Public Interest Evaluation of the Trans Mountain Expansion Project

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Executive Summary

1. The purpose of this report is:
   a) To evaluate the National Energy Board's (NEB or the Board) assessment in its 2016 and 2019 reports (NEB, 2016, 2019a) and information provided by the Canadian government in the Trans Mountain Expansion Project (TMEP) Phase III consultations with the Tsleil-Waututh Nation (TWN) that the TMEP is in the public interest; and
   b) To present the results of a comprehensive benefit cost analysis of the TMEP based on federal government guidelines to determine if the TMEP generates a net benefit to Canada and is in the public interest.
2. In December 2013, Trans Mountain (TM) submitted its application to the NEB seeking approval of the TMEP. TM's application is a proposal to twin an existing pipeline from Edmonton, Alberta to Burnaby, BC to expand oil transport capacity from 300 kbpd to 890 kbpd and to construct a marine terminal to load oil tankers to ship oil from Vancouver to Pacific Rim markets.
3. In May 2016, the NEB issued its report recommending that the Governor in Council (GIC) approve the TMEP on the grounds that the TMEP is needed and is in Canada's public interest. On November 29, 2016, the GIC issued an Order in Council that accepted the NEB's recommendations and directed the NEB to issue a certificate of public convenience and necessity approving the construction and operation of the TMEP, subject to the conditions recommended by the Board.
4. In May 2018, Canada announced its intent to purchase TM and the purchase was approved by Kinder Morgan's shareholders in August 2018.
5. On August 30, 2018, the Federal Court of Appeal quashed the GIC's Order approving the TMEP on the grounds that there had been insufficient consultation with First Nations and the NEB had erred in omitting consideration of Project-related marine shipping from the environmental assessment it was required to carry out under the *Canadian Environmental Assessment Act, 2012* (CEAA). The GIC subsequently issued an Order in Council directing the NEB to conduct an additional review to address the Court's decision that Project-related marine shipping was unreasonably excluded from the designated project that the Board assessed under CEAA.
6. In February 2019, the NEB released its reconsideration report (NEB, 2019a) recommending re-approval of the TMEP (Reconsideration Report). The NEB concluded that the TMEP is likely to cause significant adverse effects that can be justified in the circumstances by the economic benefits of TMEP. The Reconsideration Report did not consider any new information on TMEP economics despite significant changes in oil markets, TMEP costs, and approval of alternative pipelines that weakened the justification for the TMEP.
7. The NEB also expressly refused to consider an expert report that TWN filed during the Reconsideration hearing establishing that there have been significant changes in Project economics since the completion of the 2016 NEB Report that undermine the justification for the Project and that there is no need for the Project. TWN's

expert report is the only evidence filed on those issues in the Reconsideration Hearing.

8. In its 2016 and 2019 assessment of the TMEP, the NEB listed what it termed the benefits and the burdens of the Project. According to the NEB, the major benefits of the TMEP would be market diversification, jobs, competition among pipelines, spending on pipeline materials, community benefit programs, enhanced marine spill response, capacity development, and government revenue. The major burdens of the Project would be adverse effects on southern resident killer whales, adverse effects on Aboriginal culture, greenhouse gas (GHG) emissions, adverse effects on municipal development plans, impairment of Aboriginal and stakeholder use of land and water, and pipeline and marine tanker spill risk.

9. The NEB's method for comparing benefits and burdens in the 2016 and 2019 Reconsideration Report consisted of ranking them by a qualitative scale based on the magnitude and geographic scope of the impact. Two ratings were applied to the magnitude of the effect (modest and considerable) and three ratings were used for the geographic scope of the effect (local, regional, and/or national). At no point did the NEB provide any definition of "modest" or "considerable" or any transparent method for how it determined whether an effect was modest or considerable. For Project oil spills, the NEB changed its rating to "acceptable risk". Again, the NEB did not provide a definition of"acceptable risk" or data to determine the level of risk. The NEB did not define what constituted "local", "regional", and "national" effects, and failed to use a transparent method to make this determination. In "balancing the benefits versus the burdens" the NEB placed considerable weight on the economic impacts which it deemed to be national in scope while the environmental burdens were deemed to be local. Based on this assessment, the NEB concluded that the TMEP would be in the public interest.

10. The NEB 2019 Reconsideration Report concluded the risk of oil spills was acceptable. The NEB made several errors in reaching this conclusion that invalidate its finding of acceptable risk. The NEB correctly concluded that small spills could have significant adverse effects. However, it mistakenly concluded that there is a very low probability of a marine spill from a Project related tanker (NEB, 2019, p. 26) without citing any probabilities to support its conclusion. Based on a review of the methods and assumptions of various probability estimates, Gunton and Joseph (2018) concluded that the probability of a marine tanker spill of any size over a 50-year operating period is between 43% (TM's mid-range estimate) and 75% (US Oil Spill Risk Assessment mid-range estimate), with the best estimate being the upper end of the range of 75%. A tanker spill probability of between 43% and 75% would be rated as high to very high consequence event based on the NEB's risk rating framework. Therefore, the NEB's conclusion that the tanker spill risk is acceptable is inconsistent with the evidence and with the NEB's risk assessment framework.

11. A fundamental problem with the NEB's comparison of benefits and burdens of the TMEP is that it is impossible to understand, verify or replicate the NEB's ratings of each benefit and burden because the NEB failed to define key terms or outline the method it used to determine its respective ratings. It is also impossible to understand how the NEB compared benefits and burdens and reached its conclusion that the benefits exceeded the burdens because the NEB did not weigh

and compare benefits and burdens in any coherent or systematic way. For example, the NEB did not describe how it compared the burden of significant adverse effects on southern resident killer whales to the alleged benefit of market diversification. Nor did the NEB provide any rationale for its decision to automatically discount burdens incurred by a regional population relative to benefits received by a larger national population regardless of the magnitude of the burden or benefit. Further, we could not find any rationale in the evaluation literature for this type of weighting. Without a transparent evaluation framework, the NEB's conclusion that the TMEP would be in the public interest is therefore subjective and unfounded.

12. Overall, our evaluation shows that the NEB's public interest assessment of the TMEP has the following deficiencies:

    a) Failure to provide any comparison of benefits and burdens in accordance with well-established principles and guidelines such as benefit cost analysis that can be used to assess whether the TMEP benefits exceed burdens and is a net benefit to Canada;

    b) Incorrect characterization of benefits and burdens as national, regional, and local, and incorrect assumption that regional or local costs and benefits should be discounted relative to "national" benefits;

    c) Failure to consider potential costs associated with building the TMEP (e.g. excess pipeline capacity and environmental costs);

    d) Incorrect conclusion that the risks of oil spills from the TMEP are low and that the risk is acceptable;

    e) Incorrect assumption that the TMEP may increase Canadian oil prices;

    f) Failure to complete any comparative evaluation of the social, economic, and environmental costs and benefits of alternative pipeline options to determine if the TMEP is a superior option from a public interest perspective;

    g) Failure to complete an overall supply and demand assessment for oil pipelines to determine if the TMEP is needed;

    h) Overstating the benefits by using gross economic impacts as a measure of the contribution of the Project to the public interest instead of net impacts and net economic benefits. For example, the NEB identifies that a benefit of the TMEP's operation is the creation of 443 jobs, but it ignores the fact that net job creation is likely closer to nil because these jobs would be created by other projects that would proceed if the TMEP is not built; and

    i) Overstating the revenue benefits by using gross revenue estimates that omit incremental costs to government such as the $1.5 billion Ocean Protection Plan, and government revenue that would be generated by other projects that would proceed if the TMEP is not built.

13. In contrast to the NEB's approach that used arbitrary, subjective approaches to compare benefits and costs, there are well accepted, comprehensive evaluation methods such as benefit cost analysis and multiple accounts analysis that the NEB could have employed to make these comparisons. These more technically sophisticated methods are well developed, transparent, based on sound theoretical

foundations, and have been used for decades to compare project costs and benefits to determine whether a project will generate a net benefit and is in the public interest.

14. Another major problem with the NEB's conclusion that the TMEP is in the public interest is that the NEB assessment is based on outdated information that is no longer relevant. Since the completion of the NEB report in 2016, there have been significant changes that invalidate the NEB's conclusion that the TMEP would be in the public interest. Key changes include:

    a) Advancement of new major pipeline capacity additions that are alternatives to the TMEP totaling 1,710 kbpd of capacity (Enbridge Line 3 (370), other Enbridge expansions (510), and Keystone XL (830)) that have the combined effect of eliminating the need for the TMEP;

    b) Escalation of the projected costs of the TMEP from $5.5 billion to $9.3 billion that undermine the TMEP's competitive advantage relative to other pipelines; and

    c) Weaker oil markets that lower the need for new pipeline capacity (Canadian Association of Petroleum Producers' (CAPP) 2018 supply forecast for 2030 is 1.8 mbpd lower than their 2014 forecast).

15. In Phase III consultations with TWN in April 2019, Canada provided several memos (Canada, 2019a, 2019b) to TWN that purport to show that TMEP is needed and in the public interest. The memos stated that oil production is growing, there is a shortage of pipeline space, and there is a need to diversify oil export markets to reduce the dependence on the US market and the discounting of Canadian oil prices. The information and analysis set out in these memos relies on the NEB reports (2016, 2019a) to justify the TMEP and therefore suffers from the same methodological deficiencies as the NEB reports cited above (see point 8). Canada also provided a pipeline supply and demand analysis purporting to document the need for TMEP. Canada's analysis underestimates potential pipeline capacity by omitting 510 kbpd of proposed capacity expansions on Enbridge's main pipeline system and the Express pipeline. Further, Canada's analysis show that if even with the omission of this 510 kbpd of proposed new pipeline capacity, TMEP is not needed until the end of the forecast period (2030) if Enbridge Line 3 and Keystone XL are built.

16. To assess the need for the TMEP, we completed an updated supply and demand analysis for Western Canada Sedimentary Basin (WCSB) oil transportation services using 2018 estimates of current and proposed pipeline capacity and estimates of WCSB oil exports based on the 2018 forecast from the CAPP and an "under-construction" supply forecast based on projects currently under construction. The analysis shows that while there is a need for more pipeline capacity, the construction of the TMEP along with other proposed pipeline projects will create significant surplus pipeline capacity in the oil transportation sector (Figure ES-1).

    a) Based on CAPP's 2018 forecast, the WCSB oil sector will require only the Enbridge expansions (Line 3 plus other proposed expansions) and one additional pipeline (Keystone XL) to accommodate demand until 2035. If the

TMEP is constructed in addition to the proposed Enbridge projects and Keystone XL, there would be 1.4 million bpd of surplus capacity in 2023.

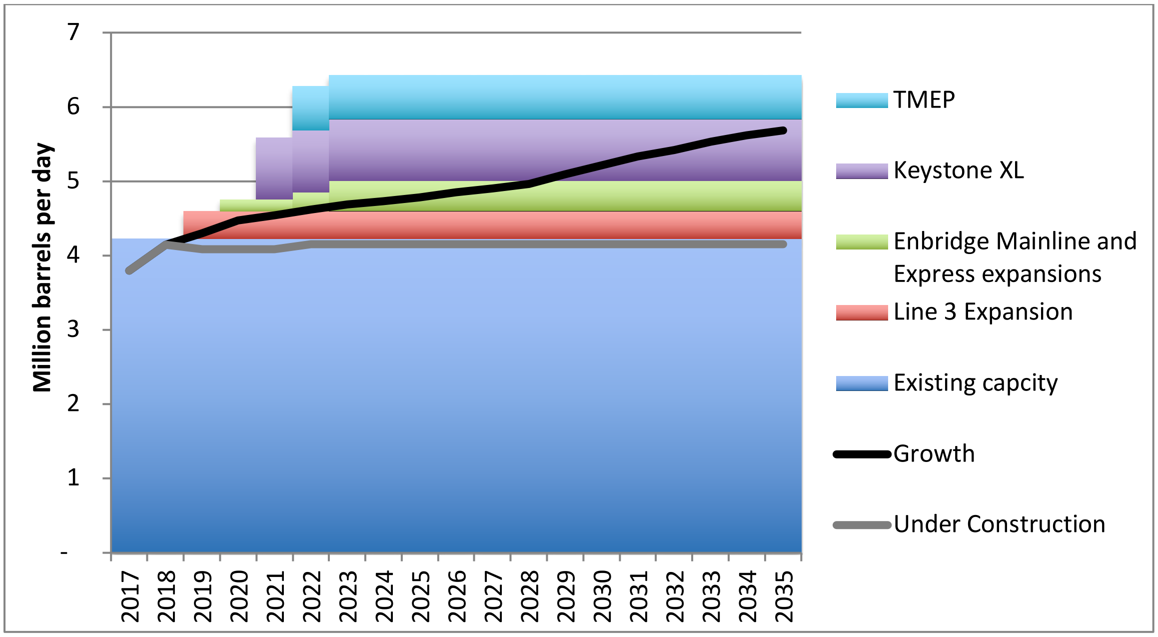
b) Based on the under-construction oil production growth forecast, the WCSB oil sector will require only the Enbridge expansions (Line 3). If the TMEP and Keystone XL are built along with the proposed Enbridge projects, there would be 2.0 million bpd of surplus capacity from 2023 to the end of the forecast period (2051).

c) If Keystone XL is not built, the TMEP would not be needed until 2025 based on CAPP's 2018 forecast and would never be needed based on the under-construction growth forecast.

d) There is considerable uncertainty regarding future oil markets and oil production. However, stronger climate change policies to meet Canada's Paris commitments, new International Maritime Organization fuel regulations that will reduce demand for heavy oil, and relatively high costs of producing WCSB oil will likely result in future Canadian oil production being below the CAPP 2018 forecast and closer to the under-construction forecast. Consequently, Enbridge expansions alone may be sufficient to meet the transportation needs of the WCSB oil sector without building either Keystone XL or the TMEP. **Further, there is no likely scenario in which building both Keystone XL and the TMEP is required by 2035.**

e) Although some unused capacity is necessary and beneficial, the magnitude of unused capacity resulting from construction of the TMEP along with other proposed projects would impose a large cost on Canada's oil sector and the Canadian public in the form of reduced tax revenues. The NEB has not included the costs of this unused capacity in its evaluation of TMEP costs and benefits. As shown in Table ES-1, these costs omitted by the NEB are significant, ranging between $3.4 and $7.5 billion.

Figure ES-1. Estimates of Western Canadian Oil Supply and Transportation Capacity



17. To assess whether the TMEP is in the Canadian public interest we completed a comprehensive benefit cost analysis of the TMEP consistent with Canadian government benefit cost guidelines (Table ES-1). We assessed the benefits and costs by key sector and stakeholder group and tested a range of scenarios and assumptions in our analysis to address uncertainty in project parameters and impacts. Our benefit cost analysis shows that:

a) Under base case assumptions the TMEP results in a **net cost to Canada of $11.8 billion**.

b) Based on sensitivity analyses to address uncertainties in Project parameters, the **net costs** of the TMEP could range between **$8.2 and $18.7 billion** and there is no likely scenario under which the TMEP would generate a net benefit for Canada.

c) We also completed a risk assessment of building and not building the TMEP. If the TMEP is built, there will be a net cost to Canada under all likely scenarios. *Not building the TMEP has minimal downside risk because if demand for new transportation projects is significantly higher than forecast or other proposed pipeline expansions do not proceed, there would be sufficient lead time to provide new transportation services to accommodate increased demand*.

Table ES-1. Benefit Cost Analysis Results for TMEP

Item	Net Benefit (Cost), Base Case (million $)	Sensitivity Analysis Range (million $)
TMEP Pipeline Operations	(1,699)	(1,699) to 0
Unused Oil Transportation Capacity	(6,919)	(7,480) to (3,351)
Option Value/Oil Price Netback Increase	0	0 to 2,837
Employment	159	159 to 534
Tax Revenue	252	252 to 1,170
Electricity	(109)	No sensitivity
GHG Emissions from Construction and Operation of TMEP and marine traffic in defined study area	(359)	(1,084) to (140)
Other Air Emissions	(103)	(509) to (6)
Oil Spills	(637)	(1,363) to (76)
Passive Use Damages from Oil Spill	(2,396)	(2,794) to (2,396)
Other Socio Economic and Environmental Costs not monetized	See Appendix 1	
Net Cost Without Passive Use Damages	**(9,416)**	**(16,333) to (5,848)**
Net Cost with Passive Use Damages	**(11,812)**	**(18,729) to (8,244)**

18. One of the primary reasons that the TMEP would result in a large net cost to Canada is because building the TMEP under the proposed schedule will create excess pipeline capacity. There are currently more WCSB oil transportation projects planned than required, and construction of currently proposed projects will result in a net cost to Canada. These pipeline projects were proposed before the

current downturn in the oil markets and some were able to secure long-term shipping contracts that may allow them to be financially feasible to the project builder while externalizing the cost of the surplus capacity onto existing transportation systems, oil producers, and governments. The creation of this excess capacity can be prevented by rejecting or deferring new projects that are not required.

19. A further factor that can increase the likelihood of uneconomic surplus capacity is the purchase of TMEP by the Canadian government in August 2018. Kinder Morgan was considering shelving TMEP or selling it because of increasing risks due to higher capital costs, lower oil production growth forecasts, approval of competing pipeline and rail projects, and regulatory risks. These higher risks reduce the likelihood of a private sector investor building an uneconomic project. However, the Canadian government is not constrained by the need to earn a return for investors and is therefore more likely to build the TMEP regardless of whether the Project is economically justified.

20. A further reason that the TMEP will result in a net cost to Canada is due to the environmental risks it entails, including the risk of marine oil spills in British Columbia, which could be avoided if other transportation options are used that pose no marine oil spill risk. Estimating these environmental costs is challenging. Many environmental impacts of the TMEP are not included in our benefit cost estimates because they are difficult to estimate in dollar terms. Inclusion of these impacts would increase our environmental cost estimates. Increased environmental costs of shipping oil on the TMEP may also to some degree be offset by reduced oil shipments on other transportation facilities. Inclusion of these potential avoided environmental costs on other transportation facilities would reduce our environmental cost estimates. We have also omitted all environmental costs associated with the upstream production of oil consistent with the NEB's terms of reference. These costs are significant and should be assessed as part of a comprehensive energy and climate change policy.

21. An alleged major benefit of the TMEP is that it will increase prices received by Canadian oil producers and reduce the so-called Canadian discount on oil exports to the US. We evaluated this potential benefit and concluded that TM's price benefit estimates were based on inaccurate assumptions and methodological deficiencies. For example, the estimates mistakenly assumed that if the TMEP is not built, WCSB oil would have to be shipped by rail. As our supply and demand analysis shows, this assumption is incorrect. Further, we analyzed the price discounts over the last decade and found no evidence to support the contention that increased exports to the US result in a higher discount for Canadian oil or that there is any distinct advantage in shipping oil to Asian markets on the TMEP relative to shipments on other pipelines to the US Gulf Coast. There have been periods of increased discounts for Canadian heavy oil above the normal levels attributed to quality differences and shipping costs, but these higher discounts disappeared when the short-term transportation constraints that caused them were removed by expanding pipeline capacity to the US. Therefore, providing sufficient new pipeline capacity regardless of whether it serves the US Gulf or Asia will eliminate price discounts. Although we conclude that it is highly unlikely that there is any price advantage shipping to Asian relative to US Gulf oil markets, we did

undertake a sensitivity analysis assuming an Asian price premium and found that the TMEP would still incur a net cost to Canada under this scenario.

22. In summary, our evaluation shows that:

a) The NEB's conclusion that the TMEP is in Canada's public interest contains serious errors and deficiencies including failure to use best practice project evaluation methodology.

b) There have been significant changes since the completion of the NEB report on the TMEP in 2016 including emergence of new oil pipeline projects, rising costs of the TMEP, and a lowering of oil production forecasts that significantly reduce the benefits and increase the costs of the TMEP. As a result of these changes, the conclusions of the 2016 NEB report are no longer valid, and the NEB needs, but failed, to reevaluate whether the TMEP is in the public interest in light of these changes.

c) Based on our benefit cost analysis, we conclude **that the TMEP will result in a significant net cost of between $8.2 and $18.7 billion to Canada if the TMEP is built as planned. Therefore, approving the application for the TMEP as currently proposed is not in Canada's public interest.**

d) If and when the TMEP transportation capacity is required, the TMEP should be evaluated as part of a comprehensive oil transportation strategy that comparatively evaluates all proposed projects from a social, economic, and environmental perspective to determine which project or mix of projects are required and best meet Canada's public interest.

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List of Acronyms

BC	British Columbia
BCA	benefit cost analysis
Bpd	barrels per day
CAPP	Canadian Association of Petroleum Producers
CBC	Conference Board of Canada
CERI	Canadian Energy Research Institute
EconIA	economic impact analysis
ENGP	Enbridge Northern Gateway Project
EVOS	*Exxon Valdez* oil spill
GDP	gross domestic product
GHG	greenhouse gas
GWh	gigawatt hour
IEA	International Energy Association
IOPCF	International Oil Pollution Compensation Fund
Kbpd	thousand barrels per day
LNG	liquefied natural gas
MWh	megawatt hour
NEB	National Energy Board
NEBA	*National Energy Board Act*
TM	Trans Mountain
TMEP	Trans Mountain Expansion Project
TMPL	Trans Mountain Pipeline
US EIA	US Energy Information Administration
USGC	United States Gulf Coast
WCSB	Western Canada Sedimentary Basin
WTI	West Texas Intermediate
WTA	willingness to accept
WTP	willingness to pay

1. Introduction

We have been retained by the Tsleil-Waututh Nation (TWN) to prepare a report to:

- evaluate the NEB's (2016, 2019a) conclusion and information provided by the Canadian government in the Trans Mountain Expansion Project (TMEP) Phase III consultations with the TWN that the TMEP is in the public interest; and
- present the results of a benefit cost analysis of the TMEP consistent with federal government guidelines to determine if the TMEP generates a net benefit to Canada.

This report has been prepared in accordance with our duty as experts to assist (i) the TWN in conducting their assessment of the Project; (ii) provincial or federal authorities with powers, duties or functions in relation to an assessment of the environmental and socio-economic effects of the Project; and (iii) any court seized with an action, judicial review, appeal, or any other matter in relation to the Project.

Our analysis shows that:

- There have been significant changes since the completion of the 2016 NEB report that undermine the justification for TMEP and the NEB's conclusion that the TMEP would be in the public interest. Key changes include:
    - Advancement of pipeline alternatives to the TMEP totalling 1,710 kbpd of incremental capacity to export Western Canada Sedimentary Basin (WCSB) oil (Enbridge Line 3 (370 kbpd), other Enbridge projects (510 kbpd) and Keystone XL (830 kbpd));
    - Escalation of the costs of the TMEP from $5.5 billion to more recent estimates of $9.3 billion that undermine the TMEP's competitive advantage relative to other pipelines, and
    - Weaker oil markets that lower the need for new pipeline capacity (CAPP's 2108 supply forecast for 2030 is 1.8 mbpd lower than their 2014 forecast);

- There is a need for new pipeline capacity, but building the TMEP along with other approved projects will result in excess capacity that will impose a significant cost burden on Canada and the oil sector;

- The NEB's conclusion that the TMEP would be in Canada's public interest is based on flawed analysis inconsistent with accepted best practices in project evaluation and Canadian evaluation guidelines; and

- After taking all costs and benefits into account, building the TMEP as planned would result in a significant **net cost** to Canada and would therefore not be in Canada's public interest.

We begin this report with a brief description of the TMEP. We then evaluate the NEB's conclusion that the TMEP would be in Canada's public interest. Finally, we provide results from a comprehensive benefit cost analysis consistent with Canadian government guidelines to assess whether the TMEP would generate a net benefit to Canada.

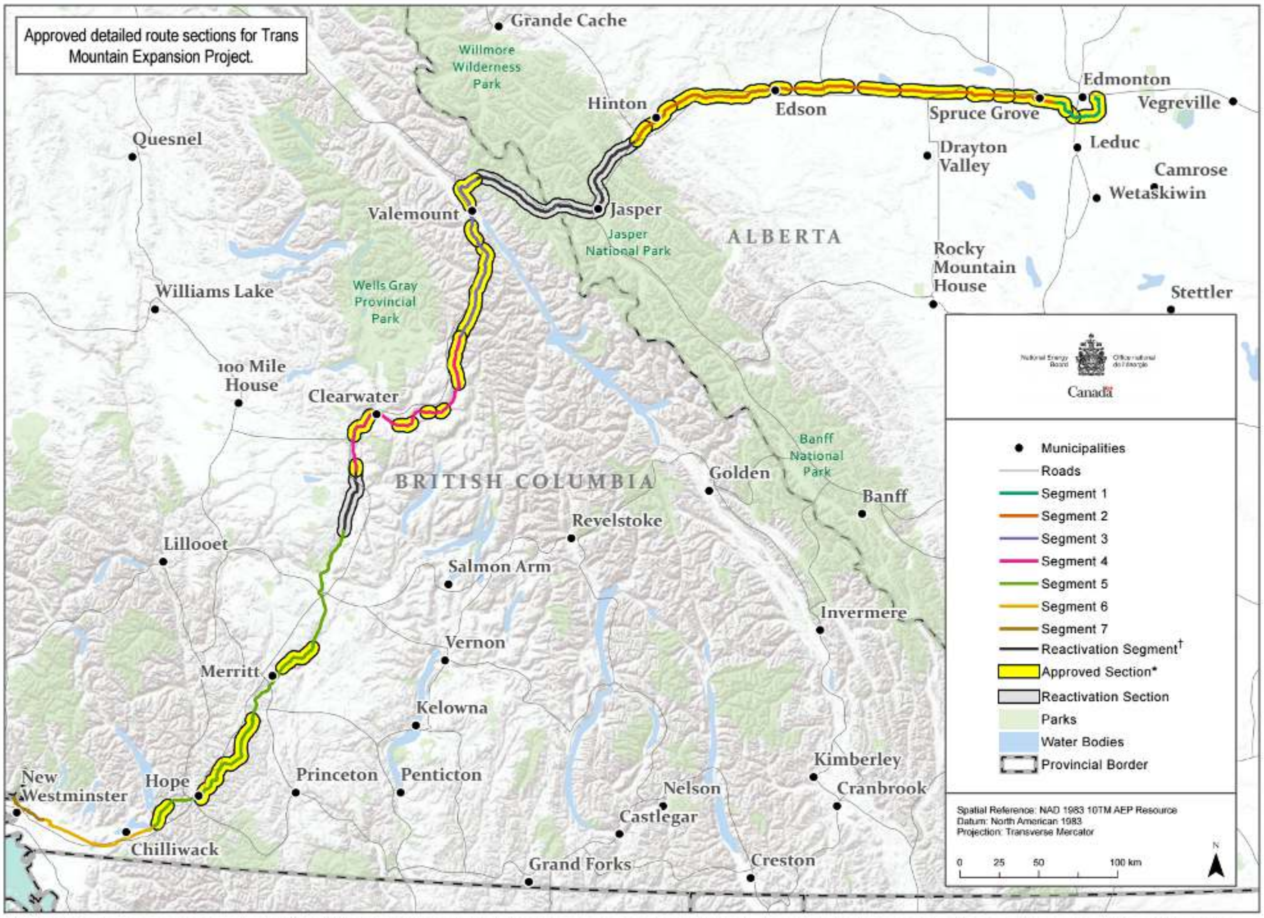
2. Trans Mountain Expansion Project

The TMEP is a proposal to expand the existing Trans Mountain Pipeline (TMPL), which has been operating since 1953. According to TM, the purpose of the TMEP is "to provide additional transportation capacity for crude oil from Alberta to markets in the Pacific Rim including British Columbia, Washington State, California, and Asia" (TM 2013b, Vol. 1, p. 1-4). The TMEP would consist of twinned pipelines, a marine terminal, and tanker traffic to meet the Project's stated objective.

2.1 Pipeline

The proposed TMEP would twin the existing TMPL from Edmonton, Alberta to the Westridge Marine Terminal in Burnaby, British Columbia (BC) and increase operating capacity from the current 300 thousand barrels per day (kbpd) of oil to 890 kbpd (TM 2013b, Vol. 2, p. 2-12). The TMEP would consist of two pipelines. The first line (Line 1) is a 1,147-km pipeline with the capability of transporting 350 kbpd (TM 2013b, Vol. 4A p. 4A-2-3). Line 1 would use mostly existing and reactivated TMPL pipeline to transport refined products and light crude oils but would also have the capability to carry heavy crude oil at a reduced throughput rate (TM 2013b, Vol. 4A p. 4A-2-3). Line 2 is a 1,180 km pipeline with throughput capacity of 540 kbpd for heavy crude oils but would also be capable of transporting light crude oils (TM 2013b, Vol. 4A p. 4A-3). Line 2 would consist of approximately 987 km of newly built pipeline and some existing pipeline built in 1957 and 2008 (TM 2013b, Vol. 4A p. 4A-2). The proposed route for the TMEP largely parallels the existing TMPL route (Figure 1) (TM 2013b, Vol. 5A). The TMEP would include 12 new pump stations, new storage tanks, and other new components to support Lines 1 and 2 (TM 2013b, Vol. 4A p. 4A-3).

Figure 1. Approved Route Sections for TMEP



*This map shows the approximate location of the PPBoR sheets that have been approved by the Board. Approval of all pre-construction conditions may still be outstanding. Check the Board's website for most current information. † No PPBoR's for the reactivation segments.
Map produced by the NEB, April 2018. The map is a graphical representation intended for general informational purposes only.

Source: NEB (2018d).

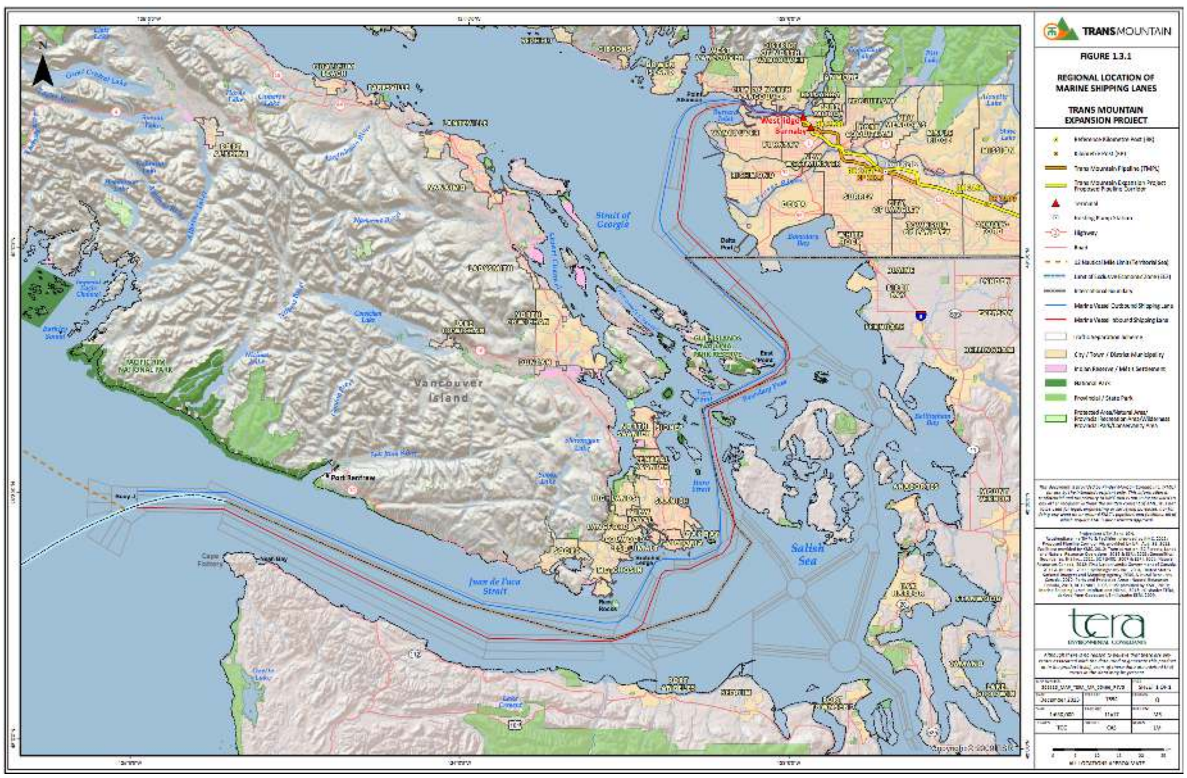
2.2 Terminal

TM would expand Westridge Marine Terminal in Burnaby, BC to accommodate increased pipeline throughput and tanker traffic. The expanded marine terminal would require the removal of the existing tanker loading dock and the construction of a new dock complex having the capability to handle Aframax-sized tankers (75,000 to 120,000 deadweight tonnes) (TM 2013b, Vol. 1 p. 1-11 and Vol. 4A p. 4A-3). The dock complex would also include cargo transfer arms to load crude oil on tankers and vapour recovery and vapour combustion units to capture hydrocarbon vapours (TM 2013b, TERMPOL 3.15 p. 22). Oil for tanker export would be collected and stored in new storage tanks at Burnaby Terminal and delivered to Westridge Terminal via three delivery lines (TM 2013b, TERMPOL 3.15 p. 22 and Vol. 4A p. 4A-3). According to TM (2013b, Vol. 2 p. 2-27), up to 630 of the 890 kbpd in system capacity delivered on the TM pipeline would be for export via the marine terminal.

2.3 Tankers

The TMEP would increase tanker traffic from 60 to an estimated 408 tankers per year (TM 2013b, Vol. 2 p. 2-27). Tankers accessing Westridge Marine Terminal would be Panamax-sized (less than 75,000 deadweight tonnes) or larger Aframax-sized tankers, which are the current class of tankers calling at the terminal for the TMPL (TM 2013b, Vol. 8A p. 8A-68 and -71). Tankers would use between two and four tethered tugs to navigate the Vancouver Harbour Area (TM 2013b, TERMPOL 3.15 p. 12). TM would not own or operate the tankers (TM 2013b, Vol. 2 p. 2-27) and thus the tanker owner would be liable to pay any costs associated with an oil tanker spill (TM 2013b, Vol. 8A p. 8A-52). TMEP tankers travelling to and from Westridge Marine Terminal would use existing marine transportation routes(TM 2013b, Vol. 8A p. 8A-67).

Figure 2. Regional Location of Marine Shipping Lanes



Source: (TM 2013b, Vol. 8A p. 8A-67).

3 NEB's Public Interest Assessment of the TMEP

3.1 Overview

Section 52 of the *National Energy Board Act* (*NEBA*) states that the NEB will make a recommendation to the Minister responsible for the NEB on project applications and in making its recommendation it may have regard to the following factors:

a) the availability of oil, gas or any other commodity to the pipeline;
b) the existence of markets, actual or potential;
c) the economic feasibility of the pipeline;
d) the financial responsibility and financial structure of the applicant, the methods of financing the pipeline and the extent to which Canadians will have an opportunity of participating in the financing, engineering and construction of the pipeline;
e) any public interest that in the Board's opinion may be affected by the granting or the refusing of the application.

The NEB defines the public interest as follows:

> *The public interest is inclusive of all Canadians and refers to a balance of economic, environmental, and social interests that change as society's values and preferences evolve over time. The Board estimates the overall public good a project may create and its potential negative aspects, weighs its various impacts, and makes a decision (NEB, 2010a).*

In addition to these general criteria, the NEB (2013d) approved the following list of issues to be considered in the TMEP application:

- the need for the proposed project;
- the economic feasibility of the proposed project;
- the potential commercial impacts of the proposed project;
- the potential environmental and socio-economic effects of the proposed project including any cumulative environmental effects that are likely to result from the project, including those required to be considered by the NEB's *Filing Manual* (NEB, 2013c);
- the potential environmental and socio-economic effects of marine shipping activities that would result from the proposed Project, including the potential effects of accidents or malfunctions that may occur;

- the appropriateness of the general route and land requirements for the proposed project;
- the suitability of the design of the proposed project;
- the terms and conditions to be included in any approval the Board may issue;
- potential impacts of the project on Aboriginal Interests;
- potential impacts of the project on landowners and land use;
- contingency planning for spills, accidents or malfunctions, during construction and operation of the project, and
- safety and security during construction of the proposed project and operation of the project, including emergency response planning and third-party damage prevention.

The NEB (2013d) did not consider the environmental and socio-economic effects associated with upstream activities, the development of oil sands, or the downstream use of the oil transported by the pipeline. Factors such as greenhouse gas (GHG) emissions from oil production, therefore, are excluded by the NEB in its consideration of the TMEP. In May 2016, the NEB (2016) issued its report recommending that the GIC approve the TMEP on the grounds that the TMEP is needed and in Canada's public interest.

On November 29, 2016, the GIC issued an Order in Council accepting the Board's recommendation and directed the Board to issue a certificate of public convenience and necessity approving the construction and operation of the TMEP, subject to the conditions recommended by the Board.

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In February 2019 the NEB released its Reconsideration Report (NEB, 2019a) recommending approval of the TMEP. The Reconsideration Report concluded that the TMEP is likely to cause significant adverse effects, but these adverse effects would be justified by the economic benefits of TMEP. The Reconsideration Report did not consider any new information on TMEP economics despite significant changes in oil markets, TMEP costs and approval of alternative pipelines that weakened the justification for the TMEP. In particular, the NEB expressly refused to consider the only new evidence filed in the Reconsideration Hearing on the need for the TMEP and its economics, an expert report by Mr. Hughes prepared on behalf of TWN and other

First Nations.

3.2 Deficiencies in the NEB Evaluation of the TMEP

3.2.1 Overview

In its 2016 and 2019 reports, the NEB concluded that the TMEP would be in the public interest[1]. In making this determination, the NEB listed what it considered to be the benefits and burdens of the TMEP and concluded that the benefits exceeded the burdens in large part because the benefits would be national in scope while the burdens would be regional and local (Table 1). In this section of the report we evaluate the NEB's rationale for determining that the TMEP is in the public interest and identify deficiencies and omissions in the NEB's analysis.

Table 1. NEB Assessment of Benefits and Burdens of TMEP

Benefits	Rating	Burdens	Rating
Market Diversification	Considerable Regional and National	**Adverse Effect on Southern Killer Whales**	Considerable Local, Regional and National
Jobs	Considerable Local, Regional and National	**Adverse Effect on Aboriginal Culture**	Considerable Local and Regional
Competition among Pipelines	Considerable Regional and National	**Marine GHG Emissions**	Considerable Regional and National
Spending on Pipeline Materials	Considerable Local and Regional	**Municipal Development Plans**	Modest Local
Community Benefit Program	Modest Local and Regional	**Impairment of Aboriginal Use of Land and Water**	Modest Local

[1] The Reconsideration Report contains the same economic and public interest analysis as the 2016 report so the critique of the 2016 NEB report applies to the equally to the Reconsideration Report.

Enhanced Marine Spill Response	Modest Local and Regional	**Impairment of Stakeholders Use of Land and Water**	Modest Local and Regional
Capacity Development (Humans resources)	Modest Local and Regional	**Pipeline Oil Spill**	Acceptable Risk Local and Regional
Government Revenue	Considerable Local, Regional and National	**Marine Tanker Spill**	Acceptable Risk Local and Regional

Source: NEB (2016, pp. xiii-xiv).

3.2.2 Deficient Comparison of Benefits and Burdens

The NEB (2016, p. 17) stated that it found "[t]his task of balancing the benefits versus the burdens of the Project was a difficult one." The NEB's method for addressing this challenge was to compare benefits and burdens by ranking them on qualitative scale based on the magnitude and geographic scope of the impact (Table 1). Two ratings were applied to the magnitude of the effect (modest and considerable) and three ratings were used for the geographic scope of the effect (local, regional and/or national). At no point did the NEB provide any definition of "modest" or "considerable" or any transparent method for how it determined whether an effect was modest or considerable. For pipeline spills, the NEB changed its rating to "acceptable risk". Again, the NEB did not provide a definition for "acceptable risk" and or data to determine the level of risk. The NEB also did not provide definitions for "local", "regional" or "national" effects, and the NEB failed to use a transparent method to make this determination. In "balancing the benefits versus the burdens" the NEB placed considerable weight on the economic impacts and the fact that most of the benefits would be national in scope while the burdens would be local. Based on this assessment, the NEB concluded that the Project would be in the public interest.

A fundamental problem with the NEB's comparison of benefits and burdens is that it is impossible to understand, verify or replicate the NEB's ratings of each benefit and burden due to the lack of definitions and method for determining the respective ratings. For example, why did the NEB determine that jobs would be "considerable" and "national" in scope when the NEB concludes that permanent operating employment is 443 jobs, which is equivalent to only 0.13% of the employment gain in Canada in 2017 (StatsCan, 2018), and all of this employment growth occurs in just two provinces (Alberta and BC). There may be reasonable explanations for these ratings, but without a transparent method it is not possible to know. Further, how are the ratings compared to determine if the benefits exceed the burdens? For example, how does the NEB compare two “modest” burdens against one “considerable” benefit or compare the “considerable” burden of adverse impacts on southern resident killer whales to the “considerable” benefit of 443 jobs? Again, the NEB has not used any transparent method for comparison, other than to assume that a benefit or burden that is national in scope is more important than one that is regional or local. The NEB provides no justification for giving more weight to a benefit that is national versus one that is regional, and we cannot find any justification in NEB guidelines or in the project evaluation literature to justify such a weighting. The only justification for weighting benefits and costs we can find in the project evaluation literature is on the basis of equity (e.g. Shaffer, 2010), which provides higher weighting of benefits to disadvantaged groups than benefits accruing to well off segments of the population. By providing no transparent scaling, it is not possible for the NEB to compare benefits and burdens in any coherent or systematic way and the NEB conclusion that the TMEP is in the public interest is therefore arbitrary and subjective.

There is no basis for the NEB’s use of arbitrary, subjective judgments to compare benefits and costs given that there are clear and transparent methods such as benefit cost analysis (BCA) and multiple accounts analysis that the NEB could have employed to make such comparisons. These more sophisticated methods are well developed, transparent, based on sound theoretical foundations, and have been used for decades to compare project costs and benefits to determine whether a particular project will generate a net benefit. The NEB had access to a comprehensive BCA provided in evidence (Gunton et al., 2015), but gave little weight to it on the grounds that the supply projections that were used in the BCA misrepresented the CAPP supply forecast by incorrectly assuming that CAPP provided a range based on two forecasts (NEB, 2016, p.320). This is unfortunate because the NEB’s allegation that CAPP did not provide two forecasts is simply incorrect. As CAPP clearly stated in its 2015 forecast:

> Given the challenge of developing a forecast in the current low oil price environment, a range is presented. …The oil sands production outlook that includes only projects that are currently operating or in construction represents the lower range outlook from the oil sands. On the lower range outlook, total oil production grows from 3.7 million b/d in 2014 to 4.3 million b/d in 2030. (CAPP, 2015, p. ii).

If the NEB had checked to confirm that CAPP did indeed provide a range of forecasts that were used in the Gunton et al. (2015) BCA and not erroneously dismissed the BCA findings, the NEB would have had the benefit of a more systematic and sophisticated methodology for comparing costs and benefits. And if the NEB concluded that the low range provided in the CAPP 2015 forecast was too low, the NEB could still have relied on the “base case” scenario in the

Gunton et al. (2015) BCA that showed that the TMEP would impose a net cost to Canada under the higher CAPP forecast. Further, even if the NEB disagreed with the findings of the Gunton et al. (2015) BCA, it could still have conducted its own BCA to compare benefits and burdens instead of relying on an arbitrary and deficient method for undertaking its analysis.

3.2.3 No Assessment of Costs and Benefits of Alternative Projects

The NEB *Filing Manual* (NEB 2013c, p. 4-3) requires proponents to describe other economically-feasible alternatives to applied-for projects and to provide a rationale for choosing the proposed project over alternatives. According to the NEB (2013c, p. 4-4), the proponent must evaluate feasible project alternatives that meet the objective of and are connected to the applied-for project. To justify the proposed project, the NEB recommends that the proponent provide an analysis of the various project alternatives with criteria to determine the most appropriate option (NEB 2013c, p. 4-4). The criteria the proponent should use to evaluate different project alternatives include construction and maintenance costs, public concern, and environmental and socio-economic effects (NEB 2013c, p. 4-3).

The TMEP application (TM 2013b) considered different pipeline corridors and alternative pump station locations in its environmental and socio-economic assessment in *Volume 5A* and *Volume 5B* and used some of the criteria referenced by the NEB (2013c) to evaluate alternatives. However, the TMEP application did not include an analysis of project alternatives that would meet the primary purpose of the TMEP, which is “to provide additional transportation capacity for crude oil from Alberta to markets in the Pacific Rim including BC, Washington State, California, and Asia” (TM 2013b, Vol. 1 p. 1-4) and the more general objective of transporting Alberta crude to world-priced oil markets other than rail options as assessed by Muse Stancil (MS) (2015). Consequently, the NEB did not compare the TMEP to any alternatives that could meet the same objectives as the TMEP and hence did not assess whether the TMEP was superior from an economic, social, and environmental perspective to other transportation options. Instead, the NEB evaluated the TMEP as a single stand-alone project in isolation from the alternatives.

As indicated by our supply demand analysis in this report and the evidence submitted to the NEB TMEP hearings (Gunton et al., 2015), there are several alternative transportation projects that should have been assessed relative to the TMEP to identify which option or combination of options is more cost-effective from an economic, environmental, and social perspective. There are also alternative designs and locations of the TMEP that could significantly reduce adverse effects and could reduce and even eliminate all tanker traffic (see e.g. Ensys, 2018) that were never considered by the NEB. The US government’s assessment of pipeline proposals provides a good framework for how the NEB should have conducted a comparative evaluation of transportation options.[2]

3.2.4 Failure to Assess Project Need by Supply/Demand Analysis

A key criterion for project review under the *NEBA* is the need for the project. Neither the project proponent nor the NEB provided any comprehensive assessment of the demand and supply of WCSB transportation capacity to assess the need for the TMEP. Information provided by the project proponent (MS, 2015) showed that the TMEP would be used, but the analysis omitted key proposed pipeline capacity (e.g. Enbridge mainline expansions and Keystone XL) in its analysis. The NEB relied on this deficient analysis by MS and the fact that TM had commercial contracts with shippers to conclude that the TMEP was needed. The problem with the NEB's analysis is that by not completing an overall supply and demand assessment, the NEB did not assess the impacts of building the TMEP on the utilization of the overall oil transportation system. As discussed below, the NEB did not therefore identify the adverse impacts on the TMEP in creating excess pipeline capacity.

3.2.5 Omission of Project Burdens

A major deficiency in the NEB's analysis of the public interest is that the NEB omitted important "burdens" in its assessment of the benefits and burdens of the TMEP. One significant burden omitted by the NEB is the cost of excess capacity. The cost of surplus capacity has been identified as a concern in previous NEB pipeline hearings including the Enbridge Northern Gateway Project (ENGP) hearings that reference potential costs of surplus capacity of $857 million (Wright Mansell, 2012, p. 144), and the Keystone XL hearings in which the NEB referenced unused capacity costs of $315-515 million per year, which would result in increased tolls for

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[2] A good example of evaluating alternatives is the US government's *Final Supplemental Environmental Impact Statement for the Keystone XL Project* (USDS 2014). The analysis of alternatives considers three major categories of alternatives and a large number of sub-options under each category including ten alternative scenarios for shipping WCSB oil to the USGC involving rail, a combination of rail and tanker, rail and pipeline, trucking, existing pipeline systems, other recent crude transportation proposals, and additional scenarios that consist of using alternative energy sources and implementing energy conservation measures (USDS 2014, Vol. 2.2 p. 2.2-6). The alternatives were evaluated using comprehensive economic, social and environmental criteria. According to the USDS (2014, Vol 2.2 p. 2.2-1), an evaluation of all feasible project alternatives provides decision-makers and the public with a range of reasonably different options to the proposed project to consider.

shippers (NEB, 2010b, p. 24). The NEB had evidence in the TMEP hearing that building the TMEP would result in excess pipeline capacity costs between $2.2 and $6.2 billion as producers redirected their oil shipments from existing pipelines such as the Enbridge system, where they did not have commercial contracts, to fulfill their contractual obligations on the TMEP. The NEB acknowledged the potential for excess pipeline costs in the TMEP hearing but concluded that "… there is no reliable evidence before it demonstrating that any excess capacity would be unmanageable by sophisticated industry parties" (NEB, 2016, p. 311). Even if the NEB's unsubstantiated conclusion that the costs of excess capacity were not significant, the NEB should still have listed the potential costs of excess capacity as a burden in its evaluation.

The NEB also omitted consideration of many of the environmental and social costs of the Project. In its application, TM identified 160 potential adverse effects of the TMEP (see Appendix 1: Potential Adverse Impacts of the TMEP). While some of these are included in the NEB's burdens under the categories of impairment of use by First Nations and stakeholders, many of the adverse environmental and social costs are not listed or considered in the NEB's assessment.

3.2.6 Inaccurate Assessment of Project Economic Benefits and Oil Spill Risks

Economic Benefits

The NEB lists jobs, spending on pipeline materials, and government revenue as "considerable" benefits of the TMEP (Table 1). The NEB's assessment is based on an economic impact assessment (EconIA) completed for TM by the Conference Board of Canada (CBC) (2015). The NEB's interpretation of the CBC analysis of economic benefits is incorrect. The CBC estimated the **gross** economic impacts of the TMEP, not **net** impacts and it is the net impacts, not the gross impacts, that measure potential net benefits of the Project (Grady and Muller, 1988; Shaffer, 2010). For example, if the TMEP created 443 operating jobs and those employed by the TMEP would have been employed at the same wages on other projects if the TMEP was not built, the **gross** impact is 443 jobs, but the **net** benefit is **zero** because there are no net jobs being created. Therefore, it is incorrect for the NEB to list gross job creation as a "considerable" benefit of the TMEP when it should have used net job creation as the measure of benefit.

To analyze net job creation, one must assess how other firms and industries are affected by the Project due to direct diversion of expenditures and by the more general economy-wide effects the Project may have in terms of impacts on wages, prices, interest, and exchange rates. To evaluate net benefits one must further assess the "opportunity cost" of labour and capital, defined in terms of how the labour and capital would be employed in the absence of the project (Pearce et al., 2006; Ward, 2006; Shaffer, 2010). In a well-functioning economy such as Canada's, most if not all the labour and capital employed on the TMEP will be employed elsewhere in the economy if the TMEP does not proceed, and the net gain in economic activity generated by the TMEP will be much less, potentially minimal, as compared to the gross impacts estimated by the CBC. For example, MS (2015) concludes that if the TMEP is not built, other transportation capacity such as rail or other pipelines will be developed to meet transportation requirements and these alternative transportation projects would generate comparable employment and economic activity in the absence of the TMEP. Further to this point, labour market studies document the shortage of skilled labour in Canada and BC, indicating that those who would be employed by the TMEP would likely have to be drawn away from other jobs, with little to no effect on total employment. For example, Canada's unemployment rate in November 2018 was 5.6%, indicating a very tight labour market, and in BC:

> … the number of people available for work is growing more slowly and a wide range of indicators—including reports from employers—show that having enough trained workers to meet future needs will be a challenge (BC Stats, 2018, p. 3)

The NEB's interpretation of the CBC's estimates of government fiscal benefits is also incorrect. Again, the CBC estimates **gross** government revenue, not **net** revenue, and it is the net revenue that measures the benefit. The gross government revenue estimate for the TMEP construction and operation is based on the assumption that all the labour and capital employed by the TMEP would otherwise be unemployed and would not therefore generate any tax revenue absent the TMEP. As discussed above, most if not all of this labour and capital would be otherwise employed and would generate tax revenue in alternative employment. The CBC's EconIA is also problematic in that it only assesses gross government revenue without considering any potential incremental fiscal costs on government induced by the TMEP such as emergency response to clean up oil spills and regulatory oversight. For example, the federal government has announced its plans to spend $1.5 billion in an Ocean Protection Plan to mitigate adverse impacts from the TMEP tanker traffic (ECCC, 2018). None of these costs are deducted from the gross revenue estimates. The gross revenue estimates also include the revenue generated by an alleged price lift for Canadian oil exports attributed to the TMEP. As is discussed in Appendix 2: Deficiencies in TM's Assessment of Oil Price Netbacks for TMEP, the data and methods used to forecast this price lift are flawed and given the construction of other proposed pipelines and the increased costs to complete the TMEP, no price lift is likely to occur.

Oil Spill Risks

The NEB incorrectly assessed the risks of oil spills from the TMEP and therefore its conclusion that the risks of oil spills are acceptable is based on faulty analysis. The NEB (2016) report on the Project concluded that large and credible worst-case marine tanker and terminal oil spills and credible worst-case pipeline spills would have significant adverse effects, but that large spills would be unlikely to occur and therefore the risk would be acceptable. The deficiencies in the NEB's analysis are that it: did not refer to any spill probability estimates to justify the conclusions that large spills would be unlikely; did not provide any definition of large and small spills; failed to determine whether small spills could cause significant adverse effects; and provided no estimate of the costs of a credible worst-case marine spill and consequently no assessment of the adequacy of financial capacity to cover the costs of a credible worst-case marine spill.

In its 2019 Reconsideration Report, the NEB again assessed the risk of oil spills. The NEB Reconsideration Report contains the same deficiencies as the 2016 NEB report cited above, with one exception. While the 2016 NEB report did not reach any conclusion on the consequences of small marine spills that were not quickly contained, the NEB Reconsideration Report concluded that small marine oil spills could cause significant adverse effects. As the NEB stated in the Reconsideration Report:

> For example, a small spill that is quickly contained could have adverse effects of low magnitude, whereas a credible worst-case spill could have adverse effects of larger geographic extent and longer duration, and such effects would probably be significant. Dr. Short said that small to medium sized oil spills on the order of 100 to 1 000 m3 from the Project can cause substantial mortalities to seabirds, and estimated effects for small to medium spills in Canada and in Alaska. In the Board's view, there is a spectrum of potential spill outcomes ranging from small quickly contained spills that do not result in significant effects to credible worst-case spills that would result in significant effects. In between these two extremes, are other spills that could also result in significant effects depending upon the circumstances (NEB, 2019, p. 489).

But while the 2019 Reconsideration Report concluded that small spills could have significant adverse effects, it mistakenly concluded that "there is a very low probability of a marine spill from a Project related tanker (NEB, 2019, p. 26). In reaching this conclusion, the NEB did not provide any probability estimates of a tanker spill other than a vague reference that "this view is informed by its acceptance of the marine shipping risk analysis conducted by Trans Mountain and the spill probabilities estimated therein, including the probability of a spill any size, and the mitigation measures that would be in place for Project related marine shipping" (NEB, 2019, p.517). In reaching this conclusion on spill probability, the NEB ignored the fact that TM's risk assessment provided a range of probabilities of a tanker spill from 16% to 67% for any size spill over a 50-year operating period and that the lower end estimate of 16% is unreliable because it is based on double counting mitigation measures and overstating mitigation impacts (Gunton and Joseph, 2018). The NEB also erred in concluding that estimates based on the US Oil Spill Risk Model provided by Gunton and Joseph (2018) to the NEB hearing do not take into account geographical and safety factors relevant to the Project or the safety record of US tanker traffic. In fact, the 75% probability estimate based on the US Oil Spill Risk Model relies on US tanker data that reflects the same type of mitigation measures proposed by TM for the Project. Gunton and Joseph (2018) conclude that the probability of a marine tanker spill of any size over a 50-year operating period is estimated to be between 43% (TM's mid-range estimate) and 75% (US Oil Spill Risk Assessment mid-range estimate), with the best estimate being the upper end of the range of 75%. A tanker spill probability of between 43% and 75% cannot be defined as a "very low probability" by any standard. Consequently, the NEB's conclusion regarding the risk of an oil spill is incorrect and its conclusion that the risk of a tanker spill is acceptable is inconsistent with the NEB's own risk assessment matrix shown below. A spill probability of between 43% and 75% would be rated as medium to high probability. As the NEB concluded, the consequence of even a smaller marine spill could be significant. As the NEB's risk table shows, the risk of a high to very high consequence event with medium to high probability of occurrence is high to very high risk, which cannot be defined as acceptable. **Consequently, by incorrectly assessing marine spill risk, the NEB Reconsideration report has significantly underestimated the burdens of the Project.**

Probability (P)						
	Very high P	Medium R	High R	High R	Very high R	Very high R
	High P	Medium R	Medium R	High R	High R	Very high R
	Medium P	Low R	Medium R	Medium R	High R	High R
	Low P	Very low R	Low R	Medium R	Medium R	High R
	Very low P	Very low R	Very low R	Low R	Medium R	Medium R
		Very low C	Low C	Medium C	High C	Very high C
		Consequences (C)				

3.2.7 Summary of Deficiencies in NEB Assessment of Public Interest

In sum, the NEB's assessment of whether the TMEP would be in Canada's public interest has the following deficiencies:

- failure to provide any comparison of benefits and burdens in accordance with well-established principles and guidelines such as benefit cost analysis that can be used to assess whether the TMEP benefits exceed burdens and is a net benefit to Canada;
- incorrect characterization of benefits and burdens as national, regional, and local,

and incorrect assumption that regional or local costs and benefits should be discounted relative to benefits deemed national;

- omission of potential costs associated with building the TMEP (e.g., excess pipeline capacity and environmental costs);
- incorrect conclusion that the risks of oil spills from the TMEP are low and that the risk is acceptable;
- incorrect assumption that the TMEP may increase Canadian oil prices;
- failure to complete any comparative evaluation of the social, economic, and environmental costs and benefits of alternative pipeline options to determine if the TMEP is a superior option from a public interest perspective;
- failure to complete an overall supply and demand assessment for oil pipelines to determine if the TMEP is needed;
- overstating the TMEP's economic benefits by using gross economic impacts as a measure of the contribution of the project instead of net impacts;
- incorrect conclusion that the TMEP will "likely [result] in considerable revenues to various levels of government" by incorrectly using gross revenue estimates that omit incremental costs to government and government revenue that would be generated by other projects that would proceed if the TMEP is not built; and
- incorrect assumption that economic impacts such as employment creation are a measure of benefits.

4 Benefit Cost Analysis of the TMEP

In its assessment of the TMEP application, the NEB must determine whether the Project is in the public interest. As stated in the previous section of this report, the NEB defines the public interest as: "*inclusive of all Canadians and refers to a balance of economic, environmental, and social interests that change as society's values and preferences evolve over time. The Board estimates the overall public good a project may create and its potential negative aspects, weighs its various impacts, and makes a decision*" (NEB, 2010a).

This definition of the public interest used by the NEB requires identification and comparison of all costs and benefits to determine if there is a net benefit to Canada. As discussed in Section 3, the NEB (2016) applied this public interest test by comparing the burdens of the TMEP to the benefits but its analysis was deficient because it did not use a systematic analytical framework to compare costs and benefits to determine if the TMEP will generate a net benefit to Canada.

The purpose of this section of our report is to provide an assessment of the costs and benefits of the TMEP to determine whether the TMEP generates a net benefit to Canada by using benefit cost analysis (BCA), which is a more advanced and rigorous method for comparing benefits and costs than the one used by the NEB. The objective of BCA is to identify all the positive and negative consequences of a project and to assess the relative significance of these consequences to determine whether a project generates a net gain or net loss to society. BCA is based on a well-developed theoretical foundation, its methodology and application is outlined in numerous publications, and it is required for various types of approvals in many jurisdictions including Canada (Pearce et al., 2006; Zerbe and Bellas, 2006; TBCS, 2007; Shaffer, 2010; Boardman et al., 2011). Although BCA is not formally required by the NEB, it is the best method for meeting the NEB's requirement for identifying and comparing the burdens of a project to the benefits. Consequently, we apply BCA to the TMEP to assess whether the Project is in the public interest.

The basic steps in BCA are: (1) specify the alternative scenarios (with and without the project) that will be assessed, (2) determine standing (i.e., the jurisdiction and scope of interests that will be assessed), (3) catalogue all types of potential impacts of the project and whether they are benefits or costs and to whom, (4) predict impacts quantitatively over the life of the project, (5) monetize impacts where possible and record impacts that cannot be monetized in other quantitative or qualitative terms, (6) discount benefits and costs, (7) compute net benefits, (8) perform sensitivity analyses, and (9) make a recommendation (adapted from Boardman et al., 2011).

A challenge in BCA is identifying the distribution of impacts and valuing impacts that cannot be easily translated into monetary terms. To address these and other concerns we use a modified BCA approach termed *Multiple Accounts Benefit-Cost Analysis* that disaggregates costs and benefits by stakeholder and by type of cost and benefit and explicitly recognizes that not all costs and benefits can be reliably and meaningfully translated into monetary units (Shaffer, 2010). We also conduct a range of sensitivity analyses to test how results may change under alternative assumptions and forecasts. Where applicable we use Canadian benefit cost analysis guidelines published by the federal government (TBCS, 2007).

4.1 BCA Overview and Assumptions

We summarize the components of the potential benefits and costs of the TMEP that we consider in our BCA in Table 2. The benefits of the TMEP are: revenues associated with transporting WCSB oil to market; potential increases in oil netbacks and option value by accessing new markets and reducing transportation costs; employment generation; and tax revenue. The costs of the Project are the capital and operating costs of the TMEP, the costs of unused capacity created by the Project, costs to BC Hydro due to rates being less than long run marginal costs, plus environmental externality costs such as GHG emissions, air pollutants, potential damages from oil spills, other environmental and social costs, and costs specific to First Nations.

We evaluate and compare two options in our BCA: building the TMEP and not building the TMEP. The ‘building the TMEP’ and ‘no TMEP’ options both assume operation of existing oil transportation facilities and completion of some new transportation projects (Enbridge Line 3, other Enbridge expansions projects, and Keystone XL). Following the guidelines of the Treasury Board of Canada Secretariat (TBCS, 2007), we assume all Canadians have standing and therefore evaluate the TMEP from the perspective of Canada and we include a number of sensitivity analyses to test the impacts of alternative feasible assumptions on the results (Table 3). For the base case we use the recommended TBCS (2007) real discount rate of 8%, with sensitivities of 10%, and 3%. All costs and benefits are reported in 2017 Canadian dollars unless otherwise stated and are estimated over a 30-year operating period.

Table 2. Components of our Benefit Cost Analysis

Component	Benefit	Cost
TMEP Pipeline Operations	Toll revenue	Capital and operating costs of TMEP
Unused Oil Transportation Capacity		Cost of building and maintaining unused transportation capacity (reduced net revenues of impacted transportation capacity and/or opportunity cost of unused capacity)
Option Value/Oil Price Netback	Increased netbacks to producers	Higher tolls on TMEP than alternative transportation options
Employment	Increased wages and employment generated by TMEP	
Tax Revenue	Net tax revenue gain to government	Net tax revenue loss to government
Electricity		Net loss (incremental costs less revenues) from supplying electricity to TMEP
Air Emissions		Damage costs from TMEP air emissions
GHG Emissions		Damage costs from direct TMEP GHG emissions
Oil Spills		Expected value of TMEP oil spill costs
Passive Use Damages from Oil Spill		TMEP passive use oil spill damages
Other Environmental Costs and Benefits	Other environmental benefits[1]	Other environmental costs[1]
Other Socio-economic Costs and Benefits	Other socio-economic benefits[1]	Other socio-economic costs[1]

Note: 1. These components are identified but not estimated in monetary units in our BCA (see Appendix 1: Potential Adverse Impacts of the TMEP).

Table 3. Base Case and Sensitivity Assumptions of our Benefit Cost Analysis

Component	Base Case	Sensitivities
TMEP Pipeline	Tolls set to cover $7.4 billion of the $9.3 billion capital cost	Tolls set to cover $9.3 billion capital

Component	Base Case	Sensitivities
Operations	and all variable costs	cost and all variable costs
Unused Capacity Costs	Net revenue loss from unused capacity on Enbridge based on Alberta to Chicago toll revenue	1) Higher unused capacity cost: Net revenue loss on unused capacity on Enbridge based on Alberta to Cushing toll revenue 2) Unused capacity cost based on TMEP unused capital cost
TMEP Capital Costs	$9.3 billion	$7.4 billion
WCSB Oil Supply	CAPP 2018 forecast	Operating and under construction projects only
Transportation Capacity	Existing pipelines and proposed pipelines (Enbridge Line 3, Mainline and Express expansions, and Keystone XL) at 95% nameplate capacity	Same as base case, except Keystone XL not constructed
Option Value/Oil Price Netback	No oil price netback	Average historical Asian premium estimated by MS (2010; 2012) from 2000-11 applied to 500 kbpd shipped on TMEP until 2038
Employment	Benefit of 5% applied to construction employment	Benefit of 15% applied to construction and operations employment
Tax Revenue	Property tax revenue	Property tax revenue plus royalty and income tax revenue from a price premium induced by TMEP
Electricity	Net loss to BC Hydro from supplying electricity to TMEP	No sensitivity
Air Emissions	Average damage costs from construction and operation air pollution from TMEP	1) Lower air pollution damage costs per unit with assumed mitigation 2) Higher air pollution damage costs per unit
GHG Emissions	Social damage costs from direct TMEP GHG emissions	Higher social damage costs from direct TMEP GHG emissions

Component	Base Case	Sensitivities
Pipeline Oil Spills	PHMSA average spill damage cost of about $15,000/barrel	No sensitivity
Tanker Oil Spills	In port spills – OSRA model probability (0.031 annual probability)	1) Higher estimate: OSRA in port/at sea tanker spill probabilities (0.071 annual probability) 2) Lower estimate: TM probability for tanker spills (0.011 annual probability) and lower spill size (8,184 barrels)
Passive Use Damages from Oil Spill	Upper bound of WTP – Canadian households	WTA – BC households
Discount Rate	8%	10%, 3%

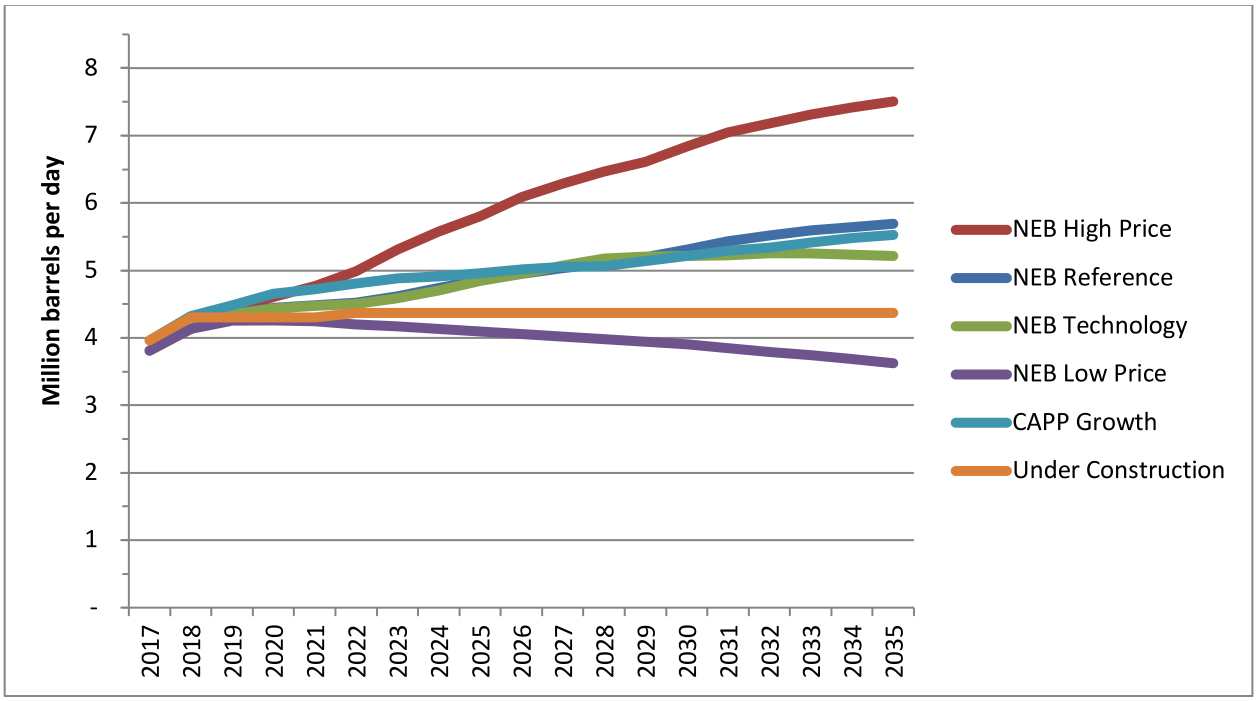
4.2 Supply and Demand for Oil Transportation Capacity

The purpose of the TMEP is to expand pipeline capacity to ship WCSB oil to world priced markets. The first step in estimating the benefits of this expanded transportation capacity of the TMEP is to forecast overall supply and demand for WCSB transportation services and to assess the need for the TMEP.

Demand for WCSB transportation services is based on WCSB oil production. Recent NEB (2018b) and CAPP (2018) forecasts are shown in Figure 3. The NEB's High Price scenario forecasts an almost doubling of WCSB oil production in 2017 to 7,506 kbpd in 2035. This is an outlier forecast that is highly unlikely due to downward pressures on oil markets discussed below. The CAPP forecast and NEB Reference forecast are similar in their projections of production to 2035 with the difference being that CAPP forecasts slightly higher production in the early 2020s compared to NEB Reference (282 kbpd higher in 2022), whereas NEB Reference is slightly more optimistic in the long term (165 kbpd higher in 2035). The NEB Technology forecast assumes implementation of stronger climate change policies to achieve Canada's international commitments. The NEB Technology forecast projects lower oil production than the CAPP and NEB Reference over the longer run as climate change policies constrain the demand for oil and WCSB production relative to the NEB Reference scenario (474 kbpd less in 2035 compared to

NEB Reference). The forecast based on only currently operating and under construction projects in the WCSB is lower than the NEB Reference and CAPP (about 1,239 kbpd less in 2035) forecasts but is higher than the NEB Low Price forecast. This suggests that if oil prices assumed in the NEB Low Price forecast are sustained over the forecast period, operating projects could be shut in, resulting in a decline in overall WCSB oil production. Under the NEB Low Price forecast, production peaks in 2020 and then declines by 634 kbpd to 3,624 kbpd in 2035.

Figure 3. Comparison of WCSB Oil Production Forecasts



Sources: CAPP (2018); NEB (2018b).

The most recent International Energy Agency (IEA) (2018) report published in November 2018 forecast presents three price scenarios for IEA crude:

- *Current Policies*, which assumes that none of the new policies that have been announced by governments are implemented. This scenario predicts that oil prices will be $101/bbl (2017USD IEA crude) in 2025 and rise to $137/bbl (2017USD IEA crude) in 2040.

- *New Policies*, which is based on existing and new policies announced as of mid-2017. This scenario predicts that oil prices will be $88/bbl (2017USD IEA crude) in 2025 and rise to $112/bbl (2017USD IEA crude) in 2040, which is about $18/bbl (2017USD IEA crude) lower than the IEA's 2016 *New Policies* scenario.

- *Sustainable Development*, which is based on meeting the Paris Accord climate commitments and UN millennium goals. Prices in this scenario are forecast to be \$74/bbl (2017USD IEA crude) in 2025 and then gradually declining to \$64/bbl (2017USD IEA crude) in 2040, corresponding with a 26% decline in world oil production.

Under the *New Policies* scenario, the IEA forecasts very little expansion of Canadian oil sands production beyond the building out of existing projects under construction (IEA, 2018, p. 144). From 2017 to 2030, the IEA forecasts expansion of only 800 kbpd, which is well below CAPP's forecast of 1,249 kbpd. Although the IEA does not provide a Canadian oil sands production forecast for the *Sustainable Development* scenario, Canadian oil production under the *Sustainable Development* scenario would be lower than the *New Policies* scenario.

The forecasts indicate that there is significant uncertainty regarding future oil markets, particularly related to climate change policies. If more ambitious climate change policies to achieve Paris commitments are implemented, oil production worldwide will decline. This will have more significant impacts on Canadian oil production than other jurisdictions because Canadian oil sands production (Figure 4, see Oil Sands) is among the highest cost sources of oil in the world and Canadian oil sands production has higher intensity GHG emissions and will therefore be more heavily impacted by GHG emission regulations than other jurisdictions (Jaccard et al., 2018).[3] Consequently, Canadian production will be among the first to decline in a weak world oil market. In addition, new International Maritime Organization shipping fuel standards to reduce sulphur emissions will put further downward pressure on Canadian oil production because Canadian heavy oil is high in sulphur. According to one recent study (CERI, 2018b), these new standards will increase the discount on WCSB oil (Western Canada Select) relative to WTI oil from about \$13/bbl (US 2017 \$) to between \$31-\$33/bbl, resulting in a significant decline in netbacks to Canadian producers and significant decline in investment in new Canadian oil production capacity.

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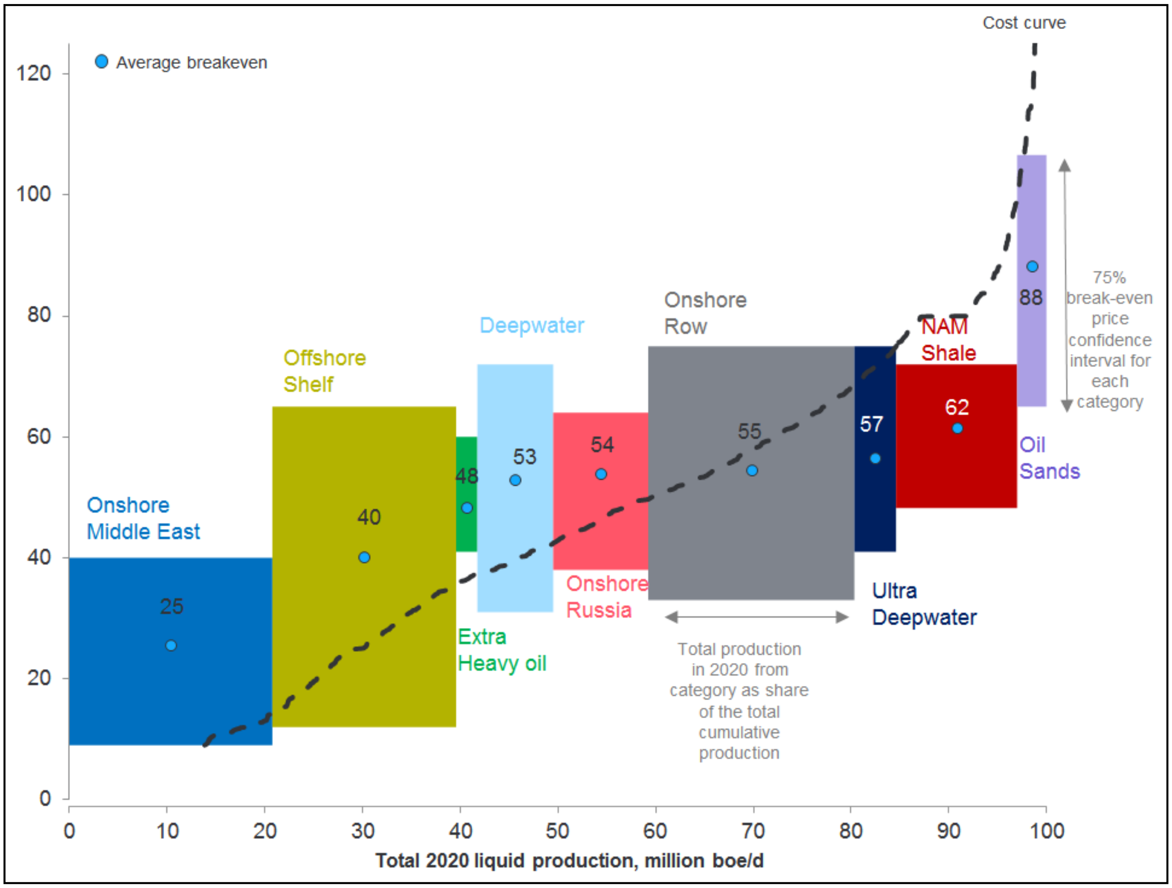
[3] Oil production costs have declined in Canada with improved efficiency and changes in exchange rates. For example, CERI (2015,2018) estimates the supply costs for a greenfield SAGD has declined from \$80.06/bbl (2014 WTI US \$) to \$60.17/bbl (2017 WTI US \$) from 2015 to 2018 and that brownfield SAGD projects are economic at a WTI price of \$ 51.59/bbl (2017 WTI US \$). The key determinant of future Canadian production however is the cost of Canadian production relative to competitors as summarized in Figure 4. If the marginal cost of new supply is lower in competing jurisdictions, which have also benefitted from improved efficiencies, then expansion in Canada will be constrained even though the absolute costs have declined over time.

Figure 4. Oil Supply Cost Curve (US$ per bbl)



Source: Rystad Energy Research and Analysis (2015)

Given the uncertainty regarding future oil markets, we use a range of Canadian WCSB oil production forecasts in our supply/demand analysis for our BCA. For our upper range we use CAPP's supply forecast, which is similar to the NEB Reference forecast. The CAPP forecast only goes to 2035, so for the period 2036 to 2051 we assume that oil production remains constant at 2035 levels. For our lower range we use existing WCSB production plus WCSB projects under construction. Projects under construction are estimated based on Alberta government project inventory data (AER, 2018) updated to include recent project announcements (Table 4). The two forecasts are essentially the same to 2020 as existing projects under construction are completed. After 2020, the under-construction forecast assumes additional production capacity of just 75 kbpd while the growth forecast adds 308 kbpd of capacity by 2025 and then another 437 kbpd by 2030. We believe that these two forecasts provide a reasonable upper and lower range of likely outcomes. However, given Canada's relatively higher costs of production combined with the implementation of increasingly stricter climate change policies and International Maritime Organization fuel standards, we expect that it is more likely that future WCSB production will be nearer the lower end of this range.

Table 4. New WCSB Projects Under Construction

Proponent	Project	Nameplate Oil Production Capacity (kbpd)
Suncor/Total E&P Canada*	Fort Hills Phase 1	194
Cenovus	Christina Lake Phase G	50
CNRL	Kirby North Phase 1	40
Imperial**	Aspen Phase 1	75
Husky	Sunrise Phase 1B	60
MEG	Christina Lake Phases 2B eMSAGP	20
Osum	Orion Phase 2B	13
Total Forecast Oil Production Capacity		**452**
Total Forecast Oil Supply* **		**431**

Sources: AER (2018); * Fort Hills was completed on 2018. ** Imperial's Aspen Project construction was announced in November, 2018 (Imperial, 2018) and is not defined as a project under construction in the 2018 AER (2018) inventory. ***Projects are assumed to operate at 90% utilization (AER, 2018) and production is converted to supply by using the incremental supply to incremental production ratio of 1.06 assumed by CAPP (2018) for the period 2017 to 2023.

Several additional adjustments are required to the forecast WCSB oil production to estimate the WCSB export demand for transportation services. First, refinery consumption from Alberta and Saskatchewan refineries are deducted from the production forecasts. Export shipments of refined oil products from the WCSB are then added back in as a source of demand for transportation services. Second, the export volume needs to be adjusted to include diluent volumes that are added to bitumen so it can be shipped in pipelines. The additional volume of diluent is added by CAPP to estimate what CAPP defines as the total WCSB supply. The details of these adjustments to the WCSB production forecasts to derive export demand for transportation services are provided in the notes to Table 7 and Table 8.

One additional factor in determining demand for WCSB transportation capacity is Bakken production in the US, which is shipped on the Enbridge mainline. In 2017, Enbridge shipped an average of 121 kbpd of Bakken crude on its Bakken pipeline entering its mainline at Cromer, Manitoba (NEB, 2019b). In 2018, Bakken shipments on Enbridge mainline decreased by about one-half and Enbridge states that it will be phasing out Bakken shipments to free up space for more WCSB crude, which Enbridge estimates will add 100 kbpd of pipeline capacity for WCSB exports (Enbridge, 2018). Also, as shown in Table 5, there is an overall surplus transportation capacity available for the Bakken region that will reduce Bakken demand for Enbridge pipeline space. Consequently, based on Enbridge's intent to phase out Bakken shipments and the overall surplus of oil transport capacity serving the Bakken region, we assume that no Bakken crude on the Enbridge mainline exiting Gretna will be shipped unless there is surplus pipeline capacity after meeting WCSB export needs.

Table 5. Transportation Capacity Supply and Demand, Bakken Region

	2017 (kbpd)	**2020 (kbpd)**
Pipeline Capacity	1,371	1,750
Rail Capacity	1,520	1,520
Total Transportation Capacity	2,891	3,270
Production (August 2018)	1,348	Not applicable
Surplus Transportation Capacity	**1,543**	Not applicable

Sources: North Dakota Pipeline Authority (2018a; 2018b).

The next step in the supply demand analysis is estimation of available and potential WCSB oil transportation capacity. Existing and proposed transportation projects based on CAPP (2018) data and other sources are summarized below (Table 6). We assume that the transportation system operates at 95% of nameplate capacity. We note that our transportation capacity estimates are conservative because they exclude rail capacity estimated at 770 kbpd (CAPP, 2018) and do not include potential capacity of proposed projects such as Enbridge Line 3 that is estimated to be 84 kbpd higher than the 370 kbpd estimate provided in the Enbridge Line 3 application (Minnesota, 2018, p.55).

Table 6. Existing and Proposed Projects (Based on CAPP 2018)

Pipeline	**Nameplate Capacity (kbpd)**
Enbridge Mainline	2,851
Express/Platte	280
Milk River/Rangeland	203
Trans Mountain	300
Keystone	591
Existing Capacity Subtotal	**4,225**

Pipeline	Nameplate Capacity (kbpd)
Enbridge Line 3 Expansion*	370
Enbridge Mainline Expansions**	350
Express Expansion***	60
Keystone XL	830
Trans Mountain Expansion Project	590
Proposed Capacity Subtotal	**2,200**
Existing and Proposed Pipeline Capacity Total	**6,425**
Current Rail Capacity	**770**
Existing and Proposed Pipeline and Rail Capacity Total	**7,195**

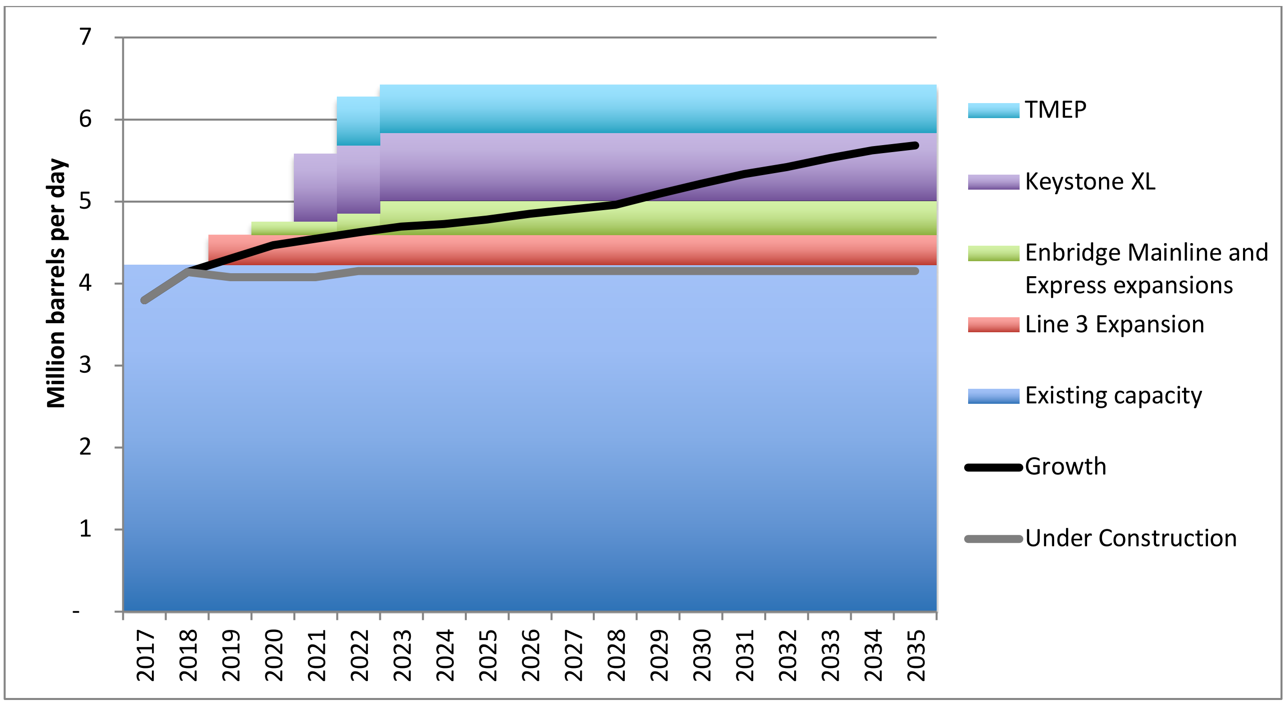
Sources: CAPP (2018). Notes: We list nameplate capacities in this table but use effective capacities for existing and proposed pipelines in our BCA, which we assume to be 95% of nameplate capacity. Adjustments for refined products, Bakken shipments and refineries are made on the WCSB oil supply estimates as noted in Tables 7 and 8. Rangeland and Milk River capacity is from AER (2018). *Potential for Line 3 Expansion to increase to 454 kbpd (Minnesota, 2018, p. 55). **Enbridge mainline expansions (Enbridge, 2018, pp. 34-36) include system optimizations (75 by 2020 and 100 by 2022), Line 4 restoration (25 kbpd by 2020), and reversal of Southern Lights pipeline (150 kbpd in 2023). Enbridge estimates additional capacity of 450 kbpd which includes 100 kbpd of reduced Bakken shipments. We have accounted for this 100 kbpd of reduced Bakken shipments in our crude supply forecast instead of in the pipeline capacity forecast and therefore we show only 350 kbpd of additional capacity. ***Express expansion as estimated by Enbridge (2018, p. 36).

WCSB oil export demand for transportation services and the transportation capacity are compared to estimate overall supply and demand balance for transportation services (Figure 5 and Table 7 and Table 8). *The analysis shows that pipeline capacity is currently tight and additional capacity is required*. We note that our findings on capacity are similar to the NEB's (2018c) analysis that concludes that there is a shortage of 202 kbpd of pipeline space as of September 2018[4]. *This shortage will be addressed by completion of the Enbridge Mainline expansion and phasing out of Bakken shipments (100 kbpd in 2020 and additional 250 kbpd by 2023) and the replacement of Enbridge Line 3, which adds 370 kbpd of capacity in 2020*. With completion of these projects, no additional pipeline expansions are required in the low range (under construction) forecast to the end of the forecast period. Under the CAPP forecast completion of Enbridge Line 3, Express, and mainline expansions and Keystone XL provides

[4] We show a pipeline shortage of 128 kbpd in 2018 based on 2018 oil supply forecasts and using 95% capacity of pipelines. Note that Figure 5 shows nameplate capacity.

sufficient capacity to 2035. If Keystone XL is not built, there is sufficient pipeline capacity until 2025. In 2025, only one new pipeline project (TMEP or Keystone XL) is required under the CAPP forecast and a second new project may be required around 2035 when pipeline capacity becomes close to fully utilized. The analysis shows that the TMEP is not needed until around 2035 under the CAPP forecast and assuming that the other proposed projects are completed. Under the operating and under construction forecast, the TMEP is not required at all during the forecast period to 2051. We note that none of these forecasts include any of the 770 kbpd rail capacity and if some rail capacity is used, the need for pipeline projects will be deferred further then shown in Figure 5.

Figure 5. Estimates of Western Canadian Oil Supply Transportation Capacity



Source: Adapted from CAPP (2018). Note: Pipeline capacities reflect nameplate capacities.

Table 7. WCSB Oil Pipeline Supply and Demand Balance: CAPP Forecast (kbpd)

	2017	2020	2025	2030	2035
Oil Supply Exports*	3,797	4,471	4,779	5,215	5,684
Current Pipeline Capacity	4,225	4,225	4,225	4,225	4,225
Enbridge Line 3, Express, and Mainline expansions		530	780	780	780
Keystone XL			830	830	830
TMEP			590	590	590
Surplus (Deficit) without TMEP	**428**	**284**	**1,056**	**620**	**151**
Surplus (Deficit) with TMEP	**428**	**284**	**1,646**	**1,210**	**741**
Surplus (Deficit) without TMEP at 95% capacity **	**217**	**47**	**765**	**328**	**(140)**

*Forecast is based on CAPP's 2018 WCSB supply forecast. CAPP's oil supply forecast adjusts their oil production forecast to include the extra volume of diluents mixed with bitumen to allow it to be transported in pipelines. CAPP's oil supply forecast has been further adjusted by deducting WCSB refinery consumption (95% of 682 kbpd), adding refined product shipments of 125 kbpd on Enbridge Mainline as estimated by Muse Stancil (2015b) and refined product shipments on TMEP (50 kbpd) as estimated by CAPP (2018) for a net reduction in oil supply of 473 kbpd by 2019. ** Pipeline surplus and deficit is estimated on the basis of 95% pipeline capacity utilization.

Table 8. WCSB Oil Pipeline Supply and Demand Balance: Operating and Under Construction Forecast (kbpd)

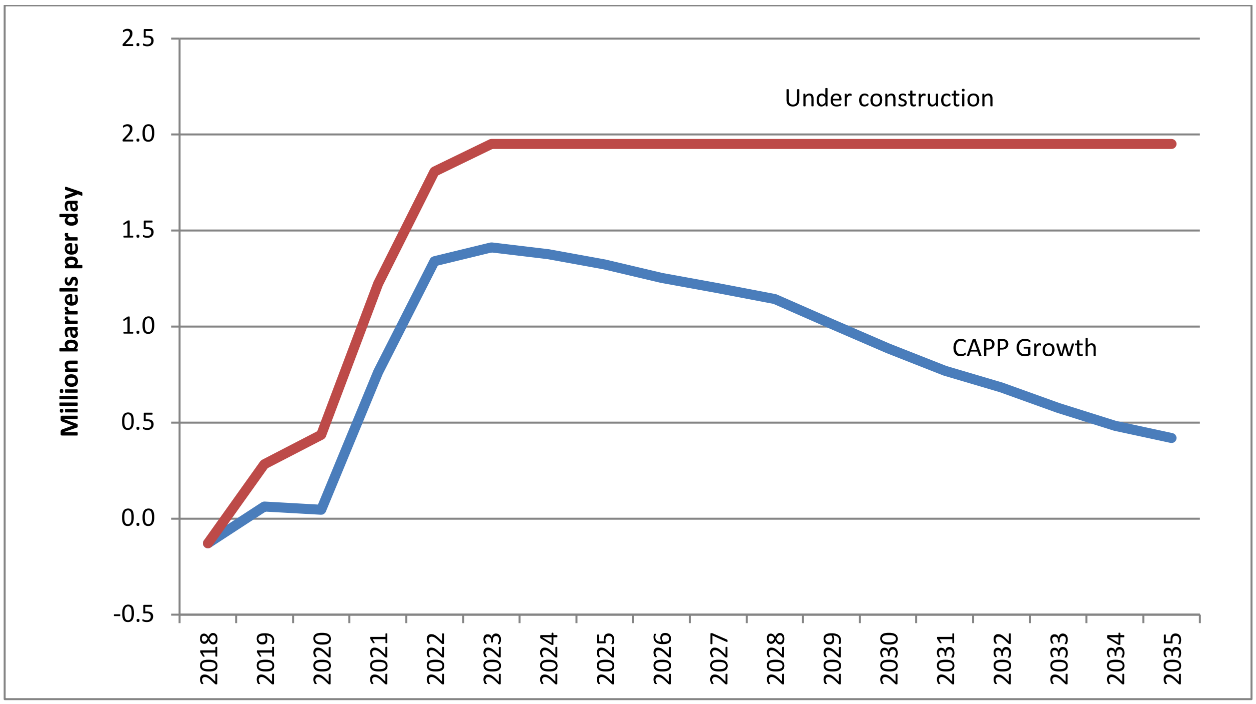
	2017	2020	2025	2030	2035
Oil Supply Exports*	3,797	4,081	4,153	4,153	4,153
Current Pipeline Capacity	4,225	4,225	4,225	4,225	4,225
Enbridge Line 3, Express, and Mainline expansions		530	780	780	780
Keystone XL			830	830	830
TMEP			590	590	590
Surplus (Deficit) without TMEP	**428**	**674**	**1,682**	**1,682**	**1,682**
Surplus (Deficit) with TMEP	**428**	**674**	**2,272**	**2,272**	**2,272**
Surplus (Deficit) without TMEP at 95% capacity**	**217**	**436**	**1,391**	**1,391**	**1,391**

*Forecast is based on capacity of projects under construction as provided in Table 4. Under construction projects are assumed to operate at 90% capacity (AER, 2018) and production is converted to supply by the incremental supply to incremental production ratio of 1.06 assumed by CAPP (2018) for the period 2017 to 2023. CAPP's oil supply forecast has been further adjusted by deducting WCSB refinery consumption (95% of 682 kbpd), adding refined product shipments of 125 kbpd on Enbridge Mainline as estimated by Muse Stancil (2015b) and refined product shipments on TMEP (50 kbpd) as estimated by CAPP (2018) for a net reduction in oil supply of 473 kbpd by 2019. ** Pipeline surplus and deficit is estimated on the basis of 95% pipeline capacity utilization.

In Figure 6, we show estimated surplus capacity under the two oil supply forecasts using pipeline capacity based on 95% of nameplate capacity utilization and completion of all Enbridge expansions projects, Keystone XL and TMEP. In the under-construction forecast, surplus capacity increases from 436 kbpd in 2020 to 2.0 million bpd in 2023 and this surplus capacity remains over the forecast as no new WCSB projects are completed. Under the CAPP forecast, surplus capacity peaks at about 1.4 million bpd in 2023 and declines to 420 kbpd in 2035.

The conclusion of the supply and demand analysis is that building the TMEP along with other proposed projects would result in significant surplus capacity. While some degree of surplus capacity is beneficial to provide some degree of flexibility in the oil transportation system, the magnitude of surplus capacity that would be created with completion of all proposed projects is unprecedented and will impose a significant cost to Canada and the oil sector.

Figure 6. Surplus Capacity Estimates Under CAPP Growth and Under Construction Forecasts



Note: Surplus capacity estimated based on 95% of nameplate pipeline capacity.

4.3 Costs and Benefits for Trans Mountain Pipeline Operations

As indicated in our supply and demand analysis, building the TMEP along with other proposed projects would result in significant unused transportation capacity. However, because the TMEP has take-or-pay shippers' contracts for 80% of its proposed capacity, the unused capacity will be created on other pipelines, such as Enbridge, that do not have long term contracts as shippers divert oil to fulfill their contractual obligations to TM. The costs and benefits of this surplus capacity on the other pipelines are estimated in Section 4.4.

For the purposes of the TMEP pipeline operations, we assume that the benefit is the toll revenue TM receives for transporting oil to market. Tolls for the TMEP are set to cover all the operating and capital costs of the pipeline as defined in the TMEP toll hearings. We assume that the TMEP will be fully utilized, or at least in accordance with the utilization rate used to determine the cost recovery tolls and as provided for in the TM shippers' contracts (TM, 2013c; 2013d). Tolls are set to cover the costs of the TMEP, so the net present value of the costs of capital and operation are equivalent to the net present value of the toll revenue. Therefore, the **net** benefit (revenue less cost) of the direct operation of the pipeline is nil.[5] If the TMEP costs are higher than forecast in the toll hearings there will be a net cost because toll revenues may no longer fully cover costs, and if the TMEP costs are lower there will be a net benefit because toll revenues could exceed costs.

Previous pipeline projects have experienced significant cost escalation, which is consistent with other research on large projects (Flyvbjerg et al., 2003; Flyvbjerg, 2014; Gunton, 2003).[6] The TMEP's capital cost forecasts have followed this trend with an increase from the original estimate of \$5.5 billion to \$7.4 billion in the "final cost" review provided to shippers in March 2017 for confirmation of shippers' contracts (TM, 2017). In the recent valuation report to shareholders for the sale to the Canadian government, two capital cost estimates were provided: \$8.4 billion based on an assumed completion date of December 31, 2020, and \$9.3 billion based on an assumed completion date of December 31, 2021 (KM, 2018). The \$9.3 billon estimate provided by KM to its shareholder is approximately 79% higher than estimated in the TMEP application.

The shippers' confirmation of the contracts based on the \$7.4 billion cost estimate in

[5] Although the direct operation of the TMEP generates a net present value of zero (benefits equal costs), the operation has the potential to generate other benefits (such as improved market access) and costs which are addressed in other components of the BCA.

[6] Estimates of the capital costs of the Enbridge Northern Gateway project increased by about one-third from \$5.5 billion (2009\$) (\$5.9 billion in 2012\$) as stated in its application (Enbridge, 2010) to \$7.9 billion as stated in NEB Joint Review Panel Report (NEB 2013b, p. 4). Keystone XL cost estimates increased by approximately 45% between 2012 and 2014, from \$5.5 billion to \$8.0 billion (TransCanada 2013, p. 40; TransCanada 2015, p. 65). The Mackenzie Valley Pipeline costs have reported to have increased by more than 40% from 2007 to 2013 (Jones, 2013). Enbridge's Clipper project is reported to have come in on budget, suggesting that costs overruns are not a certainty (Enbridge, 2010, p. 50). Although there are many reasons for these increases such as change in project designs and delays, the record shows a propensity for cost escalation.

March 2017 indicates their willingness to pay tolls to cover the $7.4 billion capital and operating costs of the TMEP. Hence, pipeline benefits are assumed to be equal to the pipeline construction and operating costs at a $7.4 billion cost estimate. However, as indicated in the KM report to shareholders (KM, 2018), the capital costs could increase to between $8.4 and $9.3 billion. Given that the TMEP has now been delayed by the Federal Court of Appeal's decision and the likelihood that additional changes to the Project will be made to accommodate First Nations and others concerns, costs are likely to be closer to $9.3 billion, if not higher. Therefore, for the base case assumption we use the $9.3 billion capital cost estimate.

Shippers have agreed to pay tolls to cover $7.4 billion in costs but have not agreed to pay the tolls to cover this higher $9.3 billion cost. Therefore, we cannot assume that shippers will be willing to pay for the additional $1.9 billion in capital costs of the TMEP. It is possible that shippers may ultimately agree to cover these higher costs in part because they would incur financial penalties for exiting the contracts (TM, 2013c; 2013d).[7] But as the comparison of tolls to cover the higher TMEP capital costs and tolls to ship oil on alternative pipelines (Table 9) show, the TMEP tolls could end up being higher than other transportation options such as shipping WCSB oil to the US Gulf on Enbridge's expanded system. Consequently, although shippers may ultimately agree to pay these higher tolls to avoid paying penalties for exiting the contracts, the benefits of shipping on the TMEP are unlikely to be high enough to justify the extra $1.9 billion in capital cost. Therefore, our base case assumes that the tolls are high enough to cover the $7.4 billion capital cost, but not the $1.9 billion cost overrun. Under this assumption, there is a net cost to operating the TMEP equivalent to the incremental $1.9 billion cost overrun. We also undertake a sensitivity analysis assuming that shippers are willing to pay the incremental tolls to cover any cost overruns beyond the $7.4 billion and that the benefits are equivalent to the costs of the TMEP. Below we also assess other benefits from the TMEP in terms of option values and higher prices that could offset the higher costs.

Table 9. Comparison of the TMEP Tolls to Asia to US Tolls to Gulf

Option	Toll per barrel (2018 US $)
TMEP to Asia ($9.3 billion capital cost)	$10.78

[7] If shippers decide to exit their contracts after the final cost determination, they are obligated to cover their prorated share of expenditures on the TMEP incurred prior to the final cost review (TM, 2013c).

Enbridge to US Gulf (with Line 3 Expansion)	$ 8.10
TMEP Cost Penalty	$ 2.68

Source: Hughes (2018, p.18).

4.4 Costs of Unused Transportation Capacity

There are two components to estimating the costs of surplus capacity: the quantity of unused capacity created by building the TMEP along with other proposed transportation projects, and the cost per unit of unused capacity. We estimate the quantity of unused capacity based on our estimates of WCSB oil supply and transportation capacity. As stated in Section 4.2, for our base case we use CAPP's 2018 forecast and for our low supply scenario we assume WCSB oil supply does not grow beyond projects already under construction. Our transportation capacity assumptions are also provided in Section 4.2. To reiterate, our assumptions include operation of existing pipelines plus capacity additions provided by Enbridge Express, Enbridge mainline, Enbridge Line 3, Keystone XL, and TMEP. Capacity is adjusted for refined product shipments on Canadian pipelines and transportation capacity is assumed to be 95% of nameplate capacity. We also include an alternative capacity sensitivity analysis in which Keystone XL is not constructed.

Under all these scenarios, construction of the TMEP results in surplus capacity. Under CAPP's forecast, the surplus capacity peaks at 1,431 kbpd in 2023 and the TMEP is not needed until 2034 in the base case scenario. In the lower range supply forecast (under construction projects only), surplus capacity is 1,951 kbpd in 2023 and the TMEP is not required at any point within the forecast period. The quantity of unused capacity used in our BCA is the lower of: (1) the 590 kbpd diverted to the TMEP and (2) total unused oil transportation capacity at 95% capacity utilization. Therefore, our surplus capacity cost estimates are only the proportion of surplus costs that can be attributed to the TMEP.

The second step in estimating surplus capacity costs is to estimate the cost per barrel of surplus capacity. We use two methods for estimating the per unit costs of surplus capacity. The first method is to assume that the toll revenue received by TM to recover its capital costs should only be included as a benefit when the TMEP capacity is required (i.e., when the TMEP is not simply diverting shipments from other oil pipelines). If the TMEP capacity is not required, the toll revenues are not an incremental benefit to the transportation sector – they simply replace the toll revenues that would have been paid to other pipelines. In this method, the TMEP toll revenue is included as a benefit for only the years that the TMEP capacity is needed, while the capital costs of the TMEP are deducted in the years that the capital costs are incurred. The second method to estimate unused capacity costs is to use the loss in net revenue on existing pipelines resulting from the diversion of oil to the TMEP. Enbridge used this approach in its estimates of the costs of unused capacity generated by the ENGP and Keystone XL pipelines referenced above. In this method, the cost of the unused capacity is defined as the net revenue that would have been generated on other pipelines if the 590 kbpd was not diverted to the TMEP. We estimate the net revenue loss per barrel based on Enbridge's audited financial statements for pipeline operations as reported in their 2014 annual report (Enbridge, 2015, p. 66-67).[8] We use several alternative estimates of net revenue loss per barrel based on different assumptions (Table 10). For our base case, we use shipments to Chicago to estimate unused capacity costs. This base case likely underestimates unused capacity costs since shippers are more likely to divert higher cost oil shipments from the United States Gulf Coast (USGC) to the TMEP and net revenue loss from shipments to the USGC are more than twice those to Chicago (CAPP, 2014). For the sensitivity analysis we include surplus capacity costs associated with shipments to Cushing on Enbridge. The net present value of these scenarios ranges from $2.1 to $7.5 billion in unused capacity costs (Table 10). The low end of this range ($2.1 billion) is based on the assumption that Keystone XL is not built, while the high end of the range ($7.5 billion) is based on the lower under-construction growth forecast.

[8] Enbridge data is used for the net revenue loss estimate because much of the oil shipped on the TMEP is likely to be diverted from Enbridge, given that Enbridge is the largest shipper, and oil shipped on competing pipelines and some rail is under long-term contracts while most of the oil shipped on Enbridge is not. Net revenue loss is calculated from p. 66 of Enbridge's 2014 annual report (Enbridge 2015) for their Canadian mainline based on a three year average (2012-14) of revenue less power costs. A portion of the operating and administrative costs are deducted for three scenarios (Mainline, Chicago and Cushing), which will understate net revenue loss per barrel because they include operating and administrative costs that Enbridge (2015, p. 67) states are relatively insensitive to throughput. Administrative and operating costs are also deducted in the Enbridge Alberta to Chicago/Rail scenario to provide a lower bound estimate of net revenue loss. As there will be a propensity for shippers to divert oil that incurs higher toll charges, oil shipped to further shipment points will be the most likely to be diverted, subject to other constraints such as contracts and destination oil prices. We acknowledge that oil shipped on the TMEP may be diverted from other non-Enbridge facilities that may have different cost profiles and that there is uncertainty regarding the destination of the oil diverted from the Enbridge line. We have addressed this uncertainty by using a range of net revenue loss estimates for different Enbridge shipment options.

Table 10. Unused Capacity Costs

Cost Assumption	Unused Capacity Cost (billion $ net present value)
Enbridge Alberta to Chicago toll (base case)	6.9
Enbridge Alberta to Chicago toll (under-construction supply forecast)	7.5
Enbridge Alberta to Chicago toll (no Keystone XL)	3.4
Enbridge Alberta to Cushing toll	8.9
TMEP Unneeded Capital Cost Method	5.6

Source: Unused capacity costs are estimated by multiplying the quantity of oil diverted by year by the net revenue per barrel. Enbridge net revenue estimates are based on three year average net revenue ratios for 2012-2014 from Enbridge (2015, p. 66-67) . For Enbridge Mainline, the net revenue per barrel is estimated by dividing annual oil throughput by annual net revenue. For the Enbridge Alberta to Chicago option and the Enbridge Alberta to Cushing option the net revenue/total revenue ratio for Enbridge is multiplied by the toll rate for heavy oil for Enbridge tolls as reported in CAPP (2014, p. 42) and converted to 2017 Canadian dollars.

4.5 Higher Netbacks to Oil Producers and Option Value

MS states that a major benefit of the TMEP to the oil and gas sector is increased netbacks by reducing the need to transport large volumes of WCSB crude via rail and reduction of supply to the North American market (MS, 2015, p. 56). As discussed in Appendix 2 of this report, there are major deficiencies in the method and assumptions that MS uses to generate its forecast of increased netbacks and the escalation in the TMEP capital costs is more likely to result in the TMEP reducing producer netbacks due to the higher transportation tolls compared to alternatives that would offset any potential price premium. Therefore, we consider it very unlikely that the TMEP would result in increased netbacks for Canadian producers.

Further, although price differentials for homogenous types of oil are possible due to shorter-term market constraints, they are highly unlikely over the longer term. For example, although oil prices in Asia were higher than European and US prices by up to $1.50 per barrel throughout the 1990s (Ogawa, 2003), price differentials have fluctuated between premiums and discounts (Cui and Pleven, 2010; Doshi and D'Souza, 2011; Broadbent, 2014, p.108-110) with no discernible pattern or trend line with which to forecast a long term premium. Doshi and D’Souza (2011) note a recent reversal of the Asian price premium between 2007 and 2009 and conclude that Asia received a discount on crude oil relative to Atlantic markets at this time. Cui and Pleven (2010) suggest that recent discounts on crude oil priced in Asia result from Asia’s diversification of crude oil supplies beyond the Middle East and that Asia's increased bargaining power will eliminate the Asian premium. Hughes (2018) compared price data for Mexican heavy oil exports (Maya blend) to Asia versus the US Gulf and found that netbacks for shipments to Asia have been lower than shipments to the Gulf over the last five years.

The reason that long term price differentials are unlikely is because the world oil market is an integrated single world market linked by shippers' ability to transport oil between geographic locations according to supply and demand dynamics; if demand and prices rise in one location, producers will increase supply to that location until the oil market equilibrates and price differentials disappear (Adelman, 1984; Kleit, 2001; Nordhaus, 2009; Fattouh, 2010; Huppmann and Holz, 2012). While there may be short-term impediments in oil markets that restrict adjustments in global supply, such as transportation constraints that result in temporary price differentials, the global oil market will erode these differences. As TM's expert and author of MS (2015) stated in NEB hearings on the ENGP:

> And as you can kind of see from this chart here, I mean, millions and millions of barrels of crude are transported by waterborne -- on the water around the world. And accordingly, the global crude market can pretty quickly re-equilibrate their prices. Oil prices are very high in one part of the world, you'll have more tankers starting to come into that part of the world and the price will equilibrate (Earnest, 2012, p. A47316).

This view is also held by Bruce March, Chief Executive Officer for Imperial Oil, who states that oil is fungible and easily transportable, and oil prices in the Pacific and US will balance as the price of oil in the USGC rises and the price of oil in Asia falls (Vanderklippe, 2012). Therefore, while oil prices are uncertain, relying on the assumption of a permanent Asian premium in project evaluation is not supported by world oil market dynamics and would not be prudent.[9] MS (2015), for example, does not include the possibility of an Asian premium in its market analysis for the TMEP.

Although option values generated by long-term price differentials in oil markets are highly unlikely, there may be short-term price differentials that shippers on the TMEP could take advantage of from a new Pacific port. Therefore, we test a scenario based on the TMEP generating increased returns to producers by providing an option value based on the possibility of

[9] There may be some option value in having transportation facilities that allow for exploitation of short-term market disequilibria or locational rents. The benefits, however, would be shorter-term, challenging to exploit given the large number of competitive suppliers, and would have to be weighed against the costs of maintaining the transportation capacity required to exploit different market options.

exploiting potentially higher priced oil markets such as Asia from a new oil port on the Pacific. The sensitivity analysis uses the average historical difference between US and Asian prices for the short-term period between 2000 and 2011 estimated by MS (2010; 2012) for the ENGP of $2.15 (2017 CDN $) per barrel of heavy crude. In the sensitivity, we assume that this price premium is received for 500 kbpd of crude oil shipped on the TMEP over the 17-year operating period used in the MS analysis of netbacks. The estimated benefit of this price lift from TMEP shipments to Asia is $2.8 billion net present value.

We caution that this estimate of a $2.8 billion price premium benefit that may accrue from building the TMEP is highly unlikely because the assumption of a long-term price premium used in the sensitivity is not evident from past price data and is inconsistent with the operation of the world oil market. Indeed, as recent Mexican Maya price data show, the netback on heavy oil shipments to Asia is actually lower than the Gulf (Hughes, 2018) and the US Gulf is among the strongest markets for heavy oil in the world (IHS Markit, 2018). Further, the higher tolls on the TMEP relative to other pipeline options would offset any premium that may exist.

4.6 Employment Benefits

A potential benefit of the TMEP is providing employment to workers. As discussed in Section 3.2.6 of this report, the economy of Western Canada has been characterized by tight labour markets and it is therefore unlikely that workers employed on the TMEP would otherwise be unemployed. However, given recent slowdowns in the energy sector and the potential of TM training and hiring employees through impact benefit agreements, it is possible that there will be an employment benefit, with some hiring of persons who would otherwise be unemployed or employed at a lower wage. Consequently, we include an employment benefit in our BCA.

The measurement of potential employment benefits depends on labour market conditions and hiring policies of companies that are difficult to forecast. To illustrate the potential significance of the employment benefits, a percentage is applied to the wages paid to represent the incremental income that might be earned, or more specifically the income in excess of the labour's opportunity cost (e.g., 5% (Wright Mansell, 2012, p. 73); 10-15% (Shaffer, 2010)). In the base case we assume an employment benefit of 5% applied to construction employment income. We also include a sensitivity of 15% applied to construction and operating employment income to measure the range of potential employment benefits. We use the percent of direct labour income for construction and operating employment incomes of total construction and operating costs based on data in the TMEP application, which we note is high compared to other pipeline projects and may therefore overstate the employment benefit (TM 2013b, Vol. 5B).[10] Total estimated employment benefits for the TMEP range from $159 to $534 million (net present value).

4.7 Benefits and Costs to Taxpayers

Incremental tax revenues not offset by incremental government expenditures are a benefit to taxpayers. As discussed earlier in Section 3.2.6 of this report, the net increase in tax revenue is much less than the gross increase because the gross increase includes tax revenue that would have been generated in the absence of the TMEP being built. TM's gross revenue estimates also do not deduct incremental costs to government such as emergency response and regulatory monitoring resulting from the Project.

In BCA it is normally assumed that most economic activity-related tax revenue (e.g., income and sales taxes) is not incremental or, for example with respect to the taxes paid by in-migrants, is required to offset the incremental costs of government services and infrastructure needed to accommodate the larger population (Shaffer, 2010). Accordingly, tax revenue is not included as a benefit unless the tax revenue is unique to the project (i.e., it would have not been generated in alternative economic activity) and is not required to fund incremental government expenditures due to the project.

In the case of the TMEP there are two streams of tax revenue that could generate net benefits: royalty and income tax revenue from an Asian price premium induced by the TMEP, and property tax revenue from the new pipeline and related facilities. As previously discussed, a permanent oil price benefit is highly unlikely and even if it did exist, it would be offset by the higher transportation costs on the TMEP relative to the other transportation options. Nonetheless, we do include a sensitivity analysis based on the historical Asian price premium from 2000 to 2011 estimated by MS (2010; 2012). In this scenario, we include the incremental tax revenue generated by the higher oil prices as a benefit to government based on the government revenue to oil price

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[10] We use total direct construction labour income (TM 2013b, Vol. 5B p. 7-168) and total direct operating income for the upper bound scenario (p. 7-170). We note that the labour income to capital spending ratio provided in the TM application (approximately 39%) is more than double the ratio used for employment benefit estimates in other pipeline projects such as the ENGP (14.55%) (WM 2012, p. 73). Due to lack of detail on the how the labour income estimates were derived in TM's Conference Board report (CBC, 2015), we are unable to assess the reasons for the difference. We note that using the Enbridge labour ratio would reduce the employment benefit by more than one-half.

assumptions in the CBC report (CBC, 2015) applied to the increased netback. We estimate the net benefit of the incremental tax revenue is $919 million (net present value), which is included in the overall $2.8 billion price benefit estimate. Secondly, although some of the property tax revenue from the TMEP may be required to cover incremental government costs, we assume that most of the TMEP property tax revenue is a net revenue gain unique to the TMEP not offset by increased costs. Therefore, we include property tax revenue as a benefit to government, with the qualification that this will overstate the benefit gain to government to the extent there are offsetting incremental local government costs. TM estimates the incremental property tax revenue of the TMEP at $26.5 million per year (2012$), of which $23.1 million is paid in BC and $3.4 million in Alberta (TM, 2013b, Vol. 5B p. 7-185). The net benefit of the property tax is $252 million (2017 net present value $).

There are also a number of potential costs to governments. The Government of Canada, for example, has committed to a large-scale Ocean Protection Plan with an estimated cost of $1.5 billion (ECCC, 2018). The government has stated that this plan was initiated to mitigate the risks associated with the TMEP and is therefore a cost to taxpayers for the TMEP. The cost is to some degree offset by the mitigation benefits of reducing spill risks from the TMEP and other current activities such as barge transport of oil and refined products. However, these mitigation benefits are already included in the oil spill risk costs in Section 4.9.3, which assume that this program is effectively implemented. Due to data limitations on the details of these mitigation expenditures, we have not attempted to include them in our BCA. Therefore, our government tax revenue estimates overstate incremental government revenue because we have not deducted incremental costs to government such as the mitigation costs of Canada's Ocean Protection Plan in our BCA.

A second cost is the potential for lower government tax revenue resulting from lower netbacks to oil producers due to the higher toll costs on the TMEP relative to other transportation options. This is in effect the reverse of the higher netback scenario. We have not included this extra cost in our BCA.

4.8 Costs to BC Hydro and BC Hydro Customers

TM estimates that the TMEP will consume approximately 1,045 gigawatt-hours (GWh) of electricity per year, 526 of which will be consumed in BC (TM, 2014a, p. 110-111). Although TM will pay for the electricity, current rates in BC are significantly below the long-run incremental costs of supplying new loads. Consequently, there is a net loss to BC Hydro and its ratepayers equal to the difference between electricity rates paid by TM and the incremental cost of supplying the increased requirements due to the TMEP. BC Hydro's estimated long-run incremental cost of energy is $90-$106 per megawatt-hour (MWh) (BC Hydro, 2013) while the average amount paid by TM for power requirements in BC is $70 per MWh (TM, 2014a, p. 110-111), resulting in a net cost to BC Hydro of $28 per MWh (based on an incremental cost of $98 per MWh), or $12 million per year.[11] The net cost to BC Hydro and BC ratepayers is $109 million (net present value). We assume that any electricity generated in Alberta to supply the project is covered by the rates that Alberta will charge TM.

4.9 Environmental Costs

4.9.1 Air Pollution

Installation and operation of the pipeline, construction and operation of Westridge Terminal, and incremental tanker and tug traffic associated with the Project would release sulphur dioxide, nitrogen oxides, and particulate matter that affect human and ecosystem health. Exposure to these pollutants can cause respiratory and heart health effects and increase mortality rates in humans (IMO, 2009; US EPA, 2009). Sulphur dioxide and nitrogen oxides are also associated with acid precipitation that can affect forest and aquatic ecosystems (US EPA, 2009), and particulate matter deposition contributes to acidification and nutrient enrichment (IMO, 2009). Construction and operations of the TMEP would also emit carbon monoxide, volatile organic compounds, and other hazardous air pollutants including benzene, toluene, ethyl benzene, and xylene.

TM estimates that some types of air pollution will be reduced with the TMEP as tank vapour activation units will be installed at the Westridge Terminal (TM, 2013b, Vol. 5A p. 7-86-87). These reductions, however, are not necessarily a benefit of the TMEP if they could be installed without the TMEP. To reflect this possibility, we examine air emission damage costs in our BCA based on two scenarios: one showing the reductions in air pollution estimated by TM based on the assumption that the mitigation measures to reduce emissions could only be implemented if the TMEP is built, and one assuming that the mitigation measures can be implemented whether or not the TMEP proceeds.

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[11] BC Hydro has not produced an updated long run marginal cost estimate, so we have used the estimate from their 2013 study.

Our summary of air pollution damage costs estimated from several studies shows that there is a wide variation in air pollutant damage costs due to differing underlying methodological approaches, health and environmental impacts assessed, and physical and socio-economic characteristics of impacted areas (Table 11).

Table 11. Unit Damage Costs for Air Pollution

Pollutant	Social Damage Cost ($ per tonne)[1]			
	Matthews and Lave (2000)[2]	**Muller and Mendelsohn (2007)[3]**	**DEFRA (2011)[4]**	**Sawyer et al. (2007)[5]**
CO	2 – 2,278	n/a	n/a	n/a
SO_2	1,670 – 10,195	1,591 – 2,651	1,969 – 2,768	843 – 2,884
NO_X	477 – 20,607	530	1,110 – 1,619	2,228 – 2,747
PM_{10}	2,061 – 35,140	353 – 884	n/a	n/a
$PM_{2.5}$	n/a	1,944 – 5,832	17,495 – 25,487	5,577 – 7,108
VOC	347 – 9,544	530 – 884	n/a	119 – 291

Sources: Matthews and Lave (2000), Muller and Mendelsohn (2007), DEFRA (2011), Sawyer et al. (2007). Notes: CO = carbon monoxide; SO_2 = sulphur dioxide; NO_X = nitrogen oxides; PM = particulate matter; VOC = volatile organic compounds. 1. All damage costs adjusted to 2017 CDN $. 2. Range for Matthews and Lave (2000) represents minimum and maximum damages. 3. Range for Muller and Mendelsohn (2007) represents average marginal damages in rural areas and urban areas. 4. Range for DEFRA (2011) represents low and high damage values. 5. Range for Sawyer et al. (2007) represents damage in Alberta and British Columbia.

We estimate air pollution costs of the TMEP using air emissions data provided by TM (TM, 2015a, p. 21; TM, 2013a, p. 200; EC, 2004) and the cost damage data summarized in Table 11. We generate estimates for three cases: a base case using the average damage costs for each pollutant, a high estimate using the upper end damage costs for each pollutant, and a low estimate using the lower end damage costs for each pollutant from Table 11. Based on these assumptions, air pollution from the TMEP could cause between $6 and $509 million (net present value) in social damage costs over the life of the TMEP. We caution that there is a wide range of uncertainty in damage costs from air pollution and that costs will vary depending on regional factors including the concentration of existing pollutants, exposure to newly emitted pollutants, the population impacted, and the physical and environmental characteristics of the impacted airshed.

4.9.2 Greenhouse Gas Emissions

TM estimates that the TMEP will emit 1,020,000 tonnes of GHGs during construction and 479,100 tonnes annually from pipeline, terminal, and marine operations in the TMEP defined study area from Burrard Inlet to Juan de Fuca Strait (TM, 2013b, Vol. 8A, p. 266; TM, 2015c, p.30). Other GHG sources indirectly associated with the TMEP are emissions associated with the extraction and end-use consumption of oil transported on the TMEP and marine transportation outside the 12-mile marine study area.

The NEB's list of issues for the TMEP (NEB, 2013d) explicitly excludes consideration of impacts associated with upstream oil production and downstream consumption and marine emissions outside of the study area. Consistent with the NEB's directive for the TMEP hearings, we have omitted the cost of upstream and downstream GHG emissions from our analysis. However, we note that the upstream and downstream effects of oil account for approximately 99% of the GHG emissions associated with oil and hence our BCA includes only about 1% of the GHG emission costs (IHS CERA, 2010). GHG emissions associated with the production and consumption of oil transported on the TMEP is a concern to many Canadians and need to be assessed at some point in the project evaluation process.[12]

One approach to measuring GHG costs is to estimate the "offset costs" to eliminate or reduce emissions to avoid damage. BC, for example, has a carbon offset program based on a target cost offset of $25 per tonne of carbon dioxide-equivalent (PCT, 2014). However, an evaluation of offset programs by the BC Auditor General concluded that offset programs provide inaccurate estimates of offset costs because many of the offsets are based on investments that would have already been made to reduce GHG emissions without the payment and therefore do not represent the costs of incremental reductions (BC OAG, 2013).

A second approach is to use abatement costs. Stern (2009) estimated abatement measures to achieve GHG reductions at approximately 30 euros per tonne (approximately $45 Canadian), while Canada's since dissolved National Roundtable on the Environment and Economy estimated prices for carbon dioxide-equivalent required to achieve Canada's medium- and long-term goals of reducing GHG emissions by 20% below 2006 levels by 2020 and 65% by 2050 (NRTEE, 2009) to be $100 per tonne (2006$, or $120 in 2017$) by 2020 rising to $300

[12] There is uncertainty whether the new pipeline projects such as the TMEP result in an increase in oil production and an associated increase in GHG emissions. Our analysis assumes that if the TMEP is not built, other transportation facilities would be used in place of the TMEP and therefore building the TMEP does not directly result in increased oil production. GHG impacts of increased oil production should be assessed as part of an overall energy and climate change policy instead of being assessed as part of specific transportation project by project assessments.

(2006$) by 2050.

A third approach to estimating GHG damage costs is to estimate the social cost of GHG damage. In a meta-analysis of the social cost of carbon, Tol (2011) examines 311 estimates of the social cost of carbon in 61 studies from 1991 to 2010. The average mean and average mode marginal cost estimates are $177 and $49 per tonne, respectively (1995 US $). In more recent reviews, Weitzman (2013) and van den Berg and Boltzen (2015) caution that most GHG damage cost estimates – including many reviewed by Tol in his 2011 study – are too low because they do not incorporate the willingness to pay to avoid potentially catastrophic events.

Given the problems with reported offset costs in BC, and uncertainty as to whether offsets would in fact be implemented for the TMEP, we use the social damage cost approach based on damage costs recommended in US government guidelines (US GAO, 2016). These US guidelines recommend using a range of damage costs to reflect the range of potential GHG emission damage costs. For our base case we use the US government (US GAO, 2016) recommended cost of $56 per tonne (2017 CDN $) in 2018, and for our sensitivity we use the upper range US government cost of $162 per tonne (2017 CDN $) in 2018. The US government GHG cost estimates escalate in real terms over time. This two tier approach is similar to the approach used by the Canadian government in its regulatory evaluations of carbon emission reduction programs (Canada, 2013). Based on this approach, we estimate that net GHG damage costs from the transportation of oil on the TMEP (excluding upstream and downstream emissions) are between $359 million and $1.08 billion (net present value).[13]

We account for the effect on the TMEP of the carbon pricing system introduced in 2016 by the federal government in a sensitivity analysis. The Pan-Canadian Framework on Clean Growth and Climate Change agreed to by a majority of provinces and territories, including BC and Alberta, includes a carbon pricing benchmark rising to $50 per tonne of carbon dioxide in 2022. In a sensitivity analysis, we assume carbon taxes are collected for emissions occurring in BC and Alberta from TMEP according to the federal benchmark, resulting in a partial offset of the damage costs associated with these GHG emissions of $219 million (net present value).

[13] A challenge in estimating the GHG impacts of the TMEP is in estimating what the net increase in emissions would be after taking into account potential reductions in emissions from lower shipments on other pipelines. The net increase in emissions will be lower than our gross emission estimate to the extent that GHG emissions are reduced by lower shipments and consequently lower power consumption on other pipelines. All GHG emissions from construction of the TMEP will be incremental.

4.9.3 Oil Spill Damages

Spills from tanker and pipeline operations associated with the TMEP have the potential to lead to significant environmental costs. We estimate spill costs based on an expected value calculated as:

*Annual expected value = p*c*q*

where:

p is the annual probability of a spill (i.e., the inverse of the return period);

c is the damage and clean-up cost per volumetric or areas unit of spill (barrels or hectares); and

q is the size of the spill (in barrels or hectares).[14]

We use oil spill probability and damage costs estimates for spills based on the findings of Gunton and Joseph in their oil spill risk assessment report of the TMEP (Gunton and Joseph, 2018).[15]

4.9.3.1 Tanker and Terminal Spills

The US government's oil spill risk analysis (OSRA) model is the standard method used by the US government to assess marine oil spill probabilities.[16] The US government publishes tanker and terminal oil spill rates for their OSRA model disaggregated by port and at sea (US BOEM, 2016). The OSRA model defines spills in ports as spills that are in close enough proximity to shorelines to impact shoreline environment. For the base case, we use the OSRA in-port probability for a tanker spill because the in-port spills are more likely to reflect the risk and damage costs to the Canadian environment. While tanker spill costs based on spills that occur in-port are likely more indicative of costs incurred by Canadians since they occur in Canadian waters, these

[14] This approach is consistent with BCA theory (Zerbe and Bellas, 2006) and was the approach that Enbridge used to assess the costs of oil spills in its NGP application (Wright Mansell, 2012).

[15] We provide only a brief summary of the spill probability and costs assumptions here. For more detailed background consult Gunton and Joseph (2018).

[16] The model has been peer reviewed and used in a variety of environmental impact assessment reports and the model's data have been recently updated to include impacts of mitigation measures adopted over the last few decades to reduce the probability of tanker spills (US BOEM, 2016).

costs understate total costs associated with the TMEP tanker spills because they exclude at-sea spill damages. Therefore, we include a sensitivity analysis using probability data for tanker spills that occur in-port and at-sea from the OSRA model, as this estimate provides a more inclusive measure of potential spill costs associated with the TMEP. We also complete a sensitivity using a lower estimate of spill probability based on TM's tanker and terminal spill probability estimates in the TMEP application. We note that the evaluation of oil spill risks by Gunton and Broadbent (2015) and Gunton and Joseph (2018) identify 27 deficiencies with the TM spill probability estimates, some of which result in an underestimate of spill risk. Also, TM's lower probability tanker spill estimates are significantly lower than estimates generated by other studies and methods. Consequently, we use one of TM's mid-range probability estimates (called New Case 1) with a return period of 90 years for any size tanker spill. Table 12 presents the parameters used in our oil spill damage costing.

Table 12. Summary of Major Marine Spill Parameters for Oil Spill Cost Estimates

	Base Case: OSRA (in-port)	Sensitivity Analysis	
		Higher Estimate: OSRA (in-port/at-sea)	**Lower Estimate: TM's New Case 1**
Annual Probability[1]	0.031	0.071	0.011 (Tanker) 0.045 (Tanker and Terminal)[2]
Mean Size Tanker Spill	50,313 barrels	50,313 barrels	8,184 barrels[3]
Damage Cost[4]	$40,181/barrel	$40,181/barrel	$40,181/barrel (Tanker) $21,609 (Terminal)

Sources: Gunton and Broadbent (2015), Gunton and Joseph (2018), US BOEM (2016); TM (2013b, TERMPOL 3.15; 2015b). Notes: 1. The annual probability for the base case represents spills that occur in-port estimated with the OSRA model, while the higher estimate represents combined in-port and at-sea spills from the OSRA and the annual probability for TM Case 1 is just at-sea spills. 2. The annual probability of 0.045 for the lower sensitivity analysis scenario is the combined probability for terminal and at-sea spills. Actual spill costs are calculated by using the annual probabilities for terminals and tankers separately (not combined) 3. Mean size spill for TM New Case 1 is based on US BOEM (2016) estimate of the median size tanker spill. 4. Costs are based on Wright Mansell (2012, p. 77) updated to 2017 CDN $. Estimation of spill damage costs for the sensitivity scenario sums the cost of at-sea spills and terminal spill costs. Terminal spill costs are estimated by using an annual probability of 0.029 for terminal spills <63 barrels and 0.0043 for terminal spills > 63 and <629 barrels; spill damage costs for TM New Case 1 terminal spill costs based on TM's (2013b, Vol. 7 App. G p. 24) estimated cost of $20,350/barrel updated to 2017 dollars.

In their BCA of the ENGP, Wright Mansell uses two marine damage spill costs: $37,500/barrel (2012$) for the base case and a sensitivity analysis in which they double the cost of a marine oil spill to $75,000/barrel (2012$) (Wright Mansell, 2012, p. 93). We use their base case damage cost of spills of $37,500/barrel (2012$) updated to $40,181 (2017$). This estimate is comprised of clean-up costs ($15,000/barrel) plus damage costs ($22,500/barrel) and is based on an extensive review of the tanker spill cost literature. Wright Mansell concludes that their spill cost estimate is at the high end of the estimates in the literature but justifies it on the grounds that “higher unit costs should be used in cost benefit analyses where public safety and risk concerns are being evaluated for a hypothetical event” (Wright Mansell, 2012, p. 81). We agree with Wright Mansell on the use of a conservative approach when examining the potential costs of oil spills.

We caution that Wright Mansell’s spill cost estimates may underestimate actual damage costs. Wright Mansell’s tanker spill cost estimate relies on studies from Kontovas et al. (2010) that estimate tanker spill cost data from the International Oil Pollution Compensation Fund (IOPCF) which has several weaknesses. First, the cost data from the IOPCF dataset represent only the amount of money the IOPCF agrees to compensate claimants, and this amount is often less than the damage costs (Thébaud et al., 2005).[17] Second, IOPCF payments are limited by maximum payout limits set by the funds and therefore only compensate a portion of total spill damages if damages exceed the fund limits.[18] Third, IOPFC data exclude several types of damage costs including non-market use values and passive use values. Fourth, tanker spill cost data represent world averages that are not adjusted for geographically-specific differences in damage costs to the environment impacted by the spill. Costs of spills can vary significantly depending on the characteristics of the area impacted, the conditions at the time of the spill, the spill response, and the characteristics of the oil spilled (Vanem et al., 2008). For these reasons, Wright Mansell’s $37,500 per barrel damage cost (2012$) may underestimate actual tanker spill costs.

For terminal spills we use the probability and clean-up cost estimates contained in the TMEP application (TM, 2013b, Vol. 7 App. G, p. 24). Terminal costs are only calculated for the marine spill cost estimate (New Case 1) and not the OSRA estimates because the OSRA already incorporate port spills in the return period estimates.

4.9.3.2 Pipeline Spills

Alternative estimates for pipeline spill probabilities are summarized in Table 13. For our

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[17] Thébaud et al. (2005) determine that the percentage of compensation claimed from the IOPCF compared to compensation actually paid to claimants for six large spills (*Amoco Cadiz*, *Tanio*, *Aegean Sea*, *Braer*, *Sea Empress*, and *Erika*) ranged from 5% to 62%.

[18] For example, victims of the 38,000 tonne (278,500 barrel) *Prestige* oil tanker spill only received €172 million from the 1992 Civil Liability Convention and the 1992 International Oil Pollution Compensation Fund, which represented only 2% of the total long-term spill costs (Liu and Wirtz, 2006).

base case we use the probabilities and average size spills based on PHMSA data, which we consider the most comprehensive data set on pipeline spills publicly available and is used by the US government in its Keystone XL environmental impact assessment (USDS, 2014). Note that PHMSA return periods are between the return periods based on Enbridge historical spill data and the return period estimated by TM.

Table 13. Comparison of Pipeline Spill Risk Estimates for TMEP Line 2

Source of Spill Rates	Size and Type of Spill	Return Period (years)[1]
TMEP	Line 2 Rupture	2
NEB	Line 2 spill (> 9 barrels)	2
PHMSA	Line 2 spill (any size)	0.5
Enbridge	Line 2 spill (any size)	0.3

Source: Gunton and Broadbent (2015). Note. 1. Return periods are for only TMEP Line 2, which comprises 540 kbpd of the 590 kbpd of the TMEP, and therefore our estimates of pipeline spill costs may under-represent the spill costs for the TMEP because about 10% of incremental TMEP oil shipments are excluded.

Estimates of pipeline spill damage costs range from about $3,000 to $174,000 per barrel depending on the size of spill, the type of oil, and the area impacted (Table 14). We use the PHMSA average spill damage cost of about $15,000/barrel (weighted average of ruptures and leaks) which is in the mid-range of spill cost estimates because it is based on a large number of spills and is consistent with the PHMSA average spill size and probability data that we use (PHMSA, 2014b; PHMSA, 2014a). This results in an average cost per pipeline spill in our BCA of $4.0 million, which is then used to estimate the annual expected value of a spill by multiplying the cost times the annual probability.

Table 14. Summary of Alternative Spill Cost Estimates per Barrel for Pipelines

Type of Spill[1]	TMEP Application	BOSCEM	PHMSA 2010-2014	Enbridge Line 6B	ENGP Application
Leak	$29,405 - $90,477	$13,224 - $174,190	$3,320	n/a	$10,501
Rupture	$6,785 - $16,878	$3,148 - $50,887	$32,027	$62,676	$12,858

Sources: TM (2013b, Vol. 7), Etkin (2004), PHMSA (2014b) Enbridge (2015), and Wright Mansell (2012).

We caution that the PHMSA cost data may underestimate average spill costs by excluding some relevant socio-economic and environmental costs. For example, the PHMSA dataset includes costs to non-operator private property damage although it is not clear whether these costs include compensation for individuals or businesses whose livelihoods have been disrupted and groups whose cultural activities have been disrupted. Similarly, although PHMSA data include costs to remediate the environment, it is uncertain what portion of total environmental costs are covered by the remediation expenses. For example, excluded damage costs could include compensatory damages to the public for loss of use of the environment and lost ecological services while the spill site is recovering. Third, spill costs do not include passive use values that reflect the value that individuals place on the protection or preservation of resources or psychological costs associated with factors such as stress and dislocation of impacted parties. We acknowledge that to the extent that toll costs include insurance premiums to cover oil spill damage costs, the costs of TMEP pipeline spills may to some degree already be incorporated in the costs of pipeline operations. Also reduced shipments on other pipelines resulting from building the TMEP may lower oil spill risk oil spill risk on other pipelines thus to some degree offsetting the oil spill risk costs from the TMEP.[19]

4.9.4 Passive Use Damages

Passive use values are the values that people place on the protection or preservation of natural resources and the environment that they may not directly use (Freeman, 2003; Kramer,

[19] Estimating the reduction in spill risk and spill damage resulting from reduced shipment on existing transportation facilities is challenging because spill risk and spill damage is a function of the volume shipped, length of the pipeline system, and the location impacted. Diverting volumes will reduce the volume shipped in existing transportation facilities but will not change the length of the pipeline system.

2005). Estimating passive values is challenging and for some stakeholders and First Nations monetary estimation of passive values may not be viewed as possible or appropriate. Nonetheless, passive values exist and should be taken into account in assessing the costs of project development.

A common method for estimating passive use values is a contingent valuation study that relies on surveys to ask stakeholders to place a value on specific resource and environmental assets (Carson et al., 2003). For the TMEP, First Nations and stakeholders could be asked how much they would be willing to pay to eliminate the risk of a major tanker spill in the Georgia Basin or how much compensation they would require to accept the risk posed by increased tanker traffic. TM has not undertaken this type of contingent valuation study for the TMEP.

A second approach is the benefit transfer method that adopts damage cost values from a contingent valuation study conducted elsewhere. This approach is recommended when there is insufficient time and resources to complete an original valuation study (Brouwer, 2000; Boardman et al., 2011; Johnston et al., 2018). Good practice in benefit transfer includes selecting appropriate transfer studies that: have similar environmental characteristics and similar non-market commodities being valued; rely on good data; and use sound economic methods and empirical techniques (Boyle and Bergstrom, 1992; Desvousges et al., 1992; Johnston et al., 2018).

We estimate potential passive use values for marine oil spill risk for the TMEP using the benefit transfer method based on two studies estimating WTP to prevent damage from oil spills in Alaska and California. The first study completed by Carson et al. (1992), and updated by Carson et al. (2003), estimates how much US residents would be willing to pay to prevent oil spill damage from another oil spill similar to the *Exxon Valdez* oil spill (EVOS) disaster.[20] Another contingent valuation study from Carson et al. (2004) estimates the amount that households in California

[20] The *Exxon Valdez* ran aground on Bligh Reef on March 24, 1989 releasing 258,000 barrels of crude oil that contaminated 1,900 km of shoreline and spread over 750 km from the point of impact. The EVOS caused short- and long-term impacts to marine vegetation, marine invertebrates, fish and fish habitat, marine birds, marine mammals, the regional economy, and subsistence activities of Alaska natives (EVOSTC, 2010). As of 2010, 19 of the 32 environmental and human resources injured by the spill have yet to recover (EVOSTC, 2010).

would be willing to pay to prevent oil spill damage along the California Coast.[21] The Carson studies are among the most sophisticated contingent valuation studies for assessing passive use values.[22]

The per household willingness to pay (WTP) estimated in the two Carson studies are similar despite the different oil spill scenarios and populations surveyed. The EVOS study (Carson et al., 2003) estimates a lower bound mean WTP value of $53.60 (1991 US $) per household and an upper bound value of $79.20 (1991 US $). The California oil spill study (Carson et al., 2004) estimates a lower bound of $76.45 (1995 US $), which is in the mid-range of the EVOS estimates after adjusting for inflation.[23] Carson et al. (2004) caution that the results between the two studies are not directly comparable because of the differences in the scenarios and populations tested (Table 15).

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[21] Carson et al. (2004) do not define the volume of oil spilled in the California oil spill study in order to focus on the damage that the spill would cause. Instead, the authors provide a description to survey respondents of the spill effects resulting from the harm that is expected to occur from moderately large spills along the California Coast. Carson et al. (2004) avoid mentioning the EVOS in the survey to prevent respondents from answering questions with the belief that they were valuing spill prevention from a spill the size of the EVOS, not comparatively smaller spills along the California Coast.

[22] The courts and independent experts scrutinized the study's results and the study underwent the peer review process for refereed publications when it was published in *Environmental and Resource Economics* in 2003.

[23] EVOS estimates are $60 and $89 in 1995 US $.

Table 15. Comparison of EVOS and California Oil Spill Studies

Study Feature	EVOS Study	California Oil Spill Study
Spill location	South Central Alaska Coast	Central California Coast
Spill prevention mechanism	Escort ship program that would prevent a second EVOS over the next 10 years	Escort ship program that would prevent cumulative damage from oil spills along the California Central Coast over the next 10 years
Description of injuries from a spill	1,000 miles of shoreline oiled 75,000 to 150,000 bird deaths 580 otters and 100 seals killed 2 to 5-year recover period	10 miles of shoreline oiled 12,000 bird deaths Many small plants and animals killed 10-year recovery period
Payment vehicle	One-time increase in federal income taxes	One-time increase in state income taxes
Residents sampled	United States	California

Source: Adapted from Carson et al. (2004).

While undertaking a contingent valuation study specifically for the TMEP would be the most accurate way of estimating passive use values for this project, the two contingent valuation studies by Carson et al. (2003; 2004) on oil spill prevention can provide an order of magnitude assessment of the monetary cost of oil spill risk created by the TMEP because the Carson studies used best practices methods, are assessing the WTP to prevent marine oil spill risk, and the BC study area has many similar biophysical and socio-economic characteristics to those of Alaska and the California Coast. Nonetheless, there are a number of issues and qualifications that should be noted.

One issue in using the Carson studies is that they are based on the WTP to prevent oil spills. Another way to frame the question is to ask individuals what compensation they would require to accept the increased risk of an oil spill. Values derived from asking the willingness to accept (WTA) question are significantly higher than values derived from asking WTP because one's WTA a change that is perceived as a loss tends to be valued much more highly than one's WTP to prevent the loss (Rutherford et al., 1998; Horowitz and McConnell, 2002; Knetsch, 2005). Horowitz and McConnell (2002), for example, evaluated 45 studies with WTA/WTP ratios and found that WTA values were on average 10.4 times higher than WTP values for public and non-market goods.

Determining which measure is appropriate depends on prior rights regarding the ownership of the resource or the reference point that individuals use to value the underlying good or service (Knetsch, 2005; Zerbe and Bellas, 2006; Shaffer, 2010). Unlike private goods defined by legal entitlement, the marine environment along the BC coast is collectively held. There is no consensus on whether WTA or WTP is the most appropriate in cases involving collective ownership cases, with some arguing that WTP should be used (Mitchell and Carson, 1989) and others concluding that WTA is more appropriate because proposed projects will alter the status quo, which stakeholders perceive they have a right to maintain (Knetsch, 2005). However, in the case of increasing oil spill risk, Carson et al. (2003) state that WTA is a more appropriate measure because oil spills result in a loss of values relative to the status quo. We agree with Carson et al. (2003) that WTA is the most appropriate measure for oil spill risk but we provide both WTP and WTA estimates with the qualification stated by Carson et al. (2003) that the WTP is a conservative estimate of passive value damages.

Another issue with applying the Carson et al. (2003) WTP estimates is whether to adjust the potential passive use damage estimate by the probability of a spill to give expected values, or to assume that the survey respondents are already providing an estimate of the expected value because they are being asked what they would be willing to pay to reduce the likelihood of tanker spill damage from its current probability to zero. Both the EVOS and California contingent valuation studies by Carson et al. (2003) are structured in a way that asks what people would be willing to pay to reduce the oil spill damages from the current likelihood to zero risk of damage. Therefore, respondents are providing a WTP that does not need to be adjusted for likelihood of occurrence of a spill. However, although respondents were provided with some information of the likelihood of spills, it is unclear how respondents perceive probabilities of spill damage with and without the spill damage prevention measures for which they are being asked to pay. Therefore, we conduct a sensitivity analysis scenario in which we test the impact of adjusting the passive value damage estimates by the probability of a large spill occurring to generate an expected value.

Carson et al. (2004) found that the WTP varies with a number of factors including the distance that respondents lived from the impacted site. We expect that this same relationship would hold in Canada, with those closer and those more familiar with the Georgia Basin having higher WTP and WTA values than those further away or less familiar. Although the WTP we are using should already incorporate this because they are based on a national survey, we develop a scenario in which we only apply the WTA to BC households in addition to scenarios that include all Canadian households, with the qualification that the national survey results likely underestimate the WTP of BC residents to avoid marine oil spill risks.

To estimate passive use values for the TMEP tanker spill risk we use the upper and lower bound of Carson et al. (2003) EVOS study estimates of US household WTP. Given that these estimates are based on a national survey of Americans, we also use a national approach and multiply WTP (adjusted to 2017 CDN $) by the total number of households in Canada.[24] To provide an order of magnitude estimate of potential WTA values we adjust WTP estimates with the WTA/WTP ratio of 10.4 for public and non-market goods from Horowitz and McConnell (2002). We also provide an estimate of the WTA applied to just BC households. We use the upper bound WTP for Canadian households for our base case ($2.4 billion) because this scenario is the most consistent with the national parameters of Carson et al.'s (2003) study and the upper bound better reflects the increase in the WTP that is likely to have occurred since the study (1991) due to the increase in real incomes.

The alternative estimates of the risk of marine spills to passive use value range from a low of $1.6 billion based on WTP for Canadian households to a high of $2.8 billion based on WTA for BC households (Table 16). We could also include a WTA estimate for Canadian households which would be as high as $24.9 billion, but we have decided not to include this estimate in our sensitivity analysis because an accurate estimate of WTA for the Canadian population would require additional survey research. Our base case of $2.4 billion (upper bound of WTP for Canadian households) is at the lower end of the range and represents a very conservative estimate because it is based on WTP. For our sensitivity analysis we use the WTA for BC households ($2.8 billion).

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[24] We adjust lower and upper bound WTP values from the Carson et al. (2003) study for inflation, to convert US $ to Canadian $, and to aggregate the results to reflect the number of households in Canada in 2016 from Statistics Canada data.

Table 16. Estimate of Passive Use Values for Preventing Oil Spill Damages

Scenario	Total Passive Value Estimate to Prevent Marine Oil Spill Damage (million $)
WTP Canadian households (upper bound is base case)	$1,622 – 2,396
WTA BC households	$2,794

There are several qualifications with respect to our estimates of passive value damages of the TMEP that should be noted. First, the calculations of passive use reflect the values and attitudes of American society and are based on WTP values to prevent a major oil spill in Alaska, not BC. Canadians may value passive use damages impacted by a spill in BC differently than Americans value Alaskan spill damages. Second, although we use the upper end of the Carson et al. (2003) WTP range for our base case, we do not adjust their WTP values for increases in median household incomes since the study was conducted even though Carson et al. (2003) observe a strong association between higher incomes and a higher WTP to prevent another EVOS. Third, we estimate WTA for passive use damages based on a ratio for public and non-market goods from Horowitz and McConnell (2002) that may be higher or lower than the actual WTA for TMEP tanker oil spill risk. Fourth, Carson et al. (2003) characterize oil spill damages as short-term in their survey, with the environment recovering within five years (Carson et al., 2004, p. 194) yet the research on recovery of the Alaska coastline from EVOS shows that environmental recovery from oil spills tends to be much longer, with only 10 of the 32 environmental and human resource categories monitored having recovered 20 years after the oil spill (EVOSTC, 2010). Given that potential damages from a TMEP oil tanker spill could persist longer than stated in the EVOS study survey, passive use damages could be higher than Carson et al.'s (2003) estimates. The Carson et al. (2003) study was also done following a major oil spill and the *ex post* WTP for a major spill may be higher than the *ex ante* WTP to prevent a future spill. However, the similarity in *ex ante* WTP estimates in Carson et al.'s (2004) California study suggests the differences between *ex ante* and *ex post* may not be significant. Finally, we again caution that relying on estimates from a benefit transfer method is inferior to undertaking a contingent valuation study applied to the TMEP case which may produce higher or lower results than the benefit transfer method. We also caution that for some individuals, stakeholders, and First Nations there may be no amount of monetary payment that could compensate for oil spill damages. For these reasons, our estimates of passive use damages values should be viewed as only illustrative of the potential order of magnitude of passive use damages.

Another issue raised by TM (2015d) is that the Carson et al. (2003; 2004) studies may not be relevant to assessing passive use damages from oil spills in BC because the mitigation measures (i.e., escort ships and double-hull tankers) that respondents were asked their WTP for in the survey will be provided by projects such as ENGP and TMEP (Wright Mansell, 2012). This critique is based on a misunderstanding of the methodology. The mitigation measures used in the Carson studies asked respondents how much they would be willing to pay to implement mitigation measures to *prevent* oil spill damages, not reduce the likelihood of spill damage. Thus, while mitigation measures such as escort tugs and double-hull tankers are used in the survey to make the survey realistic, the underlying good that respondents are willing to pay for is prevention of spill damage, not the reduction in likelihood of spill damage. The fact that the TMEP may adopt similar mitigation measures may affect respondents' perception of the risk and their WTP to reduce it, but it does not eliminate the risk, which is what respondents were asked their WTP for on the Carson study. Consequently, Carson et al.'s (2003) estimates are not invalidated just because the TMEP may adopt similar mitigation measures similar to those used in the survey.

A final issue is the potential double counting of use values and passive values. A contingent valuation survey of British Columbians' WTP to reduce oil spill risk, for example, will capture both passive values and use values, the latter of which are already included in the spill cost estimates. However, given that Carson et al. (2003) surveyed non-Alaskans, the WTP estimates are unlikely to have included much in the way of use value. Consequently, transferring estimates of passive use damage costs from oil spills from the Carson studies to the TMEP case should not lead to double counting.

We note that the inclusion of passive use values in BCA is sometimes considered controversial. For example, the NEB (2016, p. 407) report on the TMEP rejected marine oil spill damage costs that included passive use values costs on the grounds that such costs are "overly hypothetical". The NEB's conclusion is inconsistent with accepted practice in BCA. For example, even project proponents such as Enbridge accept the validity of passive use values in their applications (Wright Mansell, 2012, p. 106-9). Nonetheless, given the controversy over passive values, we provide our BCA results with and without inclusion of passive value damages.

4.9.5 Damages to Other Ecosystem Goods and Services

The TMEP would cause damages to a variety of other ecosystem goods and services not already covered in previous subsections of our report. Construction, installation, operation, and maintenance of project facilities would result in habitat destruction, fragmentation of terrestrial species, loss of flora and fauna, changes in quality and supply of groundwater, and releases of sequestered carbon while marine operations could have negative impacts on marine ecosystems and species (TM, 2013b, Vol. 5). A BCA (Broadbent, 2014) for the ENGP estimated terrestrial ecosystem goods and services losses to be in the range of $8 million to $707 million net present value (2012$), indicating that losses of ecosystem goods and services from pipeline construction alone can be significant. We do not provide an estimate of these damage costs for the TMEP due to data limitations and thus our environmental damage cost estimates may underestimate the total costs of the TMEP.

4.10 Other Costs

In Appendix 1: Potential Adverse Impacts of the TMEP, we list 160 negative impacts associated with the TMEP of which only a few are monetized for our BCA results. We did not attempt to "monetize" most of these impacts into dollar amounts due to data limitations and methodological challenges in estimating the costs. Many of these impacts result from construction activities that can create social and economic problems such as increased prices for necessities (e.g., housing), increased social problems such as drug use and crime, and other problems caused by the influx of large transitory construction work forces into smaller communities. There are also many biophysical impacts, only several of which we have been able to estimate monetary damages for to include in our BCA (air pollution and GHG emissions).

It is important to emphasize that these non-monetized costs need to be taken into consideration in the TMEP evaluation even though they are not directly incorporated into the BCA. Our monetary estimates therefore underestimate the costs of the TMEP due to omission of these other adverse impacts.

4.10.1 Impacts on First Nations from Oil Spills

The importance of environmental valuation for First Nations was recently demonstrated by the decision of the Lax Kw'alaams First Nation in the Prince Rupert area of the North Coast who rejected an offer of over $1.1 billion in cash payments and land by the terminal and pipeline proponents of the Pacific Northwest LNG project and the BC government for the Nation's agreement to develop the project (Lax Kw'alaams Band, 2014). This amounts to an undiscounted

$308,000 per member of the First Nation.[25] The Nation rejected the offer on the grounds that the project would affect salmon habitat and have unacceptable environmental and cultural implications. As the Lax Kw'alaams First Nation stated:

> *[h]opefully, the public will recognize the unanimous consensus in communities (and where unanimity is the exception) against a project where those communities are offered in excess of a billion dollars, sends an unequivocal message this is not a money issue: this is environmental and cultural (Lax Kw'alaams Band 2015, 2)*

No assessment has been made of the monetary value of the risk posed by the TMEP to First Nations such as TWN, but the decision by the Lax Kw'alaams First Nation to reject an offer of $1.1 billion for an LNG project that has no oil tanker spill risk illustrates that the valuation of potential environmental costs for a project that has a risk of oil spills such as the TMEP would be very high.

Oil spills can be particularly devastating to First Nations. Oil spills can result in reductions in subsistence and commercial harvests that can have potentially significant socio-cultural impact on Aboriginal people. The traditional lifestyle and culture of First Nations depends on food resources within the project area of the proposed TMEP. Marine resources harvested from traditional territories provide food, medicine, fuels, building materials, and resources for ceremonial and spiritual purposes. Fishing for food, social, and ceremonial purposes is a defining cultural practice of the traditional lifestyle of First Nations that has preserved close relationships throughout their territories and sustained the social structure of their communities.

It is difficult to monetize costs associated with losses from reduced subsistence harvest. However, research on the impacts of the EVOS spill on Aboriginal peoples shows that the costs can be significant. The EVOS caused long-term adverse impacts to the economic, cultural, and social infrastructure provided by traditional subsistence harvests (Fall et al., 2001). Subsistence harvests were negatively impacted by real and perceived contamination of resources and concerns over current and future scarcities of wild foods (Fall et al., 2001), and the influx of people following the spill (Miraglia, 2002). These disruptions coincide with an average 50% reduction in

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[25] According to the federal government, the Lax Kw'alaams First Nation has a total registered population of 3,733 (AANDC, Undated). The undiscounted total benefits package amounts to $1,149,983,183 (Lax Kw'alaams Band, 2014). If the benefits package is discounted at 8%, the total package amounts to a net present value of approximately $374 million, or $100,206 per member.

the production of wild food volumes in spill-affected communities (Fall et al., 2001). When subsistence harvests eventually returned to near pre-spill levels 14 years after the EVOS, there was a change in the composition of harvests with a reduction in the proportion of marine mammals relative to fish due to the reduced number of marine mammals and the perception that mammals were contaminated and unsafe to eat (Fall et al., 2001).

Another cost of the EVOS was psychological stress caused by the disruption of traditional and cultural practices. Palinkas et al. (1993) found that exposure to the EVOS was significantly associated with the post-spill prevalence of generalized anxiety disorder, and an increase in drinking, drug abuse, and domestic violence. Further, Alaska Natives perceive long-term cultural effects including impairment of intergenerational knowledge transfer (Fall, 2006). The EVOS disrupted opportunities for young people to learn about cultural practices and techniques, and almost three-quarters (72%) of Alaskan Natives stated that their traditional way of life had not recovered from the effects of the oil spill (Fall, 2006).

The resolution of compensation issues from spill damage also imposed large costs on impacted parties. Difficulties and uncertainties in resolving compensation issues are exemplified by the drawn out, 20-year court case seeking punitive damages against Exxon in the aftermath of the EVOS. Alaska Natives impacted by the EVOS were particularly exposed to the uncertainties and stressors of ongoing litigation (Fall et al., 2001). As Picou et al. (2009) conclude:

> *[t]hese findings reveal that litigation resulting from the EVOS has perpetuated negative community and individual impacts for over a decade. As such, litigation functions as a "secondary disaster" that denies community recovery by fostering a necessary adversarial discourse that divides and fragments communities long after the original technological catastrophe. This legal discourse results in repeated reminders of the original event and victims continue to be economically impacted, disrupted and stressed by court procedures and appeals that appear unfair and irrelevant to the original damage claims (p. 306-07).*

4.10.2 Conflict and Opposition

Another potential social cost that is difficult to value monetarily is the cost of major conflict over the building of the TMEP as a result of opposition to the Project. Polls show strong opposition to major crude oil pipeline projects in BC. Many interveners including the City of Vancouver, the City of Burnaby, and some First Nations are opposed to the TMEP and there have been demonstrations against the TMEP. The ongoing legal and political conflict over the TMEP is indicative of the types of legal and other costs associated with attempting to develop projects that may lack "social license". Trying to build a major project in such a conflicted environment may result in significant costs in the form of both direct costs associated with resolving disputes and indirect costs resulting from impairment of Canada's international reputation and business environment. For example, in its most recent annual report, Enbridge (2015, p.113) identifies opposition to its projects as a significant business risk affecting Enbridge's reputation. Although none of these potential costs are included as monetary values in our BCA, the costs could be significant.

4.11 Benefit Cost Analysis Results

Our multiple account BCA results are summarized in Table 17 and Table 18. The results of the BCA for the base case (Table 17) show that the TMEP will result in a **net cost to Canada of $9.4 billion** without inclusion of passive value damages and **$11.8 billion** with passive use damages. A large component of the cost is the cost of unused capacity of $6.9 billion, which will be borne by the oil transportation sector, oil producers, and the Canadian public in the form of reduced tax and royalty revenue.[26] The significance of unused capacity costs is not surprising given that the TMEP is forecast to contribute to unused capacity in the Canadian oil transportation sector to 2034 under our base case assumptions. Based on the lower range WCSB oil production forecast with operating and under construction projects only, there would be surplus capacity over the entire 30-year forecast period. Tax revenue benefits in the base case are minimal because most of the tax revenue to government is offset by costs to government and/or replaced by taxes generated in alternative economic activity if the TMEP is not built. Environmental costs are significant ($3.5 billion), comprising $359 million for GHG emissions, $103 million for other air pollution, $637 million for oil spills, and an additional $2.4 billion for passive use damages.

The results of our sensitivity analyses (Table 18) show that the TMEP has a **net cost** to Canada under all scenarios, ranging between costs of **$8.2 billion and $18.7 billion**. The highest net cost of $18.7 billion is based on a lower discount rating (3%). The assumption of an Asian price premium until 2038 reduces net costs while lower oil production and higher environmental impacts increase net costs. The lowest net cost of $8.2 billion is based on the assumption that Keystone XL is not built. **In sum, there is no likely scenario in which the TMEP results in a net**

[26] The distribution of unused capacity costs among various parties and governments is difficult to determine because it depends on many factors including the degree to which the costs result in higher transportation tolls that reduce netbacks to oil producers and reduce tax and royalty payments to governments.

benefit to Canada. Indeed, the only scenario that even approaches being a net benefit to Canada is one in which Keystone XL is not built, TMEP is able to be built at its last estimated cost of $7.4 billion, the TMEP results in an oil price lift benefit, employment benefits are higher than anticipated, and there are no oil spills or passive use costs. Under this highly unlikely combination of assumptions, the TMEP would still generate a net cost of $994 million.

An obvious question is why would the TMEP have been proposed if it is expected to be a net cost to Canada? The explanation is based on the existence of market failures. TM was presumably expecting to earn a reasonable return on the TMEP because it had negotiated contracts during a period of more optimistic expectations of oil development that would obligate shippers to pay tolls that could financially justify TM's investment. The costs, however, would be externalized onto other parties in the form of unused capacity costs and environmental and other externalities. Therefore, it may have been financially feasible for TM to build the TMEP even though the project would've imposed a net cost to Canada. However, even with long term contracts, Kinder Morgan considered the TMEP to be higher risk due to the rising costs of construction, regulatory delays, lower oil production growth forecasts, and increased number of alternative pipeline and rail projects that have emerged since the TMEP was originally proposed. As a result of increased risks, Kinder Morgan sold the TMEP to the Canadian federal government in August of 2019. Now that the TMEP is owned by the government, it could still be built even if it was uneconomic because the government is not required to earn a return for their shareholders and could therefore subsidize the Project.

We also note that the BCA results for the TMEP are very much a function of the fact that the TMEP will contribute to excess transportation capacity and the supposition that the TMEP therefore will have little to no impact on oil production in the WCSB. If and when the oil transportation system nears full capacity, decisions on new transportation capacity will affect WCSB production. In this case, a BCA of new transportation projects should include the full social costs and benefits of incremental oil production resulting from the availability of new transportation capacity, including factors such as resource rent benefits and environmental costs of upstream production such as GHG emissions. We have not conducted an evaluation of these upstream costs and benefits in our BCA.

Table 17. Benefit Cost Analysis Results for TMEP

Item	Net Benefit (Cost), Base Case (million $)	Sensitivity Analysis Range (million $)[1]
TMEP Pipeline Operations	(1,699)	(1,699) to 0
Unused Oil Transportation Capacity	(6,919)	(7,480) to (3,351)
Option Value/Oil Price Netback Increase	0	0 to 2,837
Employment	159	159 to 534
Tax Revenue	252	252 to 1,170
Electricity	(109)	No sensitivity
GHG Emissions from Construction and Operation of TMEP and marine traffic in defined study area	(359)	(1,084) to (140)
Other Air Emissions	(103)	(509) to (6)
Oil Spills	(637)	(1,363) to (76)
Passive Use Damages from Oil Spill	(2,396)	(2,794) to (2,396)
Other Socio Economic, Environmental Costs not estimated	See Appendix 1	
Net Cost Without Passive Use Damages	**(9,416)**	**(16,333) to (5,848)**
Net Cost with Passive Use Damages	**(11,812)**	**(18,729) to (8,244)**

Note. 1. Based on sensitivity scenarios summarized in Table 3 and Table 18.

Table 18. TMEP BCA Sensitivity Analysis Results

Scenario	Description	Net Benefit (Cost) (million $)
Base Case		(11,812)
Lower TMEP Capital Costs	$7.4 billion ($1.9 billion lower than base case)	(10,113)
Higher Unused Capacity Cost	Diverted shipments from Cushing	(13,777)
Unused Capacity Cost based on TMEP Capital Cost approach		(8,753)
Lower Oil Production	WCSB operating and under construction projects	(12,374)
Lower Pipeline Transport Capacity	Keystone XL not constructed	(8,244)
Option Value/Oil Price Netback Increase	Average historical Asian premium estimated by MS (2010; 2012) from 2000-11 applied to 500 kbpd shipped on TMEP until 2038	(8,975)
Higher Employment Benefit	15% of construction and operating employment	(11,437)
Higher GHG Emission Damage Cost	Higher damage costs per unit	(12,538)
Higher Air Pollution Costs	Higher damage costs per unit	(12,218)
Lower Air Pollution Costs	Lower damage costs per unit and assumed mitigation	(11,716)
Higher Passive Values	WTA for BC households	(12,210)
Higher Oil Spill Costs	OSRA in-port/at-sea tanker spill probabilities (0.071 annual probability)	(12,538)
Lower Oil Spill Costs	TM probability for tanker spills (0.011 annual probability) and lower spill size (8,184 barrels)	(11,252)
Higher Discount Rate (10%)		(10,271)
Lower Discount Rate (3%)		(18,729)

4.12 Risk Assessment and Uncertainty

As our sensitivity analysis illustrates, different assumptions result in different estimates of the net impacts of the TMEP. In project evaluation it is important to assess the uncertainties underlying assumptions used in the evaluation and their implications on the net impacts of the project.

One principal variable impacting our BCA results is the cost of unused oil transportation capacity. This variable is in turn shaped by three variables – oil supply, transportation capacity, and the costs per barrel of unused capacity – and there is uncertainty in forecasting each one of these variables. As the recent downward revision of oil supply forecasts indicate, forecasting future oil production is uncertain. Higher oil production forecasts will reduce unused capacity while lower oil production forecasts will increase unused capacity. We have addressed this uncertainty by using a range of WCSB oil export forecasts in our sensitivity analysis. The results show that under all the oil supply scenarios tested there is still a large unused capacity cost (Table 17).

The second variable impacting our estimate of unused capacity costs is the magnitude of existing and proposed transportation projects. There is uncertainty in the projects that will be built, and their completion dates and capacity may therefore be lower or higher than forecast, resulting in lower or higher unused capacity estimates. We have addressed this uncertainty by using lower and higher transportation capacity scenarios and under all scenarios there is a substantial cost from unused capacity.

We acknowledge that some unused capacity resulting from construction of large, new pipeline projects is inevitable and can be beneficial in terms of providing flexibility in the transportation system. However, the magnitude of potential unused capacity in the Canadian oil transportation sector is unprecedented if all proposed projects are built and our BCA shows that the cost is not offset by the option value of accessing higher priced markets. It is also possible that transportation capacity could become constrained at some point in the future if oil production is significantly higher than forecast and/or new transportation facilities are not built as planned and this could result in reduced returns on Canadian oil. However, if there is higher than forecast production and/or lower than forecast capacity additions, there will be sufficient lead time to assess and accommodate these unanticipated changes to avoid any longer term shutting in of production.[27] There is, for example, surplus rail capacity that can respond relatively quickly to changes in demand and we have not included any rail capacity on our analysis. If, on the other hand, unneeded expensive pipeline facilities are built, the costs of the unused capacity are fixed and will impose long-term costs on the oil and gas sector, as well as costs to government in the form of lower tax revenue. For these reasons it is more advisable to err on the side of avoiding expensive, irreversible investments in pipelines that cannot be justified by forecast demand. We also reiterate that when and if demand justifies new capacity, the new capacity should be subject to a comprehensive benefit cost analysis.

The third variable impacting our estimate of unused oil transportation capacity costs is the per barrel cost of unused capacity. The costs of unused capacity depend on how much and from where the oil is diverted to be shipped on the TMEP. Our analysis assumes that the oil shipped on the TMEP would most likely be diverted from Enbridge's pipeline system due to Enbridge's lack of long-term contracts, but it is also likely that some diversions from other oil transportation systems such as Keystone XL may occur and the net revenue losses from oil diverted from Keystone XL may be lower than Enbridge. Further, the destination point for oil diverted from Enbridge is also unknown and as our estimates show, the destination assumption has a significant impact on unused capacity cost estimates. We have addressed uncertainty over destination points for diverted oil by using a range of unused capacity cost estimates based on different destinations. The sensitivity analysis shows that there are significant unused capacity costs for all of the scenarios tested. Therefore, while there is uncertainty over what transportation facilities are impacted by the diverted oil, this uncertainty does not alter the conclusion that there will be sizeable unused capacity costs.

Another important cost parameter in our BCA is environmental costs. Accurately estimating environmental costs is challenging. Many environmental impacts of the TMEP are not included in our benefit cost estimates because they are difficult to estimate in dollar terms (see Appendix 1: Potential Adverse Impacts of the TMEP). Inclusion of these impacts would increase our environmental cost estimates and the net cost of the TMEP. There are also environmental costs of shipping oil on other transportation facilities that could to some extent offset some of the environmental costs associated with the TMEP. We have not included potential avoided

[27] There can be short term constraints such as the current period (late 2018 and early 2019) in which transportation capacity is constrained and some reduction in production is warranted, but these periods are short term and mitigated by expansion of transportation capacity.

environmental costs on other transportation facilities in our BCA and inclusion of avoided costs would reduce our environmental cost estimates. We have also omitted all environmental costs associated with the upstream production of oil consistent with the NEB’s terms of reference.

Estimating the costs of oil spill damages is also challenging. There is uncertainty relating to oil spill probability and oil spill damage estimates that affect the accuracy of oil spill damage cost forecasts. We have addressed this uncertainty by testing different assumptions. However, while the impact of alternative assumptions affects the magnitude of the oil spill damage estimates, there is still a high cost from oil spills under all scenarios.

We also caution that our oil spill damage estimates may be conservative. Oil spill costs vary with the unique characteristics of the type of spill and impacted environment. We would expect spill costs to be higher in the Georgia Strait than spills in many other areas due to its high value environment (WSP, 2014). We also note the high values placed on environmental protection by the Lax Kw’alaams First Nation in its rejection of a $1.1 billion offer (just over $300,000 per person) to approve an LNG project. While there are many factors affecting this decision, the decision by the Lax Kw’alaams First Nation may indicate that current WTP estimates and WTA estimates commonly used in BCA studies, including ours, significantly underestimate environmental protection values.

5 Conclusion

The NEB has two criteria that need to be satisfied for a project to be recommended under the *National Energy Board Act*: that the project is clearly demonstrated to be needed, and that the project is clearly found to be in the public interest. The NEB (2016, 2019a) concluded that the TMEP is in the public interest because the benefits of the Project will exceed the burdens. In reaching this conclusion, the NEB did not use any systematic framework to compare benefits to burdens and therefore had a deficient evidentiary basis to reach its conclusion.

The best method for comparing costs and benefits to determine whether a project is in the public interest is BCA. We have completed a comprehensive BCA of the TMEP that shows that the TMEP will result in a **net cost to Canada ranging between $8.2 and $18.7 billion in net present value**. We tested a number of alternative scenarios and assumptions and found that under every scenario tested the TMEP results in a net cost to Canada.

We have also assessed the risks of approving versus not approving the TMEP. Oil production forecasts for the WCSB show wide variation reflecting high uncertainty regarding long-term oil prices and public policy developments on matters such as climate change. At the same time there are an unprecedented number of new WCSB oil transportation projects under consideration. Under CAPP's forecast, construction of the TMEP along with Enbridge Line 3, Enbridge mainline and Express expansions and Keystone XL would create excess pipeline capacity beyond 2051. In the under-construction forecast, construction of the TMEP along with just Enbridge Line 3 and mainline and Express expansions will result in excess capacity beyond 2051. The risk of building the TMEP as planned is that it would create an unprecedented magnitude of high cost surplus capacity. The risk of not building the TMEP as planned is low because if markets change and new transportation capacity is required earlier than forecast, there is sufficient lead time to develop new transportation capacity to accommodate demand and rail, which we have not included in our analysis, would be available to accommodate transportation needs.

We have also assessed the argument that the market will achieve the public interest by ensuring that only those projects that result in a net benefit to Canada will be built. We conclude that the oil transportation market is characterized by major imperfections that prevent the market from achieving public interest outcomes. Long-term shipping contracts and transportation investment decisions made during a market boom are difficult to change when market conditions change and the costs of uneconomic investments in new transportation capacity are externalized onto third parties and government. Therefore, the market can allow for the construction of the project such as the TMEP even if the project is not required and is not in the public interest.

We conclude that the TMEP is not in Canada's public interest and approving and constructing the TMEP will result in a significant net cost to Canada. We further conclude that NEB's (2016) evaluation of the TMEP is deficient and that there have been significant changes that have occurred since the NEB's evaluation that invalidate the findings of the NEB. The current NEB approach of evaluating proposed oil transportation projects on a case-by-case basis is deficient and that a better approach is to develop a comprehensive oil transportation strategy that assesses and compares all viable transportation options to identify the option or mix of options that meets the transportation needs of the Canadian oil sector in the most cost-effective social, environmental, and economic manner.

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Appendix 1: Potential Adverse Impacts of the TMEP

The following table lists potential adverse impacts of building and operating the TMEP that are identified in the TMEP application (TM, 2013b)

Type	Potential Impacts from TMEP
Heritage Resources	1. Disturbance to known and previously unidentified archaeological sites during field studies and construction 2. Disturbance to previously unidentified historic sites during field studies and construction 3. Disturbance to previously unidentified paleontological sites during construction
Traditional Land and Resource Use	4. Disruption of the use of trails and travel ways 5. Loss of habitation sites or reduced use of habitation sites 6. Alteration of plant harvesting sites 7. Disruption of subsistence hunting, fishing, and trapping activities 8. Disruption of marine subsistence activities including marine access and use patterns 9. Disturbance of gathering places and sacred areas 10. Disruption of cultural sites in the marine environment 11. Sensory disturbance during construction and operation (from noise, air emissions, lighting, visual)
Human Occupancy and Resource Use	12. Physical disturbance to protected areas and facilities, including trails and trailheads, within protected areas 13. Change to access of protected areas 14. Sensory disturbance of land and marine resource users (from noise, air emissions, lighting, visual) 15. Physical disturbance to First Nation Reserves, Aboriginal communities, and asserted traditional territories 16. Disruption of traditional land and marine resource use activities

Type	Potential Impacts from TMEP
	17. Change to access of First Nation Reserves and asserted traditional territories 18. Physical disturbance to residential areas and community use areas 19. Changes to all agricultural land uses including effects on livestock or agricultural plants due to the introduction of pests and disease 20. Disturbance of natural pasture, grazing areas, livestock movement and grazing patterns 21. Disturbance of field crop areas and organic and specialty crop areas 22. Disruption of farm facilities and risk to livestock and plant health 23. Physical disturbance of waterways used for recreational activities, outdoor recreation trails and use areas 24. Disruption to commercial recreation tenures and outfitting, trapping, hunting, and fishing activities 25. Disturbance to managed forest areas, Old Growth Management Areas, and merchantable timber areas and production 26. Decline in forest health during construction 27. Disruption of oil and gas activities and mineral and aggregate extraction activities 28. Physical disturbance to industrial and commercial use areas 29. Change to access for other land and resource users during construction 30. Alteration of surface water supply and quality for downstream water users 31. Alteration of well water flow and quality for water users 32. Alteration of viewsheds 33. Disruption to Rockfish Conservation Areas and marine access to protected areas 34. Physical disturbance to marine Aboriginal traditional use areas
Community Well-being	35. Change in population and demographics during construction and operations

Type	Potential Impacts from TMEP
	36. Changes in income patterns 37. Effects on community way-of-life from the presence of construction activity and temporary workers 38. Physical disturbance to community assets (e.g. schools, public facilities, parks) 39. Effects on Aboriginal harvesting practices and cultural sites 40. Effects on Aboriginal culture from employment opportunities and other TMEP activities
Infrastructure and Services	41. Increased traffic from transportation of workers and supplies including traffic safety effects 42. Physical disturbance to roads due to pipeline road crossings 43. Disturbance to railway lines 44. Physical disturbance to the Merritt Airport that could restrict the ability for flights to take off and land 45. Increased use of Port Metro Vancouver during construction and potential disruption to navigable water 46. Effects on linear infrastructure (e.g. sub-surface lines and power lines) and increased demand for power 47. Increase in water infrastructure demand including temporary increase in water demand during construction 48. Increased need for waste management during construction 49. Demand for housing during construction including upward pressure on rental price and/or short-term accommodations 50. Demand for post-secondary educational services/training 51. Demand for emergency, protective, and social services during construction 52. Use of recreational amenities by workers during construction
Employment and Economy	53. Reduced labour availability for other regional industries due to workers taking TMEP-related

Type	Potential Impacts from TMEP
	employment opportunities 54. Disruption to business or commercial establishments in the form of reduced income 55. Disruption to resource-based income or livelihoods
Human Health	56. Effects on mental well-being from demographic changes, changes in income, and changes to culture 57. Effects on alcohol and drug misuse 58. Increase in demand on mental health and addictions services 59. Increase in number of sexually transmitted infections 60. Increase in number of respiratory or gastrointestinal illnesses 61. Increase in stress and anxiety related to perceived contamination 62. Increase in traffic-related injury and mortality 63. Increased demand on hospitals, health care facilities, and emergency medical response services 64. Effects on diet and nutritional outcomes 65. Effects on mental well-being in Aboriginal communities
Marine Resource Use	66. Disruption to marine access and use patterns during construction and operations 67. Alteration of subsistence resources 68. Disturbance to cultural sites including sensory disturbance from noise, air emissions, lighting, and visual during construction and operations 69. Sensory disturbance for commercial, recreation, and tourism users (e.g. noise, lighting, visual, air quality) during construction and operation 70. Change in distribution and abundance of harvested species including marine fish and fish habitat 71. Displacement of commercial, recreational and tourism users around Westridge Marine Terminal during construction and operations 72. Change in commercial, recreational and tourism

Type	Potential Impacts from TMEP
	vessel access routes during construction and operations 73. Disruption to subsistence hunting, fishing, and plant gathering activities 74. Disruption to use of travel ways by traditional marine resource users 75. Disturbance to gathering places including increased sensory disturbance for marine users 76. Disturbance to sacred sites 77. Disruption to commercial fishing activities 78. Sensory disturbance (e.g. noise, visual effect, air quality) for commercial fishers, recreational users, and tourism users 79. Change in distribution and abundance of target species for commercial fishers 80. Alteration of existing movement patterns of marine commercial, recreational, and tourism users 81. Increased rail bridge operations 82. Marine vessels collision with built infrastructure, marine facilities or shoreline with a commercial, recreational, or tourism use 83. Marine vessel collisions with marine commercial users, other recreational users, and marine tourism users 84. Marine vessel wake effects on small fishing vessels, recreational vessels and tourism operator vessels 85. Negative recreational and tourism user perspectives of increased project-related marine vessel traffic
Accidents and Malfunctions (terrestrial and marine)	86. Spills of hazardous materials during construction and maintenance potentially resulting in contamination or alteration of surface or groundwater 87. Fires that may adversely affect adjacent property 88. Damage to utility lines that could interrupt services and lead to fires 89. Transportation accidents that could cause injury to people or result in a fire

Type	Potential Impacts from TMEP
	90. Use of explosives that could cause injury from flying rock 91. Security risk including damage from criminal activity 92. Change in marine water quality from an accidental release of contaminated bilge water 93. Physical contact between a tanker's hull and marine subtidal habitat from vessel grounding 94. Interference with navigation from a vessel grounding 95. Physical injury or mortality of a marine mammal due to a vessel strike 96. Venting of tanker at anchor or in transit 97. Negative recreational and tourism user perspectives of increased project-related marine vessel traffic
Physical Environment	98. Terrain instability due to slumping at watercourse crossings and sidehill terrain 99. Alteration of topography along steep slopes, slopes of watercourse crossings, sidehill terrain, and areas of blasting 100. Acid generation or metal leaching rock
Soil and Soil Productivity	101. Decreased topsoil/root zone material productivity during topsoil/root zone material salvaging 102. Decreased topsoil/root zone material productivity through trench instability during trenching, mixing due to shallow topsoil/root zone material, mixing due to poor colour change, and mixing with gravely lower subsoils 103. Decreased soil productivity resulting from changes in evaporation and transpiration rates, use of sand as bedding material, flooding of soil as a result of release of hydrostatic test water on land, disturbance (e.g., maintenance dig activities) during operations, trench subsidence, and soil diseases (i.e., clubroot disease and potato cyst nematodes) 104. Degradation of soil structure due to compaction, rutting, and pulverization of soil and sod

Type	Potential Impacts from TMEP
	105. Loss of topsoil/root zone material through wind and water erosion 106. Erosion of soil as a result of release of hydrostatic test water on land 107. Loss of topsoil/root zone material from disturbance (e.g., maintenance dig activities) during operations 108. Increased stoniness in surface horizons 109. Bedrock or large rocks within trench depth 110. Disturbance of previously contaminated soil 111. Contamination of soil as a result of release of hydrostatic test water on land 112. Soil contamination due to spot spills during construction
Water Quality and Quantity	113. Instability of trench at locations with high water table 114. Suspended sediment concentrations in the water column during instream activities 115. Erosion from approach slopes 116. Inadvertent instream drilling mud release 117. Alteration or contamination of aquatic environment as a result of withdrawal and release of hydrostatic test water 118. Reduction of surface water quality due to small spill during construction or site-specific maintenance activities 119. Alteration of natural surface drainage patterns 120. Disruption or alteration of streamflow 121. Shallow groundwater with existing contamination encountered during trench construction 122. Areas susceptible to drilling mud release during trenchless crossing construction, sedimentation in the aquifer, and blasting effects 123. Areas with potential artesian conditions 124. Aquifers (including unconfined aquifers) or wells vulnerable to possible future contamination from a spill during construction 125. Areas susceptible to changes in groundwater flow patterns

Type	Potential Impacts from TMEP
	126. Disruption of shallow groundwater in high permeable materials in proximity to rivers or watercourse crossings with fluvial materials or colluvium in the substrate 127. Disruption of groundwater flow where springs and shallow groundwater are encountered 128. Areas where dewatering may be necessary during pipeline construction activities 129. Impacts to shallow wells
Air Emissions	130. Project contribution to emissions: increase in air emissions during construction and increase in air emissions during site-specific maintenance and inspection activities 131. Dust and smoke during construction
GHG Emissions	132. Increase in carbon dioxide-equivalent emissions 133. Changes in environmental parameters (e.g., increase in global average temperature)
Acoustic Environment	134. Changes in sound level during construction and operation 135. Changes in vibrations during construction and operation
Fish and Fish Habitat	136. Riparian and instream habitat loss or alteration during construction, maintenance, and operation activities 137. Riparian and instream habitat loss or alteration from accidental drilling mud release 138. Contamination from spills during construction and maintenance 139. Increased access to instream habitat during operation 140. Fish mortality or injury during construction 141. Fish mortality or injury due to accidental release of hazardous materials during power line construction 142. Increased suspended sediment concentrations in the water column during instream construction or from accidental mud release 143. Increased access to fish and fish habitat during operations

Type	Potential Impacts from TMEP
	144. Blockage of fish movements 145. Effects on fish species of concern 146. Loss of habitat, mortality, or injury of Burbot, Northern Pike, Walleye, Bull Trout/Dolly Varden, Chinook Salmon, Coho Salmon, Cutthroat Trout, and Rainbow Trout/Steelhead
Wetland Loss and Alteration	147. Loss or alteration of wetlands of High Functional, High-Moderate, Low-Moderate and Low Functional Condition (i.e., habitat, hydrology, biogeochemistry) 148. Contamination of wetland function (i.e., habitat, hydrology, biogeochemistry) due to a spill during construction
Vegetation	149. Loss or alteration of native vegetation, the most affected vegetation communities, grasslands in the BG BGC Zone, rare ecological communities, and rare plant and/or lichen occurrences 150. Weed introduction and spread
Wildlife and Wildlife Habitat	151. Change in habitat, movement, and increased mortality risk of the following wildlife: Grizzly Bears, Woodland Caribou, Moose, forest furbearers, coastal riparian small mammals, bats, grassland/shrub-steppe birds, mature/old forest birds, early seral forest birds, riparian and wetland birds, Wood Warblers, Short-eared Owls, Rusty Blackbirds, Flammulated Owls, Lewis' Woodpecker, Williamson's Sapsucker, Western Screech-owl, Great Blue Heron, Spotted Owl, Bald Eagle, Common Nighthawk, Northern Goshawk, Olive-sided flycatcher, Pond-dwelling amphibians, stream-dwelling amphibians, and arid habitat snakes
Marine Sediment and Water Quality	152. Change in sediment quality during construction 153. Change in water quality during construction or operations
Marine Fish and Fish Habitat	154. Loss of marine riparian, intertidal, and subtidal habitat 155. Decrease in productive capacity of suitable habitat, injury, or mortality of Dungeness Crab 156. Decrease in productive capacity of suitable habitat,

Type	Potential Impacts from TMEP
	injury, or mortality of inshore Rockfish 157. Decrease in productive capacity of suitable habitat, injury, or mortality of Pacific salmon
Marine Mammals	158. Permanent or temporary auditory injury and sensory disturbance of Harbour Seals, Southern resident Killer Whale, Humpback Whale, and Stellar Sea Lion 159. Injury or mortality due to vessel strikes
Marine Birds	160. Change in habitat quality or availability, sensory disturbance, injury, or mortality of the following marine birds: Great Blue Heron, Pelagic Cormorant, Barrow’s Goldeneye, Glaucous-winged gull, and Spotted Sandpiper

Appendix 2: Deficiencies in TM's Assessment of Oil Price Netbacks for TMEP

Consultants to TM (Muse Stancil, 2015) estimate that the TMEP would increase netbacks for Canadian crude oil producers by an estimated $73.5 billion over the project's 20-year operating period. These benefits would result from: (1) a reduction in oil transportation costs with the TMEP as compared to rail shipping costs to the USGC; and (2) an increase in oil prices resulting from the reduction in supply of Canadian exports to the US market. These netback benefit estimates by MS are invalid because the method used to estimate them is flawed and they are based on outdated oil market data. Major changes in oil markets that have occurred since completion of the report in 2015 that invalidate the netback benefit estimates include:

- Higher capital cost forecasts for building the TMEP (from $5.5 billion used in the MS study to as high as $9.3 billion (KM, 2018)) that will result in significantly higher TMEP tolls;
- Lower WCSB production forecasts that reduce the demand for new pipeline space; and
- An additional 1,250 kbpd of proposed pipeline (Keystone XL (830) and Enbridge Mainline (450)) capacity that was not included in the MS analysis.

Changes in Oil Market Conditions Since Completion of MS Report

Since the completion of the MS report in 2015, Enbridge has announced plans to expand its mainline by 450 kbpd (Enbridge, 2018) and Keystone XL (830 kbpd) has been approved by the US President in March 2017, reversing a previous rejection by the Obama administration.[28] In addition, Enbridge Line 3 expansion has received approvals from Canada and the US and is expected to be completed in 2020.[29] MS omitted Keystone XL and Enbridge mainline expansion from its analysis and therefore underestimated likely pipeline capacity by 1,250 kpbd. Since completion of the MS report,

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[28] On November 9, 2018 a US court struck down the approval and required an additional environmental assessment review, but Trans Canada states that it is still committed to building Keystone XL despite the court setback (McCarthy, 2018). In March 2019, President Trump issued a new permit approving Keystone XL.

[29] Enbridge Line 3 environmental assessment approval was recently overturned due to an omission in the assessment that Enbridge is in the process of addressing. The implications of this on completion time is uncertain.

CAPP oil supply forecasts have come down due to weaker oil markets, with the most recent 2018 forecast for supply in 2030 being 370 kbpd lower than the 2015 forecast used by MS. As well, WTI prices for 2018 are currently (December 2018) in the low $50 range, well below MS's 2018 forecast of $79 (2018 US $).

Based on its outdated pipeline assumptions (omitting Keystone XL and Enbridge mainline) and outdated oil production forecasts, MS predicted that there would be insufficient pipeline space without TMEP and consequently WCSB oil would have to be shipped by higher cost rail to the US Gulf. According to MS, this shortage of pipeline space and reliance on higher cost rail would result in lower netbacks for Canadian producers. But as the supply/demand analysis in the BCA section of this report shows, the pipeline capacity and oil production assumptions used by MS are no longer valid. With Enbridge mainline expansions, Keystone XL, and the lower 2018 CAPP forecasts, there would be enough pipeline capacity to meet WCSB demand until 2034 without the use of any rail and without TMEP. Therefore, MS netback estimates that are based on the assumption of the need to use rail are no longer correct.

A second major change that invalidates the MS analysis is the escalation in TMEP's capital cost estimate, which has increased from the $5.5 billion used in the MS analysis to $7.4 billion in the most recent "final cost" review provided to shippers in March 2017 for confirmation of shippers' contracts (TM, 2017). In the recent valuation report to shareholders for the sale to the Canadian government, two capital cost estimates were provided: $8.4 billion based on an assumed completion date of December 31, 2020 and $9.3 billion based on an assumed completion date of December 31, 2021 (KM, 2018). Given the Project delays and the increased mitigation costs, it is likely that costs will be at the upper end of this range and may even exceed the $9.3 billion estimate. MS's (2015, p.61) estimated tolls of $4.70 per bbl (2018 Can $) for heavy oil delivered to the Westridge loading terminal in Vancouver based on the $5.5 billion cost is therefore no longer valid. The shippers' contracts provide for an increase of $.07 per $100 million in capital cost increase (TM, 2013c). Based on the $7.4 billion cost, tolls would rise by $1.33 per bbl and based on a $9.3 billion cost, the tolls would rise by $2.66 per bbl. As shown in Table 9 of the main body of this report, the tolls on TMEP shipments to Asia would now be higher than shipments to the US Gulf. MS's estimate of producer benefits based on outdated tolls are therefore is no longer valid. In fact, if TMEP tolls end up being higher cost than alternative pipelines to the US Gulf, the TMEP could result in a net producer cost, not a benefit as forecast by MS.

Inaccurate and Static Model Assumptions

A second problem with MS's estimates is that the model on which they are based is flawed. MS states that the increase in netback prices for Canadian oil exports is due in part to the reduction in supply of Canadian exports to the US market. As MS states, "[c]onsequently, about 79,500 m^3/d (500 kb/d) of crude oil is going overseas (including Hawaii), which reduces the volume of Canadian crude oil that must be consumed in the North American market by the same amount. It is a fundamental economic principle that reducing the supply of a commodity, all else equal, will increase its price" (MS, 2015, p. 10).

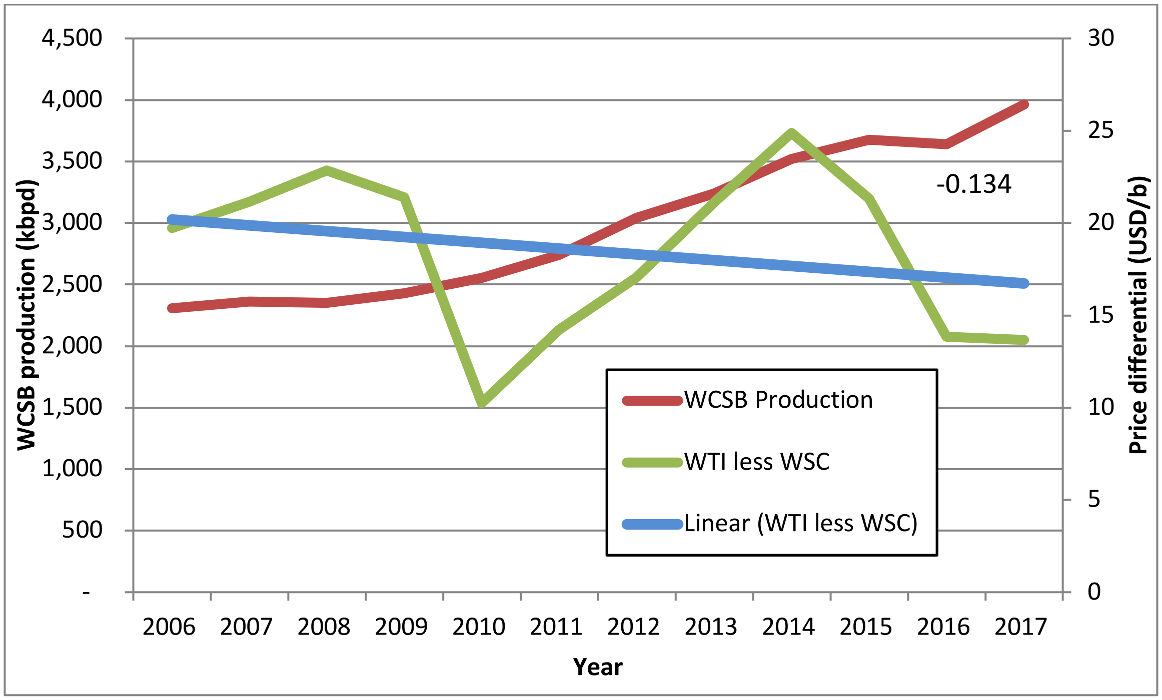
The problem with MS's analysis is that the linear programming model that MS used for its forecast is a static model that does not incorporate other adjustments in oil markets that would occur if WCSB exports to the US are reduced. If Canadian exports to the US are reduced by 500 kbpd several market adjustments will occur. First, the 500 kbpd increase in supply to Asia will put downward pressure on Asian oil prices while the reduction in supply to the US will put upward pressure on US prices. The result is that other producers will shift shipments from Asia to the US to respond to the shift in Canadian shipments, leaving overall supply and prices unaffected as markets adjust to restore market equilibrium. The reduction in Canadian shipments to the US will not therefore result in an increase in US prices for Canadian oil exports. MS's static model does not allow for these market adjustments and consequently the results are inaccurate.

A second static component of the MS model is the assumption that there will be no changes in refinery demand over the entire forecast period to 2038. Given the propensity of refineries to adjust to changing market conditions (e.g., reconfiguration of some US refineries to refine more heavy oil), MS's assumption of no change in the reconfiguration of refineries is unrealistic. Changes in refinery demand will impact price. Consequently, the price benefit estimates based on MS's refinery assumption are inaccurate.

A third deficiency in the MS model is the marginal cost pricing assumption that the price of all Canadian oil is determined by the price received by the marginal (highest cost) barrel of Canadian oil exported to the US. MS states that the marginal barrel of Canadian oil receives a lower price without the TMEP because of the increased supply to the US. However, MS also assumes that the price for oil in the US is unaffected by the TMEP. These two assumptions are inconsistent. If US oil prices are the same with and without the TMEP, Canadian shippers will get the same price for their oil regardless of whether the TMEP is built or not. The only circumstances in which Canadian oil prices would be affected is if there are impediments to market adjustments such as inadequate transportation capacity to get Canadian oil to markets. As the supply and demand analysis shows, while this transportation constraint has occurred in the past, it is unlikely to occur in the future and hence Canadian oil should not be discounted by more than market-based discounts based on differences in quality and transportation costs to market destinations. The delivered prices of Canadian oil in the US Gulf will be the same as similar quality oil from non-Canadian suppliers.

To test MS's hypothesis that increased Canadian exports to the US reduce Canadian oil prices we have plotted the relationship of WCSB production and the relative price of Canadian oil exports to international prices over the last decade (2006-2017) to see if there is any relationship between the relative price and changes in production (Figure 7). During this period, WCSB production and exports to the US have increased by approximately 1.8 million bpd. If MS's hypothesis is correct, we would expect the discount on Canadian oil prices relative to international prices to increase as Canadian exports to the US increase. In fact, the correlation between Canadian exports to the US and the price differential is weak and is driven by pipeline capacity. The difference between Canada Western Select (CWS) prices and WTI prices should be in the $13-$15 (US 2017 $) range based on differences in quality and transportation costs to markets in Cushing (CERI, 2017, 2018; NEB, 2018b). The average discount has been in close to this range ($16.22) from 2006 to 2017 but has fluctuated, with the discount being higher for the period 2011 to 2013 when the discount widened due to pipeline constraints (Figure 7). When the pipeline constraints eased with completion of more capacity from Canada to Cushing and from Cushing to the US Gulf refinery complex the discount was reduced despite the significant increase in Canadian exports to the US. In late 2018, the discount also rose due to pipeline constraints and other factors but is expected to return to normal levels when Enbridge Line 3 is completed in 2019, but then may increase to the $31 to $33 ranges due to quality differences combined with new International Maritime Office sulphur fuel standards (CERI, 2018). These price trends show that the oil market is a complex interaction of many variables and it is incorrect to assume as MS does that increased exports to the US will have a clear and predictable downward impact on Canadian oil prices.

Figure 7. Comparison of WCSB Production to Oil Price Differentials



Sources: CAPP (2017) for 2006-2009 and CAPP (2018) for 2010-2017 WCSB production. McDaniel (2018) for WSC and WTI prices. Correlation coefficient of -0.134 estimated based on the correlation of WCSB production to the price differential between WTI and WSC.

Appendix 3: Certificate of Duty

CERTIFICATE OF EXPERT'S DUTY – DR. THOMAS GUNTON

I, Dr. Thomas Gunton, of British Columbia, Canada, have been engaged on behalf of the Tsleil-Waututh Nation, to provide evidence in relation to Phase 111 of the Consultations between the Government of Canada and the Tsleil-Waututh Nation regarding Trans Mountain Pipeline ULC Application for the Trans Mountain Expansion Project, National Energy Board reconsideration of aspects of its Recommendation Report as directed by Order in Council P.C. 2018-1177.

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

1. to provide evidence that is fair, objective, and non-partisan;
2. to provide evidence that is related only to matters within my area of expertise; and
3. to provide such additional assistance as the tribunal may reasonably require to determine a matter in issue.

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

Date: June 8, 2019 Signature: ______________

CERTIFICATE OF EXPERT'S DUTY – DR. CHRIS JOSEPH

I, Dr. Chris Joseph, of British Columbia, Canada, have been engaged on behalf of the Tsleil-Waututh Nation, to provide evidence in relation to Phase 111 of the Consultations between the Government of Canada and the Tsleil-Waututh Nation regarding Trans Mountain Pipeline ULC Application for the Trans Mountain Expansion Project, National Energy Board reconsideration of aspects of its Recommendation Report as directed by Order in Council P.C. 2018-1177.

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

1. to provide evidence that is fair, objective, and non-partisan;
2. to provide evidence that is related only to matters within my area of expertise; and
3. to provide such additional assistance as the tribunal may reasonably require to determine a matter in issue.

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

Date: June 11, 2019 Signature: Chris Joseph

Appendix 4: Curriculum Vitae: Dr. Thomas Gunton and Dr. Chris Joseph

Curriculum Vitae: Dr. Thomas Gunton

Director and Professor, School of Resource and Environmental Management
Simon Fraser University
8888 University Drive
Burnaby BC
V5A 1S6

gunton@sfu.ca

Summary

Dr. Gunton is currently Professor and Director of the Resource and Environmental Planning Program at Simon Fraser University, which is recognized as one of the leading international schools providing advanced interdisciplinary training for resource professionals. Dr. Gunton has had extensive professional experience including holding the positions of Deputy Minister of Environment, Lands and Parks, Deputy Minister of Cabinet Policy Secretariat and Deputy Minister of Finance (Treasury Board) for the Government of British Columbia. He has also held senior positions with the Government of Manitoba, including Assistant Deputy Minister of Energy and Mines where he was in charge of major natural resource project development and evaluation, Senior Economic Analyst in the Ministry of Economic Development and was visiting professor in resource and environmental economics at the University of Manitoba.

Dr. Gunton regularly provides advice to private sector and public sector clients. His work includes evaluation of resource development projects, regional development strategies and negotiation and collaborative models for resolving resource and environmental conflicts. While working for the BC government he managed a number of major initiatives including: a new Environmental Assessment Act, a new Forest Practices Code, a forest sector strategy, a new regional land use planning process, a major expansion of the provincial parks system, a redesign of the regulatory and royalty system for oil and gas development and new air pollution regulations. He was also the chief negotiator for the province on a number of major resource development projects including Kemano completion and oil and gas royalties. Dr. Gunton has been an expert witness for various regulatory agencies including the National Energy Board, the Ontario Energy Board, and the Manitoba Public Utilities Commission. He has also been an expert witness before the BC Arbitration Panel providing evidence on natural resource markets and pricing.

Dr. Gunton's works on management issues in a number of resource sectors including forestry, land use, energy, mining and fisheries. He is Chair of the Sustainable Planning Research Group and heads a research team providing advice to First Nations on impacts and risk assessment of oil and gas development and pipeline proposals including the Enbridge Northern Gateway project (NGP). He was senior supervisor of recently completed (2014) PhD research evaluating risk assessment and benefit-costs for the Enbridge Northern Gateway Pipeline. Dr. Gunton also recently prepared a draft of the Federal Sustainable Development Act for the Suzuki Foundation that was passed unanimously by the Parliament of Canada in 2008. Dr, Gunton has published over 80 refereed articles in scientific journals and over 100 technical reports for private and public sector clients on resource and environmental issues and project development. He was recently awarded (2014) a large four year Mitacs research grant ($400,000) to assess social, environmental and economic impacts of natural resource development on First Nations in BC.

Current Employment

Professor and Director of the Resource and Environmental Planning Program, School of Resource and Environmental Management, Simon Fraser University. (1980-present).

Responsibilities

Teaching graduate courses in public policy analysis, regional resource development, dispute resolution. (courses include: environmental impact assessment, cost-benefit analysis, economic impact assessment, multiple accounts evaluation (social, environmental, fiscal, economic assessment techniques), conflict resolution techniques, regional development.) Senior Superviser of over 40 graduate theses on resource and environmental management

Previous Employment

1. Deputy Minister, Cabinet Policy Secretariat, Government of British Columbia, 8/96 to 8/00.
2. Deputy Minister, Ministry of Environment, Lands and Parks, Government of British Columbia, 10/93 to 7/96.
3. Deputy Minister, Treasury Board Secretariat, Ministry of Finance and Corporate Relations, and Secretary to Treasury Board. 08/92 to 10/93.
4. Director, School of Resource and Environmental Management, Simon Fraser University, 08/88 to 12/91.
5. Assistant Deputy Minister, Department of Energy and Mines, Province of Manitoba, Policy Planning and Project Development Division, 8/86 to 8/88
6. Senior Economic Analyst. Department of Energy and Mines, Province of Manitoba, Policy Planning and Project Development, 1984. (project and policy evaluation)
7. Visiting Professor, Department of Economics 1983, University of Manitoba, (teaching senior course in resource and environmental economics).
8. Senior Economic Analyst, Department of Economic Development, Province of Manitoba, 1983
9. Consultant to private and public sector clients 1980-present including. Major activities include: economic and environmental evaluation of major resource and energy projects and markets, participation as expert witness before agencies including NEB, OEB, MPUC, BC Arbitration Panel (on resource pricing and energy markets). NEB, OEB, MPUC, BC Arbitration Panel (on resource pricing and energy markets).

Refereed Publications	over 80
Professional Reports Prepared	over 100
Research Funding	$1,668,000

Education

University of Waterloo BA, MA (Planning). (Field: regional planning and natural resource analysis and policy including law, ecology, economics and public policy) University of British Columbia, Ph.D., Planning (Field: Natural resource policy, regional development planning, planning theory and public policy).

Curriculum Vitae: Chris Joseph *MRM, PhD*

Box 1513, Garibaldi Highlands, BC, V0N 1T0, Canada
cjoseph@swiftcreekconsulting.com; 604-848-9804
www.swiftcreekconsulting.com

Education

PhD (Resource Management), 2006 - 2013
School of Resource and Environmental Management. Simon Fraser University
"Megaproject Review in the Megaprogram Context: Examining Alberta Bitumen Development"
Recipient of several scholarships and awards, including Canada Graduate Scholarship – Doctoral (SSHRC) 2006-2009

Masters of Resource Management, 2002 - 2004
School of Resource and Environmental Management. Simon Fraser University
"Evaluation of the B.C. Strategic Land-Use Plan Implementation Framework"

Bachelor of Science (Honours with Distinction; Geography), 1993 - 1998
University of Victoria
"The Impact of Rock Climbing on the Soils and Vegetation at the Base of Cliffs within Greater Victoria, British Columbia"

Professional Affiliations

International Association of Impact Assessment
International Association of Impact Assessment – Western and Northern Canada
Past membership with the Association of Professional Economists of BC, International Association of Energy Economics, the Planning Institute of BC, Canadian Institute of Planners, and Connecting Environmental Professionals

Summary of Professional Experience

2016 - present
Principal, Swift Creek Consulting, Squamish, BC

2016 – 2018
Senior Socio-economic Specialist, SNC Lavalin, Vancouver BC

2003 – 2017
Sessional Instructor and Teaching Assistant, SFU, Burnaby BC
Courses: *REM 321 Ecological Economics, REM 356 Resource Management Institutions, GEOG 389 Political Ecology, HSCI 845 Occupational and Environmental Health*

2010 - 2016
Associate, Compass Resource Management, Vancouver BC

2000 - Present
Owner, Chris Joseph Photography, Squamish BC
Photography and writing published in national and international publications, websites, and catalogues including *Globe and Mail, Patagonia, Explore, Climbing, BC Paraplegic Association, Canada Science and Technology Museum, British Columbia Magazine, Mountain Equipment Co-op, Readers Digest, Ski Canada, Pique, Vancouver Sun, Westworld (BCAA),* and *National Post.*

2003 - 2013
Researcher, Sustainable Planning Research Group, SFU, Burnaby BC

2005 – 2009
Independent Consultant, Vancouver BC

2005 – 2006
Research Associate, MK Jaccard & Associates, Canadian Industrial Energy End-Use Data and Analysis Centre, Vancouver BC

2004 – 2005
Assistant, Melting Mountains Awareness Program (David Suzuki Foundation / Alpine Club of Canada / Environment Canada), Vancouver BC

2000 – 2001
Project Supervisor, Outland Reforestation, Toronto / Thunder Bay ON

Past Assignments

Athabasca Chipewyan First Nation: Review of Syncrude Economic Assessment of Mildred Lake Extension Project. Reviewed Syncrude responses to regulator information requests and related information in project EA application regarding claimed economic benefits of the project including taxes and royalties, as well as costs of carbon. Provided written and in-person evidence to the Alberta Energy Regulator. (January 2019)

LandSea Work Camps: Comparison of Effects of Workforce Housing Options in Squamish. Assessed potential economic impacts of workforce housing options if LNG and other major projects go ahead in Squamish for the purposes of LandSea's temporary use permit. (Fall 2018)

Athabasca-Chipewyan First Nation / Pembina Institute: Teck Frontier Bitumen Mine: Review of Economic Benefits and Cost-Benefit Analysis. Critiqued Teck's assessment of economic benefits including employment, and conducted a cost-benefit analysis of the proposed Teck Frontier bitumen mine. Provided written and in-person expert testimony to inform the joint Alberta-federal environmental assessment review panel. (January to October 2018)

West Moberly First Nations: Impacts of a Suspension of the Site C Project on Construction Workers and Municipalities. Wrote expert testimony to inform the court with respect to an application for injunction with regards to how suspension of the project may affect current construction workers and municipalities in the region. (May 2018)

Indian and Northern Affairs Canada: Technical Review of Socio-economic Impact Assessment of the proposed Hope Bay Phase 2 Mine. Team lead of SNC Lavalin's technical review of socio-economic material in the final environmental impact statement of TMAC Resources' proposed Hope Bay Phase 2 mine in Nunavut. Review included reviewing regulatory and proponent documentation and advising INAC on appropriate responses. (Winter and Spring 2018)

BC Parks: Development of Living Labs climate change research framework. Developed a funding framework for climate change research in BC parks and protected areas. Work included developing a database of recent climate change research in BC Parks through literature review and survey, a database of potential research and funding partners, and facilitating sessions at a meeting with BC government staff. Oversaw two subcontractors in this work. (Fall 2017-Spring 2018)

BC MFLNRO: Socio-economic profiles and scenario development – Caribou Range Planning in NE BC. Subcontracted to Green Analytics. Developed scenarios of forestry and gas development, and provided strategic advice. (Spring 2018)

Alberta Environment and Parks: Advice on Improved Integration of Project-level Environmental Impact Assessment and Regional Cumulative Effects Management. Reviewed existing linkages between project-level EIA in the South Athabasca Oil Sands area with regional cumulative effects management, including through expert interviews. Provided recommendations to improve the contribution of project-level EIA to regional cumulative effects management. (Fall 2017 – Spring 2018)

Environmental Law and Policy Center (USA): Assessment of the need for the Enbridge Line 3 Replacement Program. Provided written and in-person expert testimony of the need for the Enbridge L3R project, including an assessment of supply and demand of oil transport capacity, costs to Minnesota, and economic benefits of the project. (Fall 2017)

Centremount Coal: Socio-economic lead for SNC Lavalin's environmental assessment of the proposed Bingay coal mine. Scoping, baseline, and impact assessment studies of potential social, economic, and community health effects of the proposed Bingay coal mine in south-east BC. (2016-2018)

Pacific Future Energy: Socio-economic lead for SNC Lavalin's environmental assessment of the proposed Pacific Future Energy green refinery. Scoping and baseline studies of potential social, economic, and community health effects of the proposed green refinery in north-west BC. Advising to proponent on Aboriginal engagement, and engagement with Kitselas First Nation representatives. (2016-2017)

Gitga'at First Nation: Environmental assessment advisor. Since 2013, on an as-needed basis, provided advice to the Gitga'at First Nation regarding EA applications and processes, generally pertaining to socio-economic topics. Assignments included critiquing proponent EA applications, preparing Information Request submissions to EA bodies, and examining issues in EA application content and methodology with proponent consultants. (2013-2017)

Ng Ariss Fong: Assessment of the economic impacts of the Nathan E. Stewart tug spill on the Heiltsuk First Nation. Supported First Nation's legal claim against shipping company by gathering quantitative data, interviewing community representatives and members regarding traditional and commercial harvests, and estimating monetary impact of spill on Heiltsuk harvests. (2016)

Stk'emlupsemc te Secwepemc First Nation: Economic Review of Ajax Mine. Critiqued environmental assessment application of the KGHM Ajax mine project in Kamloops, BC with respect to economic impacts and value of the project. Conducted a multiple-accounts cost-benefit analysis of the project. Identified potential additional mitigation measures. Testified to the Nation's environmental assessment review panel. (2016)

International Pacific Halibut Commission: Facilitation of Management Strategy Evaluation workshops and design of outreach strategy. Over 2015 and 2016 designed and facilitated meetings for Management Strategy Advisory Board in support of their management strategy evaluation (a collaborative analysis of optimal fishery management actions). Also supervised the development of an outreach strategy for the board. (2015-2016)

Hemmera / Yukon Energy: Stakeholder engagement, meeting facilitation, and options assessment pertaining to the mitigation of impacts of the Southern Lakes Storage Enhancement Concept. Designed and facilitated two rounds of engagement with stakeholders regarding their preferences for erosion mitigation, including small and large group meetings. Conducted options assessment with engineering team (NHC) and explored options collaboratively with stakeholders. (2015)

Tsawout First Nation, Upper Nicola Band, Living Oceans Society: Public Interest Evaluation of the Kinder Morgan Trans Mountain Expansion Project. Contributing editor. Deliverable included an evaluation of Kinder Morgan's economic impact assessment of their proposed Trans Mountain Expansion Project and a cost-benefit analysis of the project. (2015)

Instream Fisheries Research: Facilitation of Gates Creek Sockeye Workshop. Designed and facilitated workshop focused on bringing together the variety of scientists and Aboriginal knowledge-holders, finding research gaps, and identifying steps forward with respect to information gathering, collaboration, and support of management. (2015)

Gitga'at First Nation: Impact Assessment of Prince Rupert LNG Projects. Led a two-person team and was the lead analyst in screening-level analyses of potential socio-economic impacts of three LNG projects (Prince Rupert LNG, Aurora LNG, Pacific Northwest LNG) and a detailed economic impact assessment of the Kitimat LNG project. Examined issues including: economic opportunities including jobs and contracts, access to goods and services, housing, human resources in remote communities, social cohesion, commercial fishing, tourism, carbon offsets, and economic development. Also supervised the writing of a baseline data report to help proponents fill their data gaps. (2014)

Metlakatla First Nation: Assessment of potential impacts of LNG development. Led a six-person team including subcontractor, and was lead analyst, examining the potential impacts of the Pacific Northwest LNG, Prince Rupert LNG, Westcoast Connector LNG pipeline, and Prince Rupert Gas Transmission LNG pipeline projects). Identified seven valued components through document review, interviews, and community workshop. Topic matter covered the economic, health, heritage, and social pillars. Developed baselines and gathered data for proponents. Developed a spreadsheet-based database and model to examine cumulative effects. Assessed the effects of projects in the context of cumulative effects of other development and stresses. Conducted a final workshop with community representatives to validate draft results. Researched mitigation opportunities. Developed a plain language summary for client in addition to detailed report. (2013-2014)

Gitga'at First Nation: Assessment of the potential economic impacts of LNG Canada project. Led a three-person team, and was the lead analyst. Identified six economic valued components through document review and interviews. Developed baselines. Developed a spreadsheet-based database and model to examine cumulative effects. Assessed the effects of projects in the context of cumulative effects of other development and stresses. Researched mitigation opportunities. Conducted a workshop with community representatives to validate draft results. (2013-2014)

Canadian Oil Sands Innovation Alliance: Structuring and gathering thinking on innovations in oil sands mine reclamation. Worked with two other firms on a multiple component project that gathered knowledge across oil sands mining companies on how to reclaim watersheds and to identify research priorities. (2013)

BC Ministry of Forests, Lands, and Natural Resources Operations: Recommendations for a Provincial Trails Advisory Body. Led a two-person team researching alternative governance models across Canada for recreational trails advisory bodies. Used a structured approach to identify key desired design elements, alternative governance structures, evaluate alternative models, and make recommendations for the BC trails context. (2013)

Marine Planning Partnership: Socio-economic data and editing. Supported MaPP planning team by gathering data on socio-economics including commercial fisheries and sport fishing along the BC coast and editing relevant sections of MaPP plans. (2013)

Environment Canada: Guidance on the valuation of ecosystem services for use in environmental assessment decision-making. Reviewed literature to identify existing gaps in the practice of environmental valuation in the environmental assessment context. Advised on the design of an expert workshop used to gather guidance on key issues in environmental valuation. Facilitated major portions of the workshop. Wrote guidance for Environment Canada to improve their in-house economic valuations of environmental impacts. (2012-2013)

Port Metro Vancouver: Facilitation of Technical Advisory Group in Support of Pre-EA Work for Marine Terminal Expansion at Roberts Bank. Co-designed a multi-meeting, multi-month process to engage technical experts to gather advice for Port Metro Vancouver (PMV) and their consultants to improve their baseline studies and environmental assessment methods for the proposed Terminal 2 project. Facilitated meetings over Fall 2012 and Winter/Spring 2013 in support of process, and worked with

PMV consultants to refine issues and enhance their ability to engage with the technical experts. Lead facilitator for the Coastal Geomorphology technical advisory group (one of four such groups convened as part of this contract). (2012-2013)

Gitga'at First Nation: Assessment of the potential economic impacts of the Enbridge Northern Gateway Project. Assessed the potential economic impacts of the Enbridge Northern Gateway pipeline and tanker project on the Gitga'at Nation and examined broader issues such as how to incorporate risk information into decision-making. Critiqued the proponent's application, established baseline data, conducted original impact assessment work, and wrote evidence that was submitted to the Joint Review Panel examining the project. Testified to the Panel in April 2013. (2011-2013)

BC Environmental Assessment Office: Refinement of Impact Assessment Methodology. Co-wrote discussion paper for the BC EAO making suggestions with respect to how the BC government might modify the existing environmental assessment process in order to strengthen the process, particularly with respect to cumulative effects assessment. This work involved identifying key outstanding issues, interviewing experts, and writing policy guidance. (2012)

Cumulative Environmental Management Association: Support for a structured decision-making process to identify solutions to linear footprint management issues in the oil sands. Developed objectives and measurement criteria, and led workshop discussion on these topics, for work on the linear footprint management plan for the Stony Mountain 800 Area south of Fort McMurray. The objective of this project was to identify recommendations for government to address multiple uses of the area, including SAGD, forestry, trapping, and recreation. (2012)

Department of Fisheries and Oceans: Facilitation of SARA consultations for species recovery. Developed consultation strategies with DFO and facilitated two evening open-house meetings and five day workshops for stakeholder consultations required under the Species at Risk Act for the Salish Sucker, Nooksack Dace, Cultus Pygmy Sculpin, and Rocky Mountain Ridged Mussel. (2010-2011)

Haida First Nation: Evaluation of environmental and economic impacts of proposed NaiKun offshore wind project. Provided a third-party review of BC, federal, and consultant environmental assessments of the project in terms of gaps in data and logic, identified potential significant impacts, and advised on financial viability of the project. (2011)

Tides Foundation: Benefits of Marine Planning: An Assessment of Economic and Environmental Values. Reviewed the social and economic context for marine development on the BC coast and examined the benefits of marine planning with respect to environmental protection, economic development, and social capital. This research was also published in the journal Environments. (2009)

Department of Fisheries and Oceans: Review of potential impacts of renewable ocean energy development in BC. Reviewed the potential social and economic impacts of renewable ocean energy development in BC. Examined the potential for renewable ocean energy development (tidal, wave, and wind) on the BC coast, reviewed current levels of development, reviewed the socio-economic context of the BC coast, and explored how such development might affect employment, existing industries (e.g., air travel, aquaculture, forestry, and marine navigation), energy supply in rural areas, recreation, rural demographics, traditional activities, and other values. (2008)

Coastal First Nations: Review of environmental and socio-economic impacts of port development and shipping on BC North Coast. Reviewed the potential impacts of port expansion and shipping (including tankers) on the BC North Coast. Characterized the significance of potential impacts and reviewed potential mitigation measures, including Impact Benefit Agreements. (2008)

David Suzuki Foundation: Toward a National Sustainable Development Strategy in Canada. Researched and contributing writer of an examination of the legal and policy framework for sustainability planning across jurisdictions in Europe, Japan, the US, and Canada. Identified components across jurisdictions that facilitate a jurisdiction's ability to plan for and achieve greater sustainability. Report proposed a draft federal law which in 2008 was adopted by Parliament (Federal Sustainable Development Act). (2007)

Natural Resources Canada: National Circumstances Affecting Canada's Greenhouse Gas Emissions. Contributed to a quantitative study of factors shaping Canada's GHG emission patterns. Conducted analysis of emission patterns and contributing factors to emissions of Canada's residential housing, transportation, and wood processing sectors. This research was also published in the Energy Journal. (2005)

National Round Table on the Environment and the Economy: Canada's Energy and Greenhouse Gas Context. Contributed to a study on the linkages between Canada's energy sources and economy, international comparisons, and policy options for reducing GHG emissions. (2005)

Coastal First Nations: Review of offshore oil and gas development in BC. Literature review of the legal, environmental and socio-economic issues of offshore oil and gas development in BC and evaluation of the relevant planning process. Highlighted issues relevant to strategic and project-level decision-making. (2004)

Peer-Reviewed Publications

1. Joseph, C. 2019. Problems and Resolutions in GHG Impact Assessment. *Impact Assessment and Project Appraisal*.
2. Joseph, C., T. Gunton, and M. Rutherford. 2017. A Method for Evaluating Environmental Assessment Systems. *Journal of Environmental Assessment and Policy* 19(3): 33 pp.
3. Joseph, C., T. Zeeg, D. Angus, A. Usborne, and E. Mutrie. 2017. Use of Significance Thresholds to Integrate Cumulative Effects into Project-level Socio-economic Impact Assessment in Canada. *Environmental Impact Assessment Review* (67): 1-9.
4. Joseph, C., T. Gunton, and M. Rutherford. 2015. Good practices for effective environmental assessment. *Impact Assessment and Project Appraisal* 33(4): 238-254.

5. Joseph, C., and A. Krishnaswamy. 2010. Factors of resiliency for forest communities in transition in British Columbia. *BC Journal of Ecosystems and Management* 10(3): 127-144.
6. Gunton, T. and C. Joseph. 2010. Economic and Environmental Values in Marine Planning: A Case Study of Canada's West Coast. *Environments* 37(3): 111-127.
7. Joseph, C., T.I. Gunton, and J.C. Day. 2008. Implementation of resource management plans: Identifying keys to success. *Journal of Environmental Management* 88: 594-606.
8. Bataille, C., N. Rivers, P. Mau, C. Joseph, and J. Tu. 2007. How malleable are the greenhouse gas emission intensities of high-intensity nations? A quantitative analysis. *Energy Journal* 28(1): 145-169.

Expert Evidence

1. Teck Frontier Mine. Written and in-person testimony to the Joint Review Panel. 2018.
2. Site C Clean Energy Project. Written testimony to the Supreme Court of British Columbia. 2018.
3. Enbridge Line 3 Replacement project. Written and in-person testimony to the Minnesota Public Utilities Commission. 2017.
4. Ajax Copper/Gold Mine. Written and in-person testimony to Stk'emlupsemc te Secwepemc Nation Review Panel. 2016.
5. Kinder Morgan Expansion Project. Written testimony to the National Energy Board. 2015.
6. Enbridge Northern Gateway Pipeline. Written and in-person testimony to National Energy Board. 2013.

Peer Review of Other's Research

Environmental Management
Journal of Environmental Assessment Policy and Management
Integrated Environmental Assessment and Management

Select Other Professional Publications

1. Joseph, C., and T.I. Gunton. 2010. Net economic and environmental benefits of an oil sands mine. Proceedings of the 29th USAEE/IAEE North American Conference in Calgary, Alberta, Canada, October 14-16, 2010.
2. Joseph, C. 2010. The Tar Sands of Alberta: Exploring the Gigaproject Concept. Proceedings of the Prairie Summit geography conference, June 1-5, 2010, Regina, SK.
3. Joseph, C., and T. I. Gunton. 2009. Benefits of Marine Planning: An Assessment of Economic and Environmental Values. Marine Planning Research Report No. 4. Prepared for Tides Canada Foundation. Burnaby, BC: School of Resource and Environmental Management, Simon Fraser University. 34 pp.

4. Nyboer, J., and C. Joseph. 2006. Development of Energy Intensity Indicators for Canadian Industry 1990-2004. Prepared for Canadian Industry Program for Energy Conservation and Natural Resources Canada. Canadian Industrial Energy End-use Data and Analysis Centre, Simon Fraser University. 32pp.
5. Nyboer, J., C. Joseph, and P. Mau. 2006. Development of Greenhouse Gas Intensity Indicators for Canadian Industry, 1990 to 2004. Prepared for Environment Canada and Natural Resources Canada. Canadian Industrial End-Use Energy Data and Analysis Centre, Simon Fraser University. 584pp.
6. Nyboer, J., C. Joseph, N. Rivers, and P.Mau. 2006. A Review of Energy Consumption and Related Data Canadian Aluminium Industries 1990-2003. Prepared for Aluminium Industry Association. Canadian Industrial Energy End-use Data and Analysis Centre, Simon Fraser University. 36pp.
7. Nyboer, J., C. Joseph, N. Rivers, and P.Mau. 2006. A Review of Energy Consumption and Related Data Canadian Mining and Metal Smelting and Refining Industries 1990-2003. Prepared for Mining Association of Canada. Canadian Industrial Energy End-use Data and Analysis Centre, Simon Fraser University. 159pp.

Presentations, Guest Lectures, and Workshops

1. Presentation at Canadian Institute’s Cumulative Effects 2019 conference entitled “GHGs of Major Projects: Problems and Potential Solutions in Cumulative Effects Assessment”, June 6, 2019. Calgary, AB.
2. Lead workshop for environmental professionals entitled “Understanding Environmental Assessment Today: Cases and Issues” for Faculty of Environment, Simon Fraser University, October 3, 2018. Vancouver, BC.
3. Presentation at Canadian Institute’s Cumulative Effects 2018 conference entitled “Development in a Full World: Cumulative Effects, Significance, and Justification”, June 5, 2018. Calgary, AB.
4. Lead workshop for environmental professionals entitled “Environmental Assessment in Canada: Current Issues and Prospects for Improvement” for Faculty of Environment, Simon Fraser University, October 26, 2017. Vancouver, BC.
5. Lead workshop entitled “Valued Components Masterclass” at Canadian Institute’s Cumulative Effects conference, June 21, 2017. Calgary, AB.
6. Presentation at Canadian Institute’s Cumulative Effects conference entitled “Improving Cumulative Effects Assessment in Project-Level Assessment”, June 20, 2017. Calgary, AB.
7. Presentation to SNC Lavalin staff entitled “Megaprojects: Navigating Failures, Bias, Symbolism, and Other Interesting Stuff”, April 19, 2017. Vancouver, BC.
8. Presentations at IAIA’17 entitled “Benefits Assessment in Western Canada: Case studies and Lessons”, April 6, 2017, and “Significance Thresholds to Integrate CEA in Project-level EA”, April 7, 2016. Montreal, QC.
9. Presentation to the Federal EA Review Panel, December 11, 2016, Vancouver, BC.
10. Guest lecture to undergraduate economics class on economic impact assessment and the public interest, Simon Fraser University, March 13, 2014, Burnaby, BC.

11. Public presentation for Moving Planets on Enbridge Northern Gateway project, March 27, 2012, Squamish, BC.
12. Guest lecture to undergraduate environmental studies class on megaproject review and the Enbridge Northern Gateway pipeline project at Quest University, March 15, 2012, Squamish, BC
13. Guest lecture to masters environmental assessment class on tar sands project review, School of Resource and Environmental Management, Simon Fraser University, February 28, 2011, Burnaby, BC.
14. Presentation at Unwrap the Research Conference entitled "The Tar Sands of Alberta: Exploring the Gigaproject Concept", October 24, 2010, Fort McMurray, AB.
15. Presentation at 29th USAEE/IAEE North American Conference entitled "Net economic and environmental benefits of an oil sands mine", October 16, 2010, Calgary, AB.
16. Presentation at Prairie Summit 2010 geography conference entitled "The Tar Sands of Alberta: Exploring the Gigaproject Concept", June 4, 2010, Regina, SK.
17. Guest lecture to ecological economics class on cost-benefit analysis of tar sands development at Quest University, April 26, 2010, Squamish, BC
18. Presentation at community meeting on the economic risks of the Garibaldi at Squamish ski and residential project proposal, April 12, 2010, Squamish, BC.
19. Guest lecture on environmental assessment of large-scale projects to Geography 319 "Environmental Impact Assessment" at March 17, 2010, University of British Columbia, Vancouver, BC.
20. Public presentation hosted by Squamish Climate Action Network on Alberta Tar Sands, May 25, 2009, Squamish, BC.
21. Guest lecture entitled "Energy: A Love and Hate Relationship" to students at Capilano College, September, 2008, North Vancouver, BC.
22. Presentation to Butterfield & Robinson travel group on oil sands development, August 20, 2008, Calgary, AB.
23. Panel presenter at Whistler Energy Forum on energy and sustainability, June 8, 2008, Whistler, BC.
24. Presentation for REM seminar series entitled "Can Cost-Benefit Analysis be Improved with Stakeholder Involvement?", Simon Fraser University, November 1, 2007, Burnaby, BC.
25. Presentation at Canadian Pollution Prevention Roundtable entitled "Pricing Oil Sands Pollution? Balancing Expert and Stakeholder Input", June 14, 2007, Winnipeg, MB.
26. Presentation at ISSRM 2006 Conference entitled "Implementing Resource Plans: Lessons from BC", June 5, 2006, Vancouver, BC.
27. Presentation at PIBC Conference as part of session entitled "Planning Implementation: Lessons from the Field", April 19-22, 2005, Vancouver, BC.
28. Invited Speaker at "Dialogue Café" on climate change, February, 2005, Whistler, BC.
29. Co-presenter for REM Seminar series entitled "Offshore Oil and Gas in BC", Simon Fraser University, February 28, 2005, Burnaby, BC.
30. Presentation at BC Land Summit 2004 as part of session entitled "BC's Crown Land Planning Process - Does it Work?", May 14, 2004, Vancouver, BC.
31. Presentation at CONFOR 2004 conference entitled "An assessment of the British Columbia strategic land use plan implementation framework and an identification

of best practices for plan implementation", Dalhousie University, February 6, 2004, Halifax, NS.

32. Presentation for REM Seminar Series entitled "An Evaluation of the BC Strategic Land Use Planning Implementation Framework: Best Practices, Current Practices.", Simon Fraser University, November 14, 2003, Burnaby, BC.
33. Presentation at Annual Meeting of the Western Division of the Canadian Association of Geographers entitled "The Impact of Rock Climbing on the Soils and Vegetation at the Base of Cliffs.", Kwantlen University College, March 12-14, 1998, Richmond, BC.
34. Co-presenter at Annual Meeting of the Western Division of the Canadian Association of Geographers entitled "The Geomorphology of Small Push Moraines at Hilda Glacier, Banff National Park, Alberta", Kwantlen University College, March 12-14, 1998, Richmond, BC.

Awards

1. Sustainable Prosperity research grant, 2011
2. Waterhouse Graduate Fellowship in Organizational Change and Innovation, 2009
3. Jake McDonald Memorial Scholarship, 2007
4. Canada Graduate Scholarship – Doctoral (SSHRC), 2006-2009