, LLC
TEJAS NATURAL GAS, LLC
TENNESSEE GAS PIPELINE COMPANY, L.L.C.
TENNESSEE GAS PIPELINE ISSUING CORPORATION
TEXAN TUG LLC
TGP PIPELINE SERVICES COMPANY, L.L.C.
TRANS MOUNTAIN PIPELINE (PUGET SOUND) LLC
TRANSCOLORADO GAS TRANSMISSION COMPANY LLC
TRANSLOAD SERVICES, LLC
UTICA MARCELLUS TEXAS PIPELINE LLC
WESTERN PLANT SERVICES, INC.
WYOMING INTERSTATE COMPANY, L.L.C.

By: /s/ Anthony B. Ashley
Anthony Ashley
Vice President

ANNEX A TO
THE CROSS GUARANTEE AGREEMENT

SUPPLEMENT NO. [ ] dated as of [ ] to the CROSS GUARANTEE AGREEMENT dated as of [ ] (the "Agreement"), among each of the Guarantors listed on the signature pages thereto and each of the other entities that becomes a party thereto pursuant to Section 19 of the Agreement (each such entity individually, a "Guarantor" and, collectively, the "Guarantors"). Unless otherwise defined herein, terms defined in the Agreement and used herein shall have the meanings given to them in the Agreement.

A. The Guarantors consist of Kinder Morgan, Inc., a Delaware corporation ("KMI"), and certain of its direct and indirect Subsidiaries, and the Guarantors have entered into the Agreement in order to provide guarantees of certain of the Guarantors' senior, unsecured Indebtedness outstanding from time to time.

B. Section 19 of the Agreement provides that additional Subsidiaries may become Guarantors under the Agreement by execution and delivery of an instrument in the form of this Supplement. Each undersigned Subsidiary (each a "New Guarantor") is executing this Supplement at the request of KMI or in accordance with the requirements of the Agreement to become a Guarantor under the Agreement.

Accordingly, each New Guarantor agrees as follows:

SECTION 1. In accordance with Section 19 of the Agreement, each New Guarantor by its signature below becomes a Guarantor under the Agreement with the same force and effect as if originally named therein as a Guarantor and each New Guarantor hereby (a) agrees to all the terms and provisions of the Agreement applicable to it as a Guarantor thereunder and (b) represents and warrants that the representations and warranties made by it as a Guarantor thereunder are true and correct on and as of the date hereof. Each reference to a Guarantor in the Agreement shall be deemed to include each New Guarantor. The Agreement is hereby incorporated herein by reference.

SECTION 2. Each New Guarantor represents and warrants to the Guaranteed Parties that this Supplement has been duly authorized, executed and delivered by it and constitutes its legal, valid and binding obligation, enforceable against it in accordance with its terms.

SECTION 3. This Supplement may be executed by one or more of the parties to this Supplement on any number of separate counterparts (including by facsimile or other electronic transmission), and all of said counterparts taken together shall be deemed to constitute one and the same instrument. A set of the copies of this Supplement signed by all the parties shall be lodged with KMI. This Supplement shall become effective as to each New Guarantor when KMI shall have received a counterpart of this Supplement that bears the signature of such New Guarantor.

SECTION 4. Except as expressly supplemented hereby, the Agreement shall remain in full force and effect.

SECTION 5. THIS SUPPLEMENT AND THE RIGHTS AND OBLIGATIONS OF THE PARTIES HEREUNDER SHALL BE GOVERNED BY, AND CONSTRUED AND INTERPRETED IN ACCORDANCE WITH, THE LAW OF THE STATE OF NEW YORK.

SECTION 6. Any provision of this Supplement that is prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof and in the Agreement, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction. The parties hereto shall endeavor in good-faith negotiations to replace the invalid, illegal or unenforceable provisions with valid provisions the economic effect of which comes as close as possible to that of the invalid, illegal or unenforceable provisions.

SECTION 7. All notices, requests and demands pursuant hereto shall be made in accordance with Section 12 of the Agreement. All communications and notices hereunder to each New Guarantor shall be given to it in care of KMI at the address set forth in Section 12 of the Agreement.

[Signature Pages Follow]

IN WITNESS WHEREOF, each New Guarantor has duly executed this Supplement to the Agreement as of the day and year first above written.

_____
as Guarantor

By:_____
Name:
Title:

ANNEX B TO
THE CROSS GUARANTEE AGREEMENT

FORM OF NOTATION OF GUARANTEE

Subject to the limitations set forth in the Cross Guarantee Agreement, dated as of [•] (the "Guarantee Agreement"), the undersigned Guarantors hereby certify that this [Indebtedness] constitutes a Guaranteed Obligation, entitled to all the rights as such set forth in the Guarantee Agreement. The Guarantors may be released from their guarantees upon the terms and subject to the conditions provided in the Guarantee Agreement. Capitalized terms used but not defined in this notation of guarantee have the meanings assigned such terms in the Guarantee Agreement, a copy of which will be provided to [a holder of this instrument] upon request to [Issuer].

Schedule I of the Guarantee Agreement is hereby deemed to be automatically updated to include this [Indebtedness] thereon as a Guaranteed Obligation.

[GUARANTORS],
as Guarantor

By: _____
Name:
Title:

SCHEDULE I

Guaranteed Obligations
Current as of: December 31, 2018

Issuer	Indebtedness	Maturity
Kinder Morgan, Inc.	3.05% notes	December 1, 2019
Kinder Morgan, Inc.	6.50% bonds	September 15, 2020
Kinder Morgan, Inc.	5.00% notes	February 15, 2021
Kinder Morgan, Inc.	1.500% notes	March 16, 2022
Kinder Morgan, Inc.	3.150% bonds	January 15, 2023
Kinder Morgan, Inc.	Floating rate bonds	January 15, 2023
Kinder Morgan, Inc.	5.625% notes	November 15, 2023
Kinder Morgan, Inc.	4.30% notes	June 1, 2025
Kinder Morgan, Inc.	6.70% bonds (Coastal)	February 15, 2027
Kinder Morgan, Inc.	2.250% notes	March 16, 2027
Kinder Morgan, Inc.	6.67% debentures	November 1, 2027
Kinder Morgan, Inc.	7.25% debentures	March 1, 2028
Kinder Morgan, Inc.	4.30% notes	March 1, 2028
Kinder Morgan, Inc.	6.95% bonds (Coastal)	June 1, 2028
Kinder Morgan, Inc.	8.05% bonds	October 15, 2030
Kinder Morgan, Inc.	7.80% bonds	August 1, 2031
Kinder Morgan, Inc.	7.75% bonds	January 15, 2032
Kinder Morgan, Inc.	5.30% notes	December 1, 2034
Kinder Morgan, Inc.	7.75% bonds (Coastal)	October 15, 2035
Kinder Morgan, Inc.	6.40% notes	January 5, 2036
Kinder Morgan, Inc.	7.42% bonds (Coastal)	February 15, 2037
Kinder Morgan, Inc.	5.55% notes	June 1, 2045
Kinder Morgan, Inc.	5.050% notes	February 15, 2046
Kinder Morgan, Inc.	5.20% notes	March 1, 2048
Kinder Morgan, Inc.	7.45% debentures	March 1, 2098
Kinder Morgan, Inc.	$100 Million Letter of Credit Facility	January 31, 2019
Kinder Morgan Energy Partners, L.P.	9.00% bonds	February 1, 2019
Kinder Morgan Energy Partners, L.P.	2.65% bonds	February 1, 2019
Kinder Morgan Energy Partners, L.P.	6.85% bonds	February 15, 2020
Kinder Morgan Energy Partners, L.P.	5.30% bonds	September 15, 2020
Kinder Morgan Energy Partners, L.P.	5.80% bonds	March 1, 2021
Kinder Morgan Energy Partners, L.P.	3.50% bonds	March 1, 2021
Kinder Morgan Energy Partners, L.P.	4.15% bonds	March 1, 2022
Kinder Morgan Energy Partners, L.P.	3.95% bonds	September 1, 2022
Kinder Morgan Energy Partners, L.P.	3.45% bonds	February 15, 2023
Kinder Morgan Energy Partners, L.P.	3.50% bonds	September 1, 2023
Kinder Morgan Energy Partners, L.P.	4.15% bonds	February 1, 2024
Kinder Morgan Energy Partners, L.P.	4.25% bonds	September 1, 2024
Kinder Morgan Energy Partners, L.P.	7.40% bonds	March 15, 2031
Kinder Morgan Energy Partners, L.P.	7.75% bonds	March 15, 2032
Kinder Morgan Energy Partners, L.P.	7.30% bonds	August 15, 2033
Kinder Morgan Energy Partners, L.P.	5.80% bonds	March 15, 2035
Kinder Morgan Energy Partners, L.P.	6.50% bonds	February 1, 2037
Kinder Morgan Energy Partners, L.P.	6.95% bonds	January 15, 2038
Kinder Morgan Energy Partners, L.P.	6.50% bonds	September 1, 2039

Schedule I
(Guaranteed Obligations)
Current as of: December 31, 2018

Issuer	Indebtedness	Maturity
Kinder Morgan Energy Partners, L.P.	6.55% bonds	September 15, 2040
Kinder Morgan Energy Partners, L.P.	6.375% bonds	March 1, 2041
Kinder Morgan Energy Partners, L.P.	5.625% bonds	September 1, 2041
Kinder Morgan Energy Partners, L.P.	5.00% bonds	August 15, 2042
Kinder Morgan Energy Partners, L.P.	5.00% bonds	March 1, 2043
Kinder Morgan Energy Partners, L.P.	5.50% bonds	March 1, 2044
Kinder Morgan Energy Partners, L.P.	5.40% bonds	September 1, 2044
Kinder Morgan Energy Partners, L.P.[1]	6.50% bonds	April 1, 2020
Kinder Morgan Energy Partners, L.P.[1]	5.00% bonds	October 1, 2021
Kinder Morgan Energy Partners, L.P.[1]	4.30% bonds	May 1, 2024
Kinder Morgan Energy Partners, L.P.[1]	7.50% bonds	November 15, 2040
Kinder Morgan Energy Partners, L.P.[1]	4.70% bonds	November 1, 2042
Tennessee Gas Pipeline Company, L.L.C.	7.00% bonds	March 15, 2027
Tennessee Gas Pipeline Company, L.L.C.	7.00% bonds	October 15, 2028
Tennessee Gas Pipeline Company, L.L.C.	8.375% bonds	June 15, 2032
Tennessee Gas Pipeline Company, L.L.C.	7.625% bonds	April 1, 2037
El Paso Natural Gas Company, L.L.C.	8.625% bonds	January 15, 2022
El Paso Natural Gas Company, L.L.C.	7.50% bonds	November 15, 2026
El Paso Natural Gas Company, L.L.C.	8.375% bonds	June 15, 2032
Colorado Interstate Gas Company, L.L.C.	4.15% notes	August 15, 2026
Colorado Interstate Gas Company, L.L.C.	6.85% bonds	June 15, 2037
El Paso Tennessee Pipeline Co. L.L.C.	7.25% bonds	December 15, 2025
Other	Cora industrial revenue bonds	April 1, 2024

[1] The original issuer, El Paso Pipeline Partners, L.P. merged with and into Kinder Morgan Energy Partners, L.P. effective January 1, 2015.

Schedule I
(Guaranteed Obligations)
Current as of: December 31, 2018

Hedging Agreements[1]

Issuer	Guaranteed Party	Date
Kinder Morgan, Inc.	Bank of America, N.A.	January 4, 2018
Kinder Morgan, Inc.	BNP Paribas	September 15, 2016
Kinder Morgan, Inc.	Citibank, N.A.	March 16, 2017
Kinder Morgan, Inc.	J. Aron & Company	December 23, 2011
Kinder Morgan, Inc.	SunTrust Bank	August 29, 2001
Kinder Morgan, Inc.	Barclays Bank PLC	November 26, 2014
Kinder Morgan, Inc.	Bank of Tokyo-Mitsubishi, Ltd., New York Branch	November 26, 2014
Kinder Morgan, Inc.	Canadian Imperial Bank of Commerce	November 26, 2014
Kinder Morgan, Inc.	Compass Bank	March 24, 2015
Kinder Morgan, Inc.	Credit Agricole Corporate and Investment Bank	November 26, 2014
Kinder Morgan, Inc.	Credit Suisse International	November 26, 2014
Kinder Morgan, Inc.	Deutsche Bank AG	November 26, 2014
Kinder Morgan, Inc.	ING Capital Markets LLC	November 26, 2014
Kinder Morgan, Inc.	JPMorgan Chase Bank, N.A.	February 19, 2015
Kinder Morgan, Inc.	Mizuho Capital Markets Corporation	November 26, 2014
Kinder Morgan, Inc.	Morgan Stanley Capital Services LLC	July 9, 2018
Kinder Morgan, Inc.	Royal Bank of Canada	November 26, 2014
Kinder Morgan, Inc.	SMBC Capital Markets, Inc.	April 26, 2017
Kinder Morgan, Inc.	The Bank of Nova Scotia	November 26, 2014
Kinder Morgan, Inc.	The Royal Bank of Scotland PLC	November 26, 2014
Kinder Morgan, Inc.	Societe Generale	November 26, 2014
Kinder Morgan, Inc.	The Toronto-Dominion Bank	October 2, 2017
Kinder Morgan, Inc.	UBS AG	November 26, 2014
Kinder Morgan, Inc.	Wells Fargo Bank, N.A.	November 26, 2014
Kinder Morgan Energy Partners, L.P.	Bank of America, N.A.	April 14, 1999
Kinder Morgan Energy Partners, L.P.	Bank of Tokyo-Mitsubishi, Ltd., New York Branch	November 23, 2004
Kinder Morgan Energy Partners, L.P.	Barclays Bank PLC	November 18, 2003
Kinder Morgan Energy Partners, L.P.	Canadian Imperial Bank of Commerce	August 4, 2011
Kinder Morgan Energy Partners, L.P.	Citibank, N.A.	March 14, 2002
Kinder Morgan Energy Partners, L.P.	Credit Agricole Corporate and Investment Bank	June 20, 2014
Kinder Morgan Energy Partners, L.P.	Credit Suisse International	May 14, 2010
Kinder Morgan Energy Partners, L.P.	Deutsche Bank AG	April 2, 2009
Kinder Morgan Energy Partners, L.P.	ING Capital Markets LLC	September 21, 2011

[1] Guaranteed Obligations with respect to Hedging Agreements include International Swaps and Derivatives Association Master Agreements ("ISDAs") and all transactions entered into pursuant to any ISDA listed on this Schedule I.

Schedule I
(Guaranteed Obligations)
Current as of: December 31, 2018

Hedging Agreements[1]

Issuer	Guaranteed Party	Date
Kinder Morgan Energy Partners, L.P.	J. Aron & Company	November 11, 2004
Kinder Morgan Energy Partners, L.P.	JPMorgan Chase Bank	August 29, 2001
Kinder Morgan Energy Partners, L.P.	Mizuho Capital Markets Corporation	July 11, 2014
Kinder Morgan Energy Partners, L.P.	Morgan Stanley Capital Services Inc.	March 10, 2010
Kinder Morgan Energy Partners, L.P.	Royal Bank of Canada	March 12, 2009
Kinder Morgan Energy Partners, L.P.	The Royal Bank of Scotland PLC	March 20, 2009
Kinder Morgan Energy Partners, L.P.	The Bank of Nova Scotia	August 14, 2003
Kinder Morgan Energy Partners, L.P.	Societe Generale	July 18, 2014
Kinder Morgan Energy Partners, L.P.	SunTrust Bank	March 14, 2002
Kinder Morgan Energy Partners, L.P.	UBS AG	February 23, 2011
Kinder Morgan Energy Partners, L.P.	Wells Fargo Bank, N.A.	July 31, 2007
Kinder Morgan Texas Pipeline LLC	Barclays Bank PLC	January 10, 2003
Kinder Morgan Texas Pipeline LLC	BNP Paribas	March 2, 2005
Kinder Morgan Texas Pipeline LLC	Canadian Imperial Bank of Commerce	December 18, 2006
Kinder Morgan Texas Pipeline LLC	Citibank, N.A.	February 22, 2005
Kinder Morgan Texas Pipeline LLC	Credit Suisse International	August 31, 2012
Kinder Morgan Texas Pipeline LLC	Deutsche Bank AG	June 13, 2007
Kinder Morgan Texas Pipeline LLC	ING Capital Markets LLC	April 17, 2014
Kinder Morgan Production LLC	J. Aron & Company	June 12, 2006
Kinder Morgan Texas Pipeline LLC	J. Aron & Company	June 8, 2000
Kinder Morgan Texas Pipeline LLC	JPMorgan Chase Bank, N.A.	September 7, 2006
Kinder Morgan Texas Pipeline LLC	Macquarie Bank Limited	September 20, 2010
Kinder Morgan Texas Pipeline LLC	Merrill Lynch Commodities, Inc.	October 24, 2001
Kinder Morgan Texas Pipeline LLC	Morgan Stanley Capital Group Inc.	January 15, 2004
Kinder Morgan Texas Pipeline LLC	Natixis	June 13, 2011
Kinder Morgan Texas Pipeline LLC	Phillips 66 Company	March 30, 2015
Kinder Morgan Texas Pipeline LLC	PNC Bank, National Association	July 11, 2018
Kinder Morgan Texas Pipeline LLC	Royal Bank of Canada	October 18, 2018
Kinder Morgan Texas Pipeline LLC	The Bank of Nova Scotia	May 8, 2014
Kinder Morgan Texas Pipeline LLC	Societe Generale	January 14, 2003
Kinder Morgan Texas Pipeline LLC	Wells Fargo Bank, N.A.	June 1, 2013
Copano Risk Management, LLC	Citibank, N.A.	July 21, 2008
Copano Risk Management, LLC	J. Aron & Company	December 12, 2005
Copano Risk Management, LLC	Morgan Stanley Capital Group Inc.	May 4, 2007
Copano Risk Management, LLC	Wells Fargo Bank, N.A.	October 19, 2007

[1] Guaranteed Obligations with respect to Hedging Agreements include International Swaps and Derivatives Association Master Agreements ("ISDAs") and all transactions entered into pursuant to any ISDA listed on this Schedule I.

SCHEDULE II

Guarantors
Current as of: December 31, 2018

Agnes B Crane, LLC
American Petroleum Tankers II LLC
American Petroleum Tankers III LLC
American Petroleum Tankers IV LLC
American Petroleum Tankers LLC
American Petroleum Tankers Parent LLC
American Petroleum Tankers V LLC
American Petroleum Tankers VI LLC
American Petroleum Tankers VII LLC
American Petroleum Tankers VIII LLC
American Petroleum Tankers IX LLC
American Petroleum Tankers X LLC
American Petroleum Tankers XI LLC
APT Florida LLC
APT Intermediate Holdco LLC
APT New Intermediate Holdco LLC
APT Pennsylvania LLC
APT Sunshine State LLC
Betty Lou LLC
Camino Real Gathering Company, L.L.C.
Cantera Gas Company LLC
CDE Pipeline LLC
Central Florida Pipeline LLC
Cheyenne Plains Gas Pipeline Company, L.L.C.
CIG Gas Storage Company LLC
CIG Pipeline Services Company, L.L.C.
Colorado Interstate Gas Company, L.L.C.
Colorado Interstate Issuing Corporation
Copano Double Eagle LLC
Copano Energy Finance Corporation
Copano Energy Services/Upper Gulf Coast LLC
Copano Energy, L.L.C.
Copano Field Services GP, L.L.C.
Copano Field Services/North Texas, L.L.C.
Copano Field Services/South Texas LLC
Copano Field Services/Upper Gulf Coast LLC
Copano Liberty, LLC
Copano Liquids Marketing LLC
Copano NGL Services (Markham), L.L.C.
Copano NGL Services LLC
Copano Pipelines Group, L.L.C.
Copano Pipelines/North Texas, L.L.C.
Copano Pipelines/Rocky Mountains, LLC
Copano Pipelines/South Texas LLC
Copano Pipelines/Upper Gulf Coast LLC
Copano Processing LLC
Copano Risk Management LLC
Copano/Webb-Duval Pipeline LLC
CPNO Services LLC
Dakota Bulk Terminal LLC
Delta Terminal Services LLC
Eagle Ford Gathering LLC
El Paso Cheyenne Holdings, L.L.C.
El Paso Citrus Holdings, Inc.
El Paso CNG Company, L.L.C.
El Paso Energy Service Company, L.L.C.
El Paso LLC
El Paso Midstream Group LLC
El Paso Natural Gas Company, L.L.C.
El Paso Noric Investments III, L.L.C.
El Paso Ruby Holding Company, L.L.C.
El Paso Tennessee Pipeline Co., L.L.C.
Elba Express Company, L.L.C.
Elizabeth River Terminals LLC
Emory B Crane, LLC
EP Ruby LLC
EPBGP Contracting Services LLC
EPTP Issuing Corporation
Frank L. Crane, LLC
General Stevedores GP, LLC
General Stevedores Holdings LLC
Glenpool West Gathering LLC
Harrah Midstream LLC
HBM Environmental LLC
Hiland Crude, LLC
Hiland Partners Finance Corp.
Hiland Partners Holdings LLC
HPH Oklahoma Gathering LLC
ICPT, L.L.C
Independent Trading & Transportation Company I, L.L.C.
JV Tanker Charterer LLC
Kinder Morgan 2-Mile LLC
Kinder Morgan Administrative Services Tampa LLC
Kinder Morgan Altamont LLC
Kinder Morgan Baltimore Transload Terminal LLC
Kinder Morgan Battleground Oil LLC
Kinder Morgan Border Pipeline LLC
Kinder Morgan Bulk Terminals LLC
Kinder Morgan Carbon Dioxide Transportation Company
Kinder Morgan CO2 Company, L.P.
Kinder Morgan Cochin LLC

Schedule II
(Guarantors)
Current as of: December 31, 2018

Kinder Morgan Commercial Services LLC
Kinder Morgan Contracting Services LLC
Kinder Morgan Crude & Condensate LLC
Kinder Morgan Crude Marketing LLC
Kinder Morgan Crude Oil Pipelines LLC
Kinder Morgan Crude to Rail LLC
Kinder Morgan Cushing LLC
Kinder Morgan Dallas Fort Worth Rail Terminal LLC
Kinder Morgan Deeprock North Holdco LLC
Kinder Morgan Endeavor LLC
Kinder Morgan Energy Partners, L.P.
Kinder Morgan EP Midstream LLC
Kinder Morgan Finance Company LLC
Kinder Morgan Freedom Pipeline LLC
Kinder Morgan Galena Park West LLC
Kinder Morgan IMT Holdco LLC
Kinder Morgan, Inc.
Kinder Morgan Keystone Gas Storage LLC
Kinder Morgan KMAP LLC
Kinder Morgan Las Vegas LLC
Kinder Morgan Linden Transload Terminal LLC
Kinder Morgan Liquids Terminals LLC
Kinder Morgan Liquids Terminals St. Gabriel LLC
Kinder Morgan Louisiana Pipeline Holding LLC
Kinder Morgan Louisiana Pipeline LLC
Kinder Morgan Marine Services LLC
Kinder Morgan Materials Services, LLC
Kinder Morgan Mid Atlantic Marine Services LLC
Kinder Morgan NatGas O&M LLC
Kinder Morgan NGPL Holdings LLC
Kinder Morgan North Texas Pipeline LLC
Kinder Morgan Operating L.P. “A”
Kinder Morgan Operating L.P. “B”
Kinder Morgan Operating L.P. “C”
Kinder Morgan Operating L.P. “D”
Kinder Morgan Pecos LLC
Kinder Morgan Pecos Valley LLC
Kinder Morgan Petcoke GP LLC
Kinder Morgan Petcoke LP LLC
Kinder Morgan Petcoke, L.P.
Kinder Morgan Petroleum Tankers LLC
Kinder Morgan Pipeline LLC
Kinder Morgan Port Manatee Terminal LLC
Kinder Morgan Port Sutton Terminal LLC
Kinder Morgan Port Terminals USA LLC
Kinder Morgan Production Company LLC
Kinder Morgan Products Terminals LLC
Kinder Morgan Rail Services LLC
Kinder Morgan Resources II LLC
Kinder Morgan Resources III LLC
Kinder Morgan Resources LLC
Kinder Morgan Seven Oaks LLC
Kinder Morgan SNG Operator LLC
Kinder Morgan Southeast Terminals LLC
Kinder Morgan Scurry Connector LLC
Kinder Morgan Tank Storage Terminals LLC
Kinder Morgan Tejas Pipeline LLC
Kinder Morgan Terminals, Inc.
Kinder Morgan Terminals Wilmington LLC
Kinder Morgan Texas Pipeline LLC
Kinder Morgan Texas Terminals, L.P.
Kinder Morgan Transmix Company, LLC
Kinder Morgan Treating LP
Kinder Morgan Urban Renewal, L.L.C.
Kinder Morgan Utica LLC
Kinder Morgan Vehicle Services LLC
Kinder Morgan Virginia Liquids Terminals LLC
Kinder Morgan Wink Pipeline LLC
KinderHawk Field Services LLC
KM Crane LLC
KM Decatur LLC
KM Eagle Gathering LLC
KM Gathering LLC
KM Kaskaskia Dock LLC
KM Liquids Terminals LLC
KM North Cahokia Land LLC
KM North Cahokia Special Project LLC
KM North Cahokia Terminal Project LLC
KM Ship Channel Services LLC
KM Treating GP LLC
KM Treating Production LLC
KMBT Legacy Holdings LLC
KMBT LLC
KMGP Services Company, Inc.
KN Telecommunications, Inc.
Knight Power Company LLC
Lomita Rail Terminal LLC
Milwaukee Bulk Terminals LLC
MJR Operating LLC
Mojave Pipeline Company, L.L.C.
Mojave Pipeline Operating Company, L.L.C.
Paddy Ryan Crane, LLC
Palmetto Products Pipe Line LLC
PI 2 Pelican State LLC
Pinney Dock & Transport LLC
Queen City Terminals LLC
Rahway River Land LLC
River Terminals Properties GP LLC
River Terminal Properties, L.P.

Schedule II
(Guarantors)
Current as of: December 31, 2018

ScissorTail Energy, LLC
SNG Pipeline Services Company, L.L.C.
Southern Dome, LLC
Southern Gulf LNG Company, L.L.C.
Southern Liquefaction Company LLC
Southern LNG Company, L.L.C.
Southern Oklahoma Gathering LLC
SouthTex Treaters LLC
Southwest Florida Pipeline LLC
SRT Vessels LLC
Stevedore Holdings, L.P.
Tejas Gas, LLC
Tejas Natural Gas, LLC
Tennessee Gas Pipeline Company, L.L.C.
Tennessee Gas Pipeline Issuing Corporation
Texan Tug LLC
TGP Pipeline Services Company, L.L.C.
TransColorado Gas Transmission Company LLC
Transload Services, LLC
Utica Marcellus Texas Pipeline LLC
Western Plant Services LLC
Wyoming Interstate Company, L.L.C.

SCHEDULE III

Excluded Subsidiaries

ANR Real Estate Corporation
Coastal Eagle Point Oil Company
Coastal Oil New England, Inc.
Colton Processing Facility
Coscol Petroleum Corporation
El Paso CGP Company, L.L.C.
El Paso Energy Capital Trust I
El Paso Energy E.S.T. Company
El Paso Energy International Company
El Paso Marketing Company, L.L.C.
El Paso Merchant Energy North America Company, L.L.C.
El Paso Merchant Energy-Petroleum Company
El Paso Reata Energy Company, L.L.C.
El Paso Remediation Company
El Paso Services Holding Company
EPEC Corporation
EPEC Oil Company Liquidating Trust
EPEC Polymers, Inc.
EPED Holding Company
KN Capital Trust I
KN Capital Trust III
Mesquite Investors, L.L.C.

Note: The Excluded Subsidiaries listed on this Schedule III may also be Excluded Subsidiaries pursuant to other exceptions set forth in the definition of “Excluded Subsidiary”.

Kinder Morgan, Inc.

Subsidiaries of the Registrant as of December 31, 2018

Entity Name	Place of Incorporation
2043155 Alberta Ltd.	Canada (Alberta)
Agnes B Crane, LLC	Louisiana
American Petroleum Tankers II LLC	Delaware
American Petroleum Tankers III LLC	Delaware
American Petroleum Tankers IV LLC	Delaware
American Petroleum Tankers IX LLC	Delaware
American Petroleum Tankers LLC	Delaware
American Petroleum Tankers Parent LLC	Delaware
American Petroleum Tankers V LLC	Delaware
American Petroleum Tankers VI LLC	Delaware
American Petroleum Tankers VII LLC	Delaware
American Petroleum Tankers VIII LLC	Delaware
American Petroleum Tankers X LLC	Delaware
American Petroleum Tankers XI LLC	Delaware
ANR Advance Holdings, Inc.	Delaware
ANR Real Estate Corporation	Delaware
APT Florida LLC	Delaware
APT Intermediate Holdco LLC	Delaware
APT New Intermediate Holdco LLC	Delaware
APT Pennsylvania LLC	Delaware
APT Sunshine State LLC	Delaware
Ascension Holding Company, L.L.C.	Delaware
Banquete Hub LLC	Delaware
Baseline Terminal East Limited Partnership	Canada (Manitoba)
Battleground Oil Specialty Terminal Company LLC	Delaware
Bear Creek Storage Company, L.L.C.	Louisiana
Berkshire Feedline Acquisition Limited Partnership	Massachusetts
Betty Lou LLC	Delaware
BHP Billiton Petroleum (Eagle Ford Gathering) LLC	Delaware
Bighorn Gas Gathering, L.L.C.	Delaware
Calnev Pipe Line LLC	Delaware
Camino Real Gathering Company, L.L.C.	Delaware
Cantera Gas Company LLC	Delaware
CDE Pipeline LLC	Delaware
Cedar Cove Midstream LLC	Delaware
Central Florida Pipeline LLC	Delaware
Cheyenne Plains Gas Pipeline Company, L.L.C.	Delaware
CIG Gas Storage Company LLC	Delaware
CIG Pipeline Services Company, L.L.C.	Delaware
Citrus Energy Services, Inc.	Delaware

Kinder Morgan, Inc.

Subsidiaries of the Registrant as of December 31, 2018

Entity Name	Place of Incorporation
Citrus LLC	Delaware
Cliffside Helium, LLC	Delaware
Cliffside Refiners, L.P.	Delaware
Coastal Eagle Point Oil Company	Delaware
Coastal Energy Resources Ltd.	Mauritius
Coastal Oil New England, Inc.	Massachusetts
Coastal Wartsila Petroleum Private Limited	India
Colorado Interstate Gas Company, L.L.C.	Delaware
Colorado Interstate Issuing Corporation	Delaware
Colton Processing Facility	[California]
Copano Double Eagle LLC	Delaware
Copano Energy Finance Corporation	Delaware
Copano Energy L.L.C.	Delaware
Copano Energy Services/Upper Gulf Coast LLC	Texas
Copano Field Services GP, L.L.C.	Delaware
Copano Field Services/North Texas, L.L.C.	Delaware
Copano Field Services/South Texas LLC	Texas
Copano Field Services/Upper Gulf Coast LLC	Texas
Copano Liberty, LLC	Delaware
Copano Liquids Marketing LLC	Delaware
Copano NGL Services (Markham), L.L.C.	Delaware
Copano NGL Services LLC	Texas
Copano Pipelines Group, L.L.C.	Delaware
Copano Pipelines/North Texas, L.L.C.	Delaware
Copano Pipelines/Rocky Mountains, LLC	Delaware
Copano Pipelines/South Texas LLC	Texas
Copano Pipelines/Upper Gulf Coast LLC	Texas
Copano Processing LLC	Texas
Copano Risk Management LLC	Texas
Copano/Webb-Duval Pipeline LLC	Delaware
Cortez Capital Corporation	Delaware
Cortez Expansion Capital Corporation	Delaware
Cortez Pipeline Company	Texas
Coscol Petroleum Corporation	Delaware
Coyote Gas Treating Limited Liability Company	Colorado
CPNO Services LLC	Texas
Cross Country Development L.L.C.	Delaware
Cypress Interstate Pipeline LLC	Delaware
Dakota Bulk Terminal LLC	Delaware
Deeprock Development, LLC	Delaware

Kinder Morgan, Inc.

Subsidiaries of the Registrant as of December 31, 2018

Entity Name	Place of Incorporation
Delta Terminal Services LLC	Delaware
Double Eagle Pipeline LLC	Delaware
Eagle Ford Gathering LLC	Delaware
El Paso Amazonas Energia Ltda.	Brazil
El Paso CGP Company, L.L.C.	Delaware
El Paso Cheyenne Holdings, L.L.C.	Delaware
El Paso Citrus Holdings, Inc.	Delaware
El Paso CNG Company, L.L.C.	Delaware
El Paso Energia do Brasil Ltda.	Brazil
El Paso Energy Argentina Service Company	Delaware
El Paso Energy Capital Trust I	Delaware
El Paso Energy E.S.T. Company	Delaware
El Paso Energy International Company	Delaware
El Paso Energy Marketing de Mexico, S. de R.L. de C.V.	Mexico
El Paso Energy Service Company, L.L.C.	Delaware
El Paso LLC	Delaware
El Paso Marketing Company, L.L.C.	Delaware
El Paso Merchant Energy North America Company, L.L.C.	Delaware
El Paso Merchant Energy-Petroleum Company	Delaware
El Paso Mexico Holding B.V.	Netherlands
El Paso Midstream Group LLC	Delaware
El Paso Natural Gas Company, L.L.C.	Delaware
El Paso Noric Investments III, L.L.C.	Delaware
El Paso Reata Energy Company, L.L.C.	Delaware
El Paso Remediation Company	Delaware
El Paso Rio Negro Energia Ltda.	Brazil
El Paso Ruby Holding Company, L.L.C.	Delaware
El Paso Services Holding Company	Delaware
El Paso Tennessee Pipeline Co., L.L.C.	Delaware
Elba Express Company, L.L.C.	Delaware
Elba Liquefaction Company, L.L.C.	Delaware
Elizabeth River Terminals LLC	Delaware
Emory B Crane, LLC	Louisiana
EP Ruby LLC	Delaware
EPBGP Contracting Services LLC	Delaware
EPC Building LLC	Delaware
EPC Property Holdings, Inc.	Delaware
EPEC Corporation	Delaware
EPEC Oil Company Liquidating Trust	Delaware Law
EPEC Polymers, Inc.	Delaware

Kinder Morgan, Inc.

Subsidiaries of the Registrant as of December 31, 2018

Entity Name	Place of Incorporation
EPEC Realty, Inc.	Delaware
EPED B Company	Cayman Islands
EPED Holding Company	Delaware
EPTP Issuing Corporation	Delaware
Fayetteville Express Pipeline LLC	Delaware
Fife Power	Scotland
Florida Gas Transmission Company, LLC	Delaware
Fort Union Gas Gathering, L.L.C.	Delaware
Frank L Crane, LLC	Louisiana
GEBF, L.L.C.	Louisiana
General Stevedores GP, LLC	Texas
General Stevedores Holdings LLC	Delaware
Glenpool West Gathering LLC	Delaware
Greens Port CBR, LLC	Delaware
Guilford County Terminal Company, LLC	North Carolina
Gulf Coast Express Pipeline LLC	Delaware
Gulf LNG Energy (Port), LLC	Delaware
Gulf LNG Energy, LLC	Delaware
Gulf LNG Holdings Group, LLC	Delaware
Gulf LNG Liquefaction Company, LLC	Delaware
Gulf LNG Pipeline, LLC	Delaware
Harrah Midstream LLC	Delaware
HBM Environmental LLC	Delaware
Hiland Crude, LLC	Oklahoma
Hiland Partners Finance Corp.	Delaware
Hiland Partners Holdings LLC	Delaware
Horizon Pipeline Company, L.L.C.	Delaware
HPH Oklahoma Gathering LLC	Delaware
I.M.T. Land Corp.	Louisiana
ICPT, L.L.C.	Louisiana
Independent Trading & Transportation Company I, L.L.C.	Oklahoma
Interenergy Company	Cayman Islands
International Marine Terminals Partnership	Louisiana
Johnston County Terminal, LLC	Delaware
JV Tanker Charterer LLC	Delaware
Kellogg Terminal, LLC	Delaware
Kinder Morgan 2-Mile LLC	Delaware
Kinder Morgan Administrative Services Tampa LLC	Delaware
Kinder Morgan Altamont LLC	Delaware
Kinder Morgan Baltimore Transload Terminal LLC	Delaware

Kinder Morgan, Inc.

Subsidiaries of the Registrant as of December 31, 2018

Entity Name	Place of Incorporation
Kinder Morgan Battleground Oil LLC	Delaware
Kinder Morgan Border Pipeline LLC	Delaware
Kinder Morgan Bulk Terminals LLC	Louisiana
Kinder Morgan Canada (Jet Fuel) Inc.	Canada (British Columbia)
Kinder Morgan Canada Company	Canada (Nova Scotia)
Kinder Morgan Canada GP Inc.	Canada (Alberta)
Kinder Morgan Canada Limited	Canada (Alberta)
Kinder Morgan Canada Limited Partnership	Canada (Alberta)
Kinder Morgan Canada Services Inc.	Canada (Alberta)
Kinder Morgan Carbon Dioxide Transportation Company	Delaware
Kinder Morgan CO2 Company, L.P.	Texas
Kinder Morgan Cochin LLC	Delaware
Kinder Morgan Cochin ULC	Canada (Nova Scotia)
Kinder Morgan Commercial Services LLC	Delaware
Kinder Morgan Contracting Services LLC	Delaware
Kinder Morgan Crude & Condensate LLC	Delaware
Kinder Morgan Crude Marketing LLC	Delaware
Kinder Morgan Crude Oil Pipelines LLC	Delaware
Kinder Morgan Crude to Rail LLC	Delaware
Kinder Morgan Cushing LLC	Delaware
Kinder Morgan Dallas Fort Worth Rail Terminal LLC	Delaware
Kinder Morgan Deeprock North Holdco LLC	Delaware
Kinder Morgan Endeavor LLC	Delaware
Kinder Morgan Energy Partners, L.P.	Delaware
Kinder Morgan EP Midstream LLC	Delaware
Kinder Morgan Finance Company LLC	Delaware
Kinder Morgan Foundation	Colorado
Kinder Morgan Freedom Pipeline LLC	Delaware
Kinder Morgan G.P., Inc.	Delaware
Kinder Morgan Galena Park West LLC	Delaware
Kinder Morgan Gas Natural de Mexico, S. de R.L. de C.V.	Mexico
Kinder Morgan Heartland ULC	Canada (Alberta)
Kinder Morgan Illinois Pipeline LLC	Delaware
Kinder Morgan IMT Holdco LLC	Delaware
Kinder Morgan Keystone Gas Storage LLC	Delaware
Kinder Morgan KMAP LLC	Delaware
Kinder Morgan Las Vegas LLC	Delaware
Kinder Morgan Linden Transload Terminal LLC	Delaware
Kinder Morgan Liquids Terminals LLC	Delaware
Kinder Morgan Liquids Terminals St. Gabriel LLC	Delaware

Kinder Morgan, Inc.

Subsidiaries of the Registrant as of December 31, 2018

Entity Name	Place of Incorporation
Kinder Morgan Louisiana Pipeline Holding LLC	Delaware
Kinder Morgan Louisiana Pipeline LLC	Delaware
Kinder Morgan Marine Services LLC	Delaware
Kinder Morgan Materials Services, LLC	Delaware
Kinder Morgan Mexico LLC	Delaware
Kinder Morgan Mid Atlantic Marine Services LLC	Delaware
Kinder Morgan NatGas O & M LLC	Delaware
Kinder Morgan NGPL Holdings LLC	Delaware
Kinder Morgan North Texas Pipeline LLC	Delaware
Kinder Morgan Operating L.P. "A"	Delaware
Kinder Morgan Operating L.P. "B"	Delaware
Kinder Morgan Operating L.P. "C"	Delaware
Kinder Morgan Operating L.P. "D"	Delaware
Kinder Morgan Pecos LLC	Delaware
Kinder Morgan Pecos Valley LLC	Delaware
Kinder Morgan Petcoke GP LLC	Delaware
Kinder Morgan Petcoke LP LLC	Delaware
Kinder Morgan Petcoke, L.P.	Delaware
Kinder Morgan Petroleum Tankers LLC	Delaware
Kinder Morgan Pipeline LLC	Delaware
Kinder Morgan Pipeline Servicios de Mexico S. de R.L. de C.V.	Mexico
Kinder Morgan Port Manatee Terminal LLC	Delaware
Kinder Morgan Port Sutton Terminal LLC	Delaware
Kinder Morgan Port Terminals USA LLC	Delaware
Kinder Morgan Production Company LLC	Delaware
Kinder Morgan Products Terminals LLC	Delaware
Kinder Morgan Rail Services LLC	Delaware
Kinder Morgan Resources II LLC	Delaware
Kinder Morgan Resources III LLC	Delaware
Kinder Morgan Resources LLC	Delaware
Kinder Morgan Scurry Connector LLC	Delaware
Kinder Morgan Services International LLC	Delaware
Kinder Morgan Seven Oaks LLC	Delaware
Kinder Morgan SNG Operator LLC	Delaware
Kinder Morgan Southeast Terminals LLC	Delaware
Kinder Morgan Tank Storage Terminals LLC	Delaware
Kinder Morgan Tejas Pipeline GP LLC	Delaware
Kinder Morgan Tejas Pipeline LLC	Delaware
Kinder Morgan Terminals Wilmington LLC	Delaware
Kinder Morgan Terminals, Inc.	Delaware

Kinder Morgan, Inc.

Subsidiaries of the Registrant as of December 31, 2018

Entity Name	Place of Incorporation
Kinder Morgan Texas Pipeline LLC	Delaware
Kinder Morgan Texas Terminals, L.P.	Delaware
Kinder Morgan Transmix Company, LLC	Delaware
Kinder Morgan Treating LP	Delaware
Kinder Morgan Urban Renewal II, LLC	New Jersey
Kinder Morgan Urban Renewal, L.L.C.	New Jersey
Kinder Morgan Utica LLC	Delaware
Kinder Morgan Utopia Holdco LLC	Delaware
Kinder Morgan Utopia LLC	Delaware
Kinder Morgan Utopia Ltd.	Canada (Alberta)
Kinder Morgan Vehicle Services LLC	Delaware
Kinder Morgan Virginia Liquids Terminals LLC	Delaware
Kinder Morgan Wink Pipeline LLC	Delaware
KinderHawk Field Services LLC	Delaware
Kiowa Lateral LLC	Delaware
KM Canada Edmonton North Rail Terminal Limited Partnership	Canada (Manitoba)
KM Canada Edmonton South Rail Terminal Limited Partnership	Canada (Manitoba)
KM Canada Marine Terminal Limited Partnership	Canada (British Columbia)
KM Canada North 40 Limited Partnership	Canada (Manitoba)
KM Canada Rail Holdings GP Limited	Canada (Alberta)
KM Canada Terminals GP ULC	Canada (Alberta)
KM Canada Terminals ULC	Canada (Alberta)
KM Crane LLC	Maryland
KM Decatur LLC	Delaware
KM Eagle Gathering LLC	Delaware
KM Express LLC	Delaware
KM Gathering LLC	Delaware
KM Insurance Texas Inc.	Texas
KM Kaskaskia Dock LLC	Delaware
KM Liquids Terminals LLC	Delaware
KM North Cahokia Land LLC	Delaware
KM North Cahokia Special Project LLC	Delaware
KM North Cahokia Terminal Project LLC	Delaware
KM Phoenix Holdings LLC	Delaware
KM Ship Channel Services LLC	Delaware
KM Treating GP LLC	Delaware
KM Treating Production LLC	Delaware
KMBT Legacy Holdings LLC	Tennessee
KMBT LLC	Delaware
KMGP Services Company, Inc.	Delaware

Kinder Morgan, Inc.

Subsidiaries of the Registrant as of December 31, 2018

Entity Name	Place of Incorporation
KN Telecommunications, Inc.	Colorado
Knight Power Company LLC	Delaware
KW Express, LLC	Delaware
Liberty Pipeline Group, LLC	Delaware
Lomita Rail Terminal LLC	Delaware
Mesquite Investors, L.L.C.	Delaware
Midco LLC	Delaware
Midcontinent Express Pipeline LLC	Delaware
Mid-Ship Group LLC	Delaware
Mid-Ship Oil Brokers LLC	Delaware
Milwaukee Bulk Terminals LLC	Wisconsin
MJR Operating LLC	Maryland
Mojave Pipeline Company, L.L.C.	Delaware
Mojave Pipeline Operating Company, L.L.C.	Texas
Natural Gas Pipeline Company of America LLC	Delaware
NGPL Finance LLC	Delaware
NGPL Holdings LLC	Delaware
NGPL Intermediate Holdings LLC	Delaware
NGPL PipeCo LLC	Delaware
North Cahokia Industrial, LLC	Delaware
North Cahokia Real Estate, LLC	Delaware
North Cahokia Terminal, LLC	Delaware
Paddy Ryan Crane, LLC	Louisiana
Palmetto Products Pipe Line LLC	Delaware
Permian Highway Pipeline LLC	Delaware
PI 2 Pelican State LLC	Delaware
Pinney Dock & Transport LLC	Delaware
Plantation Pipe Line Company	Delaware and Virginia
Plantation Services LLC	Delaware
Queen City Terminals LLC	Delaware
Rahway River Land LLC	Delaware
Red Cedar Gathering Company	Colorado
River Terminals Properties GP LLC	Delaware
River Terminals Properties, L.P.	Tennessee
Ruby Investment Company, L.L.C.	Delaware
Ruby Pipeline Holding Company, L.L.C.	Delaware
Ruby Pipeline, L.L.C.	Delaware
Sage Refined Products GP, LLC	Texas
Sage Refined Products, Ltd.	Texas
ScissorTail Energy, LLC	Delaware

Kinder Morgan, Inc.

Subsidiaries of the Registrant as of December 31, 2018

Entity Name	Place of Incorporation
SFPP, L.P.	Delaware
Sierrita Gas Pipeline LLC	Delaware
SNG Pipeline Services Company, L.L.C.	Delaware
Sonoran Pipeline LLC	Delaware
Southern Dome, LLC	Delaware
Southern Gulf LNG Company, L.L.C.	Delaware
Southern Liquefaction Company LLC	Delaware
Southern LNG Company, L.L.C.	Delaware
Southern Natural Gas Company, L.L.C.	Delaware
Southern Natural Issuing Corporation	Delaware
Southern Oklahoma Gathering LLC	Delaware
SouthTex Treaters LLC	Delaware
Southwest Florida Pipeline LLC	Delaware
SRT Vessels LLC	Delaware
Stevedore Holdings, L.P.	Delaware
Tejas Gas, LLC	Delaware
Tejas Natural Gas, LLC	Delaware
Tennessee Gas Pipeline Company, L.L.C.	Delaware
Tennessee Gas Pipeline Issuing Corporation	Delaware
Texan Tug LLC	Delaware
TGP Pipeline Services Company, L.L.C.	Delaware
The Pecos Carbon Dioxide Pipeline Company	Texas
TransColorado Gas Transmission Company LLC	Delaware
Transload Services, LLC	Illinois
Transport USA, Inc.	Pennsylvania
Utica Marcellus Texas Pipeline LLC	Delaware
Webb/Duval Gatherers	Texas
Western Plant Services LLC	Delaware
WYCO Development LLC	Colorado
Wyoming Interstate Company, L.L.C.	Delaware
Young Gas Storage Company, Ltd.	Colorado

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (Nos. 333-172170, 333-172582, 333-172584, 333-172606, 333-181782 and 333-205430) of Kinder Morgan, Inc. of our report dated February 8, 2019 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 8, 2019

Exhibit 31.1

KINDER MORGAN, INC. AND SUBSIDIARIES
CERTIFICATION PURSUANT TO RULE 13A-14(A) OR 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934,
AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Steven J. Kean, certify that:

1. I have reviewed this annual report on Form 10-K of Kinder Morgan, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States;

    c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 8, 2019

/s/ Steven J. Kean
Steven J. Kean
Chief Executive Officer

Exhibit 31.2

KINDER MORGAN, INC. AND SUBSIDIARIES
CERTIFICATION PURSUANT TO RULE 13A-14(A) OR 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934,
AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, David P. Michels, certify that:

1. I have reviewed this annual report on Form 10-K of Kinder Morgan, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States;

   c. evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 8, 2019

/s/ David P. Michels
David P. Michels
Vice President and Chief Financial Officer

Exhibit 32.1

KINDER MORGAN, INC. AND SUBSIDIARIES
CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906
OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of Kinder Morgan, Inc. (the "Company") for the yearly period ended December 31, 2018, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, in the capacity and on the date indicated below, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 8, 2019

/s/ Steven J. Kean
Steven J. Kean
Chief Executive Officer

Exhibit 32.2

KINDER MORGAN, INC.
CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906
OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of Kinder Morgan, Inc. (the "Company") for the yearly period ended December 31, 2018, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, in the capacity and on the date indicated below, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 8, 2019

/s/ David P. Michels
David P. Michels
Vice President and Chief Financial Officer

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2018

or

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____to_____

Commission file number: 000-55864

KINDER MORGAN CANADA LIMITED

Kinder Morgan Canada Limited

(Exact name of registrant as specified in its charter)

Alberta, Canada	**N/A**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

Suite 3000, 300 - 5th Avenue S.W. Calgary, Alberta T2P 5J2
(Address of principal executive offices) (zip code)

Registrant's telephone number, including area code: 403-514-6780

Securities registered pursuant to Section 12(b) of the Act: None

Securities registered pursuant to Section 12(g) of the Act: Restricted Voting Shares

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933. Yes ☐ No ☑

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934.

Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ ☐ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" (in Rule 12b-2 of the Exchange Act).
Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☑ Smaller reporting company ☐ Emerging growth company ☑

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☑

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes ☐ No ☑

Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant, based on closing prices in the daily composite list for transactions on the Toronto Stock Exchange on June 29, 2018 was approximately CAD$1,653,298,600. As of February 15, 2019, the registrant had 34,944,993 Restricted Voting Shares and 81,353,820 Special Voting Shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2019 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2019, are incorporated into PART III, as specifically set forth in PART III.

EXPLANATORY NOTE

Capitalized terms used throughout this document are defined in the "*Glossary*" below. References to "we," "us," "our" and the "Company" are to Kinder Morgan Canada Limited and its majority-owned and/or controlled subsidiaries. We state our financial statements in Canadian dollars. References in this document to "dollars," "$" or "CAD$" are to the currency of Canada, and references to "U.S.$" or "U.S. dollar" are to the currency of the U.S.

GLOSSARY

Company Abbreviations

Class A Units	=	the Class A limited partnership units of the Limited Partnership
Class B Units	=	the Class B limited partnership units of the Limited Partnership
Cochin	=	U.S. and Canadian Cochin pipeline system
Cooperation Agreement	=	the cooperation agreement, between the Company, the General Partner, the Limited Partnership, KMCC, KMCT and Kinder Morgan (in respect to certain provisions only) entered into in connection with the IPO
General Partner	=	Kinder Morgan Canada GP Inc.
IPO	=	Initial Public Offering of KML's Restricted Voting Shares in May 2017
Jet Fuel	=	Jet Fuel pipeline system
KMCC	=	Kinder Morgan Canada Company
KMCI	=	Kinder Morgan Canada Inc.
KMCSI	=	Kinder Morgan Canada Services Inc.
KMCT	=	Kinder Morgan Canada Terminals ULC
KMCU	=	Kinder Morgan Cochin ULC
KML	=	Kinder Morgan Canada Limited and its majority-owned and/or controlled subsidiaries
Kinder Morgan or KMI	=	Kinder Morgan, Inc.
Kinder Morgan Canada Group	=	collectively, the Company, the General Partner, the Limited Partnership, and each person that any of the Company, the General Partner or the Limited Partnership controls from time to time
Kinder Morgan Group	=	Kinder Morgan and each person that Kinder Morgan directly or indirectly controls from time to time, other than any member of the Kinder Morgan Canada Group
Limited Partnership	=	Kinder Morgan Canada Limited Partnership
Limited Partnership Agreement	=	the limited partnership agreement of the Limited Partnership, as amended from time to time
LP Units	=	collectively, the Class A Units and the Class B Units
Preferred LP Units	=	the preferred limited partnership units in the Limited Partnership
Preferred Shares	=	collectively all outstanding preferred shares in the capital of KML
Puget Sound	=	Puget Sound pipeline system
Restricted Voting Shares	=	the restricted voting shares in the capital of KML
Series 1 Preferred Shares	=	the 12,000,000 cumulative redeemable minimum rate reset Preferred Shares, Series 1 in the capital of KML
Series 3 Preferred Shares	=	the 10,000,000 cumulative redeemable minimum rate reset Preferred Shares, Series 3 in the capital of KML
Special Voting Shares	=	the special voting shares in the capital of KML
TMEP	=	Trans Mountain Expansion Project
TMPL	=	Trans Mountain pipeline system
Trans Mountain Asset Group	=	the assets sold; collectively, TMPL, along with its associated Puget Sound, the TMEP, and KMCI (the Canadian employer of the staff that operates those businesses sold)
Trans Mountain	=	Trans Mountain Pipeline ULC

Common Industry and Other Terms

/d	=	per day
Adjusted EBITDA	=	adjusted earnings before interest expense, taxes, depreciation and amortization
B.C.	=	the Province of British Columbia
BCUC	=	British Columbia Utilities Commission
bpd	=	barrels per day

BC OGC	=	British Columbia Oil and Gas Commission
DCF	=	distributable cash flow
D&A	=	depreciation and amortization
EBDA	=	earnings before depreciation and amortization expenses
FASB	=	Financial Accounting Standards Board
FERC	=	Federal Energy Regulatory Commission
GAAP or U.S. GAAP	=	United States Generally Accepted Accounting Principles
MBbl	=	thousand barrels
MMBbl	=	million barrels
MMtonnes	=	million metric tonnes
NEB	=	National Energy Board
SEC	=	United States Securities and Exchange Commission
TSX	=	Toronto Stock Exchange
U.S.	=	United States of America

Information Regarding Forward-Looking Statements

This report includes forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "intend," "plan," "projection," "forecast," "strategy," "position," "continue," "estimate," "expect," "may," or the negative of those terms or other variations of them or comparable terminology. In particular, expressed or implied statements concerning future actions, conditions or events, future operating results or the ability to generate sales, income or cash flow or to pay dividends are forward-looking statements. In particular, but without limitation, this document contains forward-looking statements pertaining to the following:

- expectations regarding our ability to generate certain targeted Adjusted EBITDA and DCF and to declare and pay dividends, including amounts thereof;
- the future commercial viability of our business;
- expectations regarding expansion projects, including our ability to complete such projects, anticipated costs, scheduling and in-service dates, future benefits and utilization, anticipated project returns and the impacts of such projects;
- the realization of benefits deriving from future growth projects;
- the potential growth opportunities and anticipated competitive position of our business segments;
- the anticipated results of our pipeline tolls and toll structure and our ability to recover certain costs and earn returns as a result of such tolls;
- performance by our counterparties of their obligations to us;
- expectations respecting our ability to generate predictable and growing cash available for distribution;
- expectations and intentions respecting distributions from the Limited Partnership, the payout of DCF and our payment of quarterly dividends to our shareholders, as well as the amounts of those dividends;
- the impact of commodity pricing;
- anticipated future capital and operating expenditures;
- expectations respecting the ongoing financing of our business and operations;
- anticipated decommissioning and abandonment costs;
- operational (including marine) safety levels and standards;
- future pipeline capacity and tolls; and
- future supply of and demand for the products we handle and demand for the services we provide.

The foregoing list should not be construed to be exhaustive. We believe the forward-looking statements in this document are reasonable. However, there is no assurance that any of the actions, events or results of the forward-looking statements will occur, or if any of them do, of their timing or what impact they will have on our results of operations or financial condition. Because of these uncertainties, investors should not put undue reliance on any forward-looking statements.

Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict. Any "financial outlook" set out in this document has been included for the purpose of providing information relating to management's current expectations and plans for the future, is based on a number of significant assumptions and may not be appropriate, and should not be used, for purposes other than those for which such forward-looking statements are disclosed herein.

Our business, financial condition and results of operations, including our ability to pay cash dividends, are substantially dependent on our financial condition and results of operations. As a result, factors or events that impact our business are likely to have a commensurate impact on us, the market price and value of the Restricted Voting Shares, the Preferred Shares, and our ability to pay dividends.

See Item 1A "*Risk Factors*" and Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook"* included in this report for a more detailed description of factors that may affect the forward-looking statements. You should keep these risk factors in mind when considering forward-looking statements. These risk factors could cause our actual results to differ materially from those contained in any forward-looking statement. Because of these risks and uncertainties, you should not place undue reliance on any forward-looking statement. Any financial outlook *or* other forward-looking statements included in this report are included for the purpose of providing information relating to

management's current expectations and plans for the future, are based on a number of significant assumptions and may not be appropriate, and should not be used, for any purpose other than those for which such forward-looking statements are disclosed herein.

Forward-looking statements in this report are given only as of the date of this report and we disclaim any obligation to update or revise any forward-looking statements included in this report, except as required by law.

PART I

Items 1 and 2. ***Business and Properties.***

Overview

We manage and are the holder of an approximate 30% minority equity interest in a portfolio of strategic energy infrastructure assets across Western Canada. Kinder Morgan, Inc. (NYSE: KMI) holds an approximate 70% majority voting interest in us and a corresponding 70% equity interest in our business and assets. We focus on stable, fee-based energy transportation and storage assets that are central to the energy infrastructure of Western Canada.

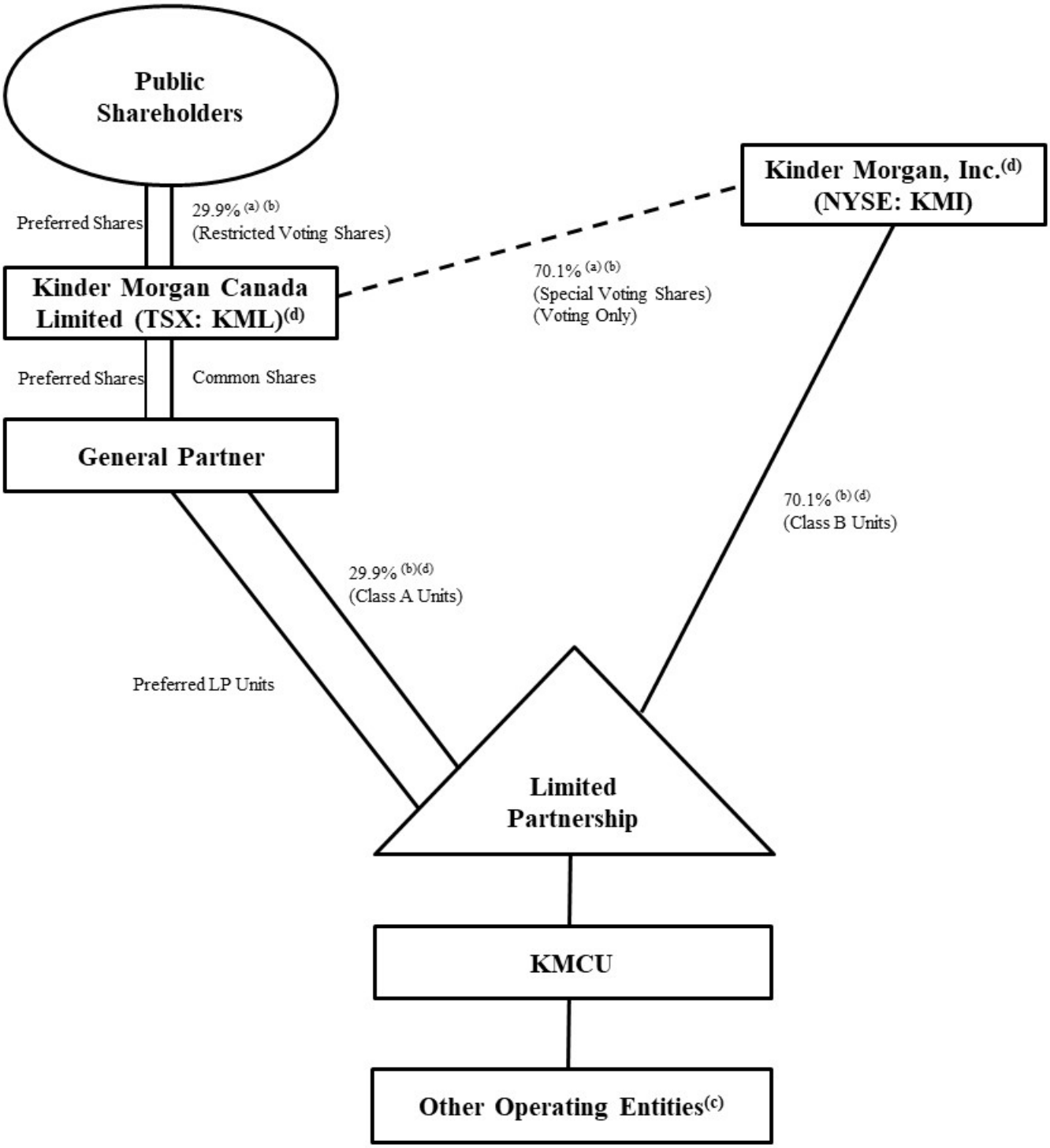
Business Organization

The Company was incorporated on April 7, 2017. On May 30, 2017, the Company completed an IPO of 102,942,000 Restricted Voting Shares (number of shares issued is before our January 4, 2019 Share Consolidation; see "*—Recent Business Developments—2019 Return of Capital and Share Consolidation*" below) on the TSX at a price to the public of $17.00 per Restricted Voting Share for total gross proceeds of approximately $1.75 billion. The IPO number of shares issued is before our January 4, 2019 Share Consolidation. We used our IPO proceeds to indirectly acquire from Kinder Morgan an approximate 30% economic interest in the Limited Partnership, while Kinder Morgan indirectly retained the remaining approximate 70% economic interest.

Concurrent with the closing of our IPO, the Limited Partnership acquired an interest in the Operating Entities from KMCC and KMCT, each a wholly owned subsidiary of Kinder Morgan, in exchange for the issuance to KMCC and KMCT of Class B Units of the Limited Partnership. In addition, KMCC and KMCT were issued Special Voting Shares in the Company for nominal consideration. See Note 1 "*General*" to our consolidated financial statements for a list of Operating Entities.

Immediately following the closing of our IPO, we used the proceeds from our IPO to indirectly subscribe for Class A Units representing an approximate 30% economic interest in the Limited Partnership while the Class B Units held by KMCC and KMCT represented, in the aggregate, an approximate 70% economic interest in the Limited Partnership. After the IPO, we issued an aggregate of $550 million of Series 1 Preferred Shares and Series 3 Preferred Shares; as a result, our and Kinder Morgan's respective interests in the Limited Partnership are subject to the preferred shareholders' priority on distributions and upon liquidation.

The intercorporate relationships of the Company, the Limited Partnership, and our Operating Entities are as follows:



a. Approximate percentages based on ownership of total outstanding Company Voting Shares as of December 31, 2018, and are unchanged after our January 4, 2019 Share Consolidation.
b. Approximate percentages based on ownership of total outstanding Class A Units and Class B Units as of December 31, 2018.
c. Other operating entities include the Operating Entities other than KMCU.
d. KML owns (indirectly through the General Partner) 100% of the Class A Units. Kinder Morgan owns (indirectly through KMCC and KMCT) 100% of our outstanding Special Voting Shares and 100% of the Class B Units.

Recent Business Developments

Trans Mountain Transaction

On August 31, 2018, we closed on the sale of the Trans Mountain Asset Group, which was indirectly acquired by the Government of Canada through Trans Mountain Corporation (a subsidiary of the Canada Development Investment Corporation) for cash consideration of approximately $4.43 billion, which is the contractual purchase price of $4.5 billion net of a preliminary working capital adjustment (the "Trans Mountain Transaction"). As of December 31, 2018, we accrued for an additional $37 million for the final working capital adjustment that was subsequently settled in cash. The underlying assets in the Trans Mountain Asset Group were primarily within our Pipelines business segment and the operating results for the Trans Mountain Asset Group are presented as Discontinued Operations within Income from operations of the Trans Mountain Asset Group, net of tax in the accompanying consolidated statements of income for all periods presented in this report, and assets and liabilities are presented as held for sale as of December 31, 2017, though these assets were not actually being held for sale at that point in time.

Subsequent to our announced preliminary 2018 earnings on January 16, 2019, (i) we increased the accrual for the final working capital adjustment from $35 million to $37 million that resulted in a reduction to the Trans Mountain Transaction gain, net of tax, by $1.8 million, which were recorded in the accompanying consolidated balance sheet and consolidated income statement, respectively, as of and for the year ended December 31, 2018 and (ii) we reclassified approximately $4.5 million of tax expense from Income Tax Expense to Income from Operations of the Trans Mountain Asset Group, net of tax in the accompanying consolidated statement of income for the year ended December 31, 2017.

2019 Return of Capital and Share Consolidation

Pursuant to our voting shareholders' approval on November 29, 2018, a distribution of approximately $1.2 billion was made as a return of capital to holders of our Restricted Voting Shares ($11.40 per Restricted Voting Share) and approximately $2.8 billion to KMI as the indirect holder of our Special Voting Shares on January 3, 2019 (the "Return of Capital"). To facilitate the Return of Capital and provide flexibility for dividends going forward, our voting shareholders also approved (i) the reduction of the stated capital of our Restricted Voting Shares by $1.45 billion (the "Stated Capital Reduction") and (ii) a "reverse stock split" of our Restricted Voting Shares and Special Voting Shares on a one-for-three basis (three shares consolidating to one share) (the "Share Consolidation"), which was effected on January 4, 2019. In accordance with U.S. GAAP, the Restricted Voting Shares and Special Voting Shares outstanding and earnings per share information in this report reflect the Share Consolidation for all periods presented unless otherwise noted.

Suspension of Dividend Reinvestment Plan (DRIP)

Effective January 16, 2019, our board of directors suspended our DRIP until further notice. Accordingly, dividends in respect of the fourth quarter of 2018, paid on February 15, 2019 to holders of Restricted Voting Shares of record as of the close of business on January 31, 2019, were not reinvested through the DRIP. Shareholders who were enrolled in the program will automatically receive dividend payments in the form of cash. We elected to suspend our DRIP in light of our reduced need for additional capital following the Trans Mountain Transaction. If we elect to reinstate the DRIP in the future, shareholders who were enrolled in the DRIP at suspension and remained enrolled at reinstatement will automatically resume participation in the DRIP. Kinder Morgan's participation in the distribution reinvestment plan for Class B Units of the Limited Partnership has been suspended since July 18, 2018, and the plan itself was automatically suspended effective January 16, 2019 pursuant to the terms of the Limited Partnership Agreement.

Also, see Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook.*"

Review of Strategic Alternatives

In light of the completion of the Trans Mountain Transaction, we continue to evaluate all options in order to maximize value to our shareholders. These options include, among others, continuing to operate as a standalone enterprise, a disposition by sale, or a strategic combination with another company.

Business and Segments

We focus on providing fee-based services to customers from an asset portfolio consisting of energy-related pipelines and liquid and bulk terminaling facilities. Our two business segments are: (i) Terminals, which is comprised of the Vancouver Wharves Terminal and the terminals located in the Edmonton, Alberta area, and (ii) Pipelines, which is comprised of Cochin and Jet Fuel.

Our key strategies are to:

- focus on stable, fee-based energy transportation and storage assets that are central to the energy infrastructure of Western Canada;
- increase utilization of our existing assets while controlling costs, operating safely, and employing environmentally sound operating practices;
- leverage economies of scale from expansions of existing assets and potential incremental acquisitions that fit within our strategy and are accretive to cash flow; and
- maintain a strong balance sheet and maximize value for our investors.

Overview of Assets

Asset	Design [Storage] Capacity	Description
Terminals		
Vancouver Wharves Terminal	6.0+ MMtonnes bulk + [250 MBbl]	Bulk commodity marine terminal provides handling, storage, loading and unloading services.
Edmonton South Terminal	[5,100 MBbl]	15 tanks currently leased from Trans Mountain; tanks sub-leased to third parties in unregulated service (merchant tanks).
North 40 Terminal	[2,150 MBbl]	Merchant crude oil storage and blending services.
Edmonton Rail Terminal	210 MBbl/d	Operated 50/50 joint venture with Imperial Oil (largest origination crude-by-rail terminal in North America).(b)
Alberta Crude Terminal	40 MBbl/d	Non-operated 50/50 joint venture with Keyera Corporation (Keyera).(b)
Base Line Terminal	[4,800 MBbl]	Operated 50/50 joint venture with Keyera with 12 tanks placed in service throughout 2018.(b)
Pipelines		
Cochin(a)	~110 MBbl/d	Transports condensate from the Canada/U.S. border near Maxbass, North Dakota to Fort Saskatchewan, Alberta.
Jet Fuel	45 MBbl	Transports jet fuel from refinery in Burnaby and the Westridge Marine Terminal to Vancouver International Airport.

a. Cochin is part of the Cochin pipeline system, which transports condensate from Kankakee County, Illinois to Fort Saskatchewan, Alberta. Capacity on the U.S. portion of the Cochin pipeline system, which is fully-owned by KMI, is approximately 95 MBbl/d.
b. The 50-50 joint ventures are proportionally consolidated into our consolidated financial statements.

For financial information on our two reportable business segments, see Note 19 "*Reportable Segments*" to our consolidated financial statements.

Terminals Business

Vancouver Wharves Terminal

Located in North Vancouver, B.C., the Vancouver Wharves Terminal is a 125-acre bulk marine terminal facility that annually transfers over 4.0 million tons of bulk cargo and 1.5 MMBbl of liquids predominantly to offshore export markets. The Vancouver Wharves Terminal, which has been in operation since 1959, was acquired by Kinder Morgan in 2007. This

acquisition included securing a 40-year operating lease and asset ownership agreement with the B.C. Railway Company for the terminal uplands. Vancouver Wharves also holds a corresponding water lot lease agreement with Port Metro Vancouver to support the terminal vessel loading and unloading operations with the same 40-year term.

Over the last five years Kinder Morgan has completed a number of projects designed to improve and expand the terminal, including: (i) the construction of a zinc concentrate truck load out facility; (ii) expansion of the terminal's lead concentrate interior shed walls; (iii) upgrading of the terminal's sulphur load out facility; and (iv) upgrading of the terminal's grain handling facility. The Vancouver Wharves Terminal currently has 1.0 million tons of bulk storage capacity, 250,000 barrels of petroleum storage capacity and facilities that can house up to 325 rail cars. The terminal assets include four berths capable of handling Panamax-size vessels. The main export products at Vancouver Wharves are sulphur, copper concentrates, diesel, jet fuel, bio-diesel, wheat and canola seed, while the most significant import products at Vancouver Wharves are zinc and lead concentrate. With good connectivity through the recently expanded Vancouver North Shore rail gateway corridor and connections with three Class 1 rail companies serving the area (the Canadian National Railway ("CN"), the Canadian Pacific Railway ("CP") and the BNSF Railway) as well as all major highway routes in western Canada, Vancouver Wharves continues to provide a safe and efficient link for customers' supply chain connectivity for water borne trade to global markets.

Edmonton South Terminal

The Edmonton South Terminal is a merchant tank terminal located in Sherwood Park, Alberta. As noted above, the assets currently making up the Edmonton South Terminal are embedded within the Edmonton Terminal, are owned by our former subsidiary, TMPL, and are operated by KMCI, for and on behalf of KM Canada North 40. The merchant use of the tanks by KM Canada North 40 is governed by a long-term leasing arrangement with TMPL, the initial term of which expires in 2038 followed thereafter with five-year evergreen auto-renewal periods subject to mutual termination rights. The first phase of the Edmonton South Terminal, comprised of nine merchant tanks, was put into service throughout 2013 and 2014. As part of a phase two expansion, an additional four tanks and associated infrastructure were constructed and placed in service in 2014. In connection with the Edmonton Rail Terminal project, a final two tanks were brought into service at the Edmonton South Terminal at the end of 2014. In total, the assets comprising this facility consist of 15 tanks with a total storage capacity of approximately 5.1 MMBbl along with associated outbound pumps, meters and pipe connections to other facilities. TMPL currently expects to recall two of the tanks in merchant service at the Edmonton South Terminal upon the completion of TMEP for use in TMPL's regulated service, comprising between approximately 700,000 and 800,000 barrels of total storage capacity. The NEB-approved agreement specifies that if Edmonton Terminal is fully built-out and additional tanks are identified as needed for TMPL for regulated purposes, more tanks can be recalled upon 24-months' notice. As the use of the recalled tanks will be included in the overall tolls charged on the expanded TMPL, such tanks will no longer generate the incremental revenue realized through leases to merchant customers. As such, the recall is expected to result in a decrease in the net cash earnings attributable to the Edmonton South Terminal, see Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook—Terminals Matters.*"

The Edmonton South Terminal provides significant optionality for customers through its diverse suite of inbound and outbound pipeline connections, including access to the vast majority of crude types in Alberta. All tanks at the terminal are in crude oil service and each tank has the flexibility to handle all products that are connected to the terminal, including in-tank mixing and outbound blending of multiple products. In addition to its connection to the Edmonton Rail Terminal and the North 40 Terminal, the Edmonton South Terminal has significant pipeline connectivity. The Edmonton South Terminal has 15 major inbound pipeline connections from throughout Alberta and two major outbound pipeline connections, which allow customers to ship their products west, east or south. In addition to its position within the larger Trans Mountain Edmonton Terminal, the Edmonton South Terminal is, similarly, adjacent, or in close proximity, to the starting point of the Enbridge Inc. cross-continent crude oil pipeline system, the North 40 Terminal, the Suncor Energy Inc. Edmonton refinery, the Keyera Edmonton terminal, the Keyera Alberta EnviroFuels plant, the Gibson Energy Inc. Edmonton terminal, the Plains Midstream Canada Edmonton Strathcona terminal and the Imperial Oil Strathcona refinery. Customers utilizing the Edmonton South Terminal tanks have the option of direct injection into the TMPL mainline or utilizing any of the other outbound connections available at the terminal.

North 40 Terminal

Located in Sherwood Park, Alberta, immediately adjacent to the Edmonton South Terminal, the nine-tank North 40 Terminal facility, in service since March 2008, provides merchant storage for crude oil products. This approximately 2.15 million barrel facility is comprised of eight 250,000 barrel tanks and one 150,000 barrel tank. The North 40 Terminal has a highly diverse suite of ten inbound pipeline connections, including access to the vast majority of crude types in Alberta, and five outbound connections. In addition to its pipeline connections, including TMPL and Enbridge Mainline, which allow customers to ship their products west, east or south, the North 40 Terminal is connected to the Alberta Crude Terminal (as described below), the Base Line Terminal (as described below), a local refinery and a third-party midstream facility. All tanks at

the terminal are in crude oil service and have the flexibility to handle all products that are connected to the terminal, including in-tank mixing of multiple products. Following the Trans Mountain Transaction, the North 40 Terminal operations are being transitioned from KMCSI to an affiliate of KM Canada North 40 in the second quarter of 2019.

Edmonton Rail Terminal

In December 2013, Kinder Morgan and Imperial Oil announced the formation of a 50-50 unincorporated joint venture to build the Edmonton Rail Terminal on land leased from Imperial Oil with an initial capacity of 100,000 bpd. By August 2014, the joint venture had entered into firm take-or-pay agreements with strong, creditworthy major oil companies. These contracted commitments allowed for an expansion of the Edmonton Rail Terminal to add incremental capacity of 110,000 bpd, for a total of 210,000 bpd. The terminal was constructed by Kinder Morgan, placed in service in April 2015 and is currently operated by an affiliate of KM Canada North 40.

The Edmonton Rail Terminal capacity at start-up in 2015 was approximately 210,000 bpd, making the terminal the largest origination crude-by-rail loading facility in North America. The terminal is connected via pipeline to the Edmonton South Terminal and the Baseline Terminal and is capable of sourcing all crude streams that are handled there for delivery by rail to North American markets and refineries. The terminal connects to both the CN and CP railway networks and can hold up to four unit trains on-site (two loading and two staged), load unit trains of up to 150 rail cars per train and load two trains with the same or differing products simultaneously. Trains are loaded at the Edmonton Rail Terminal through a 38-spot dual-sided rack (76 loading spots in total). Edmonton Rail Terminal, through its connections with the Edmonton South Terminal and the Base Line Terminal, has access to the approximately 9.9 MMBbl of crude oil capable of being stored at such terminals.

Alberta Crude Terminal

An unincorporated 50-50 joint venture between an affiliate of KM Canada North 40 and Keyera, the Alberta Crude Terminal is a crude oil rail loading facility located on land leased from Keyera in Edmonton, Alberta. The Alberta Crude Terminal construction project was sanctioned in July 2013 and placed in service in November 2014. The terminal is served by the CN and CP railway networks and is connected via pipeline to the North 40 Terminal and the Base Line Terminal. The terminal, which is fully-contracted to a single customer and operated by Keyera, has approximately 40,000 bpd of manifest crude oil rail loading capacity as well as capacity for 250 rail car storage spots, which assist in the efficient manifest movement of the railcars loaded at the facility. The Alberta Crude Terminal, through its connections with the North 40 Terminal and the Base Line Terminal, has access to the approximately 7.0 MMBbl of crude oil capable of being stored at such terminals.

Base Line Terminal

Announced in March 2015, the Base Line Terminal is a second 50-50 unincorporated joint venture between an affiliate of KM Canada North 40 and Keyera. The Base Line Terminal is a merchant crude oil storage terminal located on leased land at the Keyera Alberta EnviroFuels facility in Sherwood Park, Alberta. Construction on the 12-tank 4.8 MMBbl initial build commenced in the second half of 2015, and the tanks were placed into service throughout 2018. This project is supported by multiple long-term customer contracts that will draw revenue streams and associated risks that are similar in nature to those for the existing terminals near Edmonton.

The Base Line Terminal has some of the best tank terminal connectivity in Western Canada, with a diverse suite of ten inbound pipeline connections, including access to the vast majority of crude types in Alberta, and six outbound connections, including both pipeline and rail. This terminal leverages off of the existing North 40 Terminal by using transfer lines to facilitate product transfer between terminals via a pipeline bridge over a highway in Strathcona County. In addition to its pipeline access, the Base Line Terminal is also connected to the Alberta Crude Terminal and Edmonton Rail Terminal. All tanks at the terminal are in crude oil service and have the flexibility to handle all products that are connected to the terminal, including in-tank mixing and outbound blending of multiple products. With the completion of the Base Line Terminal in 2018, we now have more than 12.0 MMBbl of total merchant storage capacity (8/8ths) in the Edmonton area.

Customers and Contractual Relationships

The Terminals business services over 20 liquids customers, made up of a diverse mix of production, refining, marketing and integrated companies, and over 12 bulk customers at any given point in time. Approximately 75% (by revenue dollar amount) of these customers have, or their parent entity has, an investment grade credit rating; however, parent entities may not be guarantors. Our top three Terminals customers account for approximately 36% of total Terminals revenue and the top ten Terminals customers account for approximately 67% of total Terminals revenue.

The majority of the Vancouver Wharves Terminal capacity is contracted under long-term, take-or-pay terminal service agreements. For the most part, the terminal service agreements contain annual minimum volume guarantees and/or service exclusivity arrangements under which customers are required to utilize the terminal for all or a specified percentage of their production for exports. Our contractual arrangements at Vancouver Wharves have an average remaining term of three years. The majority of the Vancouver Wharves revenue originates from customers that have been using our terminal services for over five years and, including term extension options, a number of our major long-term contracts at the Vancouver Wharves Terminal could be extended out through 2039 and 2045.

Our Edmonton South, North 40, Edmonton Rail, Alberta Crude and Base Line Terminals are contracted under take-or-pay agreements with an average remaining contract term of four years. The rates charged for the Terminals business segment terminals' services are market-based and the majority of the fees charged at the Alberta-based terminals are fixed, regardless of the volumes actually handled. 90% of the total revenue of the Edmonton South, North 40, Edmonton Rail, Alberta Crude and Base Line Terminals is take-or-pay in nature, while the remaining revenue is derived from throughput in excess of contracted minimums as well as ancillary terminaling and connection services delivered, which are driven by the demand for the crude oil that is being handled and stored. One of the current contractual arrangements, which accounts for a significant source of revenue at the Edmonton Rail Terminal, will expire in 2020. This contract is subject to a right of renewal on very favorable terms for the customer and, as a result, revenue from the Edmonton Rail Terminal is expected to decline significantly following such renewal, see Item 7 *"Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook —Terminals Matters.*"

Competition

Vancouver Wharves is currently the largest mineral concentrate export and import facility on the west coast of North America. With respect to its liquids operations, Vancouver Wharves is the only merchant terminal for import and export distillates in Port Metro Vancouver. Competing liquids facilities are significantly smaller than Vancouver Wharves and Vancouver Wharves enjoys a superior and highly flexible dock, better storage, berth depth and ship loading capacity and unsurpassed rail access, when compared to the assets of the liquids terminal competitors. In terms of bulk products handling competition, significant capital investment and regulatory approval requirements are barriers to entry for new bulk handling terminals on the West Coast. While there are currently a number of potential competitive grain terminal projects contemplated or underway which may increase the competitive pressures on the Vancouver Wharves grain business, as a result of the Vancouver Wharves berth depth, rail access and location, we believe that our grain business will be able to maintain its strong competitive position. In addition, Vancouver Wharves enjoys a distinct advantage in the mineral concentrates business as it is one of only three facilities on the west coast of North America that is currently permitted to handle these commodities. Given this fact, along with its strategic location, Vancouver Wharves is well positioned to retain its current business and attract new concentrate business dependent on mine location. Additionally, sulphur competition is limited as there is only one other sulphur terminal in Vancouver Harbour.

Edmonton and Hardisty, Alberta are the two primary crude oil hubs in Canada, with a significant majority of crude gathering pipelines feeding into the Edmonton area, and the TMPL system and the Enbridge Mainline System originating from Sherwood Park. While limited land availability and the significant capital investment required to enter this business are significant barriers to entry, the Alberta-based Terminals are subject to competition from other truck and rail terminals and storage facilities which are either in the general vicinity of the facilities or have gathering systems that are, or could potentially extend into, areas served by the Alberta-based terminals. The Alberta-based Terminals currently enjoy a leading market position in the Edmonton hydrocarbon storage and rail transporting business. The Terminals' assets located in Alberta have excellent inbound and outbound connectivity, both in terms of the facilities to which these terminals are connected and the diversity of product that may be stored and transported by them. In addition to the considerable market access offered to customers via pipeline, through its Alberta Crude Terminal and Edmonton Rail Terminal origination crude-by-rail loading facilities, the Alberta-based Terminals are able to offer customers the flexibility to move crude oil to markets without pipeline access, supplement deliveries to markets with constrained pipeline capacity and supply different or unique crude types to refineries looking to maintain quality. Revenues from the Terminals business are largely fixed and generally not subject to short term fluctuations in oil and gas market prices; however, as with the rest of the business, as the long-term terminals contracts expire, while fees for tankage are generally expected to increase on renewal, the storage and handling services of the Terminals business segment's terminals will have additional exposure to the longer-term trends in supply and demand for oil and gas products.

See Item 1A *"Risk Factors—Risks Relating to Our Business.*"

Pipelines Business

Cochin

Cochin consists of a 12-inch (305 millimeters) diameter pipeline which spans from Kankakee County, Illinois to Fort Saskatchewan, Alberta, totaling approximately 2,452 kilometers. Cochin, which transports light hydrocarbon liquids (primarily to be used as diluent to facilitate bitumen transportation), traverses two provinces in Canada and four states in the U.S. The Canadian portion of Cochin is comprised of approximately 1,000 kilometers of pipeline and includes 38 block valves and ten pump stations. While the U.S. portion of Cochin is not part of our business, the U.S. portion of Cochin and the Canadian portion of Cochin are interdependent (including with respect to volumes shipped and financial and contractual obligations) and, as the bulk of the tariffs on Cochin are governed by a joint international tariff, revenue is shared between the U.S. portion of Cochin and the Canadian portion of Cochin. The U.S. portion of this pipeline system is wholly owned by an indirect subsidiary of Kinder Morgan.

In 2014, Kinder Morgan reversed the western leg of Cochin (which was previously used primarily to ship propane into the U.S.) to begin moving light condensate westbound from the Kinder Morgan Cochin terminal in Kankakee County, Illinois, to terminal facilities near Fort Saskatchewan, Alberta (the "Cochin Reversal Project"). Cochin is currently capable of transporting approximately 95,000 bpd of light condensate (constrained by the U.S. portion of the Cochin pipeline system). If additional receipt points in Canada are established, and future demand supports it, throughput on the Cochin pipeline has the potential to reach approximately 110,000 bpd. This additional volume would most likely come from the Bakken oil play in North Dakota.

KMCU is the operator of Cochin, which is operated and maintained by Canadian staff located at the KMCU regional and local offices in Wainwright, Alberta and Regina, Saskatchewan. KMCU is also the holder of the NEB certificates for Cochin.

Customers and Contractual Relationships

Cochin has three primary customers who, among them, have total contractual take-or-pay commitments of 85,000 bpd. These customers have investment grade credit ratings and financial capacity that supports their long-term contractual commitments, which expire in 2024. The take-or-pay commitments obligate the committed shippers to make payments based on their contractual volume commitments, regardless of actual throughput. The joint international tariff rate is adjusted annually in accordance with the standard FERC methodology for escalating indexed rates for petroleum products pipelines. Cochin also offers transportation under: (i) a volumes incentive rate (available to certain committed shippers who ship above their contractual commitments in a calendar year), (ii) an uncommitted joint rate, as well as (iii) local uncommitted U.S. and Canadian rates.

The Canadian portion of Cochin receives its portion of monthly revenues from the above three shippers in U.S. dollars, which are converted to Canadian dollars at the monthly average U.S. dollar to Canadian dollar exchange rate.

Jet Fuel

Jet Fuel transports jet fuel from a Burnaby, B.C. refinery and the Westridge Marine Terminal to the Vancouver International Airport. The 41-kilometer pipeline system has been in operation since 1969. It includes operational storage tanks at the Vancouver International Airport with capacity of approximately 45,000 barrels. British Columbia Oil and Gas Commission regulates the integrity and safety of the pipeline and BCUC regulates Jet Fuel's tolls. Jet Fuel is currently being operated pursuant to a BCUC conditionally approved contract.

Competition

Diluent used in Canada is primarily supplied by local production in Canada (both conventional and unconventional condensates, as well as refinery light naphtha) and imports from the U.S. Historically, as production of bitumen in Canada increased, local Canadian diluent sources were insufficient to meet demand. First imports to Canada were by rail; however, rail transport of diluent has a higher cost basis than transport via pipeline and is thus limited to areas that do not have access to pipeline transportation. In 2014, the Cochin Reversal Project came online, bringing in an additional 95,000 bpd of pipeline import capacity and offering a low all-in cost for transportation of diluent to the Alberta oil sands. While Cochin is exposed to competition from other pipeline systems that are capable of transporting significant volumes of diluent, Cochin's delivery point in Fort Saskatchewan has a low gravity diluent pool and a high level of connectivity, thereby making Cochin an attractive mode of shipping diluent. As evidence of this, Cochin had an approximate 85% utilization rate for 2018.

Historically, Jet Fuel has transported a significant proportion of the jet fuel used at the Vancouver International Airport. However, the airport also receives jet fuel through other means including trucks and an approved, and yet to be constructed, jet fuel barge-receiving terminal near the airport. Jet Fuel's supplying refinery was sold in 2017. As a result of that sale, we are unable to predict whether, and to what extent, that refinery will continue to supply jet fuel to Jet Fuel. These developments have made it unclear how much jet fuel will continue to be available for shipment to the Vancouver International Airport by way of Jet Fuel in the future. We continue to assess our options relating to our Jet Fuel assets.

See Item 1A *"Risk Factors—Risks Relating to Our Business.*"

Major Customer

For the years ended December 31, 2018 and 2017, revenues from Imperial Oil represented 31% of our total revenue from continuing operations for each year. For the year ended December 31, 2016, revenues from Imperial Oil represented 23% of our total revenue.

Operations Management

Safety, compliance and environmental protection are the key components of our Operations Management System ("OMS"), a management system capturing important operational expectations in areas such as physical operations, engineering, environmental compliance, asset integrity, efficiency, quality, and project management.

Across our operations, we strive to provide for the safety of the public, our employees and contractors; protect the environment; comply with applicable laws, rules, regulations and permit requirements; and operate and expand efficiently and safely to serve our customers. The OMS plays a critical role in setting the objectives and expectations for all these activities, and individual business unit operations, maintenance procedures, and site-specific procedures are designed to meet these objectives and expectations.

We are committed to our operational goals, which include risk reduction, efficiency and productivity, effective expansion and integration, quality assurance, and a culture of excellence. These goals are embedded into our operations. The operations of each business unit are as unique as the regulatory and commercial environments in which they operate.

As federally regulated businesses, Cochin and the Edmonton South Terminal are regularly audited by the NEB. Concerns identified in NEB audits are addressed through a comprehensive Corrective Action Plan approved by the NEB that remains in place until all items are completed. We are committed to continually improving pipeline and facility integrity to protect the safety of the public, the environment, and company employees. We are dedicated to being a good corporate citizen by incorporating responsible business practices and conducting our business in an ethical manner.

Additionally, we have implemented an Integrated Safety and Loss Management System ("ISLMS") that is designed for establishing, implementing and continually improving our processes and controls to conduct business in a safe, secure, environmentally responsible and sustainable manner. The ISLMS applies to activities involving the design, construction, operations and abandonment of certain pipelines and terminals systems, including Jet Fuel and certain Terminals assets in Alberta. Through our procedures, this system helps provide for appropriate compliance with NEB regulations and efficient, safe operations in an integrated, systematic and comprehensive manner.

Safety and Emergency Management

Our operators maintain programs designed to safeguard the health and safety of employees, contractors and the general public, including through comprehensive health and safety programs that address risk assessment and monitoring, capability, development, emergency response plans, systems for incident investigation and tracking, and employee evaluation. We believe these safety programs meet or exceed the standards set by the Canadian energy infrastructure industry and applicable government regulations. We have a strong operating and safety track record, with no reportable right of way releases since 2013.

The integrity of Cochin is regularly monitored using in-line inspection tools. These devices inspect the pipeline from the inside and can identify potential anomalies or changes to the condition of the pipe. The collected data is analyzed to find locations where further investigation is required. If necessary, a section of the pipe is exposed and assessed by qualified technicians so that it can be repaired or replaced.

Both Cochin and Jet Fuel have their own control center wherein Control Center Operators ("CCOs") monitor pipeline operations and operating conditions 24 hours a day, seven days a week using a sophisticated Supervisory Control and Data Acquisition ("SCADA") computer system. This electronic surveillance system gathers and displays such data as pipeline pressures, volume and flow rates and the status of pumping equipment and valves. Alarms notify CCOs if parameters deviate from prescribed operating limits. Both automated and manual valves are strategically located along the pipeline system to enable the pipeline to be shut down immediately and sections to be isolated quickly, if necessary. In the event of a precautionary shutdown of the pipeline, there is a formal protocol related to restarting the pipeline. This protocol includes analysis of SCADA and leak detection system data, aerial or foot patrols of the pipeline as appropriate, completion of any inspections or repairs, notifications to regulators, and development of a restart plan. All restarts must be approved by the appropriate Operations Director.

Similarly, our terminals have been built with sophisticated technology and incorporate safety and environmental protection features. In Alberta, the Strathcona District Mutual Assistance Program, assists with emergency planning and tests of the emergency preparedness of our terminals in the Edmonton area. Each of the terminals facilities, as described under "—*Terminals Business*" above, is staffed with trained personnel 24 hours a day, seven days a week.

Pipeline rights-of-way are regularly patrolled by both land and air. Any observed unauthorized activity or encroachment is reported and investigated. We have a public awareness program for each of our pipelines that is designed to create awareness about pipelines, provide important safety information, increase knowledge of the regulations for working around pipelines, and educate first responders and the public on emergency preparedness response activities.

Operations staff are trained to maintain our pipelines and to respond in the event of a spill or other safety related incident along each pipeline route.

We maintain comprehensive emergency management plans and actively maintain emergency response capabilities across our operations. We take an all-hazards approach to preparedness and use the Incident Command System ("ICS") to manage incident response. ICS is widely used by the public safety agencies with whom we may need to coordinate a response. It provides a standardized management structure that allows ready integration of public safety agencies and regulators into a unified response organization.

While we do not own, operate or control the vessels that call at the Vancouver Wharves Terminal, we are an active member of the maritime community and work with maritime agencies to promote safe business practices and facilitate improvements to provide for the safety and efficiency of tanker traffic in the Salish Sea.

In addition to our own rigorous screening process and terminal procedures, vessels calling at Vancouver Wharves must operate according to rules established by the International Maritime Organization, the Government of Canada through Transport Canada, the Pacific Pilotage Authority, and Port Metro Vancouver. Under this regime, there is a well-established system to provide for maritime safety in the Salish Sea, including established shipping lanes and aids to navigation, various inspection methodologies, coordinated vessel traffic monitoring, mandatory tug escort for laden tankers and mandatory pilotage with two pilots on the bridge of laden tankers. In addition, such vessels must maintain their membership in a mandatory spill response regime.

Discontinued Operations

The assets sold in the Trans Mountain Transaction were TMPL, its expansion project, TMEP, TMPL's associated Puget Sound, and KMCI, the Canadian employer of the staff that operates those businesses, collectively referred to as "Trans Mountain Asset Group." As the Trans Mountain Asset Group operations qualify for Discontinued Operations accounting treatment under Accounting Standards Codification ("ASC") 205-20, they are presented herein as such to allow a transparent understanding of our ongoing operations.

The TMPL is a 1,150 kilometers long common carrier pipeline regulated by the NEB, beginning in Edmonton, Alberta and terminating on the west coast of B.C. in Burnaby. The TMPL system has posted tariff rates, which are available to all shippers based on a monthly contract, that vary according to the type of product being shipped as well as receipt and delivery points. As such, it provides service to producers, marketers, refineries and terminals who sell or resell products to domestic markets, oil marketers and international shippers moving oil to such places as California, Washington State and Asia.

See Note 3 "*Trans Mountain Transaction*" to our consolidated financial statements for more financial information about the Trans Mountain Asset Group.

Regulation

Terminals

Our Alberta bulk petroleum storage and transloading facilities are provincially regulated by Alberta Environment and Parks and the Alberta Energy Regulator. Our transloading facilities are also regulated by the Railway branch of the Alberta Transportation. Our Vancouver Wharves Terminal is regulated through a combination of laws, regulations and requirements of the Canadian government, B.C. government and the Vancouver Fraser Port Authority.

Pipelines

NEB

Cochin is an international pipeline regulated by the NEB. The NEB, pursuant to the terms of the NEB Act, regulates the tolls and tariffs governing these pipeline systems, as well as the physical construction, operation and abandonment of the associated pipelines and facilities. Tolls are either determined on a contested application to the NEB or through a negotiated toll settlement between the operator and interested parties, which settlement must subsequently be approved by the NEB. Cochin currently operates under a negotiated toll settlement for its transportation services.

In addition to rate regulation, the NEB regulates all phases of a pipeline's operational life-cycle, from the planning and application phase through to the deactivation, decommissioning or abandonment. Where necessary, the NEB can issue mandatory compliance or remediation orders or use other appropriate tools to enforce its requirements, including, among other things, issuing fines and monetary penalties.

As part of its operational oversight, the NEB will hold compliance meetings with regulated companies, conduct audits of management and protection programs and systems, inspect facilities to assess compliance with requirements, review and approve key documents and evaluate regulated company emergency response exercises for the ability to respond to an emergency. The NEB requires pipeline companies to have integrity management programs in place to ensure the physical condition of the asset is monitored and maintained so that releases do not occur. In addition, pipeline companies must have an emergency management plan that anticipates, prevents, manages and mitigates conditions during an emergency that could adversely affect property, the environment, or the safety of workers or the public, as well as incident first-responders. In the case of a pipeline emergency, the NEB will monitor and assess a company's emergency response, investigate the incident, initiate enforcement actions as necessary and oversee remediation actions.

In the deactivation, decommissioning or abandonment of a project, the NEB will assess whether the applied-for plan can be conducted safely and whether risks to people or the environment can be reduced or avoided. The NEB currently requires holders of an authorization to operate a pipeline under the NEB Act to file a proposed process and mechanism to set aside funds to pay for future abandonment costs in respect of the sites in Canada used for the operation of a pipeline and associated facilities. While a pipeline company bears the ultimate responsibility for the full cost of the abandonment attributable to its assets, upon receipt of approval from the NEB, companies are able to recover certain of these abandonment costs from users of the applicable pipelines. As at the date hereof, Kinder Morgan has received approval to recover its estimated future abandonment costs from shippers on Cochin.

In June 2016, the Pipeline Safety Act, which enshrines in law the "polluter pays" principle, came into force in Canada. Under the Pipeline Safety Act, in the event an environmental incident occurs with respect to one of our pipeline assets, we will have unlimited liability if we are determined to be at fault or negligent. Further, in the event of any environmental incident, regardless of whether there is proof of fault or negligence by us, we will be liable for up to $300 million in costs and damages. In connection with this "absolute liability" of up to $300 million, we are required to demonstrate that we have the financial resources to meet these responsibilities (and a portion of our resources must be readily accessible to help ensure rapid incident response). Further, in connection with the Pipeline Safety Act requirements, among other things: (i) the government has the ability to pursue pipeline operators for the costs of environmental damages; (ii) the NEB is authorized to order reimbursement of costs and expenses incurred by others in taking actions related to an incident; and (iii) the NEB is permitted to take control of incident response in exceptional circumstances, if a company operating a pipeline is unwilling or unable to shoulder its responsibilities. The Pipeline Safety Act also provides that a pipeline company remains liable indefinitely for any pipelines that are abandoned in place.

Recent NEB Developments

On February 6 and 8, 2018, the Canadian government introduced Bills C-68 and Bill C-69 (the "Bills"), respectively, which will introduce several major changes to Canada's federal regime for the assessment of federally regulated projects and regulation of waterways. The Bills will repeal and replace the *Canadian Environmental Assessment Act, 2012* and the *National Energy Board Act,* while making several significant changes to the *Fisheries Ac*t and the *Navigation Protection Act*. The Bills are not likely to be passed into legislation until the middle of 2019, and resulting changes in regulations are not likely to be implemented until 2020. When passed, these acts would not be expected to impact the Cochin federal certificates because Cochin has been approved under prior legislation.

B.C. Regulations

Jet Fuel is wholly situated within B.C. Its operations are regulated by BC OGC and its tolls are regulated by BCUC. The financial regulation of Jet Fuel tolls is undertaken by BCUC on a complaints basis, meaning that pipeline-related matters are generally dealt with between Jet Fuel pipeline operator and the party using its services, subject to the ability to make complaint to BCUC where a dispute cannot be resolved. Jet Fuel is currently being operated pursuant to a BCUC conditionally approved contract.

Climate Change and GHG Regulation

Through our operations, we generate greenhouse gas ("GHG") emissions, which are below regulatory reporting thresholds except at the Edmonton South Rail Terminal. In Alberta, facilities that emit less than 100,000 metric tons of carbon dioxide equivalent (CO_{2e}) per annum as well as all residents are subject to a carbon tax of $30 per metric ton of carbon emitted. Similarly, B.C. has a broad-based, revenue-neutral carbon tax applicable to the purchase and use of fuels. The B.C. tax is currently set at $30 per metric ton of CO_{2e} and will increase by $5 per metric ton annually. The B.C. tax began on April 1, 2018 and will escalate to a maximum of $50 per metric ton on April 1, 2021. The imposition of carbon pricing requirements in either province is not expected to have a material direct effect on our Canadian operations.

Canada has committed to reduce its GHG emissions by 30% below 2005 levels by 2030. In December of 2015, Canada, along with 194 other countries, reached an historic agreement to maintain global temperature increases to below two degrees celsius above pre-industrial levels ("Paris Agreement"). Canada subsequently entered into the Pan-Canadian Framework on Clean Growth and Climate Change ("Framework") with most of its provincial and territorial governments. The Framework is the blueprint by which Canada will attempt to meet its commitment under the Paris Agreement. The Greenhouse Gas Pollution Pricing Act ("GGPPA") is Canada's legislative proposal for implementing the Framework and is intended to serve as a regulatory back-stop in the event a province does not otherwise implement an adequate provincial GHG regime. Saskatchewan opposes both the Framework and the GGPPA and has launched a constitutional legal challenge to the validity of the GGPPA. Ontario has launched a similar challenge. Regardless of the results of these court challenges, any application of the GGPPA is not expected to have a material direct effect on our operations.

Many climate models indicate that global warming is likely to result in rising sea levels, increased intensity of weather, and increased frequency of extreme precipitation and flooding. We may experience increased insurance premiums and deductibles, or a decrease in available coverage, for our assets in areas subject to severe weather. These climate related changes could damage our physical assets, especially operations located in low-lying areas near coasts and river banks, and facilities situated in rain-susceptible regions. However, the timing, severity and location of these climate change impacts are not known with certainty, and these impacts are expected to manifest themselves over varying time horizons.

Environmental Matters

Our business operations are subject to federal, provincial and local laws, regulations and potential liabilities arising under or relating to the protection or preservation of the environment (including with respect to climate change), natural resources and human health and safety. Such laws, regulations and obligations affect many aspects of our business' present and future operations, and generally require us to obtain and comply with various environmental registrations, licenses, permits, inspections and other approvals, including with respect to its expansion and new build projects. Liability for the remediation of contaminated areas under such laws and regulations may be incurred without regard to fault. Private parties, including the owners of properties through which our pipelines pass, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with such laws and regulations or for personal injury or property damage.

Failure to comply with these laws and regulations also may expose us to civil, criminal and administrative fines, penalties and/or interruptions in operations that could harm our business, financial position, or results of operations. For example, if an accidental leak, release or spill of liquid petroleum products, chemicals or other hazardous substances occurs at or from our pipelines or storage or other facilities, we may experience significant operational disruptions and we may have to pay a significant amount to clean up or otherwise respond to the leak, release or spill, pay government penalties, address natural resource damage, compensate for human exposure, property damage or economic loss, install costly pollution control equipment or undertake a combination of these and other measures. The resulting costs and liabilities could materially and negatively affect earnings and cash flows. In addition, emission controls required under provincial laws could require significant capital expenditures at our facilities.

We own and/or operate numerous properties and assets that have been used for many years in connection with our business activities. While we believe we have utilized operating, handling, and disposal practices that were consistent with industry practices at the time, hydrocarbons or other hazardous substances may have been released at or from properties owned, operated or used by us or our predecessors, or at or from properties where our or our predecessors' wastes have been taken for disposal. In addition, many of these properties and assets have been owned and/or operated by third parties whose management, operation, handling and disposal of hydrocarbons or other hazardous substances were not under our or our predecessors' control. These properties and the hazardous substances released and wastes disposed on them may be subject to laws which impose joint and several liability, without regard to fault or the legality of the original conduct. In addition, we could be required to remove or remediate previously disposed wastes or property contamination, including contamination caused by prior owners or operators. Imposition of such liability schemes could have a material adverse impact on our operations and financial position.

We cannot ensure that existing laws and regulations will not be revised or that new laws or regulations will not be adopted or become applicable to our business. There can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts currently anticipated. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material adverse effect on our business, financial position, results of operations and prospects. In addition to revised or additional regulations affecting our customers and/or shippers, including those related to the protection or preservation of the environment (including with respect to climate change), natural resources and human health or safety may have significant negative impacts on the business and operations of such customers and/or shippers that result in such customers and/or shippers defaulting on their contractual obligations to us (including with respect to take-or-pay obligations). We are exposed to the risk of loss in the event of non-performance by such customers and/or shippers, which could have a material adverse effect on our business, and consequently, the Company.

An environmental incident could have lasting reputational impacts to the Company, our business or Kinder Morgan and could impact their ability to work with various stakeholders. In addition to the cost of remediation activities (to the extent not covered by insurance), environmental incidents may lead to an increased cost of operating and insuring our assets, thereby negatively impacting earnings and DCF.

Although we have OMS and EMP programs in place, there remains a chance that an environmental incident could occur. Kinder Morgan also seeks to mitigate the severity of a potential environmental incident through continued process improvements and enhancements in leak detection processes and alarm analysis procedures. We have also invested significant resources to enhance our emergency response plans, operator training and landowner education programs to address potential environmental incidents. However, the mitigation efforts are incapable of guarding against all environmental risks, including in the event that there is significant damage to our assets as a result of catastrophic events (including natural disasters, other significant weather-related events or adverse sea conditions) or the actions of third parties acting outside of our control.

We maintain an insurance program which is renewed annually and has $300 million worth of financial capacity for spill events in accordance with the Pipeline Safety Act (see"—*Regulation*" above). The insurance program includes coverage for commercial liability that is considered customary for the industry in which we operate and includes coverage for operational and environmental incidents. However, the insurance program may not cover all environmental risks and costs and/or may not provide sufficient coverage in the event an environmental claim is made against us. The total insurance coverage will be allocated on an equitable basis among the members of the Kinder Morgan Canada Group in the event multiple insurable incidents exceeding our coverage limits within the same insurance period are experienced.

Other

Employees

We employed 153 full-time personnel as of December 31, 2018. Our Vancouver Wharves operations utilizes International Longshore and Warehouse Union ("ILWU") labor. While KML does not employ these individuals directly, as a member company of the British Columbia Maritime Employers' Association, we are party to a collective bargaining agreement with the ILWU.

Financial Information about Geographic Areas

Our ongoing assets are located in the Canadian provinces of B.C., Alberta and Saskatchewan. See Note 19 "*Reportable Segments*" to our consolidated financial statements for further discussion of the financial information about geographic areas.

Available Information

For this annual report on Form 10-K and future reporting periods, we will make available free of charge on or through our internet website, at www.kindermorgancanadaltd.com, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The information contained on or connected to our internet website is not incorporated by reference into this Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

Item 1A. *Risk Factors.*

You should carefully consider the risks described below, in addition to the other information contained in this document. Realization of any of the following risks could have a material adverse effect on our business, financial condition, cash flows, results of operations and ability to pay dividends. Similarly, given the nature of our relationship with Kinder Morgan, factors or events that impact Kinder Morgan may have consequences for us.

Risks Relating to Our Business

We are dependent on the supply of and demand for the commodities we handle.

Our terminals, pipelines and other assets and facilities depend in large part on continued production of crude oil and other products in the geographic areas that they serve, and the ability and willingness of our customers to supply such products. Without additions to oil and gas reserves, production will decline over time as reserves are depleted, and production costs may rise. Producers may reduce or shut down production during times of lower product prices or higher production costs, to the extent they become uneconomic. Producers in the areas we serve may not be successful in exploring for and developing additional reserves, and our facilities may not be able to maintain existing volumes of throughput. Commodity prices and tax allowances may not remain at levels that encourage producers to explore for and develop additional reserves, produce existing marginal reserves or renew terminaling or transportation contracts as they expire.

Changes in the business environment, an increase in production costs, supply disruptions, or higher development costs, could result in a slowing of supply to our terminals, pipelines and other assets. In addition, changes in the overall demand for hydrocarbons, the regulatory environment or applicable governmental policies (including in relation to climate change or other environmental concerns) may have a negative impact on the supply of crude oil and other products. In recent years, a number of initiatives and regulatory changes relating to reducing GHG emissions have been undertaken by federal, provincial and municipal governments and oil and gas industry participants (including, for example, the targets set forth in the Paris Agreement). In addition, emerging technologies and public opinion have resulted in an increased demand for energy provided from renewable energy sources rather than fossil fuels. These factors could result not only in increased costs for producers of hydrocarbons but also an overall decrease in the global demand for hydrocarbons. Each of the foregoing circumstances could negatively impact our business directly as well as the customers that are using our terminals or shipping through our pipelines, which in turn could negatively impact our prospects for new contracts for transportation or terminaling, renewals of existing contracts or the ability of our customers and shippers to honor their contractual commitments. See "*—Financial distress experienced by our customers or other counterparties could have an adverse impact on us in the event they are unable to pay us for the products or services we provide or otherwise fulfill their obligations to us"* below.

Our terminals and pipelines are largely dependent on supply and demand for the crude oil and other products originating in the Western Canada Sedimentary Basis ("WCSB"). There is significant competition for WCSB supply from several pipelines and terminals within the WCSB, and significant competition from other pipelines and modes of transportation for the delivery of the diluent required by producers in the WCSB. An overall decrease in production and/or competing demand for supply could impact throughput on WCSB-connected pipelines that, in turn, could negatively impact overall revenues generated. The WCSB has considerable reserves, but the amount actually produced depends on many variables, including commodity prices, basin-on-basin competition, pipeline tolls, demand for these products and the overall value of the reserves.

We cannot predict the impact of any of the risks set out above, all of which could reduce the production of and/or demand for crude oil, refined petroleum products and other hydrocarbons which in turn would reduce the demand for the pipeline and terminaling services we provide.

We face significant competition from other terminals, pipelines and other forms of transportation and storage.

Any current or future terminal or pipeline facilities that serve the same markets as our facilities could offer services that are more desirable to customers than those we provide, because of price, location, facilities or other factors. Likewise, other forms of transportation (such as barge, rail or truck) or other storage options may become more attractive to our customers. Additionally, many of our crude and petroleum product terminals are dependent on the third-party pipelines to which they are connected. Competition that negatively impacts these third-party pipelines could result in a decline in customer demand for services at our terminals. We also could experience competition for the supply of crude oil, refined petroleum products or other hydrocarbons from both existing and proposed pipeline systems. Any current or future terminal hub, pipeline system or other form of transportation that delivers crude oil, refined petroleum products or other hydrocarbons from the areas served by our terminals and pipelines (or by such third-party pipelines), could offer shippers more desirable market access, which may reduce demand for access to the markets we serve.

To the extent that an excess of supply into, or a decline in production from, the areas directly or indirectly served by our terminals and pipelines is created and persists, our ability to re-contract for expiring terminaling and transportation capacity at favorable rates or otherwise to retain existing customers could be impaired. We are party to numerous contracts of varying durations. Certain of the contracts associated with our services comprise a mixture of firm and non-firm commitments, varying tenures and varying renewal terms, among other differences. There can be no guarantee that, upon the expiry of our contracts, we will be able to renew such contracts on terms as favorable to us, or at all. In particular, a material contractual arrangement at the Edmonton Rail Terminal, will expire in 2020. This contract is subject to a right of renewal on very favorable terms for the customer and, as a result, revenue from the Edmonton Rail Terminal will decline significantly following such renewal. Such a revenue decline could have a significant negative impact on our financial position. See Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook—Terminals Matters.*"

Our operating results may be adversely affected by unfavorable economic and market conditions including, in particular, the volatility of commodity prices and changes in the overall demand for fossil fuels.

Disadvantageous economic conditions worldwide have from time to time contributed to slowdowns in several industries, including the energy infrastructure industry, and in the specific segments and markets in which we operate, resulting in reduced demand and increased price competition for our services. Our operating results also may be affected by uncertain or changing economic conditions within a particular region. Volatility in commodity prices or changes in markets for a given commodity might also have a negative impact on many of our customers, which in turn could have a negative impact on their ability to meet their obligations to us. Prices for crude oil are subject to large fluctuations in response to relatively minor changes in the supply of and demand for crude oil, uncertainties within the market and a variety of other factors beyond our control. These factors include, among other things: (i) weather conditions or significant weather-related events (including storms and rising sea levels on the West Coast of B.C. or other environmental events potentially related to climate change); (ii) domestic and global economic conditions; (iii) the activities of the Organization of Petroleum Exporting Countries; (iv) governmental regulation; (v) political changes in North America or political instability in oil-producing countries; (vi) the foreign supply of and demand for crude oil; (vii) the price of foreign imports; and (viii) the availability and prices of alternative fuel sources. If global economic and market conditions (including volatility in commodity markets), or economic conditions in the WCSB or other key markets, remain uncertain or persist, spread or deteriorate further, we may experience material impacts on our business, financial condition and results of operations.

Commodity transportation and storage activities involve numerous risks that may result in accidents or otherwise adversely affect our operations.

There are a variety of hazards and operating risks inherent in the storage and transportation of the products that we handle, such as leaks; releases; the breakdown, underperformance or failure of equipment or facilities, information systems or processes; the compromise of information and control systems; spills at terminals and hubs; spills associated with the loading and unloading of harmful substances at rail facilities; adverse sea conditions (including storms and rising sea levels) and releases or spills from shipping vessels loaded at our marine terminal; operator error; labor disputes/work stoppages; disputes with interconnected facilities and carriers; operational disruptions or apportionment on third-party systems or refineries on which our assets depend; and catastrophic events such as natural disasters, fires, floods, explosions, earthquakes, acts of terrorists and saboteurs, cyber security breaches, and other similar events, many of which are beyond our control.

The occurrence of any of the risks set out above could result in serious injury and loss of human life, significant damage to property and natural resources, environmental pollution, significant reputational damage, impairment or suspension of operations, fines or other regulatory penalties, and revocation of regulatory approvals or imposition of new requirements, any of which also could result in substantial financial losses. For storage and pipeline assets located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of damage resulting from these risks may be greater. In addition, the consequences of any operational incident (including as a result of adverse sea conditions) at our Vancouver Wharves Terminal or involving a vessel receiving products from our Vancouver Wharves Terminal, may be even more significant as a result of the complexities involved in addressing leaks and releases occurring in the ocean or along coastlines and/or the repair of marine terminals. Any leaks, releases or other incidents involving such vessels, or other similar operators along the West Coast, could result in significant harm to the environment, curtailment of, or disruptions of and/or delays in, offshore shipping activity in the affected areas, including our ability to effectively carry on operations at our Vancouver Wharves Terminal. Our inability to facilitate the movement of our customers' products to offshore markets, or a significant delay in such services, could have a material adverse effect on our business.

We are subject to reputational risks and risks relating to public opinion.

Our business, operations or financial condition generally may be negatively impacted as a result of negative public opinion. Public opinion may be influenced by negative portrayal of the industry in which we operate as well as opposition to development projects. In addition, market events specific to us could result in the deterioration of our reputation with key stakeholders. Potential impacts of negative public opinion or reputational issues may include delays or stoppages in expansion projects, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support from regulatory authorities, challenges to regulatory approvals, difficulty securing financing for and cost overruns affecting expansion projects and the degradation of our business generally.

Reputational risk cannot be managed in isolation from other forms of risk. Credit, market, operational, insurance, regulatory and legal risks, among others, must all be managed effectively to safeguard our reputation. Our reputation and public opinion could also be impacted by the actions and activities of other companies operating in the energy industry, particularly other energy infrastructure providers, over which we have no control. In particular, our reputation could be impacted by negative publicity related to pipeline incidents or unpopular expansion projects and due to opposition to development of hydrocarbons and energy infrastructure, particularly projects involving resources that are considered to increase GHG emissions and contribute to climate change. Negative impacts from a compromised reputation or changes in public opinion (including with respect to the production, transportation and use of hydrocarbons generally) could include revenue loss, reduction in customer base, delays in obtaining, or challenges to, regulatory approvals with respect to growth projects, and decreased value of our securities and our business.

Financial distress experienced by our customers or other counterparties could have an adverse impact on us in the event they are unable to pay us for the products or services we provide or otherwise fulfill their obligations to us.

We are exposed to the risk of loss in the event of non-performance by our customers or other counterparties, such as, joint venture partners and suppliers. Our counterparties are subject to their own operating, market, financial and regulatory risks, and some are experiencing, or may experience in the future, severe financial problems that have had or may have a significant impact on their creditworthiness. Further, while certain of our customers are subsidiaries of an entity that has an investment grade credit rating, in many cases the parent entity has not guaranteed the obligations of the subsidiary and, therefore, the parent's credit ratings may have no bearing on such customers' ability to pay us for the services we provide or otherwise fulfill their obligations to us. Furthermore, in the case of financially distressed customers, such events might force such customers to reduce or curtail their future use of our services, which could have a material adverse effect on our results of operations, financial condition and cash flows.

We cannot provide any assurance that such customers and key counterparties will not become financially distressed or that such financially distressed customers or counterparties will not default on their obligations to us or file for bankruptcy protection. If one of such customers or counterparties files for bankruptcy protection, we likely would be unable to collect all, or even a significant portion, of amounts owed to us. Significant customer and other counterparty defaults and bankruptcy filings could have a material adverse effect on our business, financial position, results of operations or cash flows.

We rely on leased facilities, third-party pipelines, refineries and other third-party facilities in providing service to our customers. To the extent that these facilities or pipelines become capacity-constrained or unavailable, our cash flows, results of operations and financial condition could be adversely affected.

Our ability to provide service to our customers depends in part on the availability, proximity and capacity of third-party pipelines, rail, refinery and other facilities, and because we do not own or operate these facilities, their continuing operation or availability is not within our control. For example, we rely on the Trans Mountain pipeline to transport crude oil from the WCSB to our Edmonton terminal facilities.

Like us, third-party service providers are subject to risks inherent in the midstream business, including capacity constraints, changes in business ownership, natural disasters and operational, mechanical or other hazards, as well as service interruptions for scheduled maintenance. The curtailments arising from these and similar circumstances may last from a few days to several months, and these interruptions could have a material adverse effect on our cash flows, results of operations and financial condition.

For example, Jet Fuel's supplying refinery was sold in 2017. As a result of that sale, we are unable to predict whether, and to what extent, that refinery will continue to supply jet fuel to Jet Fuel. These developments have made it unclear how much jet fuel will continue to be available for shipment to the Vancouver International Airport by way of Jet Fuel in the future.

Some of our leased facilities also may become unavailable pursuant a contractual right of recall. We provide service at our Edmonton South Terminal using tanks and facilities that we lease from Trans Mountain. Our lease is subject to a right of recall, which is exercisable by Trans Mountain in the event that the Edmonton Terminal is fully built out and Trans Mountain requires the tanks for its regulated service. In connection with the completion of TMEP, we expect that Trans Mountain will exercise recall rights under the leasing arrangement in respect of two of the tanks at the Edmonton South Terminal, which will reduce our net cash earnings attributable to the Edmonton South Terminal. See Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook—Terminals Matters.*"

Failure of one or more key information technology or operational (IT) systems, or those of third parties, or a breach of information security may adversely affect our business, results of operations or business reputation.

Our business depends upon our operational systems to process large amounts of data and complex transactions. The various uses of these IT systems, networks and services include, but are not limited to, controlling our terminals and pipelines with industrial control systems, collecting and storing information and data, processing transactions, and handling other processing necessary to manage our business.

If any of our systems fail to function properly, sustain damage or otherwise become unavailable, we may incur substantial costs to repair or replace them and may experience loss or corruption of critical data as well as interruptions or delays in our ability to perform critical functions, which could adversely affect our business and results of operations. The occurrence of a significant compromise, failure, breach or interruption of our systems could result in a disruption of our operations, customer dissatisfaction, loss of customers or revenues, and damage to our reputation. Our and our vendors' efforts to develop, implement and maintain security measures may not be successful in preventing these events from occurring, and any network and information systems-related events could require us to expend significant resources to remedy such event. In the future, we may be required to expend additional resources to continue to enhance our information security measures and/or to investigate and remediate information security vulnerabilities.

Attacks, including acts of terrorism or cyber sabotage, or the threat of such attacks, may adversely affect our business or our reputation.

The U.S. and Canadian governments have issued public warnings that indicate that pipelines and other infrastructure assets might be specific targets of terrorist organizations or "cyber sabotage" events. For example, in 2018, a cyber-attack on a shared data network forced four U.S. natural gas pipeline operators to temporarily shut down computer communications with their customers. Potential targets include our pipeline systems, terminals, processing plants or operating systems. The

occurrence of an attack could cause a substantial decrease in revenues and cash flows, increased costs to respond or other financial loss, damage to our reputation, increased regulation or litigation or inaccurate information reported from our operations. There is no assurance that adequate cyber sabotage and terrorism insurance will be available at rates we believe are reasonable in the near future. These developments may subject our operations to increased risks, as well as increased costs, and, depending on their ultimate magnitude, could have a material adverse effect on our business, results of operations and financial condition or could harm our business reputation.

We may be subject to abandonment costs.

We are responsible for compliance with all applicable laws and regulations regarding the abandonment of our pipeline systems and other assets at the end of their economic life, and these abandonment costs may be substantial. The proceeds of the disposition of certain assets, including in respect of certain pipeline systems and line fill, may be available to offset abandonment costs. While we estimate future abandonment costs and receive (through tolls) future abandonment costs based on such estimates, actual abandonment costs may be higher than the amounts received through tolls. We may, in the future, determine it to be prudent or required by applicable laws or regulations to establish and fund additional reclamation trusts to provide for payment of our future abandonment costs. Such reserves could decrease cash flow available for dividends to shareholders and to service our obligations under any applicable debt obligations.

To date, we have complied with the NEB's requirements on Cochin, our NEB-regulated pipeline, for the creation of abandonment trusts and have completed the compliance-based filings that are required under the applicable NEB rules and regulations regarding its abandonment. While we collect abandonment surcharges from our shippers and deposit such amounts in our abandonment trust for our NEB-regulated pipelines, there is a risk that abandonment costs and post-abandonment liabilities could exceed the amounts held in trust. Further, and unlike our approach to Cochin, we do not maintain dedicated abandonment trusts for our Jet Fuel or terminals assets. Additional or unexpected expenditures incurred in respect of abandonment costs could have a material adverse effect on our business, results of operations and financial condition.

We require a skilled workforce, and difficulties recruiting and retaining our workforce could result in a failure to implement our business plans.

The operation and management of our business requires the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals, and the loss of key members of such workforce, or a substantial portion of the workforce as a whole, could result in the failure to implement our business plans. We compete with other companies in the energy infrastructure industry for this skilled workforce. In addition, many of our current employees are retirement eligible and have significant institutional knowledge that must be transferred to other employees. If we are unable to (i) retain current employees; (ii) successfully complete effective knowledge transfers; and/or (iii) recruit new employees with comparable knowledge and experience, we could be negatively impacted. In addition, we could experience increased allocated costs to retain and recruit these professionals.

Expanding our existing assets and constructing new assets is part of our growth strategy. Our ability to begin and complete construction on expansion and new-build projects may be inhibited by difficulties in obtaining, or our inability to obtain, permits and rights-of-way, as well as public opposition, increases in costs of construction materials, cost overruns, inclement weather and other delays. Should we pursue expansion of or construction of new projects through joint ventures with others, we will share control and benefits from those projects.

We regularly undertake major construction projects to expand our existing assets and to construct new assets. Any new growth projects will be subject to, among other things, the receipt of regulatory approvals, feasibility and cost analyses, funding availability and industry, market and demand conditions. If we pursue joint ventures with third parties, those parties may share approval rights over major decisions, and may act in their own interests. Their views may differ from our own or our views of the interests of the venture, which could result in operational delays or impasses, which in turn could affect the financial expectations of the venture and our benefits therefrom. Our expansion and construction projects can be affected by a variety of factors outside of our control, such as difficulties in obtaining permits and rights-of-way or other regulatory approvals, have caused, and may continue to cause, delays in or cancellations of our construction projects. These factors can be exacerbated by public opposition to our projects. See "—*We are subject to reputational risks and risks relating to public opinion*." Additionally, events such as inclement weather or significant weather-related events (including storms and rising sea levels (potentially resulting from climate change) impacting our marine terminals), natural disasters, unforeseen geological conditions and delays in performance by third-party contractors have also resulted in, and may continue to result in, increased costs or delays in construction. Significant cost overruns or delays, or our inability to obtain a required permit or right-of-way, could have a material adverse effect on our return on investment, results of operations and cash flows, and could result in project cancellations or limit our ability to pursue other growth opportunities.

Climate change impacts may adversely affect our operations.

Many climatic models indicate that global warming is likely to result in rising sea levels, increased intensity of weather, and increased frequency of extreme precipitation and flooding. These climate related changes could damage physical assets, especially operations located near rivers, and facilities situated in rain-susceptible regions. In addition, we may experience increased insurance premiums and deductibles, or a decrease in available coverage, for our assets in areas subject to severe weather. If resulting losses exceed our insurance coverage, our business, financial condition and results of operations could be adversely impacted. See Items 1 and 2 *"Business and Properties—Regulation—Climate Change and GHG Regulation*."

We may require access to external capital.

We have limited amounts of internally generated cash flows to fund growth capital expenditures and acquisitions. If we undertake significant projects or acquisitions, we expect that we will have to rely on external financing sources, including commercial borrowings and issuances of debt and equity securities (including preferred securities) and potential joint venture arrangements, to fund such capital expenditures. Adverse changes to the availability, terms and cost of capital or interest rates affecting our ability to meet the requirements to borrow under our credit facility could cause our cost of doing business to increase by limiting our access to capital, limiting our ability to pursue expansion opportunities or additional acquisitions and reducing our cash flows. Also, disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations on satisfactory terms.

Limitations on access to external financing sources, whether due to tightened capital markets, more expensive capital or otherwise, or any significant reduction in the availability of credit would significantly impair our ability to execute our growth strategy, which could have a material adverse effect on our business, financial condition and results of operations. To the extent that we are required to issue additional equity, including preferred shares, or the Limited Partnership issues additional securities, including preferred units, to raise funds that are required to continue operating our business or complete expansion projects, the dilutive impact on existing shareholders would be increased and the market price of the Restricted Voting Shares could decline. Delays or cost overruns affecting key projects could result in depressed market prices or values of the Restricted Voting Shares, and the issuance of additional equity, including preferred shares, at such depressed prices may be required.

We could be adversely affected by future substantial levels of debt.

As of December 31, 2018, we had no debt outstanding. A significant increase in our debt levels could have significant negative consequences, including: (i) limiting our ability to obtain additional financing to fund our working capital, capital expenditures, debt service requirements or potential growth, or for other purposes; (ii) increasing the cost of our future borrowings; (iii) limiting our ability to use operating cash flow in other areas of our business or to pay dividends or distributions because we must dedicate a substantial portion of these funds to make payments on our debt; (iv) placing us at a competitive disadvantage compared to competitors with less debt; and (v) increasing our vulnerability to adverse economic and industry conditions.

Our ability to service debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, many of which are beyond our control. If cash flow is not sufficient to service our debt, we will be forced to take actions such as reducing or eliminating dividends or distributions, reducing or delaying business activities (including our expansion projects), acquisitions, investments and/or capital expenditures, selling assets or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms or at all. See also "*—We may require access to external capital*" above and "*—Risks Relating to Ownership of Restricted Voting Shares and Preferred Shares—There are limitations on voting power of the holders of Restricted Voting Shares"* below.

The terms of our credit facility, and any debt we may incur in the future, may prevent us or the Limited Partnership from engaging in certain transactions, including paying dividends or distributions, as applicable, that might have otherwise been beneficial to us and the holders of Restricted Voting Shares.

Our insurance policies do not cover all losses, costs or liabilities that we may experience, and insurance companies that currently insure companies in the energy industry may cease to do so or substantially increase premiums.

Our insurance program may not cover all operational risks and costs and may not provide sufficient coverage in the event of a claim. We do not maintain insurance coverage against all potential losses and could suffer losses for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Losses in excess of our insurance coverage could have a material adverse effect on our business, financial condition and results of operations. The total insurance coverage will be allocated among the Kinder Morgan Canada Group on an equitable basis in the event multiple insurable incidents exceeding our coverage limits within the same insurance period are experienced.

Changes in the insurance markets have made it more difficult and more expensive to obtain certain types of coverage. The occurrence of an event that is not fully covered by insurance, or failure by one of our insurers to honor its coverage commitments for an insured event, could have a material adverse effect on our business, financial condition and results of operations. Insurance companies may reduce the insurance capacity they are willing to offer or may demand significantly higher premiums or deductibles to cover our assets. If significant changes in the number or financial solvency of insurance underwriters for the energy industry occur, we may be unable to obtain and maintain adequate insurance at a reasonable cost. There is no assurance that our insurers will renew their insurance coverage on acceptable terms, if at all, or that we will be able to arrange for adequate alternative coverage in the event of non-renewal. The unavailability of full insurance coverage to cover events in which we suffer significant losses could have a material adverse effect on our business, financial condition and results of operations.

Risks Relating to Regulation

New laws, policies, regulations, rule-making and oversight, as well as changes to those currently in effect, could adversely impact our earnings, cash flows and operations.

Our assets and operations are subject to regulation and oversight by federal, state, provincial and municipal regulatory authorities. Regulatory actions taken by these agencies have the potential to adversely affect our profitability and/or the profitability of our business. Regulation affects almost every part of our business and extends to such matters as: (i) the certification and construction of expansion projects and new facilities; (ii) tariff rates, operating terms and conditions of service; (iii) the types of services we may offer to our customers; (iv) the contracts for service entered into with customers; (v) the integrity, safety and security of facilities and operations; (vi) the acquisition of other businesses; (vii) the acquisition, extension, disposition or abandonment of services or facilities; (viii) reporting and information posting requirements; (ix) the maintenance of accounts and records; and (x) relationships with affiliated companies involved in various aspects of the oil and gas industry.

Should we fail to comply with any applicable statutes, rules, regulations, and orders of such regulatory authorities, we could be subject to substantial penalties and fines and potential revocation of permits. Furthermore, new laws or regulations sometimes arise from unexpected sources. New laws or regulations, or different interpretations of existing laws or regulations, including unexpected policy changes, could have a material adverse impact on our business, financial condition and results of operations.

Environmental, health and safety laws and regulations could expose us to significant costs and liabilities.

Our business operations are subject to federal, provincial and local laws, regulations and potential liabilities arising under or relating to the protection or preservation of the environment (including with respect to climate change), natural resources and human health and safety. Such laws, regulations and obligations affect many aspects of our present and future operations, and generally require us to obtain and comply with various environmental registrations, licenses, permits, inspections and other approvals, including with respect to our expansion and new build projects. Liability under such laws and regulations may be incurred without regard to fault for the remediation of contaminated areas. Private parties, including the owners of properties through which our pipelines pass, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with such laws and regulations or for personal injury or property damage.

Failure to comply with these laws and regulations also may expose us to civil, criminal and administrative fines, penalties and/or interruptions in operations that could harm our business, financial position, results of operations or prospects. The resulting costs and liabilities could materially and negatively affect our earnings and cash flows. Also, we own and/or operate numerous properties and assets that have been used for many years in connection with our business activities or those of our predecessors or third parties, or at or from properties where our or our predecessors' wastes have been taken for disposal. These properties and the hazardous substances released and wastes disposed on them could subject us to liability schemes that

could have a material adverse impact on our operations and financial position. See Items 1 and 2 "*Business and Properties—Environmental Matters.*"

We cannot ensure that existing laws and regulations will not be revised or that new laws or regulations will not be adopted or become applicable to our business. There can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts currently anticipated. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material adverse effect on our business, financial position, results of operations and prospects. In addition, such revised or additional regulations may have significant negative impacts on the business and operations of our customers and/or shippers that could result in such customers and/or shippers defaulting on their contractual obligations to us. See "*—Risks Relating to Our Business—Financial distress experienced by our customers or other counterparties could have an adverse impact on us in the event they are unable to pay us for the products or services we provide or otherwise fulfill their obligations to us*" above.

In addition to the cost of remediation activities (to the extent not covered by insurance), environmental incidents may lead to an increased cost of operating and insuring our assets, thereby negatively impacting earnings and DCF. See Items 1 and 2 *"Business and Properties—Regulation—Climate Change and GHG Regulations*."

Although we have OMS and EMP programs in place and have invested significant resources in emergency response plans, training and education programs, our prevention and mitigation efforts are incapable of guarding against all environmental risks, including the risk of significant damage to our assets as a result of catastrophic events (including natural disasters, other significant weather-related events or adverse sea conditions), or the actions of third parties acting outside of our control. In addition, our insurance may not cover all environmental risks and costs and/or may not provide sufficient coverage in the event an environmental claim is made against us.

Changes in tax laws and reassessments could adversely impact future DCF.

Income tax returns filed by entities forming part of our business remain subject to reassessment by applicable taxation authorities, and it is possible that the taxation authorities could successfully challenge prior transactions and tax filings of such entities. In the event of a successful reassessment, we could be subject to higher than expected past or future income tax liability as well as, potentially, interest and/or penalties, which could result in a material reduction in DCF or cash available for dividends.

Income tax laws, including income tax laws applicable to the energy infrastructure industry, may in the future be changed or interpreted in a manner that adversely affects us. Furthermore, tax authorities having jurisdiction over us may disagree with how those entities calculate income for tax purposes or could change administrative practices to the detriment of those entities. A change in applicable tax laws, or the administrative interpretation thereof, in a manner adverse to us could result in a material reduction in DCF or cash available for dividends.

Changes in pipeline tariff rates may have a negative impact on our operating results.

Regulatory bodies having jurisdiction over us may establish pipeline tariff rates or requirements that could have a negative impact on our business. In addition, such regulatory bodies or our customers could file complaints challenging the tariff rates charged by us, and a successful complaint could have an adverse impact on us. The profitability of our regulated pipelines is influenced by fluctuations in costs and our ability to recover any increases in our costs in the rates charged to our shippers. To the extent that those costs increase in an amount greater than what we are permitted by the regulators to recover in our rates, or to the extent that there is a lag before we can file for and obtain rate increases, such events can have a negative impact upon our operating results.

Certain existing rates may also be challenged by complaint. Shippers on our pipelines have rights to challenge the rates that are charged under certain circumstances prescribed by applicable regulations, and regulators have discretion to deny proposed rates. We may face challenges to the rates charged on our pipelines. Any successful challenge to our rates could materially adversely affect our future earnings, DCF and financial condition.

Our Cochin pipeline is subject to Canadian dollar/ U.S. dollar exchange rate fluctuations.

We are a Canadian dollar reporting company. As a result of the operations of our Cochin pipeline in the U.S., a portion of our consolidated assets, liabilities, revenues, cash flows and expenses are denominated in U.S. dollars. Fluctuations in the exchange rate between Canadian and U.S. dollars could expose us to reductions in the Canadian dollar value of our earnings and cash flows and a reduction in our shareholders' equity under applicable accounting rules.

Risks Relating to Our Relationship with Kinder Morgan

Kinder Morgan's shareholdings in the Company may give rise to conflicts of interest.

Kinder Morgan, indirectly through its wholly owned subsidiaries KMCC and KMCT, holds the controlling voting interest in us, including with respect to the right to vote for the election of directors to the board of directors. In addition, we are the sole shareholder of the General Partner and, as such, Kinder Morgan indirectly, through controlling the Company Voting Shares, has the ability to influence elections of the directors to the board of directors of the General Partner. In its capacity as general partner of the Limited Partnership, the General Partner is authorized to manage, administer and operate the business and affairs of the Limited Partnership, to make all decisions regarding the business of the Limited Partnership and to bind the Limited Partnership in respect of any such decisions, subject to certain limitations contained in the Limited Partnership Agreement. As a result of the foregoing, Kinder Morgan, indirectly through its controlling voting interest in us and corresponding ability to influence the elections of directors, has the ability to influence the management of our business. See Item 13 *"Certain Relationships and Related Transactions, and Director Independence*" and "*—Risks Relating to Ownership of Restricted Voting Shares and Preferred Shares—There are limitations on voting power of the holders of Restricted Voting Shares*" below.

Our relationship with Kinder Morgan, as our majority shareholder, does not impose any duty on Kinder Morgan or its affiliates to act in our best interest and, other than as set out in the Cooperation Agreement, Kinder Morgan is not prohibited from engaging in other business activities that may compete with us. Our ownership structure involves a number of relationships that may give rise to conflicts of interest between us and the holders of Restricted Voting Shares and our preferred shares, on the one hand, and Kinder Morgan, on the other hand. In certain instances, the interests of Kinder Morgan may differ from our interests and the interests of our shareholders, including with respect to future acquisitions or strategic decisions. It is possible that conflicts of interest may arise between us and Kinder Morgan, and that such conflicts may not be resolved in a manner that is in our best interests or in the best interests of our shareholders. Additionally, Kinder Morgan and its affiliates have access to material confidential information about us. Although some of these entities are subject to confidentiality obligations pursuant to confidentiality agreements or pursuant to duties of confidence or applicable codes of conduct, neither the Services Agreement nor the Cooperation Agreement contains general confidentiality provisions. See Item 13 *"Certain Relationships and Related Transactions, and Director Independence.*"

Future changes in our relationship with Kinder Morgan may negatively impact our business.

Our arrangements with Kinder Morgan do not require Kinder Morgan, either directly or indirectly, to maintain any ownership level in us or the Limited Partnership. Accordingly, Kinder Morgan may transfer all or a substantial portion of its interest in the Limited Partnership (together with the Special Voting Shares) to a third party, including in a merger or consolidation or sale of its Class B Units and Special Voting Shares, without our consent or the consent of our shareholders, but subject to compliance with applicable "coattail" provisions of the Limited Partnership Agreement and our articles, market conditions, Kinder Morgan's requirements for capital or other circumstances that may arise in the future. The interests of a transferee of the Class B Units and Special Voting Shares may be different from Kinder Morgan's and may not align with those of other shareholders. We cannot predict with any certainty the effect that any such transfer would have on the trading price of the Restricted Voting Shares or our ability to raise capital in the future. As a result, our future would be uncertain and our business and financial condition may suffer.

We rely on KMI for management, financial reporting, accounting, administrative and legal services.

Certain of our officers and directors also serve as officers and directors of KMI, and we receive significant financial reporting, accounting, administrative and legal support and other services from KMI. KMI is subject to its own financial reporting and other obligations that place significant demands on its management, administrative, operational, legal, internal audit and accounting resources who provide services to us. Demands associated with KMI's reporting and other obligations may divert our management's attention from other business concerns and may adversely affect our business, financial condition and results of operations. The demands on these personnel may be intensified as a result of the management and personnel departures and related transition following the Trans Mountain Transaction.

Risks Relating to Ownership of Restricted Voting Shares and Preferred Shares

There are limitations on voting power of the holders of Restricted Voting Shares.

Each Restricted Voting Share and each Special Voting Share entitles the holder thereof to one vote per share held at all meetings of our shareholders, except meetings at which or in respect of matters on which only the holders of another class of shares are entitled to vote separately as a class pursuant to applicable laws. Unless otherwise required by law, the holders of Restricted Voting Shares and Special Voting Shares vote together as a single class. Holders of Restricted Voting Shares are entitled to approximately 30% of the votes held by all our shareholders and Kinder Morgan, the indirect holder of the Special Voting Shares, is entitled to approximately 70% of the votes held by all our shareholders.

As a result, Kinder Morgan has a controlling interest in the combined voting power of the Company Voting Shares, including with respect to the election of the board of directors. This level of ownership of Special Voting Shares indirectly by Kinder Morgan will limit the ability of holders of the Restricted Voting Shares to influence corporate and partnership matters for the foreseeable future, including the election of directors (both with respect to the Company and the General Partner) as well as with respect to decisions regarding the amendment of our share capital or the Limited Partnership Agreement, creating and issuing additional Company Voting Shares or classes of shares or limited partnership units, making significant acquisitions, selling significant assets or parts of our business, merging with other companies, significant joint ventures, the payment or non-payment of dividends or limited partnership distributions and undertaking other significant transactions. The market price of the Restricted Voting Shares could be adversely affected due to the significant voting power of Kinder Morgan. Additionally, the significant voting interest of Kinder Morgan may discourage transactions involving a change of control, including transactions in which a holder of the Restricted Voting Shares might otherwise receive a premium for their Restricted Voting Shares over the then-current market price, or discourage competing proposals if a going private transaction is proposed or undertaken by Kinder Morgan. See Item 13 *"Certain Relationships and Related Transactions, and Director Independence.*"

Cash dividend payments are not guaranteed.

The payment of dividends is not guaranteed under our dividend policy or under the terms of our Preferred Shares, and amounts of such dividends could fluctuate with the performance of our business. Additionally, the Series 1 Preferred Shares and Series 3 Preferred Shares are and, if and when issued, the Series 2 Preferred Shares and Series 4 Preferred Shares, and any preferred shares issued by us in the future may be, senior to the Restricted Voting Shares with respect to priority in payment of dividends and the distribution of assets in the event of liquidation. The terms of the Series 1 Preferred Shares, Series 2 Preferred Shares, Series 3 Preferred Shares and Series 4 Preferred Shares as issued prohibit us from declaring or paying dividends on the Restricted Voting Shares unless all dividends on then outstanding preferred shares of the Company have been paid.

The board of directors has the discretion to determine the amount of dividends, if any, to be declared and paid to shareholders. The board of directors may alter our dividend policy at any time, and the payment of dividends may be affected by, among other things, changes in: commodity prices; the financial condition of our business; current and expected future levels of earnings; capital and liquidity requirements; market opportunities; income taxes; debt repayments; legal and regulatory requirements, including the solvency requirements of the *Business Corporations Act* (Alberta) and the regulations thereunder, as amended from time to time ("ABCA"); contractual constraints; tax laws; and other relevant factors. There can be no guarantee as to the amount of distributions from the Limited Partnership and any number of factors could cause the General Partner to revise its policies and/or strategies respecting distributions. Certain terms of the Credit Facility (described below) also indirectly restricts our ability to pay dividends or the ability of the Limited Partnership to pay distributions.

Over time, our capital and other cash needs may change significantly from our current needs, which could affect whether we pay dividends and the amount of dividends, if any, we may pay in the future. If we experience a significant downturn, the currently anticipated level of distributions by the Limited Partnership (and funding for Company dividends) could leave us with insufficient cash to finance growth opportunities, meet any large unanticipated liquidity requirements or fund our activities. The board of directors may amend, revoke or suspend our dividend policy or elect not to declare Preferred Share dividends, or both, in response to such circumstances or for other reasons. A decline in the market price or liquidity, or both, of the Restricted Voting Shares or our Preferred Shares could result if we reduce or eliminate the payment of dividends, which could result in losses to shareholders.

There can be volatility in the market price of Restricted Voting Shares.

The market price for Restricted Voting Shares may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond our control, and the possibility and extent of such volatility may be increased as a result of our recent share consolidation. Factors that could cause volatility include the following: (i) anticipated fluctuations in our financial results; (ii) recommendations by securities research analysts; (iii) changes in the economic performance or market valuations of other companies that investors deem comparable to us or Kinder Morgan; (iv) the loss or resignation of directors, officers and other key personnel of the Company; (v) sales or anticipated sales of additional Restricted Voting Shares; (vi) significant acquisitions or business combinations or other strategic transactions involving us from which we do not realize the anticipated benefits; (vii) trends, concerns, technological or competitive developments, regulatory changes and other related issues in the energy infrastructure industry; and (viii) actual or anticipated fluctuations in interest rates.

Financial markets have experienced significant price and volume fluctuations in recent years that have particularly affected the market prices of equity securities of companies and that have, in many cases, been unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of the Restricted Voting Shares may decline even if our operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause decreases in asset values which may result in impairment losses. Certain institutional investors may base their investment decisions on consideration of our environmental, governance and social practices and performance against such institutions' respective investment guidelines and criteria, and failure to meet such criteria may result in a limited or no investment in the Restricted Voting Shares by those institutions, which could adversely affect the trading price of the Restricted Voting Shares.

Non-Canadian holders of Restricted Voting Shares face foreign exchange risk on dividends.

Our cash dividends will be declared in Canadian dollars. As a consequence, non-resident shareholders, and shareholders who calculate their return in currencies other than the Canadian dollar, will be subject to foreign exchange risk. To the extent that the Canadian dollar strengthens with respect to their currency, the amount of the dividend will be reduced when converted to their home currency.

Item 1B. ***Unresolved Staff Comments.***

None.

Item 3. ***Legal Proceedings.***

See Note 20 "*Litigation, Commitments and Contingencies*" to our consolidated financial statements.

Item 4. ***Mine Safety Disclosures.***

Not applicable.

PART II

Item 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.***

Restricted Voting Shares

On November 29, 2018, our shareholders approved a proposal from our board of directors to reduce the stated capital of the Restricted Voting Shares, primarily to enable a return of capital to distribute the net proceeds (after capital gains taxes, customary purchase price adjustments and repayment of our debt) from the Trans Mountain Transaction. The return of capital of $11.40 per Restricted Voting Share (the "Return of Capital") was paid on January 3, 2019 to shareholders of record as of December 14, 2018.

Preferred Shares

Our Series 1 Preferred Shares and Series 3 Preferred Shares are listed on the TSX under the symbol "KML.PR.A" and "KML.PR.C", respectively. As of February 14, 2019, there were 12,000,000 and 10,000,000 Series 1 Preferred Shares and Series 3 Preferred Shares outstanding, respectively. See "*—Ownership Interests—Preferred Shares*" below.

Related Stockholder Matters

On November 29, 2018, our shareholders also approved a proposal from our board of directors to effect a consolidation, or "reverse stock split", of Restricted Voting Shares and Special Voting Shares on a one-for-three basis (three shares consolidating into one share) (the "Share Consolidation"). The Share Consolidation was effected January 4, 2019 and the Restricted Voting Shares commenced trading on a post-consolidation basis on January 8, 2019.

On January 4, 2019, in accordance with the equivalency provisions in the Limited Partnership Agreement and contemporaneously with the Share Consolidation, the Class A Units and Class B Units were consolidated on a one-for-three basis (three units consolidating into one unit) and the common shares of the General Partner were consolidated on a one-for-three basis (three common shares consolidating into one common share).

After giving effect to the Share Consolidation, as of February 14, 2019, there were 34,944,993 Restricted Voting Shares, 81,353,820 Special Voting Shares, 12,000,000 Series 1 Preferred Shares and 10,000,000 Series 3 Preferred Shares outstanding, and there was one holder of record of our Restricted Voting Shares, two holders of record of our Special Voting Shares, one holder of record of our Series 1 Preferred Shares and one holder of record of our Series 3 Preferred Shares. These holders of record do not include beneficial owners whose shares are held by a nominee, such as a broker or bank.

Also, see Preferred Share, Restricted Voting Share, and Special Voting Share dividends and distributions for and during 2018 in Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Equity, Dividends and Distributions.*"

Tax Matters Applicable to Ownership of Restricted Voting Shares

Holders Resident in the U.S.

The following discussion is applicable to a holder of Restricted Voting Shares who, for the purposes of the Canadian Income Tax Act (the "Tax Act") and the Canada-United States Tax Convention (1980), as amended (the "Treaty"), at all relevant times, is not resident or deemed to be resident in Canada, is a resident of the United States for the purposes of the Treaty and qualifies for the full benefits thereunder, and who does not use or hold (and is not deemed to use or hold) the Restricted Voting Shares in connection with a business carried on in Canada (a "U.S. Resident Holder"). This discussion is not applicable to a U.S. Resident Holder that is an insurer that carries on an insurance business in Canada.

This discussion is not applicable to a U.S. Resident Holder whose Restricted Voting Shares are or are deemed to be "taxable Canadian property" for purposes of the Tax Act. Provided that the Restricted Voting Shares are listed on a designated stock exchange (which includes the TSX) at a particular time, the Restricted Voting Shares generally will not constitute taxable Canadian property to a U.S. Resident Holder at that time unless, at any time during the five-year period immediately preceding that time: (i) 25% or more of the issued shares of any class or series of the Company's capital stock were owned by any combination of (a) the U.S. Resident Holder, (b) persons with whom the U.S. Resident Holder did not deal at arm's length, and (c) partnerships in which the U.S. Resident Holder or a person described in (b) holds a membership interest directly or indirectly through one or more partnerships; and (ii) more than 50% of the value of the Restricted Voting Shares was derived, directly or indirectly, from one or any combination of (a) real or immoveable property situated in Canada, (b) Canadian resource properties, (c) timber resource properties, and (d) options in respect of, or an interest in, any such property (whether or not the property exists), all for purposes of the Tax Act. A U.S. Resident Holder's Restricted Voting Shares can also be deemed to be taxable Canadian property in certain circumstances set out in the Tax Act.

Taxation of Dividends

Dividends paid or credited or deemed to be paid or credited by the Company to a non-resident of Canada will generally be subject to Canadian withholding tax at the rate of 25%, subject to any applicable reduction in the rate of such withholding under an income tax treaty between Canada and the country where the holder is resident. Under the Treaty, the withholding tax rate in respect of a dividend paid to a U.S. Resident Holder that beneficially owns such dividends is generally reduced to 15%, unless the U.S. Resident Holder is a company which owns at least 10% of the voting shares of the Company at that time, in which case the withholding tax rate is reduced to 5%.

Disposition of Restricted Voting Shares

A U.S. Resident Holder will not be subject to tax under the Tax Act in respect of any capital gain realized on the disposition of Restricted Voting Shares.

Recent Sales of Unregistered Securities

Since January 1, 2018, we have issued 125,095 restricted voting shares in settlement of vesting RSU awards, after giving effect to the Share Consolidation. See Note 11 "*Share-based Compensation and Benefit Plans—Share-based Compensation*" to our consolidated financial statements.

Ownership Interests

The following description of our capital stock is a summary only and is qualified in its entirety by reference to our Articles and By-laws, each as amended, and to the Limited Partnership Agreement, which are included as Exhibits 3.2, 3.4, 3.6 and 3.8 hereto, respectively.

We are authorized to issue an unlimited number of Restricted Voting Shares, an unlimited number of Special Voting Shares and an unlimited number of preferred shares issuable in series. After giving effect to the Share Consolidation, as of February 14, 2019, there were 34,944,993 Restricted Voting Shares, 81,353,820 Special Voting Shares, 12,000,000 Series 1 Preferred Shares and 10,000,000 Series 3 Preferred Shares outstanding.

Restricted Voting Shares

Holders of Restricted Voting Shares are entitled to one vote for each Restricted Voting Share held at all meetings of our shareholders, except meetings at which or in respect of matters on which only holders of another class of shares are entitled to vote separately as a class. Except as otherwise provided by our Articles or required by law, the holders of Restricted Voting Shares will vote together with the holders of Special Voting Shares as a single class.

The holders of Restricted Voting Shares are entitled to receive, subject to the rights of the holders of another class of shares, any dividend we declare, and the remaining property of the Company upon the liquidation, dissolution or winding-up of the Company, whether voluntary or involuntary.

The terms of the Preferred Shares prohibit us from declaring or paying dividends on the Restricted Voting Shares unless all dividends on the Preferred Shares have been paid. See Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Equity*, *Dividends and Distributions*."

The payment of dividends on Restricted Voting Shares is not guaranteed, and the amount and timing of any dividends payable will be at the discretion of the board of directors. See Item 1A "*Risk Factors—Risks Relating to Ownership of Restricted Voting Shares and Preferred Shares—Cash dividend payments are not guaranteed.*"

We may not issue or distribute to all or to substantially all of the holders of the Restricted Voting Shares either (i) Restricted Voting Shares, or (ii) rights or securities of the Company exchangeable for or convertible into or exercisable to acquire Restricted Voting Shares, unless contemporaneously therewith, we issue or distribute Special Voting Shares or rights or securities of the Company exchangeable for or convertible into or exercisable to acquire Special Voting Shares on substantially similar terms (having regard to the specific attributes of the Special Voting Shares) and in the same proportion.

None of the Restricted Voting Shares will be subdivided, consolidated, reclassified or otherwise changed unless contemporaneously therewith the Special Voting Shares are subdivided, consolidated, reclassified or otherwise changed in the same proportion or same manner (having regard to the specific attributes of the classes of securities comprising the Company Voting Shares). In addition, under the Cooperation Agreement, we will make equivalent changes to the Restricted Voting Shares in the event any adjustments are made to the LP Units, in order to preserve the general alignment of the LP Units and the Company Voting Shares. See "*—Special Voting Shares*" below and Item 13 *"Certain Relationships and Related Transactions, and Director Independence—Agreements between the Company and Kinder Morgan—Cooperation Agreement.*"

We may not modify or remove any of the rights, privileges, conditions or restrictions of the Restricted Voting Shares without the approval by special resolution of the holders of Restricted Voting Shares.

Special Voting Shares

All of our outstanding Special Voting Shares are held by Kinder Morgan, indirectly through KMCC and KMCT, for the purpose of providing voting rights with respect to the Company. Under our Articles, we are prohibited from issuing any Special Voting Shares unless a corresponding number of associated Class B Units are concurrently issued by the Limited Partnership. In addition, holders of Special Voting Shares are prohibited from transferring their Special Voting Shares separately from the related Class B Units except for certain permitted transfers among affiliates.

Holders of Special Voting Shares are entitled to one vote for each Special Voting Share held at all meetings of shareholders of the Company, except meetings at which or in respect of matters on which only holders of another class of shares are entitled to vote separately as a class. Except as otherwise provided by our Articles or required by law, the holders of Special Voting Shares will vote together with the holders of Restricted Voting Shares as a single class.

The holders of Special Voting Shares are entitled to receive, subject to the rights of the holders of preferred shares and in priority to the holders of Restricted Voting Shares, an amount per Special Voting Share equal to $0.000001 on the liquidation, dissolution or winding up of the Company, whether voluntary or involuntary.

The holders of Special Voting Shares, as such, are not entitled to receive any dividends or other distributions except for such dividends payable in Special Voting Shares, as may be declared by the board of directors from time to time. Notwithstanding the foregoing, we may not issue or distribute to all or to substantially all of the holders of the Special Voting Shares either (i) Special Voting Shares, or (ii) rights or securities of the Company exchangeable for or convertible into or exercisable to acquire Special Voting Shares, unless contemporaneously therewith, we issue or distribute Restricted Voting Shares, or rights or securities of the Company exchangeable for or convertible into or exercisable to acquire Restricted Voting Shares on substantially similar terms (having regard to the specific attributes of the Restricted Voting Shares) and in the same proportion.

The Special Voting Shares are subject to anti-dilution provisions, which provide that adjustments will be made to the Special Voting Shares in the event of a change to the Restricted Voting Shares in order to preserve the voting equivalency of such shares. In addition, pursuant to the Cooperation Agreement, we will make equivalent changes to the Special Voting Shares in the event of any adjustments made to the LP Units, in order to preserve the general alignment of the LP Units and the Company Voting Shares. See Item 13 "*Certain Relationships and Related Transactions, and Director Independence—Agreements between the Company and Kinder Morgan—Cooperation Agreement*." The Special Voting Shares are also subject to "coattail" provisions which restrict the transfer of Special Voting Shares in certain circumstances. See "*—Takeover Bid Protection—Coattail Arrangements*" below.

We may not modify or remove any of the rights, privileges, conditions or restrictions of the Special Voting Shares without the approval by special resolution of the holders of Special Voting Shares.

Preferred Shares

We are authorized to issue an unlimited number of preferred shares and we may issue preferred shares in one or more series with such terms as the board of directors may fix, subject to the ABCA. Any such additional preferred shares shall rank on a parity with the preferred shares of every other series and shall be entitled to preference over the Restricted Voting Shares and the Special Voting Shares, in each case with respect to priority in payment of dividends and the distribution of assets in the event of the liquidation, dissolution or winding up of the Company.

Series 1 Preferred Shares

On August 15, 2017, we issued 12,000,000 Series 1 Preferred Shares at a price of $25.00 per share. The holders of Series 1 Preferred Shares are entitled to receive dividends at an annual rate of $1.3125 per share, payable quarterly, up to but excluding November 15, 2022. as and when declared by our board of directors. For each five-year period following November 15, 2022, the holders of Series 1 Preferred Shares shall be entitled to receive dividends, as and when declared, in the amount per share determined by multiplying one-quarter of the "Annual Fixed Dividend Rate" by $25.00. The Annual Fixed Dividend Rate for the applicable period will be equal to the sum of the five-year Government of Canada bond yield ("Government of Canada Yield") on such date plus 3.65%, provided that, in any event, such rate shall not be less than 5.25%. This spread will remain unchanged over the life of the Series 1 Preferred Shares.

The Series 1 Preferred Shares are not entitled to vote or attend meetings of the holders of Company Voting Shares (except as otherwise provided by law and except for meetings of the holders of Preferred Shares as a class and meetings of the holders of Series 1 Preferred Shares as a series) unless dividends on the Series 1 Preferred Shares have not been paid for eight quarters, whether or not consecutive, whether or not such dividends have been declared and whether or not we have sufficient cash properly applicable to the payment of such dividends. Until all such arrears of dividends have been paid, holders of Series 1 Preferred Shares will be entitled to one vote per Series 1 Preferred Share with respect to resolutions to elect directors.

The Series 1 Preferred Shares are not redeemable prior to November 15, 2022. Subject to certain conditions, on November 15, 2022, and on November 15 in every fifth year thereafter, we may, at our option, upon not less than 30 days and not more than 60 days prior written notice, redeem for cash all or any part of the outstanding Series 1 Preferred Shares by the payment of $25.00 per Series 1 Preferred Share plus all accrued and unpaid dividends.

Prior to November 15, 2022, the Series 1 Preferred Shares are not convertible. The holders of the Series 1 Preferred Shares will have the right to convert all or any of their Series 1 Preferred Shares into Series 2 Preferred Shares, subject to certain conditions, on November 15, 2022 and on November 15 in every fifth year thereafter. Other than redemption rights and dividends, the Series 2 Preferred Shares are identical to the Series 1 Preferred Shares.

The holders of the Series 2 Preferred Shares will be entitled to receive, as and when declared by the board of directors of the Company, quarterly cash dividends calculated using a floating rate of interest. Holders of Series 2 Preferred Shares have the right to convert their Series 2 Preferred Shares back into Series 1 Preferred Shares under certain circumstances.

In the event of the liquidation, dissolution or winding-up of the Company, the holders of the Series 1 Preferred Shares and Series 2 Preferred Shares are entitled to receive $25.00 per share plus all accrued and unpaid dividends thereon before any amount is paid or any property or assets of the Company are distributed to the holders of the Restricted Voting Shares, Special Voting Shares or to the holders of any other shares ranking junior to the Series 1 Preferred Shares or Series 2 Preferred Shares in any respect.

The terms of the Series 1 Preferred Shares and the Series 2 Preferred Shares prohibit the Company from declaring or paying dividends on the Restricted Voting Shares unless all dividends on the Series 1 Preferred Shares and the Series 2 Preferred Shares have been paid.

Series 3 Preferred Shares

On December 15, 2017, we issued 10,000,000 Series 3 Preferred Shares at a price of $25.00 per share. The holders of Series 3 Preferred Shares are entitled to receive dividends at an annual rate of $1.3000 per share, payable quarterly, up to but excluding February 15, 2023 as and when declared by our board of directors. For each five-year period following February 15, 2023, the holders of Series 3 Preferred Shares shall be entitled to receive dividends, as and when declared, in the amount per share determined by multiplying one-quarter of the “Annual Fixed Dividend Rate” by $25.00. The Annual Fixed Dividend Rate for the applicable period will be equal to the sum of the Government of Canada Yield on such date plus 3.51%, provided that, in any event, such rate shall not be less than 5.20%. This spread will remain unchanged over the life of the Series 3 Preferred Shares.

The Series 3 Preferred Shares are not entitled to vote or attend meetings of the holders of Company Voting Shares (except as otherwise provided by law and except for meetings of the holders of Preferred Shares as a class and meetings of the holders of Series 3 Preferred Shares as a series) unless dividends on the Series 3 Preferred Shares have not been paid for eight quarters, whether or not consecutive, whether or not such dividends have been declared and whether or not we have sufficient cash properly applicable to the payment of such dividends. Until all such arrears of dividends have been paid, holders of Series 3 Preferred Shares will be entitled to one vote per Series 3 Preferred Share with respect to resolutions to elect directors.

The Series 3 Preferred Shares are not redeemable prior to February 15, 2023. Subject to certain conditions, on February 15, 2023, and on February 15 in every fifth year thereafter, we may, at our option, upon not less than 30 days and not more than 60 days prior written notice, redeem for cash all or any part of the outstanding Series 3 Preferred Shares by the payment of $25.00 per Series 3 Preferred Share plus all accrued and unpaid dividends.

Prior to February 15, 2023, the Series 3 Preferred Shares are not convertible. The holders of the Series 3 Preferred Shares will have the right to convert all or any of their Series 3 Preferred Shares into Series 4 Preferred Shares, subject to certain conditions, on February 15, 2023 and on February 15 in every fifth year thereafter. Other than redemption rights and dividends, the Series 4 Preferred Shares are identical to the Series 3 Preferred Shares.

The holders of the Series 4 Preferred Shares will be entitled to receive, as and when declared by the board of directors of the Company, quarterly cash dividends calculated using a floating rate of interest. Holders of Series 4 Preferred Shares have the right to convert their Series 4 Preferred Shares back into Series 3 Preferred Shares under certain circumstances.

In the event of the liquidation, dissolution or winding-up of the Company, the holders of the Series 3 Preferred Shares and Series 4 Preferred Shares are entitled to receive $25.00 per share plus all accrued and unpaid dividends thereon before any amount is paid or any property or assets of the Company are distributed to the holders of the Restricted Voting Shares, Special Voting Shares or to the holders of any other shares ranking junior to the Series 3 Preferred Shares or Series 4 Preferred Shares in any respect.

The terms of the Series 3 Preferred Shares and the Series 4 Preferred Shares prohibit the Company from declaring or paying dividends on the Restricted Voting Shares unless all dividends on the Series 3 Preferred Shares and the Series 4 Preferred Shares have been paid.

Limited Partnership Units

The Limited Partnership is a limited partnership existing under the laws of the Province of Alberta and holds our business and engages in such activities from time to time as the General Partner may, in its discretion, determine.

On November 29, 2018, the board of directors of the General Partner, in its capacity as general partner of the Limited Partnership, and in accordance with the Limited Partnership Agreement, approved a consolidation of the Class A Units and Class B Units on a one-for-three basis (three units consolidating into one unit) contemporaneously with the Share Consolidation (the "Unit Consolidation"). The Unit Consolidation was effective January 4, 2019.

After giving effect to the Share Consolidation, as of February 14, 2019, the Limited Partnership had issued and outstanding two GP Units held by the General Partner, 34,944,993 Class A Units held by the Company (indirectly through the General Partner) representing an approximate 30% equity interest in the Limited Partnership, 81,353,820 Class B Units held by Kinder Morgan (indirectly through KMCC and KMCT) representing an approximate 70% equity interest in the Limited Partnership and 22,000,000 Preferred LP Units held by the General Partner.

The GP Units, Class A Units, Class B Units and Preferred LP Units are entitled to participate in distributions of the Limited Partnership on the terms set out in the Limited Partnership Agreement. See "*—Distributions*" below. In certain circumstances, the General Partner may be required to make changes to the attributes of the LP Units to maintain the equivalency among the related securities in the manner contemplated by the Limited Partnership Agreement and the Cooperation Agreement. See Item 13 "*Certain Relationships and Related Transactions, and Director Independence—Agreements Between the Company and Kinder Morgan—Cooperation Agreement.*"

Each Class B Unit is accompanied by a Special Voting Share, which entitles the holder of such Special Voting Share to receive notice of, to attend and to vote at meetings of our shareholders. Under our Articles and the Limited Partnership Agreement, as applicable, the transfer of the Special Voting Shares separately from the Class B Units to which they relate, as well as the transfer of Class B Units separately from the related Special Voting Shares, is prohibited except for certain permitted transfers among affiliates. See "*—Special Voting Shares*" above.

Distributions

Under the Limited Partnership Agreement, the Limited Partnership may make distributions to (i) the Company, indirectly through the General Partner, and (ii) Kinder Morgan, indirectly through KMCC and KMCT, on a quarterly basis, and on or before any scheduled date for payment by the Company of any declared dividends. The Company will be entirely dependent on indirectly receiving distributions from the Limited Partnership in order to pay any dividends on the Restricted Voting Shares and any then outstanding preferred shares of the Company, which dividends shall in any event be declared only at the discretion of the board of directors.

Distributions by the Limited Partnership are not guaranteed and will be at the discretion of the General Partner. The General Partner will, in its sole discretion, determine the amount of the distribution from the Limited Partnership. See Item 1A "*Risk Factors—Risks Relating to Ownership of Restricted Voting Shares and Preferred Shares—Cash dividend payments are not guaranteed.*"

The Limited Partnership will make its distributions in the following order and priority: (i) the reimbursement of costs and expenses to the General Partner pursuant to the Limited Partnership Agreement; (ii) an amount to the holders of GP Units (being the General Partner) sufficient to allow the Company to pay its expenses (including, without limitation, any fees or commissions payable to agents or underwriters in connection with the sale of securities by the Company, listing fees of applicable stock exchanges and fees of the Company's counsel and auditors) on a timely basis (the "Priority Distribution"); (iii) an amount to the holders of Preferred LP Units in accordance with the terms of the Preferred LP Units; (iv) an amount to the General Partner equal to 0.001% of the balance of the distributable cash of the Limited Partnership; and (v) an amount equal to the remaining distribution to the holders of Class A Units and the holders of Class B Units in accordance with their respective holdings of Class A Units and Class B Units. The General Partner may, in addition to the distributions described above, make a distribution in cash or other property to holders of GP Units or LP Units, provided that such distribution is paid or distributed to the holders of LP Units in accordance with their pro rata entitlements as holders of LP Units.

A holder of Class B Units has the right to elect to reinvest all distributions payable on its Class B Units in Class B Units on the same economic terms as a holder of Restricted Voting Shares that participates in the DRIP. See "*—Dividend Reinvestment Plan*" below. If a holder of Class B Units elects to reinvest its distributions, such distributions will be used to purchase additional Class B Units at the same price per unit as Restricted Voting Shares are issued by the Company under the DRIP (generally being the weighted average trading price of the Restricted Voting Shares on the TSX for the five trading days preceding the dividend payment date) at a discount of between 0% and 5%, as determined from time to time by the board of directors of the General Partner, in its sole discretion. Pursuant to the terms of the DRIP and pursuant to the Limited Partnership Agreement, the Company and the Limited Partnership may concurrently suspend the DRIP and the distribution reinvestment plan, respectively, at their discretion. Effective January 16, 2019, the board of directors of the Company elected to suspend the DRIP; the Limited Partnership's distribution reinvestment plan was also automatically suspended effective the same date pursuant to the terms of the Limited Partnership Agreement.

Allocation of Net Income and Losses

The net income of the Limited Partnership, determined in accordance with the provisions of the Income Tax Act (Canada) and the regulations thereunder, as amended from time to time, is generally allocated in respect of each fiscal year in the following manner: (i) first, to the General Partner in an amount equal to (a) the Priority Distribution, and (b) the aggregate of reimbursement of costs and expenses to the General Partner pursuant to the Limited Partnership Agreement and the distributions paid on the GP Units; (ii) second, to holders of Preferred LP Units based on their proportionate share of distributions on the Preferred LP Units received or receivable for such fiscal year; and (iii) the balance, among the holders of Class A Units and Class B Units based on their proportionate share of distributions received or receivable for such fiscal year. The amount of income for tax purposes allocated to a partner may be more or less than the amount of cash distributed by the Limited Partnership to that partner. Income and loss of the Limited Partnership for accounting purposes is allocated to each partner in the same proportion as income or loss is allocated for tax purposes.

If, with respect to a given fiscal year, no distribution is paid or payable or allocated to the partners, or the Limited Partnership has a loss for tax purposes, the taxable income or loss, as the case may be, for tax purposes of the Limited Partnership for that fiscal year will be allocated to the holders of LP Units in that fiscal year in the proportion to the percentage of LP Units held by each holder of LP Units at each of those dates. The fiscal year end of the Limited Partnership will initially be December 31.

Functions and Powers of the General Partner

In its capacity as general partner of the Limited Partnership, the General Partner is authorized to manage, administer and operate the business and affairs of the Limited Partnership, to make all decisions regarding the business and affairs of the Limited Partnership and to bind the Limited Partnership in respect of any such decisions, subject to certain limitations contained in the Limited Partnership Agreement. The General Partner is required to exercise its powers and discharge its duties honestly, in good faith with a view to the best interests of the Limited Partnership and to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. The board of directors of the General Partner is the same as the board of directors of the Company. Similarly, the executive officers of the General Partner are the same as the executive officers of the Company.

The authority and power vested in the General Partner to manage the business and affairs of the Limited Partnership includes all authority to do any act, take any proceeding, make any decision and execute and deliver any instrument, deed, agreement or document necessary or incidental to carrying out the objects, purposes and business of the Limited Partnership, including, without limitation, the ability to engage other persons to assist the General Partner to carry out its management obligations and administrative functions in respect of the Limited Partnership and its business. Pursuant to the terms of the

Services Agreement, the General Partner has contracted with KMCSI for certain services relating to the operation of the Operating Entities. See Item 13 "*Certain Relationships and Related Transactions, and Director Independence—Agreements between the Company and Kinder Morgan—Services Agreement*."

Restrictions on the Authority of the General Partner

The authority of the General Partner, as general partner, is limited in certain respects under the Limited Partnership Agreement. Certain matters must be approved by special resolution of the holders of Class A Units (all of which is held indirectly by the Company and voted in accordance with the instructions of the Company), including: (i) the removal of the general partner, (ii) the dissolution, termination, wind-up or other discontinuance of the Limited Partnership, (iii) the sale, exchange or other disposition of all or substantially all of the business or assets of the Limited Partnership, (iv) amendments to the Limited Partnership Agreement, and (v) a merger or consolidation involving the Limited Partnership. Certain other matters must be approved by special resolution of the holders of the Class A Units and Class B Units voting together as a class, including: (i) a consolidation, subdivision or reclassification of LP Units (except for the purposes of preserving the alignment of the LP Units and the Company Voting Shares pursuant to the Limited Partnership Agreement and the Cooperation Agreement), and (ii) a waiver of a default by the general partner or release of the general partner from any claims in respect thereof.

Transfer of Partnership Units

No limited partner may transfer any of the LP Units owned by it except to persons and in the manner expressly permitted in the Limited Partnership Agreement. LP Units may not be transferred to a person who is not an Eligible Person (as defined in the Limited Partnership Agreement). In addition, the Class B Units are subject to "coattail" provisions which restrict the transfer of Class B Units in certain circumstances. See "*—Takeover Bid Protection—Coattail Arrangements*" below.

The General Partner

The authorized capital of the General Partner consists of an unlimited number of common shares and an unlimited number of preferred shares issuable in series. The Company holds all of the issued and outstanding common shares of the General Partner. Pursuant to the Cooperation Agreement, the board of directors of the General Partner is the same as the board of directors. Similarly, the executive officers of the General Partner is the same as the executive officers of the Company.

Preferred Units

Concurrently with the issuance of the Series 1 Preferred Shares and the Series 3 Preferred Shares by the Company, 12,000,000 and 10,000,000 Preferred LP Units, respectively, were issued by the Limited Partnership to the General Partner. The terms of the Preferred LP Units are substantially similar to the terms of the Preferred Shares. Pursuant to the terms of the Limited Partnership Agreement, the General Partner, as the holder of the Preferred LP Units, will have priority over the holders of LP Units (being, indirectly, the Company and Kinder Morgan) on any distributions, and in the event of dissolution, of the Limited Partnership. In addition, no amendments to the provisions of the Preferred LP Units or the priority of distributions or in the event of dissolution may be made unless such amendments receive approval of two-thirds of then outstanding Preferred Shares and, if required, the approval of the TSX.

Takeover Bid Protection - Coattail Arrangements

Under applicable securities laws in Canada, an offer to purchase Special Voting Shares or Class B Units would not necessarily require that an offer be made to purchase Restricted Voting Shares. In accordance with the rules of the TSX designed to ensure that, in the event of a takeover, the holders of Restricted Voting Shares will be entitled to participate on an equal footing with holders of Special Voting Shares or Class B Units, each of the Company's Articles and the Limited Partnership Agreement contain customary coattail provisions.

Pursuant to the Articles of the Company, no holder of Special Voting Shares is permitted to transfer such Special Voting Shares unless either: (i) such transfer would not require that the transferee make an offer to holders of Restricted Voting Shares to acquire Restricted Voting Shares on the same terms and conditions under applicable securities laws, if such Special Voting Shares were outstanding as Restricted Voting Shares; or (ii) if such transfer would require that the transferee make such an offer to holders of Restricted Voting Shares to acquire Restricted Voting Shares on the same terms and conditions under applicable securities laws, the transferee acquiring such Special Voting Shares makes a contemporaneous identical offer for Restricted Voting Shares (in terms of price, timing, proportion of securities sought to be acquired and conditions) and does not acquire such Special Voting Shares unless the transferee also acquires a proportionate number of Restricted Voting Shares actually tendered to such identical offer.

In addition, pursuant to the terms of the Limited Partnership Agreement, no holder of Class B Units is permitted to transfer such Class B Units, unless: (i) such transfer would not require the transferee to make an offer to holders of Restricted Voting Shares to acquire Restricted Voting Shares on the same terms and conditions under applicable securities laws if such Class B Units, and all other outstanding Class B Units, were instead outstanding as Restricted Voting Shares; or (ii) the offeror acquiring such Class B Units makes a contemporaneous identical offer for the Restricted Voting Shares (in terms of price, timing, proportion of securities sought to be acquired and conditions) and acquires such Class B Units along with a proportionate number of Restricted Voting Shares actually tendered to such identical offer.

Dividend Reinvestment Plan

Effective January 16, 2019, the board of directors of the Company elected to suspend the DRIP; the Limited Partnership's distribution reinvestment plan was automatically suspended effective the same date.

If we elect to reinstate the DRIP, holders of Restricted Voting Shares will be able to elect to have all cash dividends of the Company payable to any such shareholder automatically reinvested in additional Restricted Voting Shares at a price per share calculated by reference to the weighted average trading price of the Restricted Voting Shares on the stock exchange on which the Restricted Voting Shares are then listed for the five trading days preceding the relevant dividend payment date, less a discount of between 0% and 5% (as determined from time to time by the board of directors, in its sole discretion). Cash undistributed by the Company upon the issuance of additional Restricted Voting Shares under the DRIP will be invested in the Company and/or the Limited Partnership to be used for general corporate purposes and working capital. Holders of Restricted Voting Shares who are non-residents of Canada are not entitled to participate in the DRIP as a result of foreign securities law restrictions.

The Limited Partnership Agreement provides for a similar distribution reinvestment plan for the holders of Class B Units such that they may elect to have all of the cash distributions on the Class B Units payable to any such person automatically reinvested in additional Class B Units on the same basis and at the same price per Class B Unit as a holder of Restricted Voting Shares purchases Restricted Voting Shares pursuant to the DRIP. See "*—Limited Partnership Units—Distributions*" above.

Item 6. ***Selected Historical Financial Information.***

The following table sets forth, for the periods and at the dates indicated, our summary historical financial data. The table is derived from our consolidated financial statements and notes thereto, and should be read in conjunction with those audited consolidated financial statements. See also Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations"* in this report for more information.

As at and for the Year Ended December 31,	2018	2017	2016
(In millions of Canadian dollars)			
GAAP Income Statement Information			
Revenues	383.8	358.9	347.8
Operating income	110.8	83.7	97.6
Income from Continuing Operations, net of tax	100.0	50.5	70.4
Income from Discontinued Operations, net of tax(a)	1,318.2	110.2	131.4
Net income	1,418.2	160.7	201.8
Non-GAAP Financial Measures(b)			
DCF from continuing operations	161.5	120.9	131.3
DCF	312.8	322.7	318.2
Adjusted EBITDA from continuing operations	189.1	153.8	163.3
Adjusted EBITDA	352.5	388.3	395.5
Allocation of Earnings to Ownership Interests			
Preferred share dividends	28.8	6.6	—
Net income attributable to Kinder Morgan interest(c)	973.2	126.2	201.8
Net income available to Restricted Voting Stockholders	416.2	27.9	—
DCF from continuing operations to Kinder Morgan interest(b)(c)	113.5	90.2	131.3
DCF from continuing operations for Restricted Voting Stockholders(b)	48.0	30.7	—
GAAP Balance Sheet Information (at end of period)			
Total Property, plant and equipment, net - continuing operations	981.3	988.4	865.0
Total assets - continuing operations	5,369.6	1,209.6	998.5
Total assets - discontinued operations	—	3,243.1	2,740.9
Outstanding debt(d) - continuing operations	—	—	1,362.1
Total equity(e)	892.5	3,637.6	1,436.0

a. 2018 includes a gain on the Trans Mountain Transaction of $1,278.4, net of tax.
b. See Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations—Non-GAAP Financial Measures.*"
c. Prior to our May 2017 IPO, net income and DCF were attributable only to Kinder Morgan interest.
d. Prior to our May 2017 IPO outstanding debt represented the Long-term debt-affiliates ("KMI Loans").
e. 2018 amount reflects an accrual for the shareholder approved January 3, 2019 Return of Capital of $3,977.4 million.

Item 7. ***Management's Discussion and Analysis of Financial Condition and Results of Operations.***

The following discussion and analysis should be read in conjunction with our consolidated financial statements and the notes thereto. We prepared our consolidated financial statements in accordance with GAAP. Additional sections in this report that should be helpful to the reading of our discussion and analysis include the following: (i) a description of our business strategy, found in Items 1 and 2 "*Business and Properties—Business and Segments*;" (ii) a description of developments during 2018, found in Items 1 and 2 "*Business and Properties—Recent Business Developments*;" and (iii) a description of risk factors affecting us and our business, found in Item 1A "*Risk Factors*."

In as much as the discussion below and the other sections to which we have referred you pertain to management's comments on financial resources, capital spending, our business strategy and the outlook for our business, such discussions contain forward-looking statements. These forward-looking statements reflect the expectations, beliefs, plans and objectives of management about future financial performance and assumptions underlying management's judgment concerning the matters discussed, and accordingly, involve estimates, assumptions, judgments and uncertainties. Our actual results could differ materially from those discussed in the forward-looking statements. Factors that could cause or contribute to any differences

include, but are not limited to, those discussed below and elsewhere in this report, particularly in Item 1A "*Risk Factors*" and at the beginning of this report in "*Information Regarding Forward-Looking Statements*."

Subsequent to our IPO, Kinder Morgan retained control of us and the Limited Partnership. As a result we accounted for our acquisition of an approximate 30% equity interest in the Limited Partnership as a transfer of net assets among entities under common control. Therefore, our consolidated financial statements presented herein were derived from the consolidated financial statements and accounting records of Kinder Morgan. The assets and liabilities in these consolidated financial statements have been reflected at historical carrying value of the immediate parents within the Kinder Morgan organization structure. Prior to May 30, 2017, our historical financial statements were presented as combined consolidated financial statements derived from information included within the consolidated financial statements and accounting records of Kinder Morgan. All significant intercompany balances between the companies included in our accompanying consolidated financial statements have been eliminated. For all periods presented in this report, Kinder Morgan's economic interest in the Limited Partnership is reflected within "Net Income Attributable to Kinder Morgan Interest" in our consolidated statements of income.

Recent Business Developments

Trans Mountain Transaction

On August 31, 2018, we closed on the sale of the Trans Mountain Asset Group, which was indirectly acquired by the Government of Canada through Trans Mountain Corporation (a subsidiary of the Canada Development Investment Corporation) for cash consideration of approximately $4.43 billion, which is the contractual purchase price of $4.5 billion net of a preliminary working capital adjustment (the "Trans Mountain Transaction"). As of December 31, 2018 we have accrued for an additional $37 million for a final working capital adjustment that was subsequently settled in cash. The underlying assets in the Trans Mountain Asset Group were primarily within our Pipelines business segment and the operating results for the Trans Mountain Asset Group are presented as Discontinued Operations within Income from operations of the Trans Mountain Asset Group, net of tax in the accompanying consolidated statements of income for all periods presented in this report, and assets and liabilities are presented as held for sale as of December 31, 2017 and for prior periods, though these assets were not actually being held for sale at that point in time.

We have recorded a Gain on sale of the Trans Mountain Asset Group, net of tax, of $1,278.4 million as presented in the accompanying consolidated statement of income for year ended December 31, 2018. The gain included a tax benefit of approximately $81.4 million comprised of the release of deferred income taxes of approximately $389.0 million, which were partially offset by an adjustment to accrued taxes of approximately $307.6 million on the accompanying consolidated balance sheet as of December 31, 2018.

Subsequent to our announced preliminary 2018 earnings on January 16, 2019, (i) we increased the accrual for the final working capital adjustment from $35 million to $37 million that resulted in a reduction to the Trans Mountain Transaction gain, net of tax, by $1.8 million, which were recorded in the accompanying consolidated balance sheet and consolidated income statement, respectively, as of and for the year ended December 31, 2018 and (ii) we reclassified approximately $4.5 million of tax expense from Income Tax Expense to Income from Operations of the Trans Mountain Asset Group, net of tax in the accompanying consolidated statement of income for the year ended December 31, 2017.

2019 Return of Capital and Share Consolidation

Pursuant to our voting shareholders' approval on November 29, 2018, a distribution of approximately $1.2 billion were made as a return of capital to holders of our Restricted Voting Shares ($11.40 per Restricted Voting Share) and approximately $2.8 billion to KMI as the indirect holder of our Special Voting Shares on January 3, 2019 (the "Return of Capital"). To facilitate the Return of Capital and provide flexibility for dividends going forward, our voting shareholders also approved (i) the reduction of the stated capital of our Restricted Voting Shares by $1.45 billion (the "Stated Capital Reduction") (ii) a "reverse stock split" of our Restricted Voting Shares and Special Voting Shares on a one-for-three basis (three shares consolidating to one share) (the "Share Consolidation"), which occurred on January 4, 2019. In accordance with U.S. GAAP, the Restricted Voting Shares and Special Voting Shares outstanding and earnings per share information in this report reflect the Share Consolidation for all periods presented unless otherwise noted.

Suspension of Dividend Reinvestment Plan (DRIP)

Effective January 16, 2019 our board of directors suspended our DRIP until further notice. Accordingly, dividends in respect of the fourth quarter of 2018, paid on February 15, 2019 to holders of Restricted Voting Shares of record as of the close of business on January 31, 2019, were not reinvested through the DRIP. Shareholders who were enrolled in the program will

automatically receive dividend payments in the form of cash. We elected to suspend our DRIP in light of our reduced need for additional capital following the Trans Mountain Transaction. If we elect to reinstate the DRIP in the future, shareholders who were enrolled in the DRIP at suspension and remained enrolled at reinstatement will automatically resume participation in the DRIP. Kinder Morgan's participation in the distribution reinvestment plan for Class B Units of the Limited Partnership has been suspended since July 18, 2018, and the plan itself was automatically suspended effective January 16, 2019 pursuant to the terms of the Limited Partnership Agreement.

Review of Strategic Alternatives

In light of the completion of the Trans Mountain Transaction, we continue to evaluate all options in order to maximize value to our shareholders. These options include, among others, continuing to operate as a standalone enterprise, a disposition by sale, or a strategic combination with another company.

Outlook

Below is a summary of our expectations for 2019:

- Generate $213 million of Adjusted EBITDA, $109 million of DCF and DCF of $0.90 per split-adjusted restricted voting share;
- Declare a 2019 dividend of $0.65 (annualized) per split-adjusted restricted voting share;
- Invest $32 million in expansion projects; and
- End 2019 with a net debt-to-Adjusted EBITDA ratio of approximately 1.3 times, after treating 50% of the outstanding preferred equity balance as debt.

Net Income to Adjusted EBITDA and DCF reconciliations for 2018 are below in "*—Results of Operations—Non-GAAP Financial Measures.*" We do not provide budgeted net income attributable to common stockholders and net income, the GAAP financial measures most directly comparable to the non-GAAP financial measures DCF and Adjusted EBITDA, respectively, due to the impracticality of quantifying certain components required by GAAP such as: realized and unrealized gains or losses on foreign currency transactions and potential changes in estimates for certain contingent liabilities.

Terminals Matters

With the final tanks placed in service early in the fourth quarter of 2018, construction of all major facilities at the Base Line Terminal in Edmonton, Alberta, Canada, is complete. The 12-tank, 4.8 million barrel facility is fully contracted with long-term, firm take-or-pay agreements with creditworthy customers. The 50-50 joint venture crude oil merchant storage terminal developed by KML and Keyera Corp. was completed on time and under budget, with Kinder Morgan investing approximately $357 million.

Permitting efforts continue on the distillate storage expansion project at our Vancouver Wharves Terminal in North Vancouver, B.C. The $43 million capital project includes the construction of two new distillate tanks with combined storage capacity of 200,000 barrels and enhancements to the railcar unloading capabilities. The project is supported by a 20-year initial term, take-or-pay contract with an affiliate of a large international integrated energy company and is expected to be placed in service in the first quarter of 2021.

As previously disclosed in prior reports, a material contractual arrangement at the Edmonton Rail Terminal expires in April 2020 and includes a right of renewal on favorable terms for our customer related to rail terminal and associated pipeline connection service fees. We expect this will result in lower revenues of approximately $43.0 million and $11.0 million on an annual basis for rail terminal fees and associated pipeline connection fees, respectively. We expect this revenue reduction will be partially offset by expansion projects as well as favorable renewal rates on expiring contracts at our other terminal facilities.

In addition, at our Edmonton South Terminal, two of our 15 leased tanks, which generate approximately $6.5 million of annual Adjusted EBITDA, net of associated tank lease costs, are expected to be recalled into regulated service upon the in-service date of the TMEP.

General

Our reportable business segments are based on the way our management organizes our enterprise. Each of our reportable business segments represents a component of the enterprise that engages in a separate business activity and for which discrete financial information is available. Our reportable business segments consist of:

- Terminals - the ownership and operations of liquid product storage and rail terminals in the Edmonton, Alberta market as well as a predominantly dry cargo import/export facility in North Vancouver, B.C.; and
- Pipelines - the ownership and operations of Cochin and Jet Fuel.

Critical Accounting Policies and Estimates

Accounting standards require information in financial statements about the risks and uncertainties inherent in significant estimates, and the application of GAAP involves the exercise of varying degrees of judgment. Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time such financial statements are prepared. These estimates and assumptions affect the amounts we report for our assets and liabilities, our revenues and expenses during the reporting period, and our disclosure of contingent assets and liabilities at the date of our financial statements. We routinely evaluate these estimates, utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates, and any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known. Significant estimates and judgments made by management in the preparation of our consolidated financial statements are outlined below.

Impairment of Long-lived Assets

We evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that our carrying amount of an asset may not be recoverable. Impairment losses may be recognized on long-lived assets when estimated future cash flows expected to result from use of the asset and its eventual disposition is less than its carrying amount. We had no long-lived asset impairments during the years ended December 31, 2018, 2017 and 2016.

Depreciation

Depreciation of our assets, except Cochin, is recorded on a straight-line basis over their estimated useful lives. For Cochin assets, we apply a composite depreciation rate to the total cost of the composite group until the net book value equals the salvage value. The computation of depreciation requires the use of management estimates of our assets' useful lives. When it is determined that the estimated service life of an asset no longer reflects the expected remaining period of benefit, prospective changes are made to the estimated service life.

Income Taxes

The calculation of income tax assets or liabilities is based on assumptions about the timing of many taxable events and the enacted or substantively enacted rates anticipated to be applicable to income in the years in which temporary differences are expected to be realized or reversed.

Contingent Liabilities

Provisions recognized are based on management's judgment about assessing contingent liabilities and timing, scope and amount of liabilities including liabilities relating to legal and environmental matters. Management uses judgment in determining the likelihood of realization of contingent liabilities to determine the outcome of contingencies.

Transactions with Affiliates

We have transactions with Kinder Morgan and its subsidiaries. Refer to accompanying consolidated balance sheets for the amounts due to or from affiliates and Note 14 "*Transactions with Related Parties*" to our consolidated financial statements for the identification of revenue and expenses with affiliated parties included in the accompanying consolidated statements of income. Accounts receivable-affiliate and accounts payable-affiliate are non-interest-bearing and are settled on demand, and subsequent to our IPO, settled monthly.

Other Risk Management Activities

For a further discussion of the risks and trends that could affect our financial performance and the steps that we take to mitigate these risks, see Note 17 "*Risk Management and Financial Instruments*" to our consolidated financial statements.

Results of Operations

We evaluate the performance of our reportable business segments by evaluating the EBDA of each segment ("Segment EBDA"). We believe that Segment EBDA is a useful measure of our operating performance because it measures segment operating results before D&A and certain expenses that are generally not controllable by our business segment operating managers, such as certain general and administrative expense, interest expense, net, and income tax expense, and prior to their pay off in the second quarter of 2017, the foreign exchange losses (or gains) on the KMI Loans. Our general and administrative expenses include such items as employee benefits, insurance, rentals, certain litigation, and shared corporate services including accounting, information technology, human resources and legal services. See Note 19 "*Reportable Segment*s" to our consolidated financial statements for further discussion of our reportable business segments.

Consolidated Earnings Results

Year Ended December 31,	**2018**	**2017**	**2016**
(In millions of Canadian dollars)			
Segment EBDA(a)			
Terminals(b)	193.2	162.8	159.2
Pipelines	39.0	19.1	29.8
Total segment EBDA(a)	232.2	181.9	189.0
D&A	(82.6)	(71.7)	(64.2)
Foreign exchange gain on the KMI Loans(c)	—	0.2	13.2
General and administrative expenses(d)	(39.0)	(30.9)	(25.7)
Interest income (expense), net(e)	27.2	(8.2)	(18.5)
Income from continuing operations before income taxes	137.8	71.3	93.8
Income tax expense	(37.8)	(20.8)	(23.4)
Income from continuing operations	100.0	50.5	70.4
Income from discontinued operations, net of tax(f)	1,318.2	110.2	131.4
Net income	1,418.2	160.7	201.8
Preferred share dividends	(28.8)	(6.6)	—
Net income attributable to Kinder Morgan interest	(973.2)	(126.2)	(201.8)
Net income available to Restricted Voting Stockholders	416.2	27.9	—

a. Represents Segment EBDA from continuing operations. Includes revenues and other (income) expense less operating expenses and other, net. Operating expenses primarily include operations and maintenance expenses, and taxes, other than income taxes. Segment EBDA for the year ended December 31, 2018, 2017 and 2016 include $0.1 million, $(5.3) million and $1.4 million, respectively, of foreign exchange gain (losses) due to changes in exchange rates between the Canadian dollar and the U.S. dollar on U.S. dollar denominated balances.

b. Segment EBDA for the year ended December 31, 2018 includes an increase to earnings of $9.6 million for a certain item described in footnote (a) to the "*—Segment Earnings Results—Terminal Segment*" table below.

c. The KMI Loans, which represented U.S. dollar denominated long-term notes payable with Kinder Morgan, were settled with proceeds from our IPO. The foreign exchange gain on the KMI Loans represents a certain item.

d. General and administrative expenses for the year ended December 31, 2018 and 2017 includes increases to expense of $5.5 million and $2.8 million, respectively, for certain items described in footnote (a) to the "*—Segment Earnings Results—General and Administrative Expense*" table below.

e. Interest income (expenses), net for the year ended December 31, 2018 includes a decrease to interest income of $1.0 million for a certain item described in footnote (a) to the "*—Segment Earnings Results—Interest (income) expense, net*" table below.

f. Includes certain items summarized in footnote (b) to the "*—Segment Earnings Results—Income from Discontinued Operations, Net of Tax*" table below.

Year Ended December 31, 2018 vs 2017

The certain items described in footnotes (b) through (e) to the table above accounted for a $5.7 million increase in income from continuing operations before income taxes for the year ended December 2018 as compared to the prior year period. After giving effect to these certain items, the $60.8 million increase from prior year in income from continuing operations before income taxes is primarily attributable to higher interest income due to deposits of the proceeds from the Trans Mountain Transaction in interest bearing cash equivalent accounts and increased earnings from both of our segments.

Year Ended December 31, 2017 vs 2016

The certain items described in footnotes (b) through (e) to the table above accounted for a $15.8 million decrease in income from continuing operations before income taxes for the year ended December 31, 2017 as compared to the same prior year period. After giving effect to these certain items, the $6.7 million decrease from 2016 in income from continuing operations before income taxes is primarily attributable to lower earnings from our Pipelines segment, increased D&A expense from assets being placed in service, and increased general and administrative expense driven by legal and audit fees related to Company financing activities, partially offset by lower interest expense primarily due to the 2017 settlement of the KMI Loans.

Non-GAAP Financial Measures

In addition to using measures prescribed by GAAP, we use DCF (both in the aggregate and per share), net income before interest expense, taxes, D&A and adjusted for certain items ("Adjusted EBITDA"), which are financial measures that do not have any standardized meaning as prescribed by GAAP ("non-GAAP measures"). DCF and Adjusted EBITDA should not be considered alternatives to GAAP net cash provided by operating activities or net income, computed under GAAP or any other GAAP measures, and such non-GAAP measures have important limitations as analytical tools. The computations of DCF and Adjusted EBITDA may differ from similarly titled measures used by others. Accordingly, the use of such terms may not be comparable to similarly defined measures presented by other entities and investors should not consider these non-GAAP measures in isolation or as a substitute for an analysis of results reported under GAAP. Management compensates for the limitations of these non-GAAP measures by reviewing our comparable GAAP measures, understanding the differences between the measures and taking this information into account in its analysis and its decision-making processes.

DCF is net income before D&A adjusted for (i) income tax expense and cash income taxes (paid) refunded; (ii) sustaining capital expenditures; and (iii) certain items that are items that are required by GAAP to be reflected in net income, but typically either (a) do not have a cash impact (for example, unrealized and realized foreign exchange gains and losses on the KMI loans and asset impairments), or (b) by their nature are separately identifiable from our normal business operations and in our view are likely to occur only sporadically (for example, certain gains or losses on asset sales, divestiture costs, legal settlements and casualty losses).

DCF is an important performance measure used by us and by external users of our financial statements to evaluate our performance and to measure and estimate our ability to generate cash earnings after servicing our debt and preferred stock dividends, paying cash taxes and expending sustaining capital, that could be used for discretionary purposes such as distributions or expansion capital expenditures. We use this performance measure and believe it provides users of our financial statements a useful performance measure reflective of our ability to generate cash earnings to supplement the comparable GAAP measure. DCF should not be used as an alternative to net cash provided by operating activities computed under GAAP. We believe the GAAP measure most directly comparable to DCF is net income. DCF per split-adjusted restricted voting share is DCF divided by average outstanding split-adjusted restricted voting shares, including stock awards that participate in dividends.

Discontinued Operations are included in our non-GAAP measures in the accompanying tables for the years ended December 31, 2017 and 2018 (which includes those discontinued operations for period from January 1, 2018 to the close of the Trans Mountain Transaction on August 31, 2018). The non-GAAP measures, DCF from discontinued operations and Adjusted EBITDA from discontinued operations, are reconciled to income from discontinued operations, the most directly comparable GAAP measure in note (d) to the following tables.

Non-GAAP measures from continuing operations reflect our ongoing operations and have been presented as DCF from continuing operations and Adjusted EBITDA from continuing operations. In addition, DCF per restricted voting share presented herein reflects our January 4, 2019 one-for-three reverse stock split and is presented as DCF from continuing operations per split-adjusted restricted voting share for all periods presented. The most comparable GAAP measure to the these two non-GAAP measures from continuing operations is income from continuing operations and the following tables include reconciliations of the these two non-GAAP measures to income from continuing operations. In addition, our aggregate DCF and Adjusted EBITDA are presented in the following tables.

Reconciliation of Income from continuing operations to DCF

Year Ended December 31,	2018	2017	2016
(In millions of Canadian dollars, except per share amounts)			
Income from continuing operations	100.0	50.5	70.4
Continuing operations - reconciling items - add/(subtract):			
Certain items before book tax(a)	(3.1)	2.6	(13.2)
Book tax certain items(b)	0.9	(0.7)	
D&A	82.6	71.7	64.2
Total book taxes before certain items	36.9	21.5	23.4
Cash taxes	(8.5)	(0.2)	(0.8)
Preferred share dividends	(28.8)	(6.6)	—
Sustaining capital expenditures	(18.5)	(17.9)	(12.7)
DCF from continuing operations	161.5	120.9	131.3
DCF from discontinued operations(d)	151.3	201.8	186.9
DCF	312.8	322.7	318.2
DCF from continuing operations to KMI interest	113.5	90.2	—
DCF from continuing operation to Restricted Voting Stockholders	48.0	30.7	—
Weighted average split-adjusted Restricted Voting Shares outstanding for dividends (in millions)(c)	34.9	34.6	—
DCF from continuing operations per split-adjusted Restricted Voting Share	1.38	0.89	—

Adjusted EBITDA is used by us and by external users of our financial statements, in conjunction with outstanding debt, net of cash, to evaluate certain leverage metrics. We do not allocate Adjusted EBITDA amongst equity interest holders as we view total Adjusted EBITDA as a measure against our overall leverage.

Reconciliation of Net Income to Adjusted EBITDA

Year Ended December 31,	2018	2017	2016
(In millions of Canadian dollars)			
Income from continuing operations	100.0	50.5	70.4
Continuing operations - reconciling items - add/(subtract):			
Total certain items, net of tax(a)	(2.2)	1.9	(13.2)
D&A	82.6	71.7	64.2
Total book taxes before certain items	36.9	21.5	23.4
Interest (income) expense, net before certain items	(28.2)	8.2	18.5
Adjusted EBITDA from continuing operations	189.1	153.8	163.3
Adjusted EBITDA from discontinued operations(d)	163.4	234.5	232.2
Adjusted EBITDA	352.5	388.3	395.5

a. Consists of certain items summarized in footnotes (b) through (e) to the "—*Consolidated Earnings Results*" table included above, and described in more detail below in the footnotes to tables included in our management's discussion and analysis of segment results, "—*Segment Earnings Results*," "—*Segment Earnings Results—General and Administrative*," "—*Segment Earnings Results—Interest (income) expense, net*."

b. Represents income tax provision on certain items.

c. Includes stock awards of restricted voting shares that participate in dividends. Also, the 2017 weighted average Restricted Voting Shares outstanding for dividends calculation is based on the actual days in which the shares were outstanding for the period from May 30, 2017 to June 30, 2017. Therefore, the amounts differ from the GAAP weighted average Restricted Voting Shares outstanding from the date of our formation.

d. DCF from discontinued operations and Adjusted EBITDA from discontinued operations reconciliations are as follows:

DCF from discontinued operations:

Year Ended December 31,	2018	2017	2016
(In millions of Canadian dollars)			
Income from discontinued operations, net of tax	1,318.2	110.2	131.4
Discontinued operations reconciling items - add/(subtract):			
Certain items before book tax(1)	(1,129.2)	2.6	(16.5)
Book tax certain items(1)	(101.4)	(0.7)	
D&A	46.8	70.7	73.0
Total book taxes before certain items	35.5	44.1	32.9
Cash taxes	—	—	(0.4)
Sustaining capital expenditures	(18.6)	(25.1)	(33.5)
DCF from discontinued operations	151.3	201.8	186.9

Adjusted EBITDA from discontinued operations:

Year Ended December 31,	2018	2017	2016
(In millions of Canadian dollars)			
Income from discontinued operations, net of tax	1,318.2	110.2	131.4
Discontinued operations reconciling items - add/(subtract):			
Total certain items(1)	(1,230.6)	1.9	(16.5)
D&A	46.8	70.7	73.0
Total book taxes before certain items	35.5	44.1	32.9
Interest, net before certain items	(6.5)	7.6	11.4
Adjusted EBITDA from discontinued operations	163.4	234.5	232.2

1. Described in more detail below in the footnotes to tables included in our management's discussion and analysis of segment results "—*Segment Earnings Results —Income from Discontinued Operation*s, Net of Tax" below.

Segment EBDA Before Certain Items

Segment EBDA before certain items (a non-GAAP measure) is used by management in its analysis of segment performance and management of our business. General and administrative expenses are generally not under the control of our segment operating managers, and therefore, are not included when we measure business segment operating performance. We believe Segment EBDA before certain items is a significant performance metric because it provides us and external users of our financial statements additional insight into the ability of our segments to generate segment cash earnings on an ongoing basis. We believe it is useful to investors because it is a performance measure that management uses to allocate resources to our segments and assess each segment's performance. We believe the GAAP measure most directly comparable to Segment EBDA before certain items is Segment EBDA.

In the tables for each of our business segments under "—*Segment Earnings Results*" below, Segment EBDA before certain Items is calculated by adjusting the Segment EBDA for the applicable certain item amounts, which are totaled in the tables and described in the footnotes to those tables (if any).

Segment EBDA and Segment EBDA before certain items excludes discontinued operations for all periods presented, see "—*Segment Earnings Results—Income from Discontinued Operation*s, Net of Tax" below.

Segment Earnings Results

Terminals Segment

Year Ended December 31,	2018	2017	2016
(In millions of Canadian dollars, except operating statistics)			
Revenues	321.6	298.6	287.5
Operating expenses, except D&A	(137.6)	(136.9)	(129.6)
Other income (expense), net	9.3	(3.1)	(0.2)
Other, net and unrealized foreign exchange gain (loss)	(0.1)	4.2	1.5
Segment EBDA	193.2	162.8	159.2
Certain items(a)	(9.6)	—	—
Segment EBDA before certain items	183.6	162.8	159.2

Change from prior period	Increase/(Decrease)	
Revenues	23.0	11.1
Segment EBDA before certain items	20.8	3.6

Operating statistics	2018	2017	2016
Bulk transload tonnage (MMtonnes)	4.1	4.5	4.3
Liquids tankage capacity available for service (MMBbl)(b)	9.6	7.3	7.3
Liquids utilization %(c)	100 %	100 %	100 %

a. Represents the gain on sale of certain assets.
b. Includes our share of joint venture capacity.
c. The ratio of our tankage capacity in service to tankage capacity available for service.

In the two following tables are the changes in both Segment EBDA before certain items and revenues between 2018 and 2017, and between 2017 and 2016:

Year Ended December 31, 2018 versus Year Ended December 31, 2017

	Segment EBDA before certain items increase/(decrease)		Revenues increase/(decrease)	
(In millions of Canadian dollars, except percentages)				
Base Line Terminal joint venture	24.9	n/a	28.0	n/a
Edmonton South Terminal	6.5	23 %	2.4	3 %
North 40 Terminal	5.2	16 %	5.9	16 %
Vancouver Wharves Terminal	(2.2)	(6)%	(4.7)	(5)%
Edmonton Rail Terminal joint venture	(12.5)	(19)%	(8.8)	(12)%
All others (including eliminations)	(1.1)	24 %	0.2	2 %
Total Terminals	20.8	12.8 %	23.0	7.7 %

n/a - not applicable

The changes in Segment EBDA before certain items for our Terminals business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable years of 2018 and 2017:

- increase of $24.9 million from Base Line Terminal joint venture as a result of the new tanks being placed into service in 2018;
- increase of $6.5 million (23%) from Edmonton South Terminal primarily due to higher rates on re-contracted tank leases and a decline in tank lease costs;
- increase of $5.2 million (16%) from North 40 Terminal primarily from increase in revenues due to higher rates on re-contracted tank leases;
- decrease of $2.2 million (6%) from Vancouver Wharves Terminal primarily due to lower agricultural product volumes and a 2017 contract buyout; and
- decrease of $12.5 million (19%) from Edmonton Rail Terminal joint venture primarily due to expiration of a third party rail terminaling contract and a 2017 adjustment in terminal fees in connection with a favorable arbitration ruling.

Year Ended December 31, 2017 versus Year Ended December 31, 2016

	Segment EBDA before certain items increase/(decrease)		Revenues increase/(decrease)	
(In millions of Canadian dollars, except percentages)				
Edmonton Rail Terminal joint venture	8.0	14 %	5.4	8 %
Edmonton South Terminal	1.3	5 %	3.9	5 %
North 40 Terminal	0.4	1 %	1.9	5 %
Vancouver Wharves Terminal	(0.3)	(1)%	6.1	7 %
Alberta Crude Terminal joint venture	(5.4)	(64)%	(6.2)	(43)%
All others (including eliminations)	(0.4)	(200)%	—	— %
Total Terminals	3.6	2.3 %	11.1	3.9 %

The changes in Segment EBDA for our Terminals business segment are further explained by the following discussion of the significant factors driving Segment EBDA in the comparable years of 2017 and 2016:

- increase of $8.0 million (14%) from Edmonton Rail Terminal joint venture primarily due to an adjustment in terminal fees in connection with a favorable arbitration ruling and an increase in unrealized foreign exchange gains primarily related to U.S. dollar denominated accounts payable to Kinder Morgan;
- increase of $1.3 million (5%) from Edmonton South Terminal primarily due to higher ancillary service fees driven by escalations in fixed and take-or-pay terminaling contract rates and higher throughput volumes in 2017, partially offset by tank lease costs;
- increase of $0.4 million (1%), from North 40 Terminal primarily due to increase in revenues due to higher throughput volumes and ancillary service fees partially offset by a decrease in unrealized foreign exchange gains primarily related to a U.S. dollar denominated payable to Kinder Morgan;
- decrease of $0.3 million (1%) from Vancouver Wharves Terminal primarily due to lower margins associated with bulk handling operations partially offset by an increase in earnings related to a customer contract buy-out, net of associated project write-off costs; and
- decrease of $5.4 million (64%) from Alberta Crude Terminal joint venture which was primarily driven by a contracted throughput fee reduction.

Pipelines Segment

Year Ended December 31,	2018	2017	2016
(In millions of Canadian dollars, except operating statistics)			
Revenues	62.2	60.3	60.3
Operating expenses, except D&A	(23.1)	(32.3)	(30.5)
Other income (expense), net	—	(0.3)	—
Other, net and unrealized foreign exchange loss	(0.1)	(8.6)	—
Segment EBDA	39.0	19.1	29.8

Change from prior period	Increase/(Decrease)	
Revenues	1.9	—
Segment EBDA	19.9	(10.7)

Operating statistics	2018	2017	2016
Cochin transport volumes (MBbl/d)	83	86	84

In the two following tables are the changes in both Segment EBDA before certain items and revenues between 2018 and 2017, and between 2017 and 2016:

Year Ended December 31, 2018 versus Year Ended December 31, 2017

	Segment EBDA before certain items increase/(decrease)		Revenues increase/(decrease)	
(In millions of Canadian dollars, except percentages)				
Cochin	19.2	124 %	1.8	3 %
Jet Fuel and others (including eliminations)	0.7	19 %	0.1	1 %
Total Pipelines	19.9	104.2 %	1.9	3.2 %

The changes in Segment EBDA for our Pipelines business segment are further explained by the following discussion of the significant factors driving Segment EBDA in the comparable years of 2018 and 2017:

- increase of $19.2 million (124%) from Cochin primarily due to a 2017 unrealized foreign exchange loss on intercompany receivables, cash, and payable balances, and a reduction in pipeline integrity expenses and outside services costs in 2018, and higher revenue due to timing on the recognition of deficiency revenue.

Year ended December 31, 2017 versus Year ended December 31, 2016

	Segment EBDA before certain items increase/(decrease)		Revenues increase/ (decrease)	
(In millions of Canadian dollars, except percentages)				
Cochin	(10.3)	(40)%	(0.1)	— %
Jet Fuel and others (including eliminations)	(0.4)	(10)%	0.2	3 %
Total Pipelines	(10.7)	(35.9)%	0.1	— %

The changes in Segment EBDA for our Pipelines business segment are further explained by the following discussion of the significant factors driving Segment EBDA in the comparable years of 2017 and 2016:

- decrease of $10.3 million (40%) from Cochin primarily resulting from unrealized foreign exchange loss on the net balance of intercompany receivables, cash, and payable balances, and higher fuel and power costs as a result of higher volumes.

Foreign Exchange Gain on the Long-term Debt - Affiliates (KMI Loans)

During June 2017 we repaid the principal on the KMI Loans utilizing proceeds from our IPO, and the associated notes payable were terminated. The exchange rate at the time of repayment of the notes was 1.3470 U.S. dollar per Canadian dollar. Prior to then, we were exposed to foreign currency risk related to the U.S. dollar denominated KMI Loans.

The $13.0 million unfavorable change between the year ended December 31, 2017 and 2016 on foreign exchange rate gains associated with the KMI Loans was primarily due to less strengthening of the Canadian dollar against the U.S. dollar during the 2017 period prior to the KMI Loans pay off in June 2017.

General and Administrative Expense

Year Ended December 31,	**2018**	**2017**	**2016**
(In millions of Canadian dollars)			
General and administrative	39.0	30.9	25.7
Certain items(a)	(5.5)	(2.8)	—
General and administrative before certain items	33.5	28.1	25.7

a. 2018 amount represents labor expenses related to the Trans Mountain Transaction.

The $5.4 million increase in general and administrative expense before certain items of $5.5 million in 2018 as compared to the prior year was primarily driven by increased labor and insurance costs, and increased legal and audit fees, most of which related to Company financing activities.

The $2.4 million increase in general and administrative expense before certain items of $2.8 million in 2017 as compared to 2016 was primarily driven by increased benefits costs, and increased legal and audit fees related to Company financing activities.

Interest (income) expense, net

Year Ended December 31,	**2018**	**2017**	**2016**
(In millions of Canadian dollars)			
Interest (income) expense, net	(27.2)	8.2	18.5
Certain items(a)	(1.0)	—	—
Interest (income) expense, net before certain items	(28.2)	8.2	18.5

a. 2018 amount represents costs associated with debt refinancing of the 2018 Credit Facility, see Note 10 "*Debt*" to the accompanying consolidated financial statements. Interest (income) expense is presented as net of interest income and capitalized interest.

The $36.4 million decrease in Interest (income) expense, net before certain items in 2018 as compared to 2017 was primarily driven by $29.7 million higher interest income from deposits of the Trans Mountain Transaction proceeds into interest bearing cash equivalent accounts in 2018 and $10.0 million decrease in interest expense due to the repayment of the KMI Loans, partially offset by a $3.0 million decrease of capitalized debt financing costs in 2018.

The $10.3 million decrease in Interest (income) expense, net in 2017 as compared to the prior year was primarily driven by a $11.3 million decrease in interest expense due to the 2017 repayment of the KMI Loans with proceeds from our IPO, partially offset by an increase in interest expense, including interest, commitment fees and amortization of debt issuance costs associated with our 2017 Credit Facility.

Income Taxes from Continuing Operations

Year Ended December 31, 2018 vs. 2017

Income tax expense for the year ended December 31, 2018 was $37.8 million as compared with the prior year income tax expense of $20.8 million. The $17.0 million increase in income tax expense was primarily due to an increase in earnings from continuing operations.

Year Ended December 31, 2017 vs. 2016

Income tax expense for the year ended December 31, 2017 was $20.8 million, as compared with the prior year income tax expense of $23.4 million. The $2.6 million decrease in income tax expense was primarily due to a decrease in pre-tax earnings from continuing operations, partially offset by capital gain tax benefits and release of valuation allowance related to exchange rate fluctuations in respect of the KMI loans in 2016.

Income from Discontinued Operations, Net of Tax

Year Ended December 31,	**2018**	**2017**	**2016**
(In millions of Canadian dollars)			
Income from discontinued operations, net of tax(a)	1,318.2	110.2	131.4
Certain items(b)(c)	(1,230.6)	1.9	(16.5)
Income from discontinued operations, net of tax, before certain items	87.6	112.1	114.9

a. See Note 3 "*Trans Mountain Transaction*" to the accompanying consolidated financial statements for the income statement line item components of income from discontinued operations.
b. The year ended December 31, 2018 includes $1,278.4 million for the gain on the Trans Mountain Transaction, (net of income tax gain of $81.4 million), approximately $42.6 million of deferred costs, net of tax, associated with our 2017 Credit Facility that were being amortized as interest expense over its term were written off and have been included as a certain item from discontinued operations, and Trans Mountain Transaction related expenses of approximately $5.2 million, net of tax.
c. The year ended December 31, 2017 and 2016 includes foreign exchange loss and (gain) on the KMI Loans allocated to the liabilities held for sale.

The $24.5 million decrease in Income from discontinued operations, net of tax before certain items for the comparable years ended 2018 and 2017 is primarily due to four less months of operations for the Trans Mountain Asset Group in 2018.

The $2.8 million decrease in Income from discontinued operations, net of tax before certain items for the comparable years ended 2017 and 2016 was primarily due to an increase in operating expenses largely due to timing of when such expenses were incurred, partially offset by an increase in capitalized equity financing costs associated with TMEP construction.

Net Income Attributable to Kinder Morgan Interest

Net income attributable to Kinder Morgan interest represents the allocation of our consolidated net income attributable to the outstanding ownership interest in our consolidated subsidiaries that are owned by Kinder Morgan's wholly owned subsidiaries. The increase in net income attributable to Kinder Morgan interest for the year ended December 31, 2018 as compared to the same period in 2017 is primarily due to the gain on the Trans Mountain Transaction. See Note 3 "*Trans Mountain Transaction*" to the accompanying consolidated financial statements. The decrease in net income attributable to Kinder Morgan interest for the year ended December 31, 2017 as compared to the respective prior year was primarily due to our IPO and associated reduction in Kinder Morgan's interest in us.

Liquidity and Capital Resources

Short-term Liquidity

As of December 31, 2018, we had $4,338.1 million of "Cash and cash equivalents" and $489.0 million of available borrowing capacity under our 2018 Credit Facility, after reducing the $500 million capacity for the $11.0 million in letters of credit issued. Of the total $11.0 million of letters of credit issued, approximately $8.0 million are issued on behalf of Trans Mountain for which it has issued a backstop letter of credit to us. Approximately $3,977.4 million of our December 31, 2018 "Cash and cash equivalents" were distributed on January 3, 2019 to holders of our Restricted Voting Shares and Special Voting Shares as a Return of Capital. We had an offsetting accrual for the shareholder approved Return of Capital within "Current liabilities—Distributions payable" and "Current liabilities-affiliates—Distributions payable" within the accompanying December 31, 2018 consolidated balance sheet. See Note 3 "*Trans Mountain Transaction*" to the accompanying consolidated financial statements.

As of December 31, 2018 and 2017, our principal source of short-term liquidity was our cash from operating activities of our continuing operations and our Credit Facility. We had a working capital (defined as current assets less current liabilities) deficit of $27.2 million and excess of $42.3 million as of December 31, 2018 and 2017, respectively. The $69.5 million unfavorable change from year end 2017 was primarily due to the increase in accrued taxes from the gain on the Trans Mountain Transaction, partially offset by the remaining cash proceeds from the Transaction net of accrued dividend. Generally, our working capital balance varies due to factors such as timing differences in the collection and payment of receivables and payables.

Our operations generated cash flows from operating activities of $382.0 million and $250.5 million, which included $182.3 million and $58.1 million of cash flows from operating activities from our discontinued operations, for the year ended December 31, 2018 and 2017, respectively. Also, see "*—Cash Flows — Operating Activities*" below.

We believe our cash position (net of the January 3, 2019 Return of Capital distributions of approximately $4.0 billion and accrued income taxes payable of approximately $308 million that is expected to be paid at the end of February 2019) remaining borrowing capacity on our 2018 Credit Facility, and our cash flows from operating activities from our continuing operations are adequate to allow us to manage our day-to-day cash requirements and anticipated obligations including the proposed special dividend as discussed further below.

Long-term Financing

Preferred Share Offerings

On August 15, 2017, we issued 12,000,000 Series 1 Preferred Shares to the public in Canada at a price of $25.00 per share for gross proceeds of $300.0 million. In addition, on December 15, 2017, we issued 10,000,000 Series 3 Preferred Shares to the public in Canada at a price of $25.00 per share for gross proceeds of $250.0 million. In each case, we used the proceeds to subscribe for a corresponding number of Preferred LP Units of the Limited Partnership, which then, directly or indirectly, used such proceeds to repay then outstanding indebtedness incurred to, directly or indirectly, finance the development, construction and completion, as applicable, of TMEP, which we subsequently sold in 2018, and the Base Line Terminal project.

2018 Credit Facility

Upon the closing of the Trans Mountain Transaction on August 31, 2018, we established a four-year, $500 million unsecured revolving credit facility (the "2018 Credit Facility") for working capital purposes, replacing a temporary credit facility that was put in place following the announcement of the Trans Mountain Transaction on May 30, 2018 (the "Temporary Credit Facility"). The $132.6 million of outstanding borrowings under the Temporary Credit Facility were paid off, prior to its termination, with a portion of the Trans Mountain Transaction proceeds. As of December 31, 2018, we had no outstanding borrowings under our 2018 Credit Facility.

Material terms of the 2018 Credit Facility are described below and such description is subject to, and qualified in its entirety by, the terms of such agreements.

Depending on the type of loan requested, interest on the loans outstanding are calculated based on (i) a Canadian prime rate of interest; (ii) a U.S. base rate; (iii) LIBOR; or (iv) bankers' acceptance fees, plus (A) in the case of Canadian prime rate or U.S. base rate loans, an applicable margin of up to 1.25% per annum; or (B) in the case of LIBOR loans or bankers' acceptance, an applicable margin ranging from 1.00% to 2.25% per annum, with such margin determined by our then applicable debt credit rating. Standby fees for the unused portion of the 2018 Credit Facility are calculated at a rate ranging from 0.20% to 0.45% per annum based on our then applicable debt credit rating.

For the year ended December 31, 2018, we incurred, in aggregate, $1.1 million in standby fees on our available credit facilities. The 2018 Credit Facility's credit agreement contains various financial and other covenants that apply to KMCU and its subsidiaries and that are common in such agreements, including a maximum ratio of consolidated total funded debt to consolidated earnings before interest, income taxes, D&A, and non-cash adjustments as defined in the credit agreement, of 5.00:1.00, and restrictions on KMCU's ability to incur debt, grant liens, make dispositions, engage in transactions with affiliates, make restricted payments (including distributions), amend our organizational documents and engage in corporate reorganization transactions.

Credit Ratings and Capital Market Liquidity

We believe that our capital structure will continue to allow us to achieve our business objectives. We expect that our short-term liquidity needs will be met primarily through retained cash from operations or short-term borrowings. The following credit ratings information is provided as it relates to our short-term financing costs and liquidity. Specifically, credit ratings affect our ability to obtain continued financing and the cost of availability for that financing and outstanding borrowings.

The following table represents our corporate credit rating of KMCU (and the Company). KMCU is a wholly owned subsidiary of the Limited Partnership and is the borrower under the Credit Facility.

Rating agency	Senior debt rating	Outlook
Standard and Poor’s Rating Service	BBB	Stable
DBRS Limited	BBB (high)	Negative

DBRS Limited also assigned a Pfd-3 (high) negative rating to our preferred shares. Moody’s Investors Service withdrew their rating following the Trans Mountain Transaction.

These securities ratings are not recommendations to purchase, hold or sell the securities in as much as such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

Capital Expenditures

We account for our capital expenditures in accordance with GAAP. We also distinguish between capital expenditures that are maintenance/sustaining capital expenditures and those that are expansion capital expenditures. Expansion capital expenditures are those expenditures that increase throughput or capacity from that which existed immediately prior to the addition or improvement, and are not deducted in calculating DCF. Sustaining capital expenditures are those which maintain throughput or capacity. The distinction between maintenance and expansion capital expenditures is a physical determination rather than an economic one, irrespective of the amount by which the throughput or capacity is increased.

Budgeting of sustaining capital expenditures is done annually on a bottom-up basis. For each of our assets, we budget for and make those sustaining capital expenditures that are necessary to maintain safe and efficient operations, meet customer needs and comply with our operating policies and applicable law. We may budget for and make additional sustaining capital expenditures that we expect will produce economic benefits such as increasing efficiency and/or lowering future expenses. Budgeting and approval of expansion capital expenditures are generally made periodically throughout the year on a project-by-project basis in response to specific investment opportunities identified by our business segments from which we generally expect to receive sufficient returns to justify the expenditures. Generally, the determination of whether a capital expenditure is classified as sustaining or as expansion capital expenditures is made on a project level. The classification of capital expenditures as expansion capital expenditures or as sustaining capital expenditures is made consistent with our accounting policies and is generally a straightforward process, but in certain circumstances can be a matter of management judgment and discretion. The classification of capital expenditures has an impact on DCF because capital expenditures that are classified as expansion capital

expenditures are not deducted from DCF, while those classified as sustaining capital expenditures are.

Our capital expenditures for the year ended December 31, 2018, and the amount that is expected to be spent to sustain and grow our business in 2019 are as follows:

	2018(a)	Expected 2019
(In millions of Canadian dollars)		
Sustaining capital expenditures(b)	18.5	22.1
Expansion capital expenditures(c)	67.3	32.2

a. 2018 includes $16.0 million of net changes from accrued capital expenditures, contractor retainage, capitalized equity financing costs and other.

b. 2018 excludes $18.6 million of TMPL sustaining capital expenditures prior to the August 31, 2018 Trans Mountain Transaction close date.

c. 2018 excludes $408.0 million of TMEP expansion capital expenditures prior to the August 31, 2018 Trans Mountain Transaction close date, net of changes from accrued capital expenditures, contractor retainage, capitalized equity financing costs and other.

Off Balance Sheet Arrangements

As at December 31, 2018, we had no off balance sheet arrangements other than those included below under "—*Contractual Obligations and Commercial Commitments*."

Contractual Obligations and Commercial Commitments

	Payments due by period				
	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
(In millions of Canadian dollars)					
Contractual obligations:					
Leases and rights-of-way obligations(a)	292.3	61.8	118.9	102.2	9.4
Pension and postretirement welfare plans(b)	1.8	—	—	0.1	1.7
Total	294.1	61.8	118.9	102.3	11.1
Other commercial commitments:					
Standby letters of credit(c)	11.0	8.0	3.0	—	—
Capital expenditures(d)	20.2	20.2	—	—	—

a. Represents commitments pursuant to the terms of operating lease agreements and liabilities for rights-of-way.

b. The payments by period include estimated benefit payments for unfunded plans.

c. Includes $8.0 million of Trans Mountain outstanding letters of credit for which it has issued us a backstop letter of credit and $3 million of letters for credit for our continuing operations.

d. Represents commitments for the purchase of plant, property and equipment as of December 31, 2018 including $13.8 million of our proportional share of commitments through joint ownership of a joint venture.

Cash Flows

The following table summarizes our net cash flows from operating, investing and financing activities for each period presented:

Year Ended December 31,	**2018**	**2017**	**2016**
(In millions of Canadian dollars)			
Net cash provided by (used in):			
Operating activities	382.0	250.5	309.9
Investing activities	3,391.7	(635.1)	(283.2)
Financing activities	324.4	464.9	59.8
Change in cash, cash equivalents and restricted deposits held by the Trans Mountain Asset Group	128.3	(78.3)	(28.9)
Effect of exchange rate changes on cash, cash equivalents and restricted deposits	1.0	(1.1)	0.1
Net increase in Cash, Cash Equivalents and Restricted Deposits	4,227.4	0.9	57.7

Operating Activities

The net increase of $131.5 million (52%) in cash provided by operating activities, including cash flows associated with the Trans Mountain Asset Group, in the year ended December 31, 2018 compared to the 2017 period was primarily attributable to:

- a $431.4 million net increase in cash associated with net changes in operating assets and liabilities, primarily attributable to the following: (i) an increase in cash associated with current income tax liabilities driven by the gain on the Trans Mountain Transaction; (ii) greater collections than refunds of Westridge Marine Terminal dock premiums; and (iii) an increase in cash due to interest payments made on the KMI Loans that were paid off in the 2017; partially offset by,
- a $299.9 million decrease in operating cash flow resulting from the combined effects of adjusting the $1,257.5 million increase in net income for the period-to-period changes in non-cash items primarily consisting of the following: (i) a $1,197.0 million before-tax gain on the Trans Mountain Transaction in 2018; (ii) deferred income taxes, including the deferred tax benefit related to the gain on the Trans Mountain Transaction in 2018; (iii) capitalized equity financing costs; (iv) unrealized changes in the foreign exchange rate; (v) D&A expense; (vi) the 2018 write-off of unamortized debt issuance costs; and (vii) other non-cash items.

The net decrease of $59.4 million (19%) in cash provided by operating activities in the year ended December 31, 2017 compared to the same period in 2016 was primarily attributable to:

- a $66.9 million net decrease in cash associated with net changes in operating assets and liabilities, primarily due to the timing of the collection of trade and affiliate receivables and payables, and due to interest payments made to Kinder Morgan subsidiaries related to the KMI Loans we paid off in 2017. These decreases were partially offset by an increase in cash due to favorable changes from the reduction in net refunds of dock premiums and toll collections related to our Westridge Marine Terminal dock customers; partially offset by,
- a $7.5 million increase in operating cash flow resulting from the combined effects of adjusting the $41.1 million decrease in net income for the period-to-period increase in non-cash items primarily consisting of the following: (i) the change in the foreign exchange rate on the KMI Loans; (ii) D&A expense; (iii) deferred income taxes; (iv) capitalized equity financing costs; and (v) other non-cash items.

Investing Activities

The net increase of $4,026.8 million in cash provided by investing activities in the year ended December 31, 2018 compared to the 2017 period was primarily attributable to:

- the $3,913.4 million of proceeds received from the Trans Mountain Transaction, net of cash disposed in the 2018 period;
- a $90.1 million decrease in capital expenditures primarily related to the Base Line Terminal expansion project and, to a lesser extent, the TMEP as the 2018 period includes expenditures only through the Trans Mountain Transaction in August 2018;
- a $16.2 million increase in cash due to higher proceeds received from the sales of certain assets in the 2018 period compared to the 2017 period; and
- a $7.1 million decrease in cash used due to lower contributions made to our reclamation trusts and the change in Other, net in the 2018 period compared to the 2017 period.

The $351.9 million net increase in cash used in investing activities in the year ended December 31, 2017 compared to the same period in 2016 was primarily attributable to a $349.4 million increase in capital expenditures for the TMEP, Base Line Terminal expansion project and other expansion projects.

Financing Activities

The net decrease of $140.5 million in cash provided by financing activities in the year ended December 31, 2018 compared to the 2017 period was primarily attributable to:

- a $1,671.0 million decrease in cash reflecting proceeds received from our IPO, net of fees paid, in the 2017 period;
- a $537.3 million decrease in cash reflecting proceeds received from the preferred shares issuances, net of fees paid;
- a $100.2 million increase in distributions paid to the Kinder Morgan interest in the 2018 period compared to the 2017 period;
- a $33.9 million increase in dividends paid to Restricted Voting Stockholders in the 2018 period compared to the 2017 period;
- a $23.7 million increase in dividends paid to preferred shareholders in the 2018 period compared to the 2017 period; and
- $6.0 million of payments made related to taxes withheld on vested employee restricted share unit awards in the 2018 period; partially offset by,
- a $1,606.3 million decrease in cash used reflecting repayments of the KMI Loans in the 2017 period using proceeds from our IPO;
- a $559.9 million increase in net borrowings under the Trans Mountain Non-recourse Credit Agreement in the 2018 period. See Note 10 "*Debt*" to the accompanying consolidated financial statements for further information; and
- a $65.4 million decrease in cash used associated with a reduction in debt issuance costs in the 2018 period compared to the 2017 period.

The net increase of $405.1 million in cash provided by financing activities in the year ended December 31, 2017, compared to the same period in 2016 was primarily attributable to:

- $1,671.0 million of proceeds from our IPO, net of fees paid;
- $536.8 million of proceeds from the preferred share issuances, net of fees paid in 2017; and
- a $21.1 million increase in cash due to the distributions we paid to Kinder Morgan in 2016 when it held 100% interest in us; partially offset by,
- a $1,676.5 million decrease in cash related to the long-term affiliate debt activity primarily due to a $1,606.3 million decrease in cash in 2017 as we paid off the KMI Loans using proceeds from our IPO;
- $74.7 million of debt issue costs paid in 2017;
- a $61.9 million decrease in cash due to the combined dividends and distributions we paid after our May 2017 IPO consisting of: (i) $41.8 million as cash distributions paid to the Kinder Morgan interest; (ii) $16.1 million as cash dividends paid to Restricted Voting Stockholders; and (iii) $4.0 million paid to preferred shareholders; and
- a $10.7 million decrease in cash due to the contribution received from Kinder Morgan in 2016.

Equity, Dividends and Distributions

The Limited Partnership currently makes quarterly cash distributions to the Company (as an indirect holder of Class A Units and Preferred LP Units, through the General Partner) and to Kinder Morgan (as an indirect holder of Class B Units) in accordance with the terms of the Limited Partnership Agreement. Distributions are not guaranteed and subject to the approval of the General Partner. To the extent distributions are approved, all distributions on the Class A Units and Preferred LP Units are immediately distributed by the General Partner to the Company, which then uses such to pay dividends to the holders of (i) then outstanding preferred shares of the Company (currently being Series 1 Preferred Shares and Series 3 Preferred Shares) pursuant to the terms of such preferred shares, and (ii) Restricted Voting Shares pursuant to the Company's dividend policy.

See Item 5 "*Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities—Ownership Interests.*"

Dividends on Series 1 Preferred Shares and Series 3 Preferred Shares

Dividends on the Series 1 Preferred Shares and Series 3 Preferred Shares are fixed, cumulative, preferential and $1.3125 per share and $1.3000 per share, respectively, annually, payable quarterly on the 15th day of February, May, August and November, as and when declared by our board of directors, for the initial fixed rate period to but excluding November 15, 2022 and February 15, 2023, respectively. Declared, or paid, as applicable, preferred share dividends for the year ended December 31, 2018 were as follows:

Period	Total Series 1 quarterly dividend per share for the period	Total Series 3 quarterly dividend per share for the period(a)	Date of declaration	Date of record	Date of dividend	Total amount of dividends paid in cash
(In millions of Canadian dollars, except per share amounts)						
November 15, 2017 to February 14, 2018 (a)	0.328125	0.22082	January 17, 2018	January 31, 2018	February 15, 2018	6.1
February 15, 2018 to May 14, 2018	0.328125	0.325	April 18, 2018	April 30, 2018	May 15, 2018	7.2
May 15, 2018 to August 14, 2018	0.328125	0.325	July 18, 2018	July 31, 2018	August 15, 2018	7.2
August 15, 2018 to November 14, 2018	0.328125	0.325	October 10, 2018	October 31, 2018	November 15, 2018	7.2
November 15, 2018 to February 14, 2019	0.328125	0.325	January 16, 2019	January 31, 2019	February 15, 2019	7.2

a. Series 3 per share amount reflects that the shares were outstanding for 62 days during the period ended February 14, 2018.

Dividends on Restricted Voting Shares

We have established a dividend policy pursuant to which we may pay a quarterly dividend on our Restricted Voting Shares in an amount based on our portion of DCF for our business. Consistent with the annualized dividend rate we paid out for 2018, for 2019 we are targeting a declared dividend in the amount of $0.65 per Restricted Voting Share (after the January 4, 2019 Share Consolidation one-for-three basis reverse stock split) assuming the payout of substantially all of our portion of DCF excluding capitalized equity financing costs. The payment of dividends to the holders of Restricted Voting Shares is not guaranteed and the amount and timing of any dividends payable will be at the discretion of our board of directors. The actual amount of cash dividends paid to shareholders, if any, will depend on numerous factors including: (i) our results of operations; (ii) our financial requirements, including the funding of current and future growth projects; (iii) the amount of distributions paid indirectly by the Limited Partnership to us through the general partner of the Limited Partnership, including any contributions from the completion of our growth projects; (iv) the satisfaction by us and the General Partner of certain liquidity and solvency tests; (v) any agreements relating to our indebtedness or the Limited Partnership; and (vi) the cost and timely completion of current and future growth projects. Pursuant to the terms of our Preferred Shares, no dividends may be declared or paid on the Restricted Voting Shares unless all dividends on the Preferred Shares have been paid. It is expected that any quarterly dividends will be payable on or about the 45th day (or the next business day) following the end of each calendar quarter to holders of our Restricted Voting Shares of record as of the close of business on or about the last business day of the month following the end of each calendar quarter. Any dividends paid on the Restricted Voting Shares will continue to be designated as

"eligible dividends" for Canadian income tax purposes, unless otherwise notified, and our website includes disclosure to this effect.

In 2017, we implemented a DRIP pursuant to which Canadian-resident holders of Restricted Voting Shares were able to elect to have all cash dividends of the Company payable to any such shareholder automatically reinvested in additional Restricted Voting Shares at a price per share calculated by reference to the weighted average trading price of the Restricted Voting Shares on the TSX for the five trading days preceding the relevant dividend payment date, less a discount of between 0% and 5% (as determined from time to time by the board of directors, in its sole discretion).

Effective January 16, 2019, our board of directors suspended our DRIP until further notice. Accordingly, dividends in respect of the fourth quarter of 2018, paid on February 15, 2019 to holders of Restricted Voting Shares of record as of the close of business on January 31, 2019, were not reinvested through the DRIP. Shareholders who were enrolled in the program will automatically receive dividend payments in the form of cash. We elected to suspend our DRIP in light of our reduced need for additional capital following the Trans Mountain Transaction. If we elect to reinstate the DRIP in the future, shareholders who were enrolled in the DRIP at suspension and remained enrolled at reinstatement will automatically resume participation in the DRIP.

The following table provides information regarding dividends declared and paid, as applicable, on our Restricted Voting Shares during the year ended December 31, 2018.

For the three month period ended	Dividend rate	Date of declaration	Date of record	Date of dividend	Total amount of dividends paid in cash(a)	Total amount of dividends paid in form of additional shares
(In millions of Canadian dollars, except per share amounts)						
December 31, 2017	0.1625	January 17, 2018	January 31, 2018	February 15, 2018	11.8	5.1
March 31, 2018	0.1625	April 18, 2018	April 30, 2018	May 15, 2018	11.1	5.9
June 30, 2018	0.1625	July 18, 2018	July 31, 2018	February 15, 2018	13.9	3.1
September 30, 2018	0.1625	October 17, 2018	October 31, 2018	November 15, 2018	13.2	3.9
December 31, 2018	0.1625	January 16, 2019	January 31, 2019	February 15, 2019	5.7	—

a. Amount includes notional dividends on outstanding restricted stock awards of $0.4 million during 2018. see Note 11 "*Share-based Compensation and Benefit Plans*" to the accompanying consolidated financial statements.

Distributions on the Kinder Morgan Interest

As the sole indirect holder of Class B Units, Kinder Morgan is entitled to quarterly distributions from the Limited Partnership in accordance with the terms of the Limited Partnership Agreement. Kinder Morgan also has the right to elect to reinvest all distributions payable on its Class B Units in Class B Units on the same economic terms as a holder of Restricted Voting Shares that participates in the DRIP. For a portion of 2018, KMI participated in the DRIP at a rate of 25% to provide a portion of TMEP's capital funding, but given that TMEP is no longer relevant, since July 18, 2018 KMI has ceased its participation.

The following table provides information regarding distributions declared and paid, as applicable, to Kinder Morgan during the year ended December 31, 2018.

For the three month period ended	Dividend rate	Date of declaration	Date of distribution	Total amount of distribution paid in cash(a)	Total amount of distribution paid in form of additional shares
(In millions of Canadian dollars, except per share amounts)					
December 31, 2017	0.1625	January 17, 2018	February 15, 2018	31.0	9.9
March 31, 2018	0.1625	April 18, 2018	May 15, 2018	31.0	9.9
June 30, 2018	0.1625	July 18, 2018	August 15, 2018	40.3	—
September 30, 2018	0.1625	October 17, 2018	November 15, 2018	39.7	—
December 31, 2018	0.1625	January 16, 2019	February 15, 2019	13.2	—

a. Distributions paid in cash include U.S. income tax reimbursements related to Puget Sound earnings of $3.4 million during 2018.

Recent Accounting Pronouncements

Please refer to Note 21 "*Recent Accounting Pronouncements*" to our consolidated financial statements for information concerning recent accounting pronouncements.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk.*

Risk management is integral to the successful operation of the Company. The strategy of the Company is to align risks and related exposures with its business objectives and risk tolerance. Our financial results are subject to a number of risks as set out in Item 1A "*Risk Factors*." Also, see Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates*" above, as well as Note 17 "*Risk Management and Financial Instruments"* and Note 20 *"Litigation, Commitments and Contingencies"* to the accompanying consolidated financial statements.

Interest Rate Risk

During the year ended December 31, 2018 we incurred approximately $2.1 million of interest expense on borrowings under our credit facilities. As of December 31, 2018 and 2017 we had no debt outstanding. We are exposed to interest rate risk attributed to floating rate debt on our 2018 Credit Facility, which is used for working capital purposes. The changes in interest rates may impact future cash flows and the fair value of our financial instruments.

Foreign Currency Transactions and Translation

Foreign currency transaction gains or losses result from a change in exchange rates between the functional currency of an entity, and the currency in which a transaction is denominated. Unrealized and realized gains and losses are recorded in Foreign exchange gain (loss) in the accompanying consolidated statements of income and include:

- As a result of the Trans Mountain Transaction, we released foreign currency translation gains previously held within Accumulated other comprehensive loss to the Gain on sale of the Trans Mountain Asset Group, net of tax in the accompanying consolidated statement of income of $10.1 million for the year ended December 31, 2018.

- Prior to repayment of the KMI Loans utilizing proceeds from our IPO, we were exposed to foreign currency risk related to the U.S. dollar denominated KMI Loans. For the years ended December 31, 2017 and 2016, our continuing operations had unrealized foreign exchange gain of $0.2 million and $13.2 million, respectively, and our discontinued operations had unrealized foreign exchange (loss) and gain of $(2.6) million and $16.5 million, respectively, related to the KMI Loans.

- Our continuing operations unrealized foreign exchange (loss) and gain for the years ended December 31, 2018, 2017 and 2016 were $1.0 million, $(5.6) million and $1.4 million, respectively, due to changes in exchange rates between the Canadian dollar and the U.S. dollar on U.S. dollar denominated balances. These currency exchange rate fluctuations affect the expected Canadian dollar cash flows on unsettled U.S. dollar denominated transactions, primarily related to cash bank accounts that are denominated in U.S. dollars and affiliate receivables or payables that are denominated in U.S. dollars. Prior to the closing of the Trans Mountain Transaction, we translated the assets and liabilities of Puget Sound that has the U.S. dollar as its functional currency to Canadian dollars at period-end exchange rates.

- Cochin earns its revenues in U.S. dollars. Therefore, fluctuations in the U.S. dollar to Canadian dollar exchange rate can affect the earnings contributed by Cochin to our overall results. Our continuing operations had realized foreign exchange (loss) and gain of $(0.9) million and $0.3 million for the years ended December 31, 2018 and 2017. The net realized foreign exchange gains and losses were nominal in 2016.

Item 8. ***Financial Statements and Supplementary Data.***

The information required in this Item 8 is in this report as set forth in the "*Index to Financial Statement*s" on page 64.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.***

None.

Item 9A. ***Controls and Procedures.***

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of December 31, 2018, our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon and as of the date of the evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the design and operation of our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in the reports we file and submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported as and when required, and is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an assessment of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, our management concluded that our internal control over financial reporting was effective as of December 31, 2018.

Changes in Internal Control Over Financial Reporting

No changes in our internal control over financial reporting occurred during the year ended December 31, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information.***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance.***

The information required by this item is incorporated by reference from KML's definitive proxy statement for the 2019 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2019.

Item 11. ***Executive Compensation.***

The information required by this item is incorporated by reference from KML's definitive proxy statement for the 2019 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2019.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management, and Related Stockholder Matters.***

The information required by this item is incorporated by reference from KML's definitive proxy statement for the 2019 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2019.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence.***

Agreements between the Company and Kinder Morgan

This section provides a description of the material terms of the principal agreements among the Company, Kinder Morgan, the General Partner and/or the Limited Partnership. The description of each agreement is subject to, and qualified in its entirety by, the terms of such agreement, which is filed as an exhibit hereto. See Note 14 "*Transactions with Related Parties*" to our consolidated financial statements attached hereto and Item 1A *"Risk Factors—Risks Relating to Our Relationship with Kinder Morgan*." For description of the material provisions of the Limited Partnership Agreement, see Item 5 "*Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities—Ownership Interests."*

Cooperation Agreement

The Cooperation Agreement provides for certain matters among the Company, the Limited Partnership, the General Partner, Kinder Morgan (in respect of certain matters only), KMCC and KMCT. The Cooperation Agreement does not in any way limit the ability of either KMCC or KMCT to exercise its rights attached to the Special Voting Shares.

The Cooperation Agreement includes an acknowledgement by the parties that the Class A Units and the Restricted Voting Shares on the one hand and the Class B Units and the Special Voting Shares on the other hand (collectively, the "Related Securities") are intended to convey, on a per security basis, equivalent rights to participate, directly or indirectly, in distributions of the Limited Partnership (subject to applicable taxes), the exercise of rights of limited partners and voting rights at the Company level. To the extent that any Related Securities, or any securities convertible into, or exchangeable or exercisable for, Related Securities, are issued, sold or distributed, the parties will determine whether any adjustments are required to ensure that the equivalency noted above is maintained, and in the event that an adjustment is required and subject to applicable laws, additional Related Securities, or securities convertible into or exchangeable or exercisable for Related Securities, may be issued or distributed on substantially equivalent terms, having regard to the particular attributes of the different classes of the Related Securities. In the event that any class of Related Security is subdivided, consolidated, reclassified or otherwise changed, an equivalent change will be made to the other classes of Related Securities if such a change is required to maintain the equivalency noted above. Subject to applicable laws, if there is a dispute among the parties as to whether an adjustment or change is required in order to maintain equivalency, any adjustment must be approved on behalf of the General Partner or the Company, as applicable, by both the board of directors of the General Partner or the Company, as applicable, as a whole, and the independent directors not affiliated with the Kinder Morgan Group.

Pursuant to the Cooperation Agreement, the parties thereto agreed that any acquisition or investing activity that would be material to the Company, on a consolidated basis, will only be undertaken through the Limited Partnership. In addition, Kinder Morgan has agreed that it will first offer to the Company, on behalf of the Kinder Morgan Canada Group, any crude oil, natural gas liquids or refined product infrastructure development opportunities and/or acquisition opportunities (individually an "Opportunity" and collectively the "Opportunities") which currently have or are expected to have a majority of their physical assets and/or infrastructure within the provinces of B.C. and Alberta, except in the event of an Opportunity involving an acquisition of all or any portion of the equity of a publicly traded company or entity or an acquisition of all or substantially all of the assets of a publicly traded company or entity, in which cases Kinder Morgan, in its sole discretion, may determine to pursue the Opportunity on its own behalf. In the event there is a conflict of interest (or potential conflict of interest) between

one or more members of the Kinder Morgan Group and the Kinder Morgan Canada Group with respect to any matter or transaction (including a transaction involving the transfer of assets and/or liabilities from a member of the Kinder Morgan Group to a member of the Kinder Morgan Canada Group), the independent directors of the board of directors shall be responsible to take all such actions and make all such decisions (such decision to be approved, subject to applicable laws, by the majority of the independent directors of the board of directors) relating to such conflict as it pertains to the applicable member of the Kinder Morgan Canada Group.

Subject to the applicable provisions in the Cooperation Agreement described above, the Company, the General Partner and the Limited Partnership expressly consent in the Cooperation Agreement to Kinder Morgan and its affiliates that are members of the Kinder Morgan Group and their respective officers, directors and employees engaging in any business or activities whatsoever, including those that may be in competition or conflict with the business and/or the interests of, the Company.

Unless terminated earlier by written agreement of the parties, the Cooperation Agreement will terminate when no Special Voting Shares or Class B Units remain outstanding. No party to the Cooperation Agreement may assign its rights or interest thereunder without the express prior written consent of the other parties, which, in the case of the consent of KMCC or KMCT, may be granted or withheld in their sole discretion, and, in the case of the consent of any other party, will not be unreasonably withheld or delayed. Notwithstanding the foregoing, KMCC or KMCT may assign any or all of its rights or interest under the Cooperation Agreement to any affiliate of Kinder Morgan without the consent of the Company. The Cooperation Agreement may be amended from time to time by the parties, provided that if any amendment constitutes, or could reasonably be expected to constitute, a conflict of interest or potential conflict of interest between the Kinder Morgan Canada Group and the Kinder Morgan Group, subject to applicable law, such amendment must be approved on behalf of the Company or the General Partner, as applicable, by both the board of directors and the board of directors of the General Partner, as applicable, as a whole and the independent directors of each entity, as applicable, not affiliated with the Kinder Morgan Group.

Services Agreement

KMCSI assumed KMCI's rights and obligations under the Services Agreement at the closing of the Trans Mountain Transaction, whereby, the Company, the General Partner and the Limited Partnership are party to the Services Agreement pursuant to which KMCSI, an Alberta corporation which is an indirect subsidiary of the Company, provides certain operational and administrative services in connection with the management of the business and affairs of the Kinder Morgan Canada Group, or where requested, will coordinate on behalf of entities in the Kinder Morgan Canada Group to procure assistance and/ or support in providing such services from its affiliates. KMCSI's activities under the Services Agreement are subject to the supervision of the executive officers of the Company and the board of directors.

The operational and administrative services provided by KMCSI to the Company, the General Partner and the Limited Partnership under the Services Agreement include certain services to: (i) enable the Company to comply with its continuous disclosure and other obligations under applicable laws; (ii) coordinate financing and investing activities of the Company, including through the Company, the General Partner, the Limited Partnership or other entities in the Kinder Morgan Canada Group; (iii) assist with development, implementation and monitoring of operational plans for the Company; (iv) assist in implementing any dividend or distribution reinvestment plans, and any incentive plans of the Company and the Limited Partnership, as applicable; (v) facilitate performance of required acts and responsibilities in connection with the acquisition and disposition of assets and property by entities in the Kinder Morgan Canada Group; (vi) provide accounting and bookkeeping services, including for the preparation of the annual and interim financial statements of the Company and the preparation and filing of all tax returns; and (vii) arrange for audit, legal and other third party professional and non-professional services. Any support and/or assistance with any services provided by an affiliate of KMCSI outside of the Kinder Morgan Canada Group will be reimbursed at cost, unless otherwise required by applicable laws.

The Services Agreement shall continue in effect until terminated by mutual agreement of the parties. The Services Agreement may be amended from time to time by the parties, provided that if any amendment constitutes, or could reasonably be expected to constitute, a conflict of interest or potential conflict of interest between the Kinder Morgan Canada Group and the Kinder Morgan Group, subject to applicable law, such amendment must be approved on behalf of the Company or the General Partner by both the board of directors and the board of directors of the General Partner, as applicable, as a whole, and the independent directors not affiliated with the Kinder Morgan Group.

Independence of the Board of Directors

The board of directors is comprised of six directors, of whom Daniel P.E. Fournier, Gordon M. Ritchie and Brooke N. Wade are "independent" when applying the definition of independence under the rules of both the TSX and the NYSE.

The board of directors does not have an independent director as Chair of the Board. Rather, it has a Lead Director and has developed a procedure for the independent directors to function independently of management and, where necessary, Kinder Morgan. The board of directors has adopted a fixed *in camera* agenda item for each board and committee meeting, during which independent directors, under the direction of the Lead Director or committee chair, may meet without any members of management or non-independent directors present. Gordon M. Ritchie, one of our independent directors, has been appointed as Lead Director. In his role as Lead Director, Mr. Ritchie is responsible for moderating the *in camera* board of directors meetings held by the independent directors and acting as principal liaison between the independent directors and the Chair of the Board on matters dealt with in such *in camera* sessions. In the absence of the Chair of the Board, the Lead Director shall preside at meetings of the board of the directors.

Additional information required by this item is incorporated by reference from KML's definitive proxy statement for the 2019 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2019.

Item 14. ***Principal Accounting Fees and Services.***

The information required by this item is incorporated by reference from KML's definitive proxy statement for the 2019 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2019.

On August 31, 2018, we completed the sale of the Trans Mountain Asset Group. As a result of the transaction, most of our accounting functions have been managed out of Houston, Texas. Accordingly, as previously disclosed, on October 24, 2018, we changed our principal independent registered public accountant from PricewaterhouseCoopers LLP (Canada) ("PWC Canada") to PricewaterhouseCoopers LLP (United States) ("PWC U.S."). This change constituted a resignation by PWC Canada and the engagement of PWC U.S. because PWC Canada and PWC U.S. are separate legal entities. The decision to change independent registered public accountants was approved by the audit committee of our board of directors on October 24, 2018.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules.***

a. (1) Financial Statements and (2) Financial Statement Schedules

See "Index to Financial Statements" set forth on Page 64.

(3) Exhibits

Exhibit Number		Description
2.1	*	Share and Unit Purchase Agreement, dated May 29, 2018, by and among Kinder Morgan Cochin ULC, Her Majesty in right of Canada, as represented by the Minister of Finance, Kinder Morgan Canada Limited, and Kinder Morgan, Inc. (filed as Exhibit 10.1 to the current report on Form 8-K of Kinder Morgan Canada Limited filed on June 1, 2018 and Incorporated herein by reference)
3.1	*	Certificate of Incorporation of Kinder Morgan Canada Limited (filed as exhibit 3.1 to Kinder Morgan Canada Limited's Form 10-12G filed on November 3, 2017 and incorporated herein by reference)
3.2	*	Certificate of Amendment and Registration of Restated Articles of Kinder Morgan Canada Limited (filed as exhibit 3.2 to Kinder Morgan Canada Limited's Form 10-12G filed on November 3, 2017 and incorporated herein by reference)
3.3	*	Certificate of Amendment of Kinder Morgan Canada Limited (filed as exhibit 3.3 to Kinder Morgan Canada Limited's Form 10-12G/A filed on December 29, 2017 and incorporated herein by reference)
3.4		Articles of Amendment of Kinder Morgan Canada Limited (Share consolidation)
3.5	*	Amended and Restated By-law No. 1 of Kinder Morgan Canada Limited (filed as exhibit 3.4 to Kinder Morgan Canada Limited's Form 10-12G filed on November 3, 2017 and incorporated herein by reference)
3.6	*	Second Amended and Restated Limited Partnership Agreement of Kinder Morgan Canada Limited Partnership, dated August 15, 2017 (filed as exhibit 3.5 to Kinder Morgan Canada Limited's Form 10-12G filed on November 3, 2017 and incorporated herein by reference)
3.7	*	First Amendment to the Second Amended and Restated Limited Partnership Agreement of Kinder Morgan Canada Limited Partnership, dated December 15, 2017 (filed as exhibit 3.6 to Kinder Morgan Canada Limited's Form 10-12G/A filed on December 29, 2017 and incorporated herein by reference)
3.8	*	Certificate of Amalgamation of Kinder Morgan Canada GP Inc. (filed as exhibit 3.6 to Kinder Morgan Canada Limited's Form 10-12G filed on November 3, 2017 and incorporated herein by reference)
3.9	*	By-law No. 1 of Kinder Morgan Canada GP Inc. (filed as exhibit 3.7 to Kinder Morgan Canada Limited's Form 10-12G filed on November 3, 2017 and incorporated herein by reference)
3.10	*	Certificate of Amendment of Kinder Morgan Canada GP Inc. (filed as exhibit 3.9 to Kinder Morgan Canada Limited's Form 10-12G/A filed on December 29, 2017 and incorporated herein by reference)
3.11		Articles of Amendment of Kinder Morgan Canada GP Inc. (Share consolidation)
10.1	*	Cooperation Agreement, dated as of May 30, 2017, by and among Kinder Morgan Canada Limited, Kinder Morgan Canada GP Inc., Kinder Morgan Canada Company, KM Canada Terminals ULC, Kinder Morgan Canada Limited Partnership and Kinder Morgan, Inc. and the other parties thereto (filed as exhibit 10.1 to Kinder Morgan Canada Limited's Form 10-12G filed on November 3, 2017 and incorporated herein by reference)
10.2	*	Services Agreement, dated as of May 30, 2017, by and among Kinder Morgan Canada Limited, Kinder Morgan Canada Inc., Kinder Morgan Canada GP Inc. and Kinder Morgan Canada Limited Partnership (filed as exhibit 10.2 to Kinder Morgan Canada Limited's Form 10-12G filed on November 3, 2017 and incorporated herein by reference)
10.3	*	Credit Agreement, dated June 16, 2017, by and among Kinder Morgan Cochin ULC, Trans Mountain Pipeline ULC and the lenders party thereto (filed as exhibit 10.1 to the current report on Form 8-K/A of Kinder Morgan, Inc. (File No. 1-35081) filed on August 25, 2017 and incorporated herein by reference)
10.4	*	First Amending Agreement to the Credit Agreement, dated January 23, 2018, by and among Kinder Morgan Cochin ULC, Trans Mountain Pipeline ULC and the lenders party thereto (filed as exhibit 10.1 to the current report on Form 8-K/A of Kinder Morgan Canada Limited filed on January 23, 2018 and incorporated herein by reference)

10.5	*	2017 Restricted Share Unit Plan for Employees (filed as exhibit 10.4 to Kinder Morgan Canada Limited's Form 10-12G filed on November 3, 2017 and incorporated herein by reference)
10.6	*	Restricted Share Unit Plan for Non-Employee Directors (filed as exhibit 10.5 to Kinder Morgan Canada Limited's Form 10-12G filed on November 3, 2017 and incorporated herein by reference)
10.7	*	Credit Agreement, dated May 1, 2018, by and among Kinder Morgan Cochin ULC, Royal Bank of Canada and the lenders party thereto ("Credit Agreement") (filed as exhibit 10.4 to the quarterly report on Form 10-Q filed on July 25, 2018 and incorporated herein by reference)
10.8	*	First Amending Agreement to the Credit Agreement, dated May 29, 2018 (filed as exhibit 10.5 to the quarterly report on Form 10-Q filed on July 25, 2018 and incorporated herein by reference)
10.9	*	Second Amending Agreement to the Credit Agreement, dated June 14, 2018 (filed as exhibit 10.6 to the quarterly report on Form 10-Q filed on July 25, 2018 and incorporated herein by reference)
21.1		Subsidiaries of KML
31.1		Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2		Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.1		Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2		Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101		Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Statements of Income for the years ended December 31, 2018, 2017 and 2016; (ii) our Consolidated Statements of Comprehensive Income for the years ended December 31, 2018, 2017 and 2016; (iii) our Consolidated Balance Sheets as of December 31, 2018 and 2017; (iv) our Consolidated Statements of Cash Flows for the years ended December 31, 2018 and 2017; (v) our Consolidated Statements of Equity for the years ended December 31, 2018, 2017 and 2016; and (vi) the notes to our Consolidated Financial Statements.

*Asterisk indicates exhibits incorporated by reference as indicated; all other exhibits are filed herewith, except as noted otherwise.

KINDER MORGAN CANADA LIMITED
INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm
To the shareholders and board of directors of Kinder Morgan Canada Limited

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of Kinder Morgan Canada Limited and its subsidiaries (the "Company") as of December 31, 2018, and the related consolidated statement of income, comprehensive income, cash flows, and equity for the year then ended, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018, and the results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audit. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audit we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audit included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audit provides a reasonable basis for our opinion.

/s/PricewaterhouseCoopers LLP

Houston, Texas
February 18, 2019

We have served as the Company's auditor since 2018.

Report of Independent Registered Public Accounting Firm
To the shareholders and board of directors of Kinder Morgan Canada Limited

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of Kinder Morgan Canada Limited and its subsidiaries (together, the "Company") as of December 31, 2017, and the related consolidated statements of income, comprehensive income, cash flows and equity for each of the two years in the period ended December 31, 2017, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Canada
February 20, 2018, except for the effects of discontinued operations discussed in Note 3 and the effects of the reverse stock split discussed in Note 13 to the consolidated financial statements, as to which the date is February 18, 2019.

We served as the Company's auditor from 2016 to 2018.

KINDER MORGAN CANADA LIMITED
CONSOLIDATED STATEMENTS OF INCOME
(In millions of Canadian dollars, except per share amounts)

Year Ended December 31,	2018	2017 (Note 3)	2016 (Note 3)
Revenues			
Services	322.6	294.8	288.5
Services-affiliate	61.2	63.7	59.1
Product sales and other	—	0.4	0.2
Total Revenues	383.8	358.9	347.8
Operating Costs, Expenses and Other			
Operations and maintenance	154.5	162.5	152.8
Depreciation and amortization(Note 6)	82.6	71.7	64.2
General and administrative	39.0	30.9	25.7
Taxes, other than income taxes	6.2	6.7	7.3
Other (income) expense, net	(9.3)	3.4	0.2
Total Operating Costs, Expenses and Other	273.0	275.2	250.2
Operating Income	110.8	83.7	97.6
Other Income (Expense)			
Interest income (expense), net(Note 15)	27.2	(8.2)	(18.5)
Foreign exchange gain (loss)(Note 17)	0.1	(5.1)	14.6
Other, net	(0.3)	0.9	0.1
Total Other Income (Expense)	27.0	(12.4)	(3.8)
Income from Continuing Operations Before Income Taxes	137.8	71.3	93.8
Income Tax Expense(Note 4)	(37.8)	(20.8)	(23.4)
Income from Continuing Operations	100.0	50.5	70.4
Discontinued Operations(Note 3)			
Income from operations of the Trans Mountain Asset Group, net of tax	39.8	110.2	131.4
Gain on sale of the Trans Mountain Asset Group, net of tax	1,278.4	—	—
Income from Discontinued Operations, Net of Tax	1,318.2	110.2	131.4
Net Income	1,418.2	160.7	201.8
Preferred share dividends	(28.8)	(6.6)	—
Net Income Attributable to Kinder Morgan Interest	(973.2)	(126.2)	(201.8)
Net Income Available to Restricted Voting Stockholders	416.2	27.9	—
Restricted Voting Shares(Note 13)			
Basic and Diluted Earnings Per Restricted Voting Share from Continuing Operations	0.62	0.31	—
Basic and Diluted Earnings Per Restricted Voting Share from Discontinued Operations	11.37	0.69	—
Basic and Diluted Weighted Average Restricted Voting Shares Outstanding	34.7	27.6	—

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN CANADA LIMITED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions of Canadian dollars)

Year Ended December 31,	2018	2017	2016
Net income	1,418.2	160.7	201.8
Other comprehensive income (loss)			
Benefit plans(Note 3)	37.5	—	(4.7)
Foreign currency translation adjustments(Note 3)	(8.2)	(3.5)	(1.7)
Total other comprehensive income (loss)	29.3	(3.5)	(6.4)
Comprehensive income	1,447.5	157.2	195.4
Comprehensive income attributable to Kinder Morgan interest	(993.7)	(124.0)	(195.4)
Comprehensive income attributable to Kinder Morgan Canada Limited	453.8	33.2	—

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN CANADA LIMITED
CONSOLIDATED BALANCE SHEETS
(In millions of Canadian dollars, except share amounts)

December 31,	2018	2017 (Note 3)
ASSETS		
Current assets		
Cash and cash equivalents	4,338.1	110.7
Accounts receivable	26.2	23.3
Inventories	7.5	7.3
Current assets held for sale(Note 3)	—	192.7
Other current assets(Note 5)	5.9	6.6
Total current assets	4,377.7	340.6
Property, plant and equipment, net(Note 6)	981.3	988.4
Long-term assets held for sale(Note 3)	—	3,050.4
Deferred charges and other assets(Note 7)	10.6	73.3
Total Assets	5,369.6	4,452.7
LIABILITIES AND EQUITY		
Current liabilities		
Credit facility(Note 10)	—	—
Accounts payable(Note 8)	49.4	54.5
Distribution payable	1,195.1	—
Distribution payable-affiliates	2,782.3	—
Accrued taxes	310.6	8.7
Current liabilities held for sale(Note 3)	—	207.3
Other current liabilities(Note 9)	63.2	27.8
Total current liabilities	4,400.6	298.3
Long-term liabilities and deferred credits		
Deferred income taxes(Note 4)	0.1	348.9
Contract liabilities	67.5	53.5
Long-term liabilities held for sale(Note 3)	—	113.6
Other deferred credits(Note 12)	8.9	0.8
Total long-term liabilities and deferred credits	76.5	516.8
Total Liabilities	4,477.1	815.1
Commitments and contingencies(Notes 10 and 20)		
Equity		
Preferred share capital, 12,000,000 shares of Series 1 and 10,000,000 shares of Series 3, issued and outstanding(Note 13)	537.2	537.2
Restricted Voting Share capital, 34,944,993 and 34,455,635 Restricted Voting Shares, respectively, issued and outstanding(Note 13)	278.1	1,707.5
Retained deficit	(165.8)	(770.0)
Accumulated other comprehensive loss	—	(8.8)
Total Kinder Morgan Canada Limited equity	649.5	1,465.9
Kinder Morgan interest, 81,353,820 and 80,960,966 Special Voting Shares, respectively, issued and outstanding(Note 13)	243.0	2,171.7
Total Equity	892.5	3,637.6
Total Liabilities and Equity	5,369.6	4,452.7

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN CANADA LIMITED
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions of Canadian dollars)

Year Ended December 31,	2018	2017	2016
Operating Activities			
Net income	1,418.2	160.7	201.8
Non-cash items:			
Depreciation and amortization	129.4	142.4	137.2
Deferred income taxes	(339.9)	57.2	55.1
Capitalized equity financing costs	(34.8)	(29.1)	(17.9)
Unrealized foreign exchange (gain) loss	(0.8)	5.6	(32.6)
Write-off of unamortized debt issuance costs	60.5	—	—
Gain on sale of the Trans Mountain Asset Group(Note 3)	(1,197.0)	—	—
Other non-cash items	9.4	8.1	(6.2)
Change in operating assets and liabilities(Note 16)	337.0	(94.4)	(27.5)
Cash provided by operating activities(Note 3)	382.0	250.5	309.9
Investing Activities			
Capital expenditures	(528.4)	(618.5)	(269.1)
Contributions to trusts	(9.9)	(16.4)	(13.7)
Sales of property, plant and equipment, net of removal costs	16.0	(0.2)	(0.4)
Proceeds from the sale of the Trans Mountain Asset Group, net of cash disposed(Note 3)	3,913.4	—	—
Other, net	0.6	—	—
Cash provided by (used in) investing activities(Note 3)	3,391.7	(635.1)	(283.2)
Financing Activities			
Issuances of debt	792.6	337.3	—
Repayments of debt	(232.7)	(337.3)	—
Proceeds received from IPO, net	—	1,671.0	—
Issuances of preferred shares, net	(0.5)	536.8	—
Proceeds from debt with affiliates	—	—	70.2
Repayments of debt with affiliates	—	(1,606.3)	—
Cash dividends - restricted shares	(50.0)	(16.1)	—
Dividends - preferred shares	(27.7)	(4.0)	—
Distributions - Kinder Morgan interest	(142.0)	(41.8)	—
Debt issuance costs	(9.3)	(74.7)	—
Contributions from Kinder Morgan - pre-IPO	—	—	10.7
Distributions to Kinder Morgan - pre-IPO	—	—	(21.1)
Other, net	(6.0)	—	—
Cash provided by financing activities	324.4	464.9	59.8
Change in Cash, Cash Equivalents and Restricted Deposits held by the Trans Mountain Asset Group	128.3	(78.3)	(28.9)
Effect of exchange rate changes on cash, cash equivalents and restricted deposits	1.0	(1.1)	0.1
Net increase in Cash, Cash Equivalents and Restricted Deposits	4,227.4	0.9	57.7
Cash, Cash Equivalents and Restricted Deposits, beginning of period	111.2	110.3	52.6
Cash, Cash Equivalents and Restricted Deposits, end of period	4,338.6	111.2	110.3
Cash and Cash Equivalents, beginning of period	110.7	109.8	52.2
Restricted Deposits, beginning of period	0.5	0.5	0.4
Cash, Cash Equivalents, and Restricted Deposits, beginning of period	111.2	110.3	52.6
Cash and Cash Equivalents, end of period	4,338.1	110.7	109.8
Restricted Deposits, end of period	0.5	0.5	0.5
Cash, Cash Equivalents, and Restricted Deposits, end of period	4,338.6	111.2	110.3
Net increase in Cash, Cash Equivalents and Restricted Deposits	4,227.4	0.9	57.7
Supplemental Disclosures of Cash Flow Information			
Cash paid including to affiliates during the period for interest (net of capitalized interest)	—	59.2	31.2
Cash paid during the period for income taxes	9.4	2.3	1.1
Non-cash Investing and Financing Activities			
Increase in property, plant and equipment from both accruals and contractor retainage		38.1	26.0
Increase (decrease) in property, plant and equipment due to foreign currency translation adjustments	1.5	(2.8)	(4.0)
Distribution accruals	3,977.4	—	—

The accompanying notes are an integral part of these consolidated financial statements.

	Canadian dollars (in millions)			
	Equity attributable to Kinder Morgan pre-IPO	Retained deficit	Accumulated other comprehensive loss	Total
Balance at December 31, 2015	1,464.3	(193.8)	(19.5)	1,251.0
Net income		201.8		201.8
Contributions	10.7			10.7
Distributions		(21.1)		(21.1)
Other comprehensive income			(6.4)	(6.4)
Balance at December 31, 2016	1,475.0	(13.1)	(25.9)	1,436.0

	Issued shares (in millions)			Canadian dollars (in millions)						
	Preferred Shares	Restricted Voting Shares	Kinder Morgan Interest - Special Voting Shares	Equity attributable to Kinder Morgan pre-IPO	Preferred Share Capital	Restricted Voting Share capital	Retained deficit	Accumulated other comprehensive loss	Kinder Morgan interest	Total
Balance at December 31, 2016	—	—	—	1,475.0	—	—	(13.1)	(25.9)	—	1,436.0
Activity attributable to Kinder Morgan prior to IPO:										
Equity interests issued				126.9						126.9
Distribution				(261.7)						(261.7)
Issuance of restricted voting shares		34.3				1,750.0				1,750.0
Issuance of special voting shares and reallocation of Kinder Morgan pre-IPO carrying basis			80.7	(1,340.2)			13.1	25.9	1,301.2	—
Reallocation of equity on common control transaction							(777.7)	(7.5)	785.2	—
Equity issuance fees					(13.9)	(69.9)				(83.8)
Issuance of preferred shares	22.0				550.0					550.0
Net income							34.5		126.2	160.7
Preferred share dividend							(4.0)			(4.0)
Restricted voting share dividends							(22.8)			(22.8)
Special voting share distributions									(55.1)	(55.1)
Dividend/Distribution reinvestment plan		0.2	0.3			6.7			13.3	20.0
Stock-based compensation						2.2				2.2
Deferred tax liability adjustment					1.1	18.8			2.8	22.7
Other						(0.3)			0.3	—
Other comprehensive loss								(1.3)	(2.2)	(3.5)
Balance at December 31, 2017	22.0	34.5	81.0	—	537.2	1,707.5	(770.0)	(8.8)	2,171.7	3,637.6

	Issued shares (in millions)			Canadian dollars (in millions)					
	Preferred shares	Restricted Voting Shares	Kinder Morgan Interest - Special Voting Shares	Preferred share capital	Restricted Voting Share capital	Retained deficit	Accumulated other comprehensive loss	Kinder Morgan interest	Total
Balance at December 31, 2017	22.0	34.5	81.0	537.2	1,707.5	(770.0)	(8.8)	2,171.7	3,637.6
Net income						445.0		973.2	1,418.2
Preferred share dividend						(27.7)			(27.7)
Restricted voting share dividends						(68.0)			(68.0)
Special voting share distributions								(161.8)	(161.8)
Return of Capital(Note 3)						(1,195.1)		(2,782.3)	(3,977.4)
Dividend/Distribution reinvestment plan		0.4	0.4		18.0			19.8	37.8
Stock-based compensation					4.5				4.5
Stated Capital Reduction(Note 3)					(1,450.0)	1,450.0			—
Other					(1.9)			1.9	—
Other comprehensive income							8.8	20.5	29.3
Balance at December 31, 2018	22.0	34.9	81.4	537.2	278.1	(165.8)	—	243.0	892.5

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN CANADA LIMITED

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. General

The Company was incorporated under the Business Corporations Act (Alberta) on April 7, 2017. On May 30, 2017, we completed an IPO of our Restricted Voting Shares and used the net proceeds of $1,671.0 million to acquire an approximate 30% indirect equity interest in the Limited Partnership from certain affiliates of Kinder Morgan, who retained an approximate 70% equity ownership of the limited partnership units in the Limited Partnership. When we refer to "us," "we," "our," "ours," "the Company," or "KML," we are describing Kinder Morgan Canada Limited.

The Limited Partnership and Kinder Morgan Canada GP Inc. (the "General Partner"), were formed under the laws of the Province of Alberta in conjunction with the IPO. After the sale of the Trans Mountain Asset Group further discussed in Note 3 , the Limited Partnership, through its ownership of KMCU, indirectly consolidates KMCSI and all or its proportion of the following operating entities (collectively the "Operating Entities"):

- KMCU
- KM Canada Marine Terminal Limited Partnership
- KM Canada North 40 Limited Partnership
- KM Canada Rail Holdings GP Limited
- KM Canada (Jet Fuel) Inc.
- KM Canada Terminals GP ULC
- KM Canada Edmonton South Rail Terminal Limited Partnership[(a)]
- KM Canada Edmonton North Rail Terminal Limited Partnership[(a)]
- Base Line Terminal East Limited Partnership[(a)]

a. Through these wholly owned partnerships we own a 50% undivided interest in joint venture operations with unaffiliated entities that are proportionality consolidated.

The Limited Partnership is a variable interest entity because a simple majority or lower threshold of the limited partnership interests do not possess substantive "kick-out" rights (i.e., the right to remove the general partner or to dissolve (liquidate) the entity without cause) or substantive participation rights. The General Partner is the primary beneficiary because it has the power to direct the activities that most significantly impact the Limited Partnership's performance and the right to receive benefits, and obligation to absorb losses, that could be significant to the Limited Partnership. As a result, the General Partner consolidates the Limited Partnership. The General Partner is a wholly owned subsidiary of the Company. Consequently, we indirectly consolidate the Limited Partnership and the Operating Entities in our consolidated financial statements.

Business Description

We have two business segments: (i) the Terminals segment which includes the ownership and operation of liquid product merchant storage and rail terminals in the Edmonton, Alberta market as well as a predominantly dry cargo import/ export facility in Vancouver, B.C. and (ii) the Pipelines segment which owns and operates Cochin and Jet Fuel.

Our Reorganization and IPO

On May 30, 2017, we completed an IPO of 102,942,000 Restricted Voting Shares (number of shares is before our January 4, 2019 Share Consolidation, see Note 3) on the TSX at a price of $17.00 per Restricted Voting Share for total gross proceeds of approximately $1.75 billion. We used our IPO proceeds to indirectly acquire from Kinder Morgan an approximate 30% equity interest in the Limited Partnership, with Kinder Morgan retaining the remaining approximate 70% equity interest.

Concurrent with closing of our IPO, the Limited Partnership acquired an interest in the Operating Entities from KMCC and KMTU, each wholly owned subsidiaries of Kinder Morgan, in exchange for the issuance to KMCC and KMCT of Class B Units of the Limited Partnership. In addition, KMCC and KMCT were issued Special Voting Shares in the Company for nominal consideration.

Immediately following the closing of our IPO, we used the proceeds from our IPO to indirectly subscribe for Class A Units representing an approximate 30% economic interest in the Limited Partnership while the Class B Units held by KMCC and KMCT represent, in the aggregate, an approximate 70% economic interest in the Limited Partnership. Following the issuance of the Series 1 Preferred Shares and Series 3 Preferred Shares, the Company's and Kinder Morgan's respective interests in the Limited Partnership are subject to the preferred shareholders' priority on distributions and upon liquidation.

After the completion of our IPO and the reorganization transaction described above and as of December 31, 2017, the issued and outstanding Restricted Voting Shares comprises approximately 30% of the votes attached to all outstanding Company voting shares, and the Kinder Morgan interest, which represents its indirect ownership of 100% of the Special Voting Shares, comprises approximately 70% of the votes attached to all outstanding Company voting shares.

Subsequent to our IPO, Kinder Morgan retained control of us and the Limited Partnership, and as a result we accounted for our acquisition of an approximate 30% equity interest in the Limited Partnership as a transfer of net assets among entities under common control. Therefore, our consolidated financial statements presented herein were derived from the consolidated financial statements and accounting records of Kinder Morgan. The assets and liabilities in these consolidated financial statements have been reflected at historical carrying value of the immediate parents within the Kinder Morgan organizational structure including goodwill and purchase price assigned amounts, as applicable. Prior to May 30, 2017, our historical financial statements were presented as combined consolidated financial statements derived from information included within the consolidated financial statements and accounting records of Kinder Morgan. All significant intercompany balances between the companies included in our accompanying consolidated financial statements have been eliminated.

In addition, as of and for the reporting periods after May 30, 2017, Kinder Morgan's economic interest in the Limited Partnership is reflected within "Kinder Morgan interest" in our consolidated statements of equity and consolidated balance sheets and earnings attributable to Kinder Morgan's economic ownership interest in the Limited Partnership is presented in "Net Income Attributable to Kinder Morgan Interest" in our consolidated statements of income.

Kinder Morgan retained control of us, therefore, the amounts recorded to "Restricted Voting Share capital," "Retained deficit," "Accumulated other comprehensive loss" and "Kinder Morgan interest" presented in the consolidated statement of equity for the year ended December 31, 2017 include (i) the "Issuance of special voting shares and reallocation of Kinder Morgan pre-IPO carrying basis" which represents Kinder Morgan's pre-IPO 100% ownership interest in us including net income for the period January 1 through May 29, 2017 and (ii) the "Reallocation of equity on common control transaction" which represents the difference between our book value prior to our IPO and the proportionate ownership percentages in the book value in our net assets after our IPO.

2. Summary of Significant Accounting Policies

Basis of Presentation

In January 2018, we completed the registration of our Restricted Voting Shares pursuant to Section 12(g) of the United States Securities Exchange Act of 1934 (the "Exchange Act") and are subject to the reporting requirements of Section 13(a) of the Exchange Act.

We have prepared the accompanying consolidated financial statements in accordance with the accounting principles contained in the FASB Accounting Standards Codification, the single source of U.S. GAAP and referred to in this report as the Codification. U.S. GAAP means generally accepted accounting principles that the SEC has identified as having substantial authoritative support, as supplemented by Regulation S-X under the U.S. Securities Exchange Commission Act of 1934, as amended from time to time. Under such rules and regulations, all significant intercompany items have been eliminated in consolidation.

Amounts are stated in Canadian dollars unless otherwise noted which is the functional currency of most of our operations. Additionally, certain amounts from prior years have been reclassified to conform to the current presentation.

Adoption of New Accounting Pronouncements

On January 1, 2018, we adopted Accounting Standards Updates (ASU) No. 2014-09, "Revenue from Contracts with Customers" and a series of related accounting standard updates designed to create improved revenue recognition and disclosure comparability in financial statements. For more information, see "—*Revenue Recognition*" below and Note 18.

On January 1, 2018, we retroactively adopted ASU No. 2016-18, "Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force)." This ASU requires the statements of cash flows to present the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents are now included with cash and cash equivalents when reconciling the beginning of period and end of period amounts presented on the statements of cash flows. The retrospective application of this new accounting guidance resulted in a net increase of $0.6 million and a net decrease of $0.3 million in the total consolidated cash, cash equivalents and restricted deposits, which is the included both at "Cash, Cash Equivalents and Restricted Deposits, beginning (end) of period" and at "Change in Cash and Cash Equivalents, and Restricted Deposits held by the Trans Mountain Asset Group" within our consolidated statements of cash flows, and a decrease of $0.6 million and an increase of $0.3 million in "Cash used in investing activities," for the years ended December 2017 and 2016, respectively, from what was previously presented in our consolidated statements of cash flows in our Annual Report on Form 10-K for the year ended December 31, 2017.

Use of Estimates

Certain amounts included in or affecting our financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions which cannot be known with certainty at the time our financial statements are prepared. These estimates and assumptions affect the amounts we report for assets and liabilities, our revenues and expenses during the reporting period, and our disclosures, including as it relates to contingent assets and liabilities at the date of our financial statements. We evaluate these estimates on an ongoing basis, utilizing historical experience, consultation with experts and other methods considered reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Certain accounting policies are of more significance in our financial statement preparation process than others, and set out below are the principal accounting policies we apply in the preparation of our consolidated financial statements.

Cash Equivalents and Restricted Cash

We define cash equivalents as all highly liquid short-term investments with original maturities of three months or less. Restricted cash of approximately $0.5 million as of both December 31, 2018 and 2017, is included in "Other current assets" on our accompanying consolidated balance sheets.

Accounts Receivable

We establish provisions for losses on accounts receivable due from customers if it is determined that all or part of the outstanding balance is probable of not being collected. We review collectability regularly and establish an allowance or record adjustments as necessary using the specific identification method. We had no allowance for doubtful accounts as of December 31, 2018 and 2017.

Inventories

Our inventories, which consist of materials and supplies, are valued at weighted-average cost, and we periodically review for physical deterioration and obsolescence.

Property, Plant and Equipment, net

We record property, plant and equipment at historical cost. We capitalize expenditures for construction, expansion, major renewals and betterments. We expense maintenance and repair costs as incurred. We capitalize expenditures for project development if they are expected to have future benefit. We capitalize Interest Incurred During Construction ("IDC") for our assets.

Our assets require the use of management estimates of the useful lives of assets. Our Terminal business segment assets are depreciated on a straight-line basis over their estimated useful lives. For Cochin we apply a composite depreciation rate to the total cost of the composite group until the net book value equals the salvage value. In applying the composite method, we generally charge the original cost of property sold or retired to accumulated depreciation and amortization, plus cost of removal and less salvage value.

Asset Retirement Obligations ("ARO")

We record liabilities for obligations related to the retirement and removal of long-lived assets used in our businesses. We record, as liabilities, the fair value of asset retirement obligations on a discounted basis when they are incurred and can be reasonably estimated, which is typically at the time the assets are installed or acquired. Amounts recorded for the related assets are increased by the amount of these obligations. Over time, the liabilities increase due to the change in their present value, and the initial capitalized costs are depreciated over the useful lives of the related assets. The liabilities are eventually extinguished when the asset is taken out of service.

Due to the lack of information that can be derived from past experience or industry practice, the timing and fair value of future removal and site restoration costs for our assets is not currently determinable. We have not recognized an ARO in these consolidated financial statements. Also, see Note 7 regarding the Cochin Pipeline Reclamation Trust Securities.

Long-lived Asset Impairments

We evaluate long-lived assets and investments for impairment whenever events or changes in circumstances indicate that our carrying amount of an asset or investment may not be recoverable. We recognize impairment losses when estimated future cash flows expected to result from our use of the asset and its eventual disposition is less than its carrying amount.

To the extent triggering events exist, we complete a review of the carrying value of our long-lived assets, including property, plant and equipment as well as other intangibles, and record, as applicable, the appropriate impairments. Because the impairment test for long-lived assets held in use is based on undiscounted cash flows, there may be instances where an asset or asset group is not considered impaired, even when its fair value may be less than its carrying value, because the asset or asset group is recoverable based on the cash flows to be generated over the estimated life of the asset or asset group. Our fair value estimates are generally based on assumptions market participants would use, including market data obtained through the sale process or an analysis of expected discounted future cash flows. We did not record any impairments to long-lived assets in the years ended December 31, 2018, 2017 and 2016.

Jointly controlled operations

Jointly controlled operations are assets over which we have joint ownership with unaffiliated entities and are not held in a partnership, corporation or other legal entity. We have three joint ventures that undertake terminaling activities through jointly controlled operations. We account for jointly controlled operations using the proportionate consolidation method for which (i) our consolidated balance sheets include our share of the assets that we control jointly with third parties and the liabilities for which we are jointly responsible and (ii) our consolidated statements of income include our share of the income and expenses generated by the jointly controlled operations.

Revenue Recognition

Adoption of Topic 606

Effective January 1, 2018, we adopted ASU No. 2014-09, "*Revenue from Contracts with Customers*" and the series of related accounting standard updates that followed (collectively referred to as "Topic 606"). We utilized the modified retrospective method to adopt Topic 606, which required us to apply the new revenue standard to (i) all new revenue contracts entered into after January 1, 2018, and (ii) revenue contracts that were not completed as of January 1, 2018. In accordance with this approach, our consolidated revenues for periods prior to January 1, 2018 were not revised. The cumulative effect of the adoption of Topic 606 as of January 1, 2018 and the impact to the financial statement line items for the current year was not material.

Revenue from Contracts with Customers

Beginning in 2018, we account for revenue from contracts with customers in accordance with Topic 606. The unit of account in Topic 606 is a performance obligation, which is a promise in a contract to transfer to a customer either a distinct good or service (or bundle of goods or services) or a series of distinct goods or services provided over a period of time. Topic 606 requires that a contract's transaction price, which is the amount of consideration to which an entity expects to be entitled in exchange for transferring promised goods or services to a customer, is to be allocated to each performance obligation in the contract based on relative standalone selling prices and recognized as revenue when (point in time) or as (over time) control of the goods or services transfers to the customer and the performance obligation is satisfied.

Our customer service contracts primarily include terminaling service and transportation service contracts, as described below. Generally, for the majority of these contracts: (i) our promise is to transfer (or stand ready to transfer) a series of distinct integrated services over a period of time, which is a single performance obligation; (ii) the transaction price includes fixed and/or variable consideration, which amount is determinable at contract inception and/or at each month end based on our right to invoice at month end for the value of services provided to the customer that month; and (iii) the transaction price is recognized as revenue over the service period specified in the contract (which can be a day, including each day in a series of promised daily services, a month, a year, or other time increment, including a deficiency makeup period) as the services are rendered using a time-based (passage of time) or units-based (units of service transferred) output method for measuring the transfer of control of the services and satisfaction of our performance obligation over the service period, based on the nature of the promised service (e.g., firm or non-firm) and the terms and conditions of the contract (e.g., contracts with or without makeup rights).

Firm Services

Firm services (also called uninterruptible services) are services that are promised to be available to the customer at all times during the period(s) covered by the contract, with limited exceptions. Our firm service contracts are typically structured with take-or-pay or minimum volume provisions, which specify minimum service quantities a customer will pay for even if it chooses not to receive or use them in the specified service period (referred to as "deficiency quantities"). We typically recognize the portion of the transaction price associated with such provisions, including any deficiency quantities, as revenue depending on whether the contract prohibits the customer from making up deficiency quantities in subsequent periods, or the contract permits this practice, as follows:

- Contracts without Makeup Rights: If contractually the customer cannot make up deficiency quantities in future periods, our performance obligation is satisfied, and revenue associated with any deficiency quantities is generally recognized as each service period expires. Because a service period may exceed a reporting period, we determine at inception of the contract and at the beginning of each subsequent reporting period if we expect the customer to take the minimum volume associated with the service period. If we expect the customer to make up all deficiencies in the specified service period (i.e., we expect the customer to take the minimum service quantities), the minimum volume provision is deemed not substantive and we will recognize the transaction price as revenue in the specified service period as the promised units of services are transferred to the customer. Alternatively, if we expect that there will be any deficiency quantities that the customer cannot or will not make up in the specified service period (referred to as "breakage"), we will recognize the estimated breakage amount (subject to the constraint on variable consideration) as revenue ratably over such service period in proportion to the revenue that we will recognize for actual units of service transferred to the customer in the service period. For certain take-or-pay contracts where we make the service, or a part of the service, continuously available over the service period, we typically recognize the take-or-pay amount as revenue ratably over such period based on the passage of time.

- Contracts with Makeup Rights: If contractually the customer can acquire the promised service in a future period and make up the deficiency quantities in such future period (the "deficiency makeup period"), we have a performance obligation to deliver those services at the customer's request (subject to contractual and/or capacity constraints) in the deficiency makeup period. At inception of the contract, and at the beginning of each subsequent reporting period, we estimate if we expect that there will be deficiency quantities that the customer will or will not make up. If we expect the customer will make up all deficiencies it is contractually entitled to, any non-refundable consideration received relating to temporary deficiencies that will be made up in the deficiency makeup period will be deferred as a contract liability, and we will recognize that amount as revenue in the deficiency makeup period when either of the following occurs: (i) the customer makes up the volumes; or (ii) the likelihood that the customer will exercise its right for deficiency volumes then becomes remote (e.g., there is insufficient capacity to make up the volumes, the deficiency makeup period expires). Alternatively, if we expect at inception of the contract, or at the beginning of any subsequent reporting period, that there will be any deficiency quantities that the customer cannot or will not make up (i.e., breakage), we will recognize the estimated breakage amount (subject to the constraint on variable consideration) as revenue ratably over the specified service periods in proportion to the revenue that we will recognize for actual units of service transferred to the customer in those service periods.

Non-Firm Services

Non-firm services (also called interruptible services) are the opposite of firm services in that such services are provided to a customer on an "as available" basis. Generally, we do not have an obligation to perform these services until we accept a customer's periodic request for service. For the majority of our non-firm service contracts, the customer will pay only for the actual quantities of services it chooses to receive or use, and we typically recognize the transaction price as revenue as those units of service are transferred to the customer in the specified service period (typically a daily or monthly period).

Revenue Recognition Policy prior to January 1, 2018

We recognized revenue as services were rendered or goods were delivered and, if applicable, risk of loss had passed.

We recognized transportation revenues when our customers' products were delivered and services had been provided and adjusted according to terms prescribed by the relevant toll settlements with shippers as approved by the regulator. To the extent a customer did not meet its minimum volume commitment, we generally recognized revenue when we had no further performance obligation at the contractual rate applicable to such committed volumes. If such minimum volume commitments contained make up rights, we deferred revenue until the expiration of the make-up right or when our obligation to the customer had otherwise ceased. We recognized differences between transportation revenue and actual toll receipts as regulatory assets or liabilities which were settled through future tolls.

We generally recognized bulk terminal transfer service revenues based on volumes handled. Liquids terminal warehousing revenue was generally recognized ratably over the contract period. We generally recognized liquids terminal throughput revenue based on volumes received and volumes delivered. We generally deferred revenue within the Terminals business segment related to capital improvements paid for in advance by certain customers, which we then amortized over the initial term of the related customer contracts.

Environmental Matters

We capitalize or expense, as appropriate, environmental expenditures. We capitalize certain environmental expenditures required in obtaining rights-of-way, regulatory approvals or permitting as part of construction. We accrue and expense environmental costs that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation. We generally do not discount environmental liabilities to a net present value, and we record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, our recording of these accruals coincides with completion of a feasibility study or our commitment to a formal plan of action. We recognize receivables for anticipated associated insurance recoveries when such recoveries are deemed to be probable. We record at estimated fair value, where appropriate, environmental liabilities assumed in a business combination.

We routinely conduct reviews of potential environmental issues and claims that could impact our assets or operations. These reviews assist us in identifying environmental issues and estimating the costs and timing of remediation efforts. We also routinely adjust our environmental liabilities to reflect changes in previous estimates. In making environmental liability estimations, we consider the material effect of environmental compliance, pending legal actions against us, and potential third-party liability claims. Often, as the remediation evaluation and effort progresses, additional information is

obtained, requiring revisions to estimated costs. These revisions are reflected in income in the period in which they are reasonably determinable. As of December 31, 2018, we had $0.1 million accrued for our outstanding environmental matters and no accrual at December 31, 2017.

Pension and Other Postretirement Benefits

We recognize the differences between the fair value of each of our pension and other postretirement benefit plans' assets and the benefit obligations as either assets or liabilities on our consolidated balance sheet. We record deferred plan costs and income—unrecognized losses and gains, unrecognized prior service costs and credits, and any remaining unamortized transition obligations—in "Accumulated other comprehensive loss," with the proportionate share associated with less than wholly owned subsidiaries allocated and included within "Kinder Morgan interest" or as a regulatory asset or liability for certain of our regulated operations, until they are amortized as a component of benefit expense. See Note 11 for additional information regarding our other postretirement benefit plans.

Kinder Morgan Interest

Kinder Morgan Interest represents the interest in our consolidated subsidiaries that are not owned by us. In our accompanying consolidated income statements, the Kinder Morgan Interest in the net income of our consolidated subsidiaries is shown as an allocation of our consolidated net income and is presented separately as "Net Income Attributable to Kinder Morgan Interest." In our accompanying consolidated balance sheets, the Kinder Morgan interest is presented separately as "Kinder Morgan interest" within "Equity."

Income Taxes

We record income tax expense based on an estimate of the effective tax rate in effect or to be in effect during the relevant periods. We include changes in tax legislation in the relevant computations in the period in which such changes are enacted. We do business in a number of provinces with differing laws concerning how income subject to each province's tax regime is measured and at what effective rate such income is taxed, requiring us to estimate how our income will be apportioned among the various provinces in order to arrive at an overall effective tax rate. Changes in our effective rate, including any effect on previously recorded deferred taxes, are recorded in the period in which the need for such change is identified.

Deferred income tax assets and liabilities are recognized for temporary differences between the basis of assets and liabilities for financial reporting and tax purposes. Deferred tax assets are reduced by a valuation allowance for the amount that is, more likely than not, to not be realized. While we have considered estimated future taxable income and prudent and feasible tax planning strategies in determining the amount of our valuation allowance, any change in the amount that we expect to ultimately realize will be included in income in the period in which such a determination is reached.

Foreign Currency

Transactions in foreign currencies are initially recorded at the exchange rate in effect at the time of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars using the closing exchange rate at the balance sheet date. The resulting exchange rate differences are included in the consolidated statements of income.

3. Trans Mountain Transaction

On August 31, 2018, we closed on the sale of the Trans Mountain Asset Group, which were indirectly acquired by the Government of Canada, through Trans Mountain Corporation (a subsidiary of the Canada Development Investment Corporation) for cash consideration of approximately $4.43 billion, which is the contractual purchase price of $4.5 billion net of a preliminary working capital adjustment (the "Trans Mountain Transaction"). As of December 31, 2018, we accrued for an additional $37.0 million for a final working capital adjustment that was subsequently settled in cash. The August 31, 2018 Trans Mountain Asset Group balance sheet included $502.4 million of cash and cash equivalents, along with $559.8 million of debt and $26.2 million of accumulated other comprehensive loss (which was realized as other comprehensive income, net, in our consolidated statement of comprehensive income for the year ended December 31, 2018).

Pursuant to our voting shareholders' approval on November 29, 2018, a distribution of approximately $1.2 billion were made as a return of capital to holders of our Restricted Voting Shares ($11.40 per Restricted Voting Share) and approximately $2.8 billion to KMI as the indirect holder of our Special Voting Shares on January 3, 2019 (the "Return of Capital"). To facilitate the Return of Capital and provide flexibility for dividends going forward, our voting shareholders also

approved (i) the reduction of the stated capital of our Restricted Voting Shares by $1.45 billion (the "Stated Capital Reduction") (ii) a "reverse stock split" of our Restricted Voting Shares and Special Voting Shares on a one-for-three basis (three shares consolidating to one share) (the "Share Consolidation"), which was effected on January 4, 2019. In accordance with U.S. GAAP, the Restricted Voting Shares and Special Voting Shares outstanding and earnings per share information in this report reflect the Share Consolidation for all periods presented unless otherwise noted.

We have recorded a Gain on sale of the Trans Mountain Asset Group, net of tax of $1,278.4 million as presented in the accompanying consolidated statement of income for year ended December 31, 2018. The gain included a tax benefit of approximately $81.4 million comprised of the release of deferred income taxes of approximately $389.0 million, which was partially offset by an adjustment to accrued taxes of approximately $307.6 million on the accompanying consolidated balance sheet as of December 31, 2018.

The underlying assets in the Trans Mountain Asset Group were primarily within our Pipelines business segment and the operating results for the Trans Mountain Asset Group are included in Income from operations of the Trans Mountain Asset Group, net of tax in the accompanying consolidated statements of income for the years ended December 31, 2018, 2017 and 2016. Major income and expense line items associated with the Trans Mountain Asset Group that have been presented within the caption Discontinued Operations in the accompanying consolidated statements of income were as follows:

Year Ended December 31,	**2018(a)**	**2017**	**2016**
(In millions of Canadian dollars)			
Revenues	214.3	324.9	328.3
Depreciation and amortization	(46.8)	(70.7)	(73.0)
Operating expenses, including general and administrative	(89.8)	(122.0)	(115.5)
Interest and other income (expense)(b)	(22.4)	21.4	24.5
Income from operations of the Trans Mountain Asset Group before income taxes	55.3	153.6	164.3
Gain on sale of the Trans Mountain Asset Group before income taxes	1,197.0	—	—
Income from Discontinued Operations before income taxes	1,252.3	153.6	164.3
Income tax benefit (expense)	65.9	(43.4)	(32.9)
Income from Discontinued Operations, Net of Tax	1,318.2	110.2	131.4

The Trans Mountain Asset Group's carrying value of assets and liabilities have been presented as held for sale in the accompanying consolidated balance sheet as of December 31, 2017 and include:

December 31,	**2017**
(In millions of Canadian dollars)	
Cash and cash equivalents	128.1
Accounts receivable	46.0
Other current assets	18.6
Property, plant and equipment, net	2,719.6
Goodwill(c)	248.0
Non-current regulatory assets	29.1
Other non-current assets	53.7
Total assets of the Trans Mountain Asset Group	3,243.1
Credit Facility	—
Accounts payable	97.6
Current regulatory liabilities	103.1
Other current liabilities	6.6
Pension and postretirement benefits	75.4
Other non-current liabilities	38.1
Total liabilities of the Trans Mountain Asset Group	320.8

Our net cash flows from operating and investing activities from the Trans Mountain Asset Group included in the accompanying consolidated statements of cash flows were as follows:

Year Ended December 31,	2018(a)	2017	2016
(Net cash provided by (used in) in millions of Canadian dollars)			
Operating activities	182.3	58.1	25.5
Investing activities	(507.3)	(462.6)	(190.3)

a. Amounts are for the period January 1, 2018 to August 31, 2018, the closing of the Trans Mountain Transaction.
b. 2018 includes approximately $60.5 million pre-tax write off of deferred financing costs, see Note 10. 2017 and 2016 amounts also include interest expenses from our credit facilities and KMI Loans that were allocated to discontinued operations for borrowings that were directly related to the Trans Mountain Asset Group.
c. Goodwill was evaluated for impairment on May 31 of each year and no impairments were recorded in 2018, 2017 and 2016.

Also, see Note 10 for information on our 4-year, $500.0 million unsecured revolving credit facility.

4. Income Taxes

Income from continuing operations before income taxes for years ended December 31, 2018, 2017, and 2016 were $137.8 million, $71.3 million, and $93.8 million, respectively.

Components of our income tax provision are as follows:

Year Ended December 31,	2018	2017	2016
(In millions of Canadian dollars)			
Current tax expense (benefit)	43.1	6.8	0.4
Deferred tax expense	(5.3)	14.0	23.0
Total tax provision	37.8	20.8	23.4

The difference between the statutory income tax rate and our effective income tax rate is summarized as follows:

Year Ended December 31,	2018		2017		2016	
(In millions of Canadian dollars, except percentages)						
Statutory income tax	37.2	27.0 %	19.2	27.0 %	25.3	27.0 %
Increase (decrease) as a result of:						
Capital gains deduction	—	— %	—	— %	(2.0)	(2.1)%
Valuation allowance	(0.2)	(0.1)%	—	— %	(2.0)	(2.1)%
Tax impact on the future tax rate change	—	— %	0.8	1.1 %	1.9	2.0 %
Inter-corporate charges not tax deducted	2.4	1.7 %	2.2	3.1 %	(0.3)	(0.3)%
Other	(1.6)	(1.2)%	(1.4)	(2.0)%	0.5	0.5 %
Total	37.8	27.4 %	20.8	29.2 %	23.4	25.0 %

Deferred tax assets and liabilities result from the following:

December 31,	2018	2017
(In millions of Canadian dollars)		
Deferred tax assets		
Non capital losses	0.1	—
Reserves	35.8	43.0
Capital losses	0.2	27.2
Investment in partnerships	144.4	117.4
Valuation allowances	(144.6)	(144.5)
Total deferred tax assets	35.9	43.1
Deferred tax liabilities		
Property, plant and equipment	(36.0)	(392.0)
Total deferred tax liabilities	(36.0)	(392.0)
Net non-current deferred tax liability	(0.1)	(348.9)

Deferred Tax Assets and Valuation Allowances: We have deferred tax assets of $0.1 million related to non-capital loss carryovers, $0.2 million capital loss carryovers and $0.2 million of valuation allowances related to these deferred tax assets as of December 31, 2018. As of December 31, 2017, we had deferred tax assets of $27.2 million for capital loss carryovers and $27.1 million of valuation allowances related to these deferred tax assets.

Expiration Periods for Deferred Tax Assets: As of December 31, 2018, we have non-capital loss carryforwards of $0.3 million which will expire in 2038 and capital loss carryforwards of $1.8 million which can be carried forward indefinitely.

Unrecognized Tax Benefits: We had no unrecognized tax benefits as of December 31, 2018 and 2017.

As a result of our IPO and subsequent revaluation (or rebalancing) of our investment in the Limited Partnership, our tax basis exceeds our accounting basis in our investment in the Limited Partnership by approximately $1.1 billion. This excess tax basis results in a deferred tax asset of approximately $144.4 million. A full valuation allowance was recorded against this deferred tax asset as we determined it was more likely than not to not be realized.

Income Tax Expense on Discontinued Operations: Income tax expense in respect of our Discontinued Operations, includes income tax expense on the Trans Mountain Asset Group earnings for the periods presented until August 31, 2018, and the Trans Mountain Transaction gain. As of December 31, 2018 and 2017, our effective tax rate on income from Discontinued Operations was (5.2)%, and 28.3%, respectively. The 2018 effective tax rate on our income from Discontinued Operations is lower than the statutory federal and provincial rate due to the taxable gain being eligible for a 50.0% capital gains deduction along with the release of the non-cash deferred tax liabilities attributable to the Trans Mountain Asset Group.

5. Other Current Assets

December 31,	2018	2017
(In millions of Canadian dollars)		
Prepaid expenses and deposits	3.5	3.9
Contract Asset(Note 18)	1.6	2.1
Restricted cash(a)	0.5	0.5
Other current deferred assets	0.3	0.1
	5.9	6.6

a. Represents restricted cash in the Trusts that is to be used solely for the purposes of satisfying NEB's Land Matters Consultation Initiative ("LMCI") liabilities. Also, see Note 7.

6. Property, Plant and Equipment, net

Classes and Depreciation

As of December 31, 2018 and 2017, our property, plant and equipment, net consisted of the following:

December 31,	2018	2017	Useful Life in Years(a)
(In millions of Canadian dollars, except years)			
Tanks and Station equipment (primarily storage of crude oil and other refined products)	1,040.9	703.4	5-40
Pipelines (primarily transportation of crude oil and other refined products)	143.7	151.9	30-64
Other(b)	195.4	173.5	5-35
Accumulated depreciation and amortization	(413.1)	(330.7)	
	966.9	698.1	
Land	0.3	0.1	
Construction work in process	14.1	290.2	
Property, plant and equipment, net	981.3	988.4	

a. For Cochin, the composite depreciation rate is included in the equivalent number of years for Pipelines.
b. Includes vehicles, docks, shiploaders, rail and other.

Depreciation and amortization expense charged against property, plant and equipment was $82.6 million, $71.7 million, and $64.2 million for the years ended December 31, 2018, 2017, and 2016, respectively.

7. Deferred Charges and Other Assets

December 31,	2018	2017
(In millions of Canadian dollars)		
Cochin Pipeline Reclamation Trust Securities(a)	6.1	4.3
Unamortized debt issue costs	0.6	67.2
Other	3.9	1.8
	10.6	73.3

a. Represents restricted investments in Canadian government bonds. Restricted long-term investments by the Cochin Pipeline Reclamation Trust (the "Trust") are to be used solely for the purposes of satisfying LMCI liabilities as further described in Note 20. We have related LMCI short-term and long-term obligations of an amount approximately equal to our restricted cash and restricted investments recorded in Other current liabilities and Other deferred credits, respectively, on our accompanying consolidated balance sheets. The restricted assets are measured at fair value with offsetting adjustments recorded to the LMCI liabilities. Fair values for the restricted asset investments were determined based on observable prices and inputs for similar instruments available in the market, utilizing widely accepted cash flow models to value such instruments. Such techniques represent a Level 2 fair value measurement, see Note 17.

8. Accounts Payable

December 31,	2018	2017
(In millions of Canadian dollars)		
Accounts payable-trade	25.0	19.7
Property, plant and equipment accrued liabilities	24.4	34.8
	49.4	54.5

9. Other Current Liabilities

December 31,	2018	2017
(In millions of Canadian dollars)		
Contract liabilities(Note 18)	12.8	14.7
Trust liability(Note 7)	0.4	4.8
Environmental capital recovery surcharge	4.1	3.8
Employee compensation	4.8	1.1
Final working capital adjustment for Trans Mountain Transaction	37.0	—
Other	4.1	3.4
	63.2	27.8

10. Debt

Credit Facilities

In conjunction with the announcement of the Trans Mountain Transaction described in Note 3, on May 30, 2018 and concurrently with the termination of our June 16, 2017 revolving credit facility ("2017 Credit Facility"), we established a $500.0 million revolving credit facility (the "Temporary Credit Facility"), for general corporate purposes, including working capital during the period from June 1, 2018 through the closing of the Trans Mountain Transaction. The approximate $100.0 million of borrowings outstanding under the terminated 2017 Credit Facility were repaid pursuant to an initial drawdown under the Temporary Credit Facility and approximately $60.5 million of deferred costs associated with the 2017 Credit Facility that were being amortized as interest expense over its term were written off.

On June 14, 2018, our former subsidiary, Trans Mountain, as the borrower, entered into a non-revolving, unsecured construction credit agreement (the "Trans Mountain Non-recourse Credit Agreement") in an aggregate principal amount of up to approximately $1.0 billion to facilitate the resumption of the TMEP planning and construction work until the close of the Transaction. The $559.8 million of outstanding borrowings under the Trans Mountain Non-recourse Credit Agreement were included in the Trans Mountain Asset Group's assets and liabilities as part of the Trans Mountain Transaction.

Upon the closing of the Trans Mountain Transaction on August 31, 2018, the Temporary Credit Facility was replaced with a new 4-year, $500.0 million unsecured revolving credit facility ("2018 Credit Facility") for working capital purposes under a credit agreement with the Royal Bank of Canada, as agent (the "Credit Agreement"). In addition, the $132.6 million of outstanding borrowings under the Temporary Credit Facility were paid off prior to its termination with a portion of the proceeds from the Trans Mountain Transaction.

Depending on the type of loan requested, interest on loans outstanding will be calculated based on: (i) a Canadian prime rate of interest; (ii) a U.S. base rate; (iii) LIBOR; or (iv) bankers' acceptance fees, plus (A) in the case of Canadian prime rate or U.S. base rate loans, an applicable margin of up to 1.25% per annum; or (B) in the case of LIBOR loans or banker's acceptances, an applicable margin ranging from 1.00% to 2.25% per annum, with such margin determined by our then applicable debt credit rating. Standby fees for the unused portion of the 2018 Credit Facility will be calculated at a rate ranging from 0.20% to 0.45% per annum based upon our then applicable debt credit rating.

The Credit Agreement contains various financial and other covenants that apply to KMCU and its subsidiaries and that are common in such agreements, including a maximum ratio of consolidated total funded debt to consolidated earnings before interest, income taxes, D&A, and non-cash adjustments as defined in the Credit Agreement, of 5.00:1.00 and restrictions on KMCU's ability to incur debt, grant liens, make dispositions, engage in transactions with affiliates, make restricted payments(including distributions), amend our organizational documents and engage in corporate reorganization transactions.

In addition, the Credit Agreement contains customary events of default, including non-payment; non-compliance with covenants (in some cases, subject to grace periods); payment default under, or acceleration events affecting, certain other indebtedness; bankruptcy or insolvency events involving KMCU or certain of its subsidiaries; and changes of control. If an event of default under the Credit Agreement exists and is continuing, the lenders could terminate their commitments and accelerate the maturity of our outstanding obligations under the Credit Agreement.

As of December 31, 2018, we had no outstanding borrowings under our 2018 Credit Facility, and had $489.0 million available under the 2018 Credit Facility, after reducing the $500.0 million capacity for $11.0 million in letters of credit. Of the

total $11.0 million of letters of credit issued, approximately $7.9 million are issued on behalf of Trans Mountain for which it has issued a backstop letter of credit to us. As of December 31, 2018, we were in compliance with all required covenants. As of December 31, 2017, we had no borrowings outstanding under our 2017 Credit Facility. For the years ended December 31, 2018 and 2017, we incurred $1.1 million and $0.7 million, respectively, in standby fees.

11. Share-based Compensation and Benefit Plans

Share-based Compensation

Restricted Share Unit Plan for Non-Employee Directors

We have adopted the Restricted Share Unit Plan for Non-Employee Directors, in which our eligible non-employee directors participate. The plan recognizes that the compensation paid to each eligible non-employee director is fixed by our board of directors, generally annually, and that the compensation is payable in cash. Pursuant to the plan, in lieu of receiving some or all of the cash compensation, each eligible non-employee director may elect to receive RSUs. Each election will be generally at or around the first board of directors meeting in January of each calendar year and will be effective for the entire calendar year. An eligible director may make a new election each calendar year. The total number of Restricted Voting Shares authorized under the plan is 156,140, after giving effect to the Return of Capital and Share Consolidation in accordance with board of directors approval and guidelines within the RSU plan.

During 2018 and 2017, we issued RSUs to our non-employee directors of 20,000 and 11,580, respectively (number of shares issued is before our January 4, 2019 Share Consolidation). These RSUs were valued at the time of issuance at $0.4 million and $0.2 million, respectively.

Restricted Share Unit Plan for Employees

We have adopted the Restricted Share Unit Plan for Employees (the "RSU Plan") for our eligible employees. The RSU Plan provides that the number of Restricted Voting Shares that may be issued or issuable by the Company pursuant to RSU awards shall not exceed 1,345,093, after giving effect to the Return of Capital and Share Consolidation in accordance with board of directors approval and guidelines within the RSU plan. The purpose of the RSU Plan is to provide incentive to our employees for our future endeavors, to advance our and our shareholders' interests and to enable us to compete effectively for the services of employees. The RSU Plan is administered by our board of directors, which will have authority to construe and interpret the RSU Plan, including any questions in respect of any RSU awards granted thereunder.

The following table sets forth a summary of activity and related balances of our RSU awards, excluding those issued to our non-employee directors:

(Per share amount in Canadian dollars)	Year Ended December 31, 2018		May 30, 2017 to December 31, 2017	
	Shares	Weighted Average Grant Date Fair Value per share	Shares	Weighted Average Grant Date Fair Value per share
Outstanding at beginning of period	781,307	15.99	—	—
Granted	85,104	16.63	784,621	15.99
Vested(a)	(703,505)	15.99	—	—
Forfeited	(8,771)	16.19	(3,314)	15.99
Outstanding prior to Return of Capital and Share Consolidation	154,135	16.33	781,307	15.99
Effect of Return of Capital and Share Consolidation	25,167	16.33	—	—
Outstanding at end of period	179,302	16.33	781,307	15.99

a. RSU awards vested upon August 31, 2018 closing of the Trans Mountain Transaction.

RSU awards under the RSU Plan have vesting periods that may range from one-year with variable to three years. Following is a summary of the future vesting of our outstanding RSUs under the RSU Plan:

For the Year Ended December 31, 2018	
2019	—
2020	83,444
2021	95,858
Total Outstanding	179,302

The compensation costs related to our RSU awards is generally recognized ratably over the vesting period of the RSU awards. Upon vesting, the grants will be paid in our split-adjusted Restricted Voting Shares.

During the year ended December 31, 2018 and 2017, we recognized $7.9 million, which included $6.5 million of expense related to the Trans Mountain Transaction, and $0.7 million, respectively, of expense related to the RSU Plan, and we capitalized $2.1 million and $1.4 million, respectively, related to the RSU Plan. At December 31, 2018, unrecognized compensation costs associated with the RSU awards was approximately $3.5 million with a weighted average remaining amortization period of 2.1 years.

Benefit Plans

The benefit plans that were provided to our employees prior to the closing of the Trans Mountain Transaction were included in the assets and liabilities held for sale, and we no longer have any obligations for those benefit plans. For our remaining employees, new pension and other postretirement benefit ("OPEB") plans became effective after the closing of the Trans Mountain Transaction that provide value similar to the prior benefit plans. Our pension benefits provided prior to the close of the Trans Mountain Transaction were under a defined benefit pension formula and are now provided under a registered defined contribution pension plan ("DCPP") and a supplemental unfunded arrangement ("SPP") which provides pension benefits in excess of Income Tax Act limits. Our new OPEB plan benefits are relatively consistent with the prior OPEB plan. As a result of the Trans Mountain Transaction, we released $36.3 million of benefit plan losses.

Pension benefits

Our pension benefits cover eligible employees and are provided under the DCPP and SPP. We contribute a percentage of eligible compensation based on a combination of age and years of service. The total cost for our DCPP was approximately $0.5 million for the period from September 1, 2018 to December 31, 2018.

The SPP benefits are unfunded and annual expense is recorded on an accrual basis based on an independent actuarial determination. No employees have accrued a benefit under the SPP as of December 31, 2018; therefore, no information on the SPP is provided in the tables below.

Other postretirement benefits

Our OPEB plan benefits are provided to eligible current and future retirees and their spouses in the form of a healthcare spending account. Postretirement benefits are unfunded and annual expense is recorded on an accrual basis based on independent actuarial determination. The most recent actuarial valuation for accounting purposes was completed as of December 31, 2018.

Benefit Obligation, Plan Assets and Funded Status

The following table provides information about our OPEB plan.

For the Periods Ended December 31, 2018	
(In millions of Canadian dollars)	
Change in benefit obligation	
Benefit obligation at September 1, 2018	1.8
Service cost	0.1
Interest cost	—
Actuarial loss (gain)	(0.1)
Benefits paid	—
Benefit obligation at December 31, 2018	1.8
Presented as follows:	
Current benefit liability(a)	—
Non-current benefit liability(b)	(1.8)
	(1.8)

a. Amount included in Other current liabilities on our consolidated balance sheets.
b. Amount included in Other deferred credits on our consolidated balance sheets as of December 31, 2018.

Components of Accumulated Other Comprehensive Loss

We include the amounts of pre-tax accumulated other comprehensive loss related to the OPEB plans on our accompanying balance sheets. These balances exclude amounts recoverable through tolls and are immaterial.

Actuarial gains and losses deferred in accumulated other comprehensive loss are amortized into income over the period of expected future service of active participants.

Expected Payment of Future Benefits and Employer Contributions

Following are the expected future benefit payments as of December 31, 2018:

For the Year Ended December 31,	
(In millions of Canadian dollars)	
2019	—
2020	—
2021	—
2022	—
2023	0.1
2024-2028	0.4

In 2019, we expect the contribution to our OPEB plan to be inconsequential.

Actuarial Assumptions and Sensitivity Analysis

Benefit obligations and net benefit cost are based on actuarial estimates and assumptions. The following table details the weighted-average actuarial assumptions used in determining the benefit obligation and net benefit costs of our OPEB plan:

For the Year Ended December 31,	2018
Assumptions related to benefit obligations:	
Discount rate	3.91%
Assumptions related to benefit costs:	
Discount rate for benefit obligations	3.76%
Discount rate for interest on benefit obligations	3.67%
Discount rate for service cost	3.78%
Discount rate for interest on service cost	3.74%

12. Other Deferred Credits

December 31,	2018	2017
(In millions of Canadian dollars)		
Trust liability(Note 7)	6.1	
Postretirement benefit liability	1.8	—
Environmental liabilities	0.1	—
Other	0.9	0.8
	8.9	0.8

13. Equity

We are authorized to issue an unlimited number of Restricted Voting Shares, an unlimited number of Special Voting Shares and an unlimited number of preferred shares issuable in series. As of December 31, 2018, we had (i) 34.9 million and 81.4 million of split-adjusted Restricted Voting Shares and Special Voting Shares outstanding, respectively, with no par value, for an aggregate of 116.3 million voting shares outstanding, (ii) 12.0 million and 10.0 million of Series 1 Preferred Shares and Series 3 Preferred Shares outstanding, respectively, and (iii) 0.2 million of restricted stock awards outstanding.

Return of Capital, Stated Capital Reduction and Share Consolidation

Pursuant to our Voting Shareholders' approval on November 29, 2018, Return of Capital disbursements of approximately $1.2 billion were made to holders of our Restricted Voting Shares ($11.40 per Restricted Voting Share) and approximately $2.8 billion to KMI as the indirect holder of our Special Voting Shares on January 3, 2019. To facilitate the Return of Capital distributions and provide flexibility for dividends going forward, our Voting Shareholders also approved (i) a Stated Capital Reduction to our stated Restricted Voting Share capital by $1.45 billion and (ii) a Share Consolidation, a "reverse stock split" of our Restricted Voting Shares and Special Voting Shares on a one-for-three basis (one-for-three basis, three shares consolidating to one), which was effected on January 4, 2019.

Preferred Share Dividends

On August 15, 2017, we completed an offering of 12.0 million Series 1 Preferred Shares on the TSX at a price to the public of $25.00 per Series 1 Preferred Share for total gross proceeds of $300.0 million. The net proceeds of $292.9 million from the offering were used to indirectly subscribe for preferred units in the Limited Partnership, which in turn were used by the Limited Partnership to repay indebtedness outstanding under our revolving credit facility and for general corporate purposes. We have the option to redeem the Series 1 Preferred Shares on November 15, 2022 and on November 15 in every fifth year thereafter by payment of $25.00 per Series 1 Preferred Share plus all accrued and unpaid dividends. The holders of the Series 1 Preferred Shares will have the right to convert all or any of their Series 1 Preferred Shares into cumulative redeemable floating rate Preferred Shares, Series 2 (Series 2 Preferred Shares), subject to certain conditions, on November 15, 2022 and on November 15 in every fifth year thereafter. The Series 1 Preferred Shares and the Series 2 Preferred Shares are series of shares in the same class. The conversion right entitles holders to elect periodically which of the two series they wish to hold and does not entitle holders to receive a different class or type of security.

In the event of our liquidation, the holders of Series 1 Preferred Shares shall be entitled to receive $25.00 per Series 1 Preferred Share plus all accrued and unpaid dividends thereon before any amount shall be paid or any property or assets of the Company shall be distributed to the holders of the Restricted Voting Shares, Special Voting Shares and holders of any other shares ranking junior to the Series 1 Preferred Shares.

Dividends on the Series 1 Preferred Shares are fixed, cumulative, preferential and $1.3125 per share annually, payable quarterly on the 15th day of February, May, August and November, as and when declared by our board of directors, for the initial fixed rate period to but excluding November 15, 2022.

On December 15, 2017, we completed an offering of 10.0 million Series 3 Preferred Shares on the TSX at a price to the public of $25.00 per Series 3 Preferred Share for total gross proceeds of $250.0 million. The net proceeds of $243.2 million (net of fees paid and accrued) from the offering were used to indirectly subscribe for preferred units in the Limited Partnership, which in turn were used by the Limited Partnership to repay indebtedness outstanding under our revolving credit facility and for general corporate purposes. We have the option to redeem the Series 3 Preferred Shares on February 15, 2023 and on February 15 in every fifth year thereafter by payment of $25.00 per Series 3 Preferred Share plus all accrued and unpaid dividends. The holders of the Series 3 Preferred Shares will have the right to convert all or any of their Series 3 Preferred Shares into cumulative redeemable floating rate Preferred Shares, Series 4 (Series 4 Preferred Shares), subject to certain conditions, on February 15, 2023 and on February 15 in every fifth year thereafter. The Series 3 Preferred Shares and the Series 4 Preferred Shares are series of shares in the same class. The conversion right entitles holders to elect periodically which of the two series they wish to hold and does not entitle holders to receive a different class or type of security.

In the event of our liquidation, the holders of Series 3 Preferred Shares shall be entitled to receive $25.00 per Series 3 Preferred Share plus all accrued and unpaid dividends thereon before any amount shall be paid or any property or assets shall be distributed to the holders of the Restricted Voting Shares, Special Voting Shares and holders of any other shares ranking junior to the Series 3 Preferred Shares.

Dividends on the Series 3 Preferred Shares are fixed, cumulative, preferential and $1.3000 per share annually, payable quarterly on the 15th day of February, May, August and November, as and when declared by our board of directors, for the initial fixed rate period to but excluding February 15, 2023.

The following table provides information regarding dividends declared, or paid, as applicable, on our Preferred Shares during the year ended December 31, 2018:

Period	Total Series 1 quarterly dividend per share for the period	Total Series 3 quarterly dividend per share for the period	Date of declaration	Date of record	Date of dividend	Total amount of dividends paid in cash
(In millions of Canadian dollars, except per share amounts)						
November 15, 2017 to February 14, 2018 (a)	0.328125	0.22082	January 17, 2018	January 31, 2018	February 15, 2018	6.1
February 15, 2018 to May 14, 2018	0.328125	0.325	April 18, 2018	April 30, 2018	May 15, 2018	7.2
May 15, 2018 to August 14, 2018	0.328125	0.325	July 18, 2018	July 31, 2018	August 15, 2018	7.2
August 15, 2018 to November 14, 2018	0.328125	0.325	October 10, 2018	October 31, 2018	November 15, 2018	7.2
November 15, 2018 to February 14, 2019	0.328125	0.325	January 16, 2019	January 31, 2019	February 15, 2019	7.2

(a) Series 3 per share amount reflects that the shares were outstanding for 62 days during the period ended February 14, 2018.

Suspension of Dividend Reinvestment Plan (DRIP)

Effective January 16, 2019, our board of directors suspended our DRIP until further notice. Shareholders who were enrolled in the program will receive dividend payments in the form of cash, including dividends paid on February 15, 2019. We elected to suspend our DRIP in light of KML's reduced need for capital following the Trans Mountain Transaction. If KML elects to reinstate the DRIP in the future, shareholders who were enrolled in the DRIP at suspension and remained enrolled at reinstatement will automatically resume participation in the DRIP. Kinder Morgan's participation in the distribution reinvestment in Class B Units of the Limited Partnership has been suspended since July 18, 2018.

Shortly after our IPO, we had implemented a DRIP pursuant to which holders (excluding holders not resident in Canada) of Restricted Voting Shares could elect to have all cash dividends of the Company payable to any such shareholder automatically reinvested in additional Restricted Voting Shares at a price per share calculated by reference to the weighted average trading price of the Restricted Voting Shares on the stock exchange on which the Restricted Voting Shares then listed for the five trading days preceding the relevant dividend payment date, less a discount of between 0% and 5% (as determined from time to time by the board of directors, in its sole discretion). Kinder Morgan had participated in a DRIP under the same general terms as described for the Restricted Voting Stockholders. In addition, KML's suspension of its DRIP on January 16, 2019 also suspended the Limited Partnership's distribution reinvestment plan under the terms of the Limited Partnership Agreement.

Restricted Voting Share Dividends

Restricted Voting Shares were issued to the public pursuant to our IPO. Holders of Restricted Voting Shares are entitled to one vote for each Restricted Voting Share held at all our meetings of shareholders, except meetings at which or in respect of matters on which only holders of another class of shares are entitled to vote separately as a class. Except as otherwise provided by our articles or required by law, the holders of Restricted Voting Shares will vote together with the holders of Special Voting Shares as a single class.

The holders of Restricted Voting Shares are entitled to receive, subject to the rights of the holders of another class of shares, any dividend we declare and the remaining property of the Company on the liquidation, dissolution or winding up of the Company, whether voluntary or involuntary. Notwithstanding the foregoing, we may not issue or distribute to all or to substantially all of the holders of the Restricted Voting Shares either (i) Restricted Voting Shares, or (ii) rights or securities of the Company exchangeable for or convertible into or exercisable to acquire Restricted Voting Shares, unless contemporaneously therewith, we issue or distribute Special Voting Shares or rights or securities of the Company exchangeable for or convertible into or exercisable to acquire Special Voting Shares on substantially similar terms (having regard to the specific attributes of the Special Voting Shares) and in the same proportion.

The following table provides information regarding dividends declared, or paid, as applicable, on our Restricted Voting Shares during the year ended December 31, 2018.

For the three month period ended	Dividend rate per share	Date of declaration	Date of record	Date of dividend	Total amount of dividends paid in cash(a)	Total amount of dividends paid in form of additional shares
(In millions of Canadian dollars, except per share amounts)						
December 31, 2017	0.1625	January 17, 2018	January 31, 2018	February 15, 2018	11.8	5.1
March 31, 2018	0.1625	April 18, 2018	April 30, 2018	May 15, 2018	11.1	5.9
June 30, 2018	0.1625	July 18, 2018	July 31, 2018	August 15, 2018	13.9	3.1
September 30, 2018	0.1625	October 17, 2018	October 31, 2018	November 15, 2018	13.2	3.9
December 31, 2018	0.1625	January 16, 2019	January 31, 2019	February 15, 2019	5.7	—

a. Amount includes notional dividends on outstanding restricted stock awards of $0.4 million during 2018.

Kinder Morgan Interest Distributions

The Kinder Morgan interest consists of Class B Units in the Limited Partnership which are owned by indirect wholly owned subsidiaries of Kinder Morgan. Each Class B Unit is accompanied by a Special Voting Share, which entitles the holder of such Special Voting Share to one vote for each Special Voting Share held at all our meetings of shareholders, except meetings at which or in respect of matters on which only holders of another class of shares are entitled to vote separately as a class. The holders of Special Voting Shares are entitled to receive, subject to the rights of the holders of preferred shares and in priority to the holders of Restricted Voting Shares, an amount per Special Voting Share equal to $.000001 on the liquidation, dissolution or winding-up of the Company, whether voluntary or involuntary. The Special Voting Shares are subject to anti-dilution

provisions, which provide that adjustments will be made to the Special Voting Shares in the event of a change to the Restricted Voting Shares in order to preserve the voting equivalency of such shares.

The Limited Partnership makes quarterly distributions, when and if declared by the board of directors, to holders of Class A Units (being the Company, through the General Partner) and Class B Units (being Kinder Morgan) on a pro rata basis subject to limitations described above for the Restricted Voting Shares. Kinder Morgan then receives its pro rata share of declared distributions from the Limited Partnership through its ownership interest in the Limited Partnership Class B Units.

The following table provides information regarding distributions declared, or paid, as applicable, to Kinder Morgan during the year ended December 31, 2018.

For the three month period ended	Dividend rate per share	Date of declaration	Date of distribution	Total amount of distribution paid in cash(a)	Total amount of distribution paid in form of additional shares
(In millions of Canadian dollars, except per share amounts)					
December 31, 2017	0.1625	January 17, 2018	February 15, 2018	31.0	9.9
March 31, 2018	0.1625	April 18, 2018	May 15, 2018	31.0	9.9
June 30, 2018	0.1625	July 18, 2018	August 15, 2018	40.3	—
September 30, 2018	0.1625	October 17, 2018	November 15, 2018	39.7	—
December 31, 2018	0.1625	January 16, 2019	February 15, 2019	13.2	—

a. Distributions paid in cash include U.S. income tax reimbursements related to Puget Sound earnings of $3.4 million during 2018.

Earnings per Restricted Voting Share

We calculate earnings per share from continuing and discontinued operations using the two-class method. Earnings were allocated to Restricted Voting Shares and participating securities based on the amount of dividends paid in the current period plus an allocation of the undistributed earnings or excess distributions over earnings to the extent that each security participates in earnings or excess distributions over earnings. Our unvested restricted stock awards, which may be settled in Restricted Voting Shares issued to employees and non-employee directors and include dividend equivalent payments, do not participate in excess distributions over earnings.

The following table sets forth the allocation of income from continuing operations and net income available to shareholders of Restricted Voting Shares and participating securities:

Year ended December 31,	2018	2017
(In millions of Canadian dollars, except per share amounts)		
Income from Continuing Operations Available to Restricted Voting Stockholders	21.8	8.9
Participating securities:		
Less: Income from Continuing Operations allocated to restricted stock awards(a)	(0.4)	(0.2)
Income from Continuing Operations Allocated to Restricted Voting Stockholders	21.4	8.7
Basic Weighted Average Restricted Voting Shares Outstanding	34.7	27.6
Basic Earnings from Continuing Operations Per Restricted Voting Share	0.62	0.31

The following table sets forth the allocation of income from discontinued operations and net income available to shareholders of Restricted Voting Shares and participating securities:

Year ended December 31,	2018	2017
(In millions of Canadian dollars, except per share amounts)		
Income from Discontinued Operations Available to Restricted Voting Stockholders	394.4	19.0
Participating securities:		
Less: Income from Discontinued Operations allocated to restricted stock awards(a)	(0.4)	(0.2)
Income from Discontinued Operations Allocated to Restricted Voting Stockholders	394.0	18.8
Basic Weighted Average Restricted Voting Shares Outstanding	34.7	27.6
Basic Earnings from Discontinued Operations Per Restricted Voting Share	11.37	0.69

a. As of December 31, 2018 and 2017, there were approximately 0.2 million and 0.3 million, respectively, unvested restricted stock awards.

For the both years ended December 31, 2018 and 2017, the weighted average maximum number of potential Restricted Voting Share equivalents of 0.2 million unvested restricted stock awards are antidilutive and, accordingly, are excluded from the determination of diluted earnings per Restricted Voting Share.

14. Transactions with Related Parties

Affiliate Activities

The following table summarizes our related party income statement activity. Revenues, operating costs and capitalized costs are under normal trade terms.

Year ended December 31,	2018	2017	2016
(In millions of Canadian dollars)			
Income Statement location			
Revenues-Services(a)	61.2	63.7	59.1
Operations and maintenance and general and administrative expenses	6.8	0.5	1.0
Interest expense(b)	—	10.0	21.3
Other			
Capitalized costs from affiliates in property, plant and equipment	0.1	6.5	19.1

a. Amounts represent sales to a customer who is a related party through joint ownership of a joint venture.
b. 2017 and 2016 amounts primarily represent interest on long-term debt with affiliates (“KMI Loans”) that was repaid with proceeds from our IPO.

Accounts receivable and payable

Accounts receivable-affiliate and accounts payable-affiliate are non-interest bearing and are settled on demand and, since our IPO, primarily settled monthly. The following table summarizes our affiliate balances:

December 31,	2018	2017
(In millions of Canadian dollars)		
Accounts receivable(a)	0.2	9.0
Contract accounts receivable(b)	0.7	1.2
Accounts payable(c)	4.7	0.7

a. Included in "Accounts receivable" on our accompanying consolidated balance sheets.
b. Included in "Other current assets" on our accompanying consolidated balance sheets.
c. Included in "Accounts payable" on our accompanying consolidated balance sheets.

15. Interest (Income) Expense, net

Year ended December 31,	2018	2017	2016
(In millions of Canadian dollars)			
Interest expense on KMI Loans	—	10.0	21.3
Interest expense on credit facilities(a)	2.1	0.9	—
Amortization expense of debt issuance costs	0.6	0.5	—
Interest expense, other	0.4	0.4	—
Interest income	(29.7)	—	—
Capitalized debt financing costs	(0.6)	(3.6)	(2.8)
	(27.2)	8.2	18.5

a. 2018 and 2017 amounts include $1.1 million and $0.7 million, respectively, of standby fees.

16. Change in Operating Assets and Liabilities

The following amounts represent consolidated changes in operating assets and liabilities, which include changes for the Trans Mountain Asset Group. See Note 3 for a summary of operating and investing cash flows related to the Trans Mountain Asset Group.

Year ended December 31,	2018	2017	2016
(In millions of Canadian dollars)	**Cash inflow (outflow)**		
Accounts receivable	25.0	(3.8)	25.9
Inventories	(0.2)	(0.7)	(1.5)
Other current assets	(4.0)	4.1	(3.2)
Deferred charges and other assets	(5.6)	(12.4)	(4.2)
Accounts payable	(48.0)	(21.3)	35.3
Accrued taxes	303.8	10.2	(0.5)
Other current liabilities	3.6	(55.5)	3.5
Other deferred credits	62.4	(15.0)	(82.8)
	337.0	(94.4)	(27.5)

17. Risk Management and Financial Instruments

Credit risk

We are exposed to credit risk, which is the risk that a customer or other counterparty will fail to perform an obligation or settle a liability, resulting in a financial loss to our business, which is primarily concentrated in the crude oil and refined products transportation industry and is dependent upon the ability of our customers to pay for these services. A majority of our customers operate in the oil and gas exploration and development, or energy marketing or transportation industries. Our customers may be exposed to long-term downturns in energy commodity prices, including the price for crude oil, or other credit events impacting these industries. We limit our exposure to credit risk by requiring shippers who fail to maintain specified credit ratings or a suitable financial position to provide acceptable security, generally in the form of guarantees from credit worthy parties or letters of credit from well rated financial institutions. Our cash and cash equivalents are held with major financial institutions, minimizing the risk of non-performance by counter parties.

Interest Rate Risk

We are exposed to interest rate risk attributed to floating rate debt, which is used to finance capital expansion projects, and general corporate operations. The changes in interest rates may impact future cash flows and the fair value of our financial instruments.

Foreign Currency Transactions and Translation

Foreign currency transaction gains or losses result from a change in exchange rates between the functional currency of an entity and the currency in which a transaction is denominated. Unrealized and realized gains and losses generated from these transactions are recorded in foreign exchange loss in the accompanying consolidated statements of income and include:

- As a result of the Trans Mountain Transaction, we released foreign currency translation gains previously held within Accumulated other comprehensive loss to the Gain on sale of the Trans Mountain Asset Group, net of tax in the accompanying consolidated statement of income of $10.1 million for the year ended December 31, 2018.

- Prior to repayment of the KMI Loans utilizing proceeds from our IPO, we were exposed to foreign currency risk related to the U.S. dollar denominated KMI Loans. For the years ended December 31, 2017 and 2016, our continuing operations had unrealized foreign exchange gain of $0.2 million and $13.2 million, respectively, and our discontinued operations had unrealized foreign exchange (loss) and gain of $(2.6) million and $16.5 million, respectively, related to the KMI Loans.

- Our continuing operations unrealized foreign exchange (loss) and gain for the years ended December 31, 2018, 2017 and 2016 were $1.0 million, $(5.6) million and $1.4 million, respectively, due to changes in exchange rates between the Canadian dollar and the U.S. dollar on U.S. dollar denominated balances. These currency exchange rate fluctuations affect the expected Canadian dollar cash flows on unsettled U.S. dollar denominated transactions, primarily related to cash bank accounts that are denominated in U.S. dollars and affiliate receivables or payables that are denominated in U.S. dollars. Prior to the closing of the Trans Mountain Transaction, we translated the assets and liabilities of Puget Sound that has the U.S. dollar as its functional currency to Canadian dollars at period-end exchange rates.

- Cochin earns its revenues in U.S. dollars. Therefore, fluctuations in the U.S. dollar to Canadian dollar exchange rate can affect the earnings contributed by Cochin to our overall results. Our continuing operations had realized foreign exchange (loss) and gain of $(0.9) million and $0.3 million for the years ended December 31, 2018 and 2017. The net realized foreign exchange gains and losses were nominal in 2016.

Liquidity risk

Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments, as they become due. We manage our liquidity risk by ensuring access to sufficient funds to meet our obligations. We forecast cash requirements to ensure funding is available to settle financial liabilities when they become due. Our primary sources of liquidity and capital resources are funds generated from operations and our 2018 Credit Facility.

Fair value measurements

We do not carry any financial assets or liabilities measured at fair value on a recurring basis, other than the Trusts described in Note 7. We disclose the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects our best estimate of market value based on generally accepted valuation techniques or models and are supported by observable market prices and rates. When such values are not available, we use discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

Fair value of financial instruments

Fair value represents the price at which a financial instrument could be exchanged in an orderly market, in an arm's length transaction between knowledgeable and willing parties who are under no compulsion to act. We classify the fair value of the financial instruments according to the following hierarchy based on the observable inputs used to value the instrument:

- Level 1— inputs to the valuation methodology are quoted prices unadjusted for identical assets or liabilities in active markets;

- Level 2— inputs other than quoted prices included in Level 1 that are observable for the asset or liability either directly (as prices) or indirectly (i.e. derived from prices); and
- Level 3 — inputs to the valuation model are not based on observable market data.

Fair value measurements are classified in the fair value hierarchy based on the lowest level input that is significant to that fair value measurement. This assessment requires judgment considering factors specific to an asset or liability and may affect placement within the fair value hierarchy. Level 1 and Level 2 are used for the fair value of cash and cash equivalents and restricted investments, respectively.

Due to the short-term or on demand nature of cash and cash equivalents, restricted cash, accounts receivable, accounts receivable from affiliates, accounts payable, accounts payable to affiliates and accrued interest, we have determined that the carrying amounts for these balances approximate fair value.

18. Revenue Recognition

Nature of Revenue by Segment

Terminals Segment

We provide various types of liquid tank and bulk terminal services. These services are generally comprised of inbound, storage and outbound handling of customer products.

Our liquid tank storage and handling service contracts generally include a promised tank storage capacity provision and prepaid volume throughput of the stored product. In these contracts, we have a stand-ready obligation to perform this contracted service each day over the life of the contract. The customer pays a transaction price typically in the form of a fixed monthly charge and is obligated to pay whether or not it uses the storage capacity and throughput service (i.e., a take-or-pay payment obligation). These contracts generally include a per-unit rate for any quantities we handle at the request of the customer in excess of the prepaid volume throughput amount and also typically include per-unit rates for additional, ancillary services that may be periodically requested by the customer.

Our bulk storage and handling contracts generally include inbound handling of our customers' dry bulk material product into our storage facility and outbound handling of these products from our storage facility. These services are provided on both a firm and non-firm basis. In our firm bulk storage and handling contracts, we are committed to handle and store on a stand-ready basis the minimum throughput quantity of bulk materials contracted by the customer. The customer is obligated to pay for its minimum volume commitment amount, regardless of whether or not it uses the storage and handling service. The customer pays a transaction price typically based on a per-unit rate for quantities handled, including amounts attributable to deficiency quantities. For non-firm storage and handling services, the customer pays a transaction price typically based on a per-unit rate for quantities handled on an as requested, non-guaranteed basis.

Pipelines Segment

We transport light hydrocarbon liquids (primarily to be used as diluent to facilitate bitumen transportation) on a firm or non-firm contractual basis, and jet fuel on a non-firm contractual basis. The regulated tariff for Cochin is designed to provide revenues sufficient to recover the costs of providing transportation to shippers, including a return on invested capital. The majority of Cochin's transportation service is provided on a firm basis under its current contracts.

We typically promise to transport on a stand-ready basis the shipper's minimum volume commitment amount. The shipper is obligated to pay for its volume commitment amount, regardless of whether or not it flows quantities in Cochin's pipeline. The shipper pays a transaction price typically based on a per-unit rate for quantities transported, including amounts attributable to deficiency quantities.

Our non-firm, interruptible transportation services are provided on Cochin's pipeline when and to the extent we determine capacity is available in this pipeline system. The shippers typically pay a per-unit rate for actual quantities of product transported.

Disaggregation of Revenues

The following table presents our revenues disaggregated by revenue source and type of revenue for each revenue source:

	Year Ended December 31, 2018		
	Pipelines	**Terminals**	**Total**
(In millions of Canadian dollars)			
Revenue from contracts with customers			
Services			
Firm services(a)	54.0	229.4	283.4
Fee-based services	1.3	79.2	80.5
Total services revenues	55.3	308.6	363.9
Other revenues(b)	6.9	13.0	19.9
Total revenues	62.2	321.6	383.8

a. Includes non-cancellable firm service customer contracts with take-or-pay or minimum volume commitment elements, including those contracts where both the price and quantity amount are fixed. In these arrangements, the customer is obligated to pay for the rendered service whether or not the customer chooses to utilize the service. Excludes service contracts with indexed-based pricing, which along with revenues from other contracts are reported as Fee-based services.

b. Amounts recognized as revenue under guidance prescribed in Topics of the Accounting Standards Codification other than in Topic 606 and primarily include regulatory-based adjustments and leases.

Contract Balances

Contract assets and contract liabilities are the result of timing differences between revenue recognition, billings and cash collections. We recognize contract assets in those instances where billing occurs subsequent to revenue recognition and our right to invoice the customer is conditioned on something other than the passage of time. Our contract liabilities are substantially related to (i) capital improvements paid for in advance by certain customers generally in our non-regulated businesses, which we subsequently recognize as revenue on a straight-line basis over the initial term of the related customer contracts, and (ii) consideration received from customers for temporary deficiency quantities under minimum volume contracts that we expect will be made up in a future period, which we subsequently recognize as revenue when the customer makes up the volumes or the likelihood that the customer will exercise its right for deficiency volumes becomes remote (e.g., there is insufficient capacity to make up the volumes, the deficiency makeup period expires).

The following table presents the activity in our contract assets and liabilities:

(In millions of Canadian dollars)	
Contract Assets	
Balance at January 1, 2018	2.1
Additions	17.9
Transfer to Accounts receivable	(18.4)
Balance at December 31, 2018(a)	1.6
Contract Liabilities	
Balance at January 1, 2018	68.2
Additions	154.5
Transfer to Revenues	(143.1)
Other (b)	0.7
Balance at December 31, 2018(c)	80.3

a. Includes current balances reported within “Other current assets” in our accompanying consolidated balance sheets at December 31, 2018.

b. Includes 2018 foreign currency translation adjustments associated with the balances at December 31, 2017.

c. Includes current balances and non-current balances of $12.8 million and $67.5 million reported within "Other current liabilities" and "Contract liabilities," respectively, in our accompanying consolidated balance sheets at December 31, 2018.

Revenue Allocated to Remaining Performance Obligations

The following table presents our estimated revenue allocated to remaining performance obligations for contracted revenue that has not yet been recognized, representing our "contractually committed" revenue as of December 31, 2018 that we will invoice or transfer from contract liabilities and recognize in future periods:

Year	Estimated Revenue
(In millions of Canadian dollars)	
2019	313.4
2020	250.0
2021	193.3
2022	183.9
2023	171.3
Thereafter	533.1
Total	1,645.0

Our contractually committed revenue for purposes of the tabular presentation above is generally limited to service customer contracts which have fixed pricing and fixed volume terms and conditions, generally including contracts with take-or-pay or minimum volume commitment payment obligations. Our contractually committed revenue amounts generally exclude, based on the following practical expedients that we elected to apply, remaining performance obligations for: (i) contracts with index-based pricing or variable volume attributes in which such variable consideration is allocated entirely to a wholly unsatisfied performance obligation or to a wholly unsatisfied promise to transfer a distinct service that forms part of a series of distinct services; (ii) contracts with an original expected duration of one year or less; and (iii) contracts for which we recognize revenue at the amount for which we have the right to invoice for services performed.

Major Customer

For the years ended December 31, 2018 and 2017, revenues from Imperial Oil represented 31% of our total revenue from continuing operations for each year. For the year ended December 31, 2016, revenues from Imperial Oil represented 23% of our total revenue.

19. Reportable Segments

Our reportable business segments are based on the way management organizes the enterprise. Each of our reportable business segments represent a component of the enterprise that engages in a separate business activity and for which discrete financial information is available.

Our reportable business segments are:

- Terminals - the ownership and operation of liquid product merchant storage and rail terminals in the Edmonton, Alberta market as well as a predominantly dry cargo import/export facility in North Vancouver, B.C. Certain Edmonton South Terminal tanks that are owned by TMPL were included in the Trans Mountain Asset Group and continue to be leased to Terminals segment; and

- Pipelines - the ownership and operation of Cochin, a 12-inch diameter multi-product pipeline which spans approximately 1,000 kilometers in Saskatchewan and Alberta and Jet Fuel serving Vancouver International Airport.

We evaluate the performance of our reportable business segments by evaluating our Segment earnings before depreciation and amortization expenses ("Segment EBDA"). We believe that Segment EBDA is a useful measure of our operating performance because it measures segment operating results before D&A and certain expenses that are generally not controllable by the operating managers of our respective business segments, such as general and administrative expense, interest expense, income tax expense and prior to May 2017, the foreign exchange losses (or gains) on the KMI Loans. Our

general and administrative expenses include such items as employee benefits, insurance, rentals, certain litigation and shared corporate services including accounting, information technology, human resources and legal services.

We consider each period's earnings before all non-cash D&A expenses to be an important measure of business segment performance for our reporting segments. We account for intersegment sales at market prices, while we account for asset transfers at either market value or, in some instances, book value. Intercompany transactions are eliminated in consolidation.

Financial information by segment for continuing operations is as follows:

Year Ended December 31,	**2018**	**2017**	**2016**
(In millions of Canadian dollars)			
Revenues			
Terminals	321.6	298.6	287.5
Pipelines	62.2	60.3	60.3
Total consolidated revenues	383.8	358.9	347.8

Year Ended December 31,	**2018**	**2017**	**2016**
(In millions of Canadian dollars)			
Operating expenses(a)			
Terminals	137.6	136.9	129.6
Pipelines	23.1	32.3	30.5
Total consolidated operating expenses	160.7	169.2	160.1

Year Ended December 31,	**2018**	**2017**	**2016**
(In millions of Canadian dollars)			
Other operating expense (income)			
Terminals	(9.3)	3.1	0.2
Pipelines	—	0.3	—
Total consolidated other expense (income)	(9.3)	3.4	0.2

Year Ended December 31,	**2018**	**2017**	**2016**
(In millions of Canadian dollars)			
D&A			
Terminals	78.5	65.7	60.2
Pipelines	4.1	6.0	4.0
Total consolidated D&A	82.6	71.7	64.2

Year Ended December 31,	**2018**	**2017**	**2016**
(In millions of Canadian dollars)			
Other expense (income) net of foreign exchange loss, net(b)			
Terminals	0.1	(4.2)	(1.5)
Pipelines	0.1	8.6	—
Total consolidated other expense (income) net of foreign exchange loss	0.2	4.4	(1.5)

Year Ended December 31,	2018	2017	2016
(In millions of Canadian dollars)			
Segment EBDA(a)(b)			
Terminals	193.2	162.8	159.2
Pipelines	39.0	19.1	29.8
Total Segment EBDA	232.2	181.9	189.0
D&A	(82.6)	(71.7)	(64.2)
Foreign exchange gain on KMI Loans(c)	—	0.2	13.2
General and administrative	(39.0)	(30.9)	(25.7)
Interest income (expense), net	27.2	(8.2)	(18.5)
Income tax expense	(37.8)	(20.8)	(23.4)
Income from Continuing Operations	100.0	50.5	70.4
Income from Discontinued Operations, Net of Tax	1,318.2	110.2	131.4
Net Income	1,418.2	160.7	201.8

Year Ended December 31,	2018	2017	2016
(In millions of Canadian dollars)			
Capital expenditures			
Terminals	100.4	172.9	97.4
Pipelines	1.4	7.1	6.3
Discontinued Operations	426.6	438.5	165.4
Total consolidated capital expenditures	528.4	618.5	269.1

December 31,	2018	2017
(In millions of Canadian dollars)		
Assets		
Terminals	974.2	863.0
Pipelines	4,395.4	346.6
Assets Held for Sale	—	3,243.1
Total consolidated assets	5,369.6	4,452.7

a. Includes revenues less operations and maintenance expense, and taxes, other than income taxes and other, net.
b. Segment EBDA for the years ended December 31, 2018, 2017 and 2016 includes $0.1 million, $(5.3) million and $1.4 million, respectively, of foreign exchange gain (losses) due to changes in exchange rates between our Canadian dollar and the U.S. dollar on U.S. dollar denominated balances.
c. The KMI Loans, which represented U.S. dollar denominated long-term notes payable to Kinder Morgan, were settled with proceeds from our IPO.

We do not allocate interest, net, general and administrative, income taxes and foreign currency exchange losses and gains associated with short and long-term debt-affiliates to any of our reportable business segments.

20. Litigation, Commitments and Contingencies

Litigation

We and our subsidiaries are parties to various legal, regulatory and other matters arising from the day-to-day operations of our businesses or certain predecessor operations that may result in claims against the Company. Although no assurance can be given, we believe, based on our experiences to date and taking into account established reserves and insurance, that the ultimate resolution of such items will not have a material adverse impact on our business, financial position, results of operations, cash flows, or dividends to our shareholders. We believe we have meritorious defenses to the matters to which we are a party and intend to vigorously defend the Company. When we determine a loss is probable of occurring and is reasonably estimable, we accrue an undiscounted liability for such contingencies based on our best estimate using information available at that time. If the estimated loss is a range of potential outcomes and there is no better estimate within the range, we accrue the amount at the low end of the range. We disclose contingencies where an adverse outcome may be material, or in the

judgment of management, we conclude the matter should otherwise be disclosed. We had no accruals for any outstanding legal proceedings as of December 31, 2018 and 2017.

Base Line Terminal Project Litigation

On March 2, 2018, Arnett & Burgess Oilfield Construction Limited ("A&B") filed a statement of claim and certificate of lis pendens, in the Court of Queen's Bench of Alberta, against Alberta Envirofuels Inc. ("AEF") and Base Line Terminal East Limited Partnership, by its general partner, KM Canada Rail Holdings GP Limited ("BLTELP"). A&B was a contractor on the Base Line Terminal Project (the "BTT Project") and has claimed it is owed $21.2 million, inclusive of goods and services tax, asserting that BLTELP failed to pay A&B for work performed on the BTT Project under a construction services agreement.

On March 26, 2018, A&B filed a separate statement of claim, in the Court of Queen's Bench of Alberta, against BLTELP solely, asserting that BLTELP failed to pay for work performed under a separate construction services agreement also related to the BTT Project. With respect to the second claim, A&B has claimed it is owed approximately $1.0 million, inclusive of goods and services tax. We dispute both claims and intend to defend against them vigorously.

On June 5, 2018, Barrier Coating Inc. ("Barrier") filed a statement of claim and certificate of lis pendens in the Court of Queen's Bench of Alberta against Enbridge Pipelines Inc., AEF, Strathcona County, BLTELP, KM Canada Rail Holdings GP Limited, Keyera Energy Ltd., Trans Mountain Pipeline ULC and Fabricom Inc. ("Fabricom"). Barrier is a subcontractor on the BTT Project and has a construction agreement with Fabricom (the "Fabricom Agreement"). In its claim, Barrier asserts that Fabricom has breached its obligations under the Fabricom Agreement and, as such, Fabricom owes damages to Barrier. The remaining defendants, including BLTELP, KM Canada Rail Holdings GP Limited and Trans Mountain Pipeline ULC, have been named in the claim as parties with registered interests on lands affected by the work performed by Barrier under the Fabricom Agreement. Barrier asserts that these parties were, collectively, unjustly enriched in the amount of $2.5 million. This matter has been resolved and dismissed without any payment from any Kinder Morgan affiliate.

On September 6, 2018, Fabricom Inc. ("Fabricom") filed a statement of claim and certificate of lis pendens in the Court of Queen's Bench of Alberta, against KM Canada Terminals ULC, BLTELP, Trans Mountain Pipeline ULC, AEF, Doran Stewart Oilfield Services (1990) Ltd., Alberta Envirofuels Inc., Enbridge Pipelines Inc., and Strathcona County. Fabricom was a contractor on the BTT Project, and claims that it is owed $30.4 million by BLTELP above the contract value for work performed on the BTT Project under a construction services agreement. Fabricom subsequently sent a notice of arbitration incorporating its claim. Pursuant to a provision in the construction services agreement, the dispute will be resolved by arbitration and the Court of Queen's Bench matter will be stayed. We dispute this claim and intend to defend against it vigorously.

Commitments

Capital Commitments

As of December 31, 2018, we have commitments for purchases of property, plant, and equipment of $20.2 million which includes approximately $13.8 million of our proportional share of commitments through joint ownership of a joint venture.

Leases and Rights-of-Way Obligations

The table below depicts future gross minimum rental commitments under our operating leases and rights-of-way obligations as of December 31, 2018:

	Commitment
(In millions of Canadian dollars)	
2019	61.8
2020	59.9
2021	59.0
2022	59.0
2023	43.2
Thereafter	9.4
Total minimum payments	292.3

The remaining terms on our operating leases range from one to twenty-five years. Total lease and rental expenses were $66.2 million, $69.8 million and $66.5 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Contingencies

We and our subsidiaries are subject to various legal and regulatory actions and proceedings which arise in the normal course of business. While the final outcome of such actions and proceedings cannot be predicted with certainty, we believe that the resolution of such actions and proceedings will not have a material impact on our financial position or results of operations.

We and our subsidiaries are also subject to environmental cleanup and enforcement actions from time to time. Although we believe our operations are in substantial compliance with applicable environmental law and regulations, risks of additional costs and liabilities are inherent in pipeline and terminal operations, and there can be no assurance that we will not incur significant costs and liabilities. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies under the terms of authority of those laws, and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities to us.

Although it is not possible to predict the ultimate outcomes, we believe that the resolution of the environmental matters to which we and our subsidiaries are a party will not have a material adverse effect on our business, financial position, results of operations or cash flows. As of December 31, 2018, we had $0.1 million accrued for our outstanding environment matters and no accrual as of December 31, 2017.

Land Matters Consultation Initiative Trust

On January 30, 2015 Kinder Morgan established the Trust, a required regulatory liability in relation to the NEB's LMCI. The Trust was created to set aside funds collected through abandonment surcharges over a collection period established by the NEB. The NEB approved the amounts to be collected by the company in respect of future pipeline abandonment. Funds are transferred to the Trust account each billing cycle. As of December 31, 2018 and 2017, our Trust liability balance was $6.5 million and $4.8 million, respectively and we had Trust assets of $6.1 million and $4.3 million. The Trust liability amounts are included within Other Current Liabilities and Other Deferred Credits, and the Trust asset amount is recorded in Deferred Charges and Other Assets, on our accompanying consolidated balance sheet.

21. Recent Accounting Pronouncements

Topic 842

On February 25, 2016, the FASB issued ASU No. 2016-02, *"Leases"* followed by a series of related accounting standard updates (collectively referred to as "Topic 842"). Topic 842 establishes a new lease accounting model for leases. The most significant changes include the clarification of the definition of a lease, the requirement for lessees to recognize for all leases a right-of-use asset and a lease liability in the consolidated balance sheet, and additional quantitative and qualitative disclosures that are designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. Expenses are recognized in the consolidated statement of income in a manner similar to current accounting guidance. Lessor accounting under the new standard is substantially unchanged. The new standard will become effective for us beginning with the first quarter 2019. We will adopt the accounting standard using a prospective transition approach, which applies the provisions of the new guidance at the effective date without adjusting the comparative periods presented. We have elected the package of practical expedients permitted under the transition guidance within the new standard, which among other things, allows us to carry forward the historical accounting relating to lease identification and as well as no reassessment of lease identification and classification for existing leases upon adoption. We have also elected the optional practical expedient permitted under the transition guidance within the new standard related to land easements that allows us to carry forward our historical accounting treatment for land easements on existing agreements upon adoption. We have made an accounting policy election to keep leases with an initial term of 12 months or less off of the consolidated balance sheet. We are finalizing our evaluation of the impacts that the adoption of this accounting guidance will have on the consolidated financial statements, and estimate approximately $300 million of additional right-of-use assets and liabilities will be recognized in our consolidated balance sheet upon adoption.

ASU No. 2016-13

On June 16, 2016, the FASB issued ASU No. 2016-13, "*Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments.*" This ASU modifies the impairment model to utilize an expected loss

methodology in place of the currently used incurred loss methodology, which will result in the more timely recognition of losses. ASU No. 2016-13 will be effective for us as of January 1, 2020, and earlier adoption is permitted. We are currently reviewing the effect of this ASU to our financial statements.

ASU No. 2018-14

On August 28, 2018, the FASB issued ASU No. 2018-14, "Compensation - Retirement Benefits - Defined Benefit Plans - General (Subtopic 715-20): Disclosure Framework - Changes to the Disclosure Requirements for Defined Benefit Plans." This ASU amends existing annual disclosure requirements applicable to all employers that sponsor defined benefit pension and other postretirement plans by adding, removing, and clarifying certain disclosures. ASU No. 2018-14 will be effective for us for the fiscal year ending December 31, 2020, and earlier adoption is permitted. We are currently reviewing the effect of this ASU to our financial statements.

Supplemental Selected Quarterly Financial Data (Unaudited)

	2018				2017			
	Q4(a)	Q3(a)	Q2	Q1	Q4	Q3	Q2	Q1
(In millions of Canadian dollars, except for per share amounts)								
Revenues	105.2	94.3	95.7	88.6	95.0	85.9	89.0	89.0
Operating Income	31.4	26.4	32.4	20.6	28.8	17.5	20.0	17.4
Foreign exchange gain (loss)	0.5	(0.6)	0.5	(0.3)	0.2	(2.0)	(18.3)	15.0
Income from Continuing Operations	40.3	22.2	23.5	14.0	22.5	9.8	5.9	12.3
Income (loss) from Discontinued Operations, net of tax	—	19.2	(9.8)	30.4	23.9	32.6	19.2	34.5
(Loss) gain on sale of the Trans Mountain Asset Group, net of tax	(29.6)	1,308.0	—	—	—	—	—	—
Net Income	10.7	1,349.4	13.7	44.4	46.4	42.4	25.1	46.8
Net Income Available to Restricted Voting Stockholders	2.1	401.5	1.8	10.8	12.0	11.7	4.2	
Basic and Diluted Earnings Per Restricted Voting Share from Continuing Operations	0.30	0.14	0.13	0.05	0.14	0.06	0.11	
Basic and Diluted (Loss) Earnings Per Restricted Voting Share from Discontinued Operations	(0.23)	11.42	(0.08)	0.26	0.20	0.28	0.21	

a. The three months ended December 31, 2018 (Q4) include an approximately $6.3 million out of period adjustment that decreased the loss on sale of the Trans Mountain Asset Group, net of tax, and increased net income in Q4. The adjustment relates to a correction on the amount released for deferred income taxes that resulted in a tax benefit from the sale of the Trans Mountain Asset Group for the three months ended September 30, 2018 (Q3), see Note 3. The impact of recognizing the adjustment in Q4 and not in Q3 was not significant to either individual period and did not impact the accompanying consolidated financial statements for the year ended and as of December 31, 2018. Management believes this adjustment between Q4 and Q3 is immaterial to the unaudited supplemental selected quarterly financial data presented above and to the previously issued unaudited consolidated financial statements for Q3.

Item 16. ***Form 10-K Summary.***

Not Applicable.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

KINDER MORGAN CANADA LIMITED
Registrant

By: /s/ Dax A. Sanders

Dax A. Sanders
Chief Financial Officer
(principal financial and accounting officer)

Date: February 18, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ DAX A. SANDERS Dax A. Sanders	Chief Financial Officer (principal financial officer and principal accounting officer); Director	February 18, 2019
/s/ STEVEN J. KEAN Steven J. Kean	Chief Executive Officer and Chairman (principal executive officer); Director	February 18, 2019
/s/ KIMBERLY A. DANG Kimberly A Dang	Director	February 18, 2019
/s/ DANIEL P. E. FOURNIER Daniel P. E. Fournier	Director	February 18, 2019
/s/ GORDON M. RITCHIE Gordon M. Ritchie	Director	February 18, 2019
/s/ BROOKE N. WADE Brooke N. Wade	Director	February 18, 2019

Articles of Amendment

Business Corporations Act
Section 6

This information is collected in accordance with the *Business Corporations Act*. It is required to update an Alberta corporation's articles for the purpose of issuing a certificate of amendment. Collection is authorized under s. 33(a) of the *Freedom of Information and Protection of Privacy Act*. Questions about the collection can be directed to Service Alberta Contact Centre staff at cr@gov.ab.ca or (780) 427-7013 (toll-free 310-0000) within Alberta.

1. Name of Corporation	2. Corporate Access Number
KINDER MORGAN CANADA LIMITED	**2020347171**

3. Item see below **of the Articles of the above named corporation are amended in accordance with Section** see below **of the *Business Corporations Act* as follows:**

Pursuant to Section 173(1)(f) of the *Business Corporations Act* (Alberta), the Articles be amended by consolidating all of the Restricted Voting Shares and the Special Voting Shares as set out in the attached Share Consolidation Schedule.

4. Authorized Representative/Authorized Signing Authority for the corporation:

Ashley, Anthony	Vice President and Treasurer
Last Name, First Name, Middle Name	Relationship to Corporation
	Not Applicable.
Telephone Number	E-mail (optional)
	/s/ Ashley, Anthony
Date	Signature

SHARE CONSOLIDATION SCHEDULE
OF
KINDER MORGAN CANADA LIMITED
(the "Corporation")

Pursuant to Section 173(1)(f) of the *Business Corporations Act* (Alberta), the Articles of the Corporation be amended by:

1. consolidating the issued and outstanding Restricted Voting Shares on the basis of three (3) pre-consolidation Restricted Voting Shares held for one (1) post-consolidation Restricted Voting Share. Fractional shares will be rounded down to the nearest whole number of post-consolidation Restricted Voting Shares (in calculating such fractional interests, all Restricted Voting Shares registered in the name of each registered shareholder will be aggregated); and

2. consolidating the issued and outstanding Special Voting Shares on the basis of three (3) pre-consolidation Special Voting Shares held for one (1) post-consolidation Special Voting Share. Fractional shares will be rounded down to the nearest whole number of post-consolidation Special Voting Shares (in calculating such fractional interests, all Special Voting Shares registered in the name of each registered shareholder will be aggregated).

Articles of Amendment

Business Corporations Act
Section 6

This information is collected in accordance with the *Business Corporations Act*. It is required to update an Alberta corporation's articles for the purpose of issuing a certificate of amendment. Collection is authorized under s. 33(a) of the *Freedom of Information and Protection of Privacy Act*. Questions about the collection can be directed to Service Alberta Contact Centre staff at cr@gov.ab.ca or (780) 427-7013 (toll-free 310-0000) within Alberta.

1. Name of Corporation	2. Corporate Access Number
KINDER MORGAN CANADA GP INC.	2020465411

3. Item see below **of the Articles of the above named corporation are amended in accordance with Section** see below **of the *Business Corporations Act* as follows:**

Pursuant to Section 173(1)(f) of the *Business Corporations Act* (Alberta), the Articles be amended by consolidating all of the Restricted Voting Shares and the Special Voting Shares as set out in the attached Share Consolidation Schedule.

4. Authorized Representative/Authorized Signing Authority for the corporation:

Ashley, Anthony	Vice President and Treasurer
Last Name, First Name, Middle Name	Relationship to Corporation
	Not Applicable.
Telephone Number	E-mail (optional)
	/s/ Ashley, Anthony
Date	Signature

SHARE CONSOLIDATION SCHEDULE
OF
KINDER MORGAN CANADA LIMITED
(the "Corporation")

Pursuant to Section 173(1)(f) of the *Business Corporations Act* (Alberta), the Articles of the Corporation be amended by:

1. consolidating the issued and outstanding Common Shares on the basis of three (3) pre-consolidation Common Shares held for one (1) post-consolidation Common Share. Fractional shares will be rounded down to the nearest whole number of post-consolidation Common Shares (in calculating such fractional interests, all Common Shares registered in the name of each registered shareholder will be aggregated).

Kinder Morgan Canada Limited

Subsidiaries of the Registrant as of December 31, 2018

Entity Name	Place of Incorporation
2043155 Alberta Ltd.	Canada (Alberta)
Base Line Terminal East Limited Partnership	Canada - Limited Partnership
Kinder Morgan Canada GP Inc.	Canada (Alberta)
Kinder Morgan Canada (Jet Fuel) Inc.	Canada (British Columbia)
Kinder Morgan Canada Services Inc.	Canada (Alberta)
Kinder Morgan Canada Limited Partnership	Canada (Alberta)
Kinder Morgan Cochin ULC	Canada (Nova Scotia)
KM Canada Edmonton North Rail Terminal Limited Partnership	Canada - Limited Partnership
KM Canada Marine Terminal Limited Partnership	Canada - Limited Partnership
KM Canada North 40 Limited Partnership	Canada - Limited Partnership
KM Canada Rail Holdings GP Limited	Canada - Limited Partnership
KM Canada Edmonton South Rail Terminal Limited Partnership	Canada - Limited Partnership
KM Canada Terminals GP ULC	Canada (Alberta)

Exhibit 31.1

KINDER MORGAN CANADA LIMITED AND SUBSIDIARIES
CERTIFICATION PURSUANT TO RULE 13A-14(A) OR 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934,
AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Steven J. Kean, certify that:

1. I have reviewed this annual report on Form 10-K of Kinder Morgan Canada Limited;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have for the registrant and have:

    a. designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States;

    c. evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

1. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2019

/s/ Steven J. Kean
Steven J. Kean
Chief Executive Officer

Exhibit 31.2

KINDER MORGAN CANADA LIMITED AND SUBSIDIARIES
CERTIFICATION PURSUANT TO RULE 13A-14(A) OR 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934,
AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Dax A. Sanders, certify that:

1. I have reviewed this annual report on Form 10-K of Kinder Morgan Canada Limited;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States;

   c. evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2019

/s/ Dax A. Sanders
Dax A. Sanders
Chief Financial Officer

Exhibit 32.1

KINDER MORGAN CANADA LIMITED AND SUBSIDIARIES
CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906
OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of Kinder Morgan Canada Limited (the "Company") for the yearly period ended December 31, 2018, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, in the capacity and on the date indicated below, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 18, 2019

/s/ Steven J. Kean
Steven J. Kean
Chief Executive Officer

Exhibit 32.2

KINDER MORGAN CANADA LIMITED
CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906
OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of Kinder Morgan Canada Limited (the "Company") for the yearly period ended December 31, 2018, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, in the capacity and on the date indicated below, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 18, 2019

/s/ Dax A. Sanders
Dax A. Sanders
Chief Financial Officer