Public Interest Evaluation of the Trans Mountain Expansion Project

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Executive Summary

1. The purpose of this report is to assess whether the proposed Trans Mountain Expansion Project (TMEP) is required and in the public interest.
2. The TMEP is a proposal to expand the existing Trans Mountain Pipeline (TMPL) to provide an additional 590 kbpd transportation capacity to ship crude oil from Alberta to markets in the Pacific Rim. The TMEP would consist of twinned pipelines (one new and one existing), a marine terminal, and tanker traffic to ship oil from Vancouver to Pacific Rim markets.
3. The National Energy Board (NEB) approval criteria as specified in Section 52 of the *National Energy Board Act* require the applicant to show that:
   a) the project is required; and
   b) the project is in the public interest.
4. The TMEP application states that the TMEP is required and in the public interest for the following reasons:
   a) growth in production from the Western Canada Sedimentary Basin (WCSB) requires increased oil transportation capacity;
   b) TMEP will provide access to new markets in Asia and the United States;
   c) TMEP will increase netbacks to all Western Canadian oil producers by lowering transportation costs and accessing higher price markets; and
   d) construction and operation of the TMEP will stimulate economic activity in Canada and generate tax revenue for government.
5. The evidence in the TMEP application that the TMEP is required and in the public interest is incomplete and deficient in the following respects:
   a) TM overstates project benefits by using gross economic impacts as the primary measure of the contribution of the project to the public interest instead of net impacts and net economic benefits;
   b) TM incorrectly assumes that economic impacts are a measure of benefits without taking into account the opportunity cost of the labour, capital and other resources it uses;
   c) TM's conclusion that the TMEP will generate significant benefits in the form of increased prices for Canadian oil exports is based on a questionable methodology, unrealistic assumptions, and is inconsistent with oil market dynamics; and
   d) TM's assessment of the need for the TMEP is deficient because it underestimates WCSB transportation capacity, likely overestimates oil production and oil prices, and does not include alternative production and transportation capacity scenarios;
6. While TM provides an estimate of the alleged benefits of the TMEP, it does not provide an estimate of the costs. Most importantly, TM provides no estimates of

the economic losses resulting from potential excess transportation capacity that TMEP may cause and no estimates of social and environmental costs of air pollution, greenhouse gas (GHG) emissions, oil spills, and other environmental and social impacts resulting from the TMEP. TM fails to provide any comparison of benefits and costs in accordance with well-established principles and guidelines such as benefit cost analysis that can be used to assess whether the TMEP is a net benefit to Canada, and does not set out in a clear and comprehensive way the advantages, disadvantages, and trade-offs of the TMEP. Consequently, TM does not provide the information necessary for determining whether the TMEP is in Canada's public interest.

7. To assess the need for the TMEP, we completed a supply and demand analysis for WCSB transportation services using forecasts from the Canadian Association of Petroleum Producers (CAPP). The analysis shows that construction of the TMEP will contribute to the creation of surplus capacity in the oil transportation sector. (Figure ES-1).

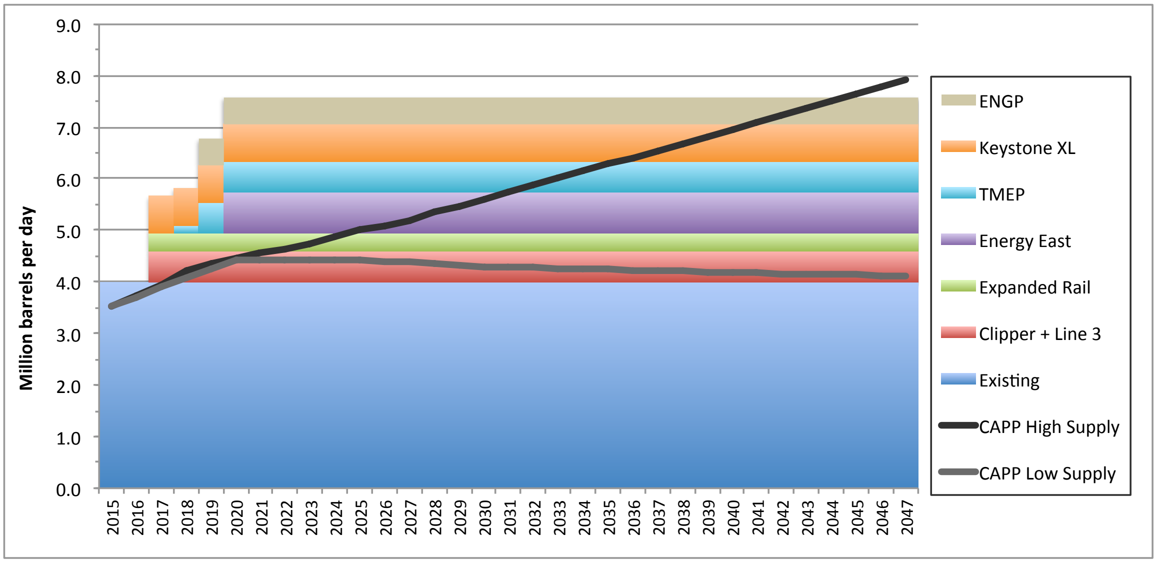
    a) Under CAPP's high growth forecast, construction of currently planned projects (Enbridge Clipper, Enbridge Line 3 replacement, TMEP, and Energy East but excluding Keystone XL and Northern Gateway) will result in surplus transportation capacity of 1.6 million bpd in 2020 and there is surplus capacity until about 2034. The surplus capacity in 2020 is equivalent to just over three Northern Gateway's worth of empty pipeline space.

    b) Under CAPP's low growth forecast there is surplus capacity to the end of the forecast period (2047).

    c) If Enbridge Clipper, Enbridge Line 3 replacement, and Energy East are built, the TMEP is not required until 2029 under CAPP's high growth forecast and is not required at all under CAPP's low growth forecast. If Energy East is not built, the TMEP is not required until 2023 under CAPP's high growth forecast and is not required at all under CAPP's low growth forecast.

    d) Although some unused capacity is necessary and beneficial, the magnitude of unused capacity resulting from premature construction of the TMEP would impose a large cost on Canada's oil transportation sector, oil producers and the Canadian public in the form of reduced tax revenues. TM has not included the costs of this unused capacity in its evaluation of TMEP costs and benefits.

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



8. To assess the need for and the impact of the TMEP on the Canadian public interest we completed a comprehensive benefit cost analysis of the TMEP (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 $7.4 billion**.

   b) Net costs could range between $**4.6 and $23.0** billion based on different scenarios and assumptions. Fewer new transportation projects, higher oil production, and lower environmental costs reduce the net costs while more new transportation projects, lower oil production, and higher environmental impacts increase the net costs. We also included a sensitivity that incorporated potential option and diversification values provided by the TMEP accessing new markets with higher oil prices. Under all scenarios tested, construction of the TMEP as planned will result in a net cost to Canada.

   c) We recognize that estimating benefits and costs of the TMEP is challenging and subject to many uncertainties. Current uncertainties in oil markets are unusually high due to uncertainty over the future direction of oil prices, Canadian oil production, and public policies such as climate change that can all significantly impact the Canadian oil sector and the demand for new transportation capacity.

   d) We have addressed these uncertainties in two ways. First we have completed a large number of sensitivity analyses using different assumptions and forecasts. Second we did a risk assessment of building and not building the TMEP. If the TMEP is built in accordance with the schedule proposed in the application, there will be a net cost to Canada under all likely scenarios. Not building the TMEP as planned has minimal downside risk because if demand for new transportation projects is higher than forecast, 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	0	(792) to 396
Unused Oil Transportation Capacity	(4,381)	(6,233) to (2,173)
Option Value/Oil Price Netback Increase	0	0 to 2,784
Employment	77	77 to 284
Tax Revenue	242	242 to 1,143
Electricity	(257)	No sensitivity
GHG Emissions from Construction and Operation of TMEP and marine traffic in defined study area	(289)	(916) to (289)
Other Air Emissions	(85)	(427) to (6)
Oil Spills	(675)	(1,022) to (310)
Passive Use Damages from Oil Spill	(2,026)	(17,667) to (2,026)
Other Socio Economic, Environmental Costs not estimated	See Appendix A	
Base Case Net Cost	**(7,394)**	**(4,610) to (23,035)**

9. One of the primary reasons that the TMEP may 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 these projects to be feasible financially 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.

10. 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. We caution that 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 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 important and should be assessed as part of a comprehensive energy and climate change policy.

11. In summary, our evaluation shows that:

    a) the TMEP application fails to show that the TMEP meets the need and public interest criteria required for NEB approval;

    b) the TMEP will result in a net cost to Canada if the project is built as planned. Therefore approving the application for the TMEP is not in Canada's public interest; and

    c) 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
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*
PHMSA	Pipeline and Hazardous Materials Safety Administration
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

The purpose of this report is to assess:

- the costs and benefits of the Trans Mountain Expansion Project (TMEP); and
- whether TMEP meets the criteria for project approval for pipelines as set out in the *National Energy Board Act (NEBA)* including whether the TMEP is in the Canadian public interest.

Our conclusions show that:

- the evidence provided by Trans Mountain (TM) in their application to justify the TMEP has significant deficiencies and does not provide the information on project need, benefits, and costs required to assess whether the project is in the Canadian public interest and support project approval; and
- if built as planned the TMEP will result in a significant net cost to Canada.

We begin this report with a review of the approval criteria in the *NEBA*. This is followed by a description of the TMEP and then an evaluation of the evidence provided in the TMEP application regarding the need for, and public interest benefits, of the TMEP. We then provide additional evidence in the form of a benefit cost analysis to assess the TMEP and determine if the TMEP meets the approval criteria as specified in the *NEBA*.

1.1. National Energy Board Approval Criteria

Section 52 of the *NEBA* states that the National Energy Board (NEB) will make a recommendation to the Minister 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; and
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) has 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) states that it does not intend to 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.

1.2. Certificate of Duty

This report has been prepared in accordance with our duty as experts to assist: (i) Tsawout First Nation, Upper Nicola Band and Living Oceans Society 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. A signed copy of our Certificate of Expert's Duty is attached as Appendix "B". Attached as Appendix "C" are our respective curriculum vitaes.

2. Overview of the 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 BC [*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. Key Project Components

2.1.1. 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 will 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 will 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 (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).

2.1.2. 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 14 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.

2.1.3. 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).

2.2. Project Costs

TM (2013b, Vol. 2 App. B) estimates that the capital costs of the TMEP would amount to $5.5 billion nominal to be spent over a seven-year period from 2012 to 2018 (or $4.9 billion in 2012 dollars).[1] Nearly $5.0 billion of the $5.5 billion nominal would be spent in 2016 and 2017 when construction is planned to take place (CBC 2015; TM 2013b, Vol. 2 App. B, pp. 10-11). TM estimates incremental operating costs of $118 million per year after construction is complete (TM 2013b, Vol. 5D). TM expects the TMEP to operate for at least 50 years after which the pipeline and facilities would be decommissioned at an incremental cost of approximately $263 million (or $603 million for both the TMPL and the TMEP) (TM 2013b, Vol. 2).

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[1] All monetary figures in this report are in 2014 Canadian dollars unless otherwise specified. The capital cost of the TMEP is now estimated to be $6.8 billion (Krugel 2015).

3. TM's Rationale for the TMEP

TM indicates in *Volume 2* of its application (TM 2013b) that the TMEP is needed because:

- new pipeline capacity is required to transport the forecast increase in oil production from the Western Canada Sedimentary Basin (WCSB);
- the TMEP will increase netbacks to Western Canadian oil producers by lowering transportation costs and accessing new markets in Asia and the United States;
- construction and operation of the TMEP will stimulate economic activity in Canada and generate tax revenue for government; and
- the TMEP will enhance the flexibility of the Canadian oil sector in the face of increasing market dynamics.

3.1. Need for Pipeline Capacity

In its evidence submitted on behalf of TM, Muse Stancil (MS) concludes that the TMEP will operate at capacity throughout the forecast period (MS 2015, p. 12). MS bases this conclusion on the fact that TM has been under apportionment since 2010 and that shippers have been paying dock bid premiums to TM, which according to MS shows that there is high demand to ship on the TMEP. MS further states that TM's Westridge Terminal is closer to Asia markets than other oil suppliers in the Middle East and Africa, and therefore TMEP has a competitive advantage relative to many other transportation options. MS also references the fact that some oil companies have signed 15- to 20-year 'take or pay' shipping agreements with TM for 80% (707.5 kbpd) of the nominal capacity of the proposed pipeline as further indication that the TMEP is needed and will be utilized (TM 2013b, Vol. 2 p. 2-36-37).

3.2. Higher Netbacks for Canadian Oil

Evidence submitted by MS on behalf of TM concludes that the TMEP will increase Canadian oil prices by reducing the need for higher cost rail transport until 2024 and reducing the supply of oil shipped into the United States (US) market. MS claims that Canadian oil prices will be higher with the TMEP because "it is a fundamental economic principle that reducing the supply of a commodity, all else equal, will increase its price (MS 2015, p. 10). MS estimates that the price increase will generate a benefit of $73.5 billion (2012 Can $) to 2038 (MS 2015, p. 14-15).

Shipments to Asia will, according to MS, help overcome the market disequilibrium that resulted in downward pressure on Canadian oil prices in 2012 and 2013. MS claims that the TMEP is in the public interest because the project will provide market diversification.

3.3. Impact on the Canadian Economy

TM provides an economic impact analysis (EconIA) of the TMEP prepared on its behalf by the Conference Board of Canada (CBC 2015). This EconIA estimates direct, indirect, and induced effects from construction and operation of the TMEP on employment, gross domestic product (GDP), and government revenues. Economic impacts of construction are estimated over a seven-year period and economic impacts of operations are estimated over a 20-year period. The analysis also includes the impact of higher netbacks received by crude oil producers.

The EconIA estimates that the TMEP will generate between 123,221 direct, indirect, and induced person-years of employment during the construction and operation of the project, which translates into 443 direct permanent jobs (CBC 2015 p.33, p.44).[2] Furthermore, the EconIA estimates that the project will generate total impacts over the 27 years from 2012 to 2038 of $22.1 billion in direct, indirect, and induced effects to GDP and up to $4.5 billion in government revenues, with potential for an additional $23.7 billion of increased government revenues related to higher netbacks (CBC 2015, p. 45, p. 52). On an annualized basis the direct GDP impacts of TMEP operations are $608 million per year, government tax revenues from operations are $165 million per year, and the government tax revenues from higher netbacks are $1.2 billion per year.

3.4. Additional Benefits

A report provided by John J. Reed of Concentric Energy Advisors on behalf of TM (Reed 2015) also addresses the justification for the TMEP. Mr. Reed states that the TMEP should be

[2] The use of person-year estimates of employment can exaggerate the significance of the full-time employment effects of the project. The TMEP regulatory application references the creation of 123,221 person-years of employment (CBC,2015, p. 8). However, the Conference Board of Canada's EconIA states that the TMEP would create only 443 direct permanent jobs (CBC, 2015, p.33). A person-year is one person working for one year. Assuming the project operates for 20 years, one permanent job is reported as 20 person-years of employment even though it is one worker employed at one job. The presentation of employment impacts in person-years for operating employment can lead to a misunderstanding of the project's actual employment impacts.

assessed in terms of a new dynamic in oil markets that reflects flexibility, diversity of market access, the ability to manage risk associated with competing in numerous markets, and the management of development and operational risk. Mr. Reed also references the benefits that TMEP will potentially provide Canadians including producers, residents along the pipeline right-of-way, suppliers, governments at the local, provincial, and federal levels, and the overall Canadian economy.

4. Evaluation of TM's Justification for the Project

The evidence provided by TM in *Volume 2* of their application (TM 2013b) and the replacement evidence (MS 2015; CBC 2015; Reed 2015) to assess the need for the TMEP and whether TMEP is in the public interest is deficient in that:

- it underestimates potential excess pipeline capacity;
- it overstates the need for oil transportation capacity by not including a range of oil production forecasts;
- it does not consider the cost of the underutilization of the pipeline capacity the project will cause;
- it estimates a price uplift benefit based on a questionable methodology and unrealistic assumptions;
- it relies on an assessment of gross, as opposed to net, economic impacts in making its case as to the value of the project from the perspective of the public interest;
- it fails to analyze all of the costs of the project and present any comprehensive assessment of cost and benefits of the project necessary for determining whether the project is in the public interest;
- it fails to analyze and present key distributional issues and trade-offs for different stakeholders as is necessary to fully understand the consequences and public interest impacts of the project;
- it does not include comprehensive compensation plans to address stakeholders who may be negatively impacted by the TMEP; and
- it does not sufficiently analyze and comparatively assess alternatives to the project.

We discuss each of these deficiencies below in more detail.

4.1. Deficiencies in the Analysis of Need

4.1.1. Underestimate of Oil Pipeline Transportation Capacity

A comparison of MS's oil transportation capacity estimates to those provided by the Canadian Association of Petroleum Producers (CAPP 2015) shows that MS capacity estimates are 3,046 kbpd lower than CAPP estimates (Table 1). The reasons for MS's lower capacity forecast are that MS uses lower estimates of the capacity of existing pipelines such as the Enbridge Mainline and omits the capacity of proposed pipelines including Energy East, Keystone XL, and Enbridge Northern Gateway Project (ENGP). The decision by MS to omit these three proposed pipelines (Energy East, Keystone XL, and ENGP) is inconsistent with the evidence MS submitted to the NEB and to the Minnesota Public Utilities Commission on behalf of Enbridge's Line 3 replacement, in which MS included all three pipelines in its analysis (MS 2014; MS 2015b). Interestingly, MS omitted any consideration of the TMEP in Enbridge Line 3 evidence.

MS provides no explanation for the inconsistencies in the different reports it has submitted to different pipeline hearings. Recent events including the US decision to reject Keystone XL announced on November 6, 2015 and the recently elected Canadian government's stated opposition to ENGP, raise doubts about the likelihood of the Keystone XL and ENGP being built.[3] But MS prepared its report for TMEP prior to the US announcement on Keystone XL and the Canadian election so these recent developments respecting these two pipelines are not relevant to MS's decision to omit them in its report. Therefore omitting any consideration of these two projects and omitting Energy East in the assessment of the need for the TMEP is a major deficiency in MS's report and is inconsistent with MS's own submissions in other current regulatory processes. The omission of these pipelines results in an inaccurate assessment of the need for the TMEP.

[3] We note that TransCanada has stated that it retains the option of reapplying for approval of Keystone XL (TransCanada 2015) and Enbridge continues to work on meeting the conditions for construction set by the Government of Canada's approval of the NGP. Therefore, it is possible that these two projects may still be built.

Table 1. Comparison of MS and CAPP Transportation Capacity Estimates

Facility	Muse Stancil Estimate (kbpd)	CAPP (2015) Estimate (kbpd)	Difference MS vs CAPP (kbpd)
Enbridge[1]	2,606	3,221	-615
Express/Milk River/Rangeland	514	490[2]	+24
Trans Mountain	300	300	0
Keystone	591	591	0
Total Existing Pipeline	**4,011**	**4,602**	**-591**
Keystone XL	0	830	-830
ENGP	0	525	-525
TMEP	590	590	0
Energy East	0	1,100	-1,100
Total Existing and Proposed Pipeline	**4,601**	**7,647**	**-3,046**
Existing Rail Capacity	550	776[3]	-226
Rail Expansion Capacity	3,320	n/a[4]	n/a
Total Existing and Proposed Rail	**3,870**	**776**	**n/a**

Sources: CAPP (2015) and MS (2015). Notes: 1. Both estimates from CAPP (2015) and MS include Enbridge Mainline capacity as well as the Alberta Clipper Expansion and Line 3 Restoration. 2. Rangeland and Milk River are included on pipeline maps and charts by CAPP but their capacity is not provided in the CAPP report. Capacity for these two pipelines is from Ensys (2010; 2011). 3. CAPP (2015) estimates rail capacity at 776 kbpd and forecasts rail shipments of between 500 and 600 kbpd in 2018 without the Keystone XL. 4. CAPP (2015) states that rail growth beyond 2018 depends on the availability of pipeline projects.

4.1.2. Failure to Include Range of Future Crude Oil Supply Scenarios

MS's market analysis (MS 2015) uses CAPP's 2015 forecast for oil supply. In its 2015 market analysis, CAPP states that due to the current high degree of uncertainty in oil markets, it provides two forecasts: a lower growth forecast based on oil production from projects currently operating and under construction and a higher growth forecast that includes currently operating and under construction projects plus new projects. The lower growth forecast for Western Canadian crude oil supply in 2030 is 4,770 kbpd while the higher growth forecast is 6,060 kbpd (CAPP 2015, p. 10). Under the lower growth forecast Western Canadian crude oil supply will increase by 770 kbpd by 2030 and under the higher growth forecast, supply will increase by 2,060 kbpd. CAPP does not provide any assessment of the likelihood of the two forecasts.

The problem with MS's market analysis is that it uses CAPP's high growth forecast while failing to acknowledge or consider CAPP's low growth forecast. Given that the difference in supply between the two CAPP forecasts is over 1 million bpd by 2030, the difference in modeling results from using the low and high range would be significant. Therefore MS's use of only CAPP's higher growth forecast results in inaccurate conclusions regarding the need and benefits of the TMEP.

4.2. No Assessment of Costs of Surplus Pipeline Capacity

The NEB's *List of Issues* for the TMEP application (NEB 2013d) requires assessment of the commercial impacts of the project (Issue 3). A major commercial impact of the project not assessed by TM or MS is the impact of the TMEP on other oil transportation infrastructure.

TM has firm 'take-or-pay' contracts that may allow the construction of the TMEP from the private financial perspective of TM. However, the construction of the TMEP will contribute to unused pipeline capacity across the broader oil transportation sector in Canada. The timing and extent of this under-utilization of pipeline capacity will depend on what oil supply forecast one uses, what other transportation projects are built, and how much rail continues to be used. Nonetheless, unused pipeline capacity appears to be significant under a range of scenarios. We discuss the magnitude and costs of surplus capacity in sections 5 and 6.3.

4.3. Deficient Assessment of Predicted Oil Price Netback

MS estimates that the TMEP would generate benefits in the form of increased 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 TMEP as compared to rail shipping costs to the US Gulf Coast (USGC); and (2) an increase in oil prices resulting from the reduction in supply of Canadian exports to the US market. There are a number of deficiencies in MS's analysis that invalidate the benefit estimates.

4.3.1. Failure to Test Reasonable Range of Oil Supply and Transportation Capacity Assumptions

As discussed, MS uses only the higher CAPP growth supply forecast and omits consideration of the lower forecast scenario. MS also omits 3,046 kbpd of proposed WCSB pipeline transportation capacity from its analysis. Using lower production and higher transportation capacity assumptions would significantly impact MS's modeling results on the impact and benefits of the TMEP. If CAPP's lower growth forecast is used, exports to the US would be approximately 1,000 kbpd lower in 2030 than MS assumes and the price benefits alleged by MS resulting from the reduction of 500 kbpd of exports to the US would be achieved without construction of the TMEP. Also if Energy East's 1,100 kbpd of capacity were included in the analysis, exports to the US market would also be significantly reduced without building the TMEP.

4.3.2. Incomplete Assessment of Transportation Cost Options

MS's modeling results rely on cost assumptions for North American oil transportation capacity. We assessed two of their assumptions - TMEP tolls and railway costs - and found deficiencies in both cases. MS toll assumptions for the TMEP use only one set of possible TMEP tolls (MS 2015 p. 44, 61). The problem with using only one set of toll assumptions is that it does not reflect the uncertainty regarding actual tolls that may be charged for TMEP. In its firm shipper contracts, TM provides a range of potential tolls to reflect uncertainty over capital costs of the project. In its evidence submitted to the NEB toll hearings, TM states that the indicative toll range for heavy oil from Edmonton to Westridge for a 20-year term, for example, could vary from $4.85 to $5.79 (TM 2012, p. B1). Given TM's recent announcement that the capital costs of the TMEP are likely to hit the upper limit specified in the contracts (Krugel 2015), the tolls are likely to reach the higher end of the range specified in the shippers' contracts, which is significantly higher than the toll assumptions used by MS. In its analysis, MS does not discuss the uncertainty regarding TMEP tolls or assess the impacts of higher toll rates on its findings. Higher tolls on the TMEP will reduce the netback received by shippers and reduce the alleged benefits.

A second issue is MS's rail cost assumptions for oil shipments. MS assumes that rail costs are almost always higher than pipeline costs and the price benefits of the TMEP are in part a result of the reduced usage of more expensive rail transport (MS 2015, p. 12, 56). MS's estimate of the price benefits from reducing the rail shipments is questionable because the rail price assumptions are inconsistent with other evidence submitted by TM in its toll hearings (Schink, 2013), which concluded that rail is not necessarily a higher cost option.

TM's evidence (Schink 2013, App. A p. 18) provides a cost comparison of transportation of dilbit (70% bitumen and 30% diluent) and undiluted bitumen by rail and pipeline on a per-barrel basis to several origin and destination markets including Edmonton to the USGC and Fort McMurray to the USGC (Table 2). Schink's conclusion is that dilbit shipments by rail to the USGC are less expensive than pipeline shipments when condensate is backhauled to the origin market, and that bitumen shipments by rail to the USGC are considerably less than pipeline shipments regardless of whether rail cars are returned empty or full of condensate. Schink concludes that "…in Western Canada, rail has become an increasingly cost-effective transporter for crude oil" (2013, App. A p. 18). Bitumen shipments are shipments in coiled/insulated tank cars that carry 100% bitumen without the need for diluents and comprise the majority of tank cars manufactured since 2013 (Torq Transloading 2012 as cited in USDS 2014, Vol. 1.4 p. 1.4-82). MS does not include any consideration of this lower cost coiled/insulated tank car option and thus overestimates rail costs.

Table 2. Comparison of Rail and Pipeline Shipping Costs to the USGC

Origin-Destination	Product[1]	Returned Rail Cars	Cost per barrel		
			Rail	Pipeline	Difference
Edmonton to USGC	Dilbit	Empty	$13.4	$9.0	+$4.4
	Dilbit	Condensate	$8.5	$9.0	-$0.5
Fort McMurray to USGC	Bitumen	Empty	$13.5	$15.1	-$1.6
	Bitumen	Condensate	$7.2	$15.1	-$8.0

Source: Adapted from Schink (2013, App. A p. 18). Note. 1. Dilbit consists of 70% bitumen and 30% condensate diluent; bitumen in the table represents 100% undiluted bitumen. Pipeline shipments are of dilbit.

Independent analysis prepared by ICF (Undated) for the *Final Supplemental Environmental Impact Statement for the Keystone XL Project* (USDS 2014) also contradicts MS's evidence by showing that crude-by-rail shipment of Canadian heavy crude is cost-competitive with pipelines to the USGC.[4] ICF compares costs of transporting crude oil from Western Canada to the USGC by estimating rail and pipeline shipments on a per barrel basis and making the necessary adjustments to ensure that costs of shipping dilbit (30% condensate) and railbit (only 15%

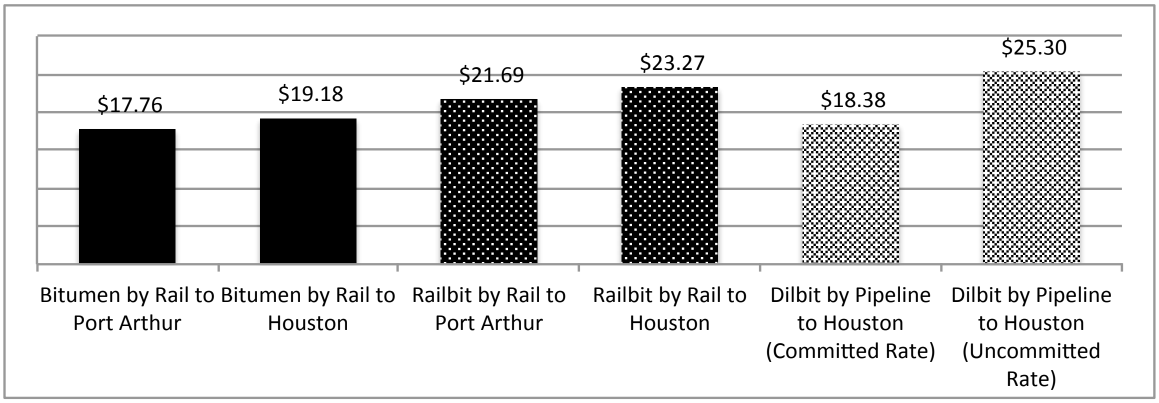
[4] Note that rail shipment costs from ICF (Undated) and Schink (2013) are not directly comparable since they rely on different assumptions, data, and methods.

condensate) are comparable to bitumen.[5] ICF concludes that the cost of shipping bitumen by rail to USGC refineries may be less than shipping bitumen by pipeline (as dilbit containing 30% diluent) to USGC refineries at a long-term committed rate. According to ICF's analysis, both bitumen and railbit shipped by rail are less expensive than shipping bitumen as dilbit at an uncommitted rate by pipeline to the USGC (Figure 1). Furthermore, crude-by-rail estimates in Figure 1 omit the potential for back-hauling diluent on the train's return journey which could create additional savings of $2 to $5 per barrel associated with rail transportation (USDS 2014, Vol. 1.4 p. 1.4-87-89). Other analyses (Fielden 2013; Genscape 2013) highlight the price advantage associated with crude-by-rail shipments and estimate that rail shipment of bitumen may increase a crude oil producer's netbacks by $4 to $10 per barrel compared to pipeline shipments of dilbit. CAPP also identifies a number of advantages of rail relative to pipelines including: lower capital costs, shorter lead times to add capacity, shorter shipment times, option and flexibility benefits to reach alternative markets, and high product integrity (CAPP 2015, p. 32).

In sum, MS's assumption that oil shipments by rail are necessarily more expensive than pipeline is not supported by TM's and the US government's evidence and MS's conclusion that reduced usage of rail generates a price benefit is therefore questionable.

[5] ICF (Undated) estimates pipeline shipment costs from Hardisty, Alberta to Houston, Texas refineries via the Keystone and Seaway pipelines. Costs associated with pipeline shipments include pipeline tariffs on the Keystone and Seaway pipelines (committed or uncommitted), a penalty for transporting diluent south (i.e., only 70% bitumen is shipped), line fill and storage costs based on a transit time of 20 days, and costs of transporting diluent north to Alberta. ICF estimates rail shipment costs from Hardisty, Alberta to refineries in both Port Arthur, Texas and Houston, Texas for bitumen and railbit. Costs associated with rail shipments include loading and unloading the unit trains, rail freight, railcar lease, a penalty for transporting diluent south (railbit), rail fill costs based on a transit time of eight days, destination movements (i.e., by barge to local refineries in Port Arthur or to refineries in Houston), and costs from transporting diluent north to Alberta. For a complete discussion of these costs see ICF (Undated).

Figure 1. Comparison of Rail and Pipeline Shipment Costs



Source: ICF (Undated).

4.3.3. Inaccurate and Inconsistent Oil Market Assumptions

MS states that the increase in netback prices for Canadian oil exports is due in large part to the reduction in supply of Canadian exports to the US market. As MS states “Consequently, about 79,500 m3/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).

It is reasonable to assume that a reduction in supply will increase price, all things being equal. But the problem with MS’s analysis is that it assumes that supply in the North American market is reduced by 500 kbpd, which is inconsistent with MS’s other statements that North American oil consumption, oil supply, and oil prices are the same with and without the TMEP (MS 2015; TM 2015c, sec. 1.4). In other words, MS assumes that reduction in supply due to the TMEP is offset by an increase in supply from other sources. World oil markets simply adjust to the changes in supply and demand and restore market equilibrium[6]. Because oil prices and oil supply in the US are the same with and without the TMEP, the prices received by Canadian exporters should be unaffected by the TMEP. Therefore, MS’s assumption that the diversion of Canadian exports from the US market increases the price of Canadian oil by reducing supply is inconsistent with MS’s other assumptions.

[6] See section 6.4 for further discussion of oil market dynamics.

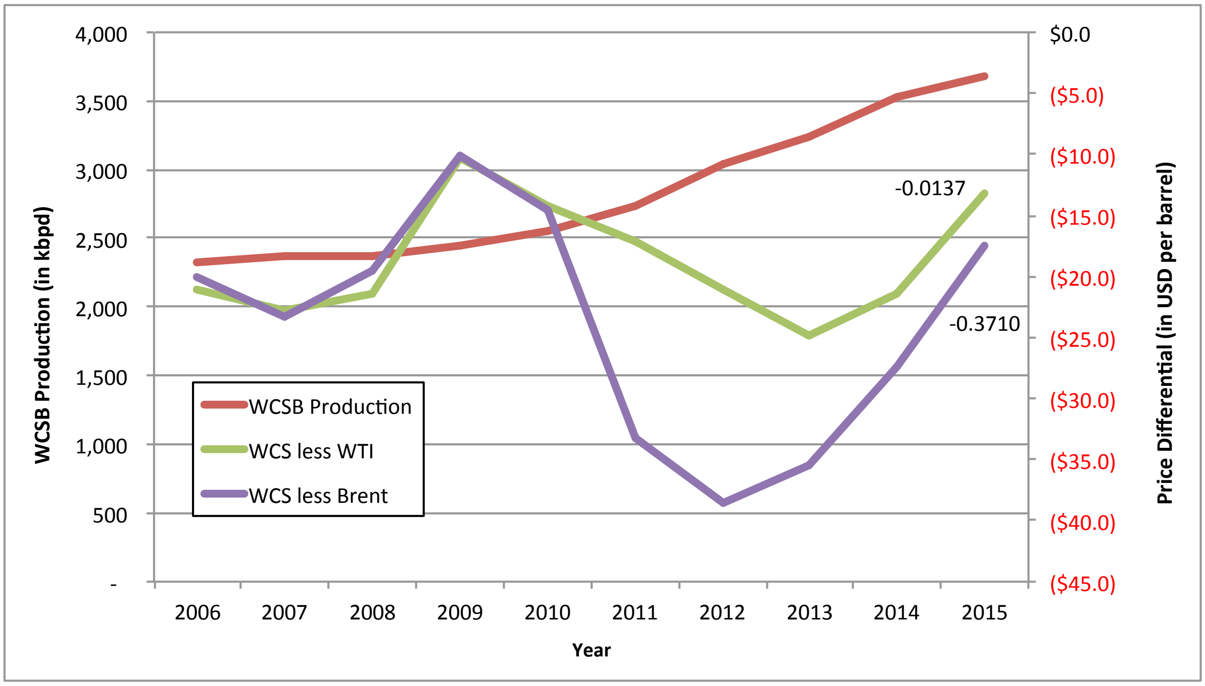
4.3.4. Unrealistic Marginal Pricing Assumption

MS assumes that the price of all Canadian oil is determined by the price received by the marginal barrel of Canadian oil exported to the US. MS states that the marginal barrel of Canadian oil receives a higher price with the TMEP because of the reduced supply to the US. As stated above, this assertion by MS is inconsistent with their statement that oil supply in the US is the same with and without the TMEP. Further, the marginal barrel of Canadian oil is shipped by rail to the same destination (USGC) with and without the TMEP and therefore the marginal price should be the same. Even if the marginal price for Canadian oil was lower without the TMEP, it is unrealistic to conclude that the price of all Canadian oil would be reduced. Fixed tolls and shippers' contracts along with other market constraints would prevent all prices adjusting to the lower marginal price. Most Canadian oil shipped to other destinations on other transportation systems would receive the same price with and without the TMEP. Therefore applying any potential price benefit to all Canadian oil overestimates the benefit if such a benefit did exist.

4.3.5. Inconsistency with Oil Market Performance

The conclusion of MS's oil price modeling results is that increased Canadian oil exports to the US market will reduce the price of Canadian oil. MS does not provide any market data to support this conclusion or any data testing the reliability of the model it is using. 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 (2006-2015) to see if there is any relationship between the relative price and changes in production (Figure 2). During this period, WCSB production and exports to the US have increased by approximately 1.4 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 what correlation exists shows that the price discount on Canadian oil declined as exports increased, exactly the opposite of MS's hypothesis. The Canadian price discount peaked around 2012-13 due to short-term oil transportation constraints but the price discount subsequently narrowed considerably despite the large increase in oil exports to the US. 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 impact on Canadian oil prices.

Figure 2. Comparison of WCSB Production to Oil Price Differentials



Source: CAPP (2010; 2012; 2013; 2014; 2015); McDaniel (2015). Note: Correlation coefficient of -0.0137 estimated based on the correlation of WCSB production to the price differential between Western Canadian Select and West Texas Intermediate (WTI) and the coefficient of -0.3710 estimated based on the correlation of WCSB production to the Western Canadian Select/Brent price differential.

4.3.6. Inaccurate Price Forecasts

The MS model requires forecasting a series of input and output refinery products based on several inputs including crude prices, natural gas prices, contribution margins at refineries, and price differentials. Accurately forecasting petroleum product prices represents a significant challenge and any forecasting errors will invalidate MS's model results and the estimates of the alleged price benefit resulting from the TMEP.

To illustrate the challenges of forecasting prices, we compare recent price forecasts by MS with actual prices. In 2012, MS (2012) provided forecasts in the Northern Gateway hearings of $96.71 (2012 US $) per barrel for WTI (at Cushing) and $100.58 (2012 US $) per barrel for Brent in 2015. However, actual crude prices as of October 2015 are $50.95 for WTI and $55.35 for Brent (McDaniel 2015), almost 50% lower than MS's crude oil price forecast (Table 3).

Table 3. Comparison of MS Crude Oil Price Forecast with Actual Prices (in 2015 US $)

Barrel of Crude Oil	MS (2012) Forecast for 2015[1]	Actual Crude Oil Price in 2015[2]	Margin of Error
WTI	$100.18	$50.95	-49%
Brent	$104.19	$55.35	-47%

Sources: Computed from McDaniel (2015), US BLS (2015), MS (2012). Notes. 1. MS (2012) crude prices adjusted for inflation to 2015 US $ in order to compare prices. 2. Prices are current as of October 2015.

The forecast that MS (2015) uses in its market analysis for the TMEP is also dated. MS (2015) relies on the 2014 IEA forecast that estimates oil prices will remain above $100 per barrel throughout the forecast period. However, the IEA has since lowered its crude oil price forecast in its most recent 2015 report. IEA (2015) provides two oil price forecasts: one that assumes that oil prices will remain below $80 until 2020 and gradually rise thereafter and a second, lower scenario, that assumes oil prices will remain in the $50-$60 range until 2020 and then gradually rise to $85 by 2048. Both the IEA scenarios are well below the forecasts used by MS.

Forecasting errors are not unique to MS's forecasting methodology. Many models and forecasters were unable to predict the severity of the recent decline in crude oil prices. Nonetheless, the significant challenges of forecasting petroleum product prices over even the short-term raises serious concerns over the accuracy of price forecasts made over longer periods. MS's short-term forecast errors of around 50% in crude prices undermine confidence in the accuracy of MS's attempts to forecast differences in oil prices in the range of +/- 2% over 20 years.

4.3.7. Unrealistic Refinery Assumptions

MS's price benefit analysis assumes that there are no changes in North American refineries during the forecast period to 2038 other than current projects. 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' refinery assumption are unreliable.

4.3.8. Weaknesses in MS Model and Failure to Complete Sensitivity Analysis

MS uses a linear programming model to estimate the impact of the TMEP on oil prices. While such models can be useful, they do have structural deficiencies (Ben-Tal and Nemirovski

2000; Eiselt and Sandblom 2007; Alhajri et al. 2008; Kanu et al. 2014). Linear programming models require holding a large number of variables constant to determine an optimal solution. Even minor changes in one variable can have significant impacts on the results. Consequently it is essential to test the impact of different assumptions to identify the profile of alternative outcomes. MS does not undertake any sensitivity analysis despite the large degree of uncertainty associated with the model inputs such as petroleum prices.

Linear programming models also assume a linear relationship between variables, which is inconsistent with real world relationships in the refinery sector. While the model used by MS is often used by specific refineries to assist in identifying profit-maximizing strategies, the use of the model to attempt to forecast the operation of the entire North American petroleum market is questionable. There is no evidence provided by MS testing the accuracy of the model and therefore it is imprudent to rely on the model's results.

4.3.9. Failure to Deduct Costs to Canadian Refineries and Benefits to Non-Canadians

Any potential price benefit to Canadian oil producers will increase the cost of oil in Canada for Canadian refineries. While a price increase paid by non-Canadian purchasers of Canadian oil can be considered a benefit to Canada, price increases paid by Canadian refineries are not a benefit and should be deducted to determine the net benefit to Canada. MS has deducted the oil price increase to Canadian refineries in previous studies (MS 2012) but has not deducted them in this study.

Also according to Canadian government guidelines (TBCS 2007, p. 12) and the NEB's definition of the public interest (NEB 2010a, p. 1), only benefits accruing to Canadians should be included as a benefit to Canada or in Canada's public interest. Therefore any increased netbacks accruing to foreign shareholders, who comprise about 40% of the Canadian oil and gas sector (Statistics Canada 2013) should be deducted from any benefit estimate. Neither MS (2015) nor the Conference Board of Canada (CBC 2015) deducted benefits accruing to non-Canadians and increased costs to Canadian refineries. Therefore any potential benefit that may exist due to higher oil prices is overstated.

4.3.10. Summary of Deficiencies in MS Price Benefit Estimate

In summary, the MS estimate of the TMEP price benefit has the following deficiencies:

- Failure to test impact of CAPP's lower range WCSB production scenario;

- Underestimate of WCSB transportation capacity;
- Incomplete and questionable transportation cost assumptions;
- Unrealistic refinery assumptions;
- Unrealistic marginal pricing assumptions;
- Inaccurate and inconsistent oil price, supply and demand assumptions;
- Inconsistency between model results and oil market performance;
- Inability to accurately forecast oil product prices;
- Failure to deduct costs to Canadian refineries;
- Failure to deduct benefits accruing to non-Canadians; and
- Failure to undertake sensitivity analysis to test alternative assumptions.

Due to these deficiencies, the price benefits estimated by MS are unlikely to occur and it would be imprudent to rely on these price benefit estimates in evaluating the TMEP.

4.4. No Analysis and Consideration of Net as Opposed to Gross Economic Impacts

TM maintains that the TMEP would generate economic “benefits” in the form of jobs, economic output, and government revenues based upon an EconIA done by the Conference Board of Canada (CBC 2015). It is widely recognized and accepted, however, that gross economic impacts as the Conference Board of Canada estimated do not indicate **net** effects on the economy and certainly do not in any way indicate the **net benefits** of the project (Grady and Muller 1988; Shaffer 2010).

To analyze net effects one must recognize 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, and 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-developed 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 Conference Board of Canada. For example, MS (2015) concludes that if the TMEP is not built, other transportation capacity such as rail will be developed to meet transportation requirements and this alternative transportation capacity will generate employment and economic activity.

Further to this point, labour market studies document the shortage of skilled labour in Canada, indicating that labour has a high likelihood of otherwise being employed in the absence of the TMEP. As the NEB concludes:

> *[a] shortage of skilled workers is developing as the workforce ages and overall demand for labour increases. According to the Petroleum Human Resources Council of Canada (PHRCC) the oil and gas industry needs to fill 36,000 job openings between 2013 and 2015, as a result of industry activity levels as well as age-related attrition. In the longer term, under a scenario of higher oil and gas prices, the PHRCC is predicting a requirement of 84,000 new hires by 2022. This challenge is being addressed through a number of government and industry initiatives, but a potential labour shortage may increase construction costs and slow the pace of oil development (NEB 2013a, p. 48).*

Recent labour market studies by the BC government similarly forecast tight labour markets in BC and find that in-migration of skilled workers will be required even if no liquefied natural gas (LNG) projects planned for the province are built (BC Statistics 2014). While the recent oil market downturn will take some pressure off the labour market in Western Canada, the assumption that all workers employed on the TMEP will otherwise be unemployed is not valid, and consequently the gross employment impacts of the TMEP cannot be expected to fairly represent net incremental gains to the Canadian economy. For example, the recent downturn in the oil sector has contributed to a decline in the Canadian dollar that has provided stimulus to other sectors of the economy (Bank of Canada 2015; Canada 2015; Myers 2015). Over the longer term the economy adjusts to these changes and new investments and employment opportunities arise to offset declines in other sectors.

The Conference Board of Canada's estimates of government fiscal benefits provided in TM's application (CBC 2015) are also not valid. The estimated gain in government revenue from project construction and operation is based on the assumption that all the labour and capital employed by the TMEP would otherwise be unemployed and would therefore generate no tax revenue absent TMEP. Again, most of this labour and capital would be otherwise employed and would generate tax revenue in alternative employment. The Conference Board of Canada's EconIA is also problematic in that it only assesses gross government revenue without considering any potential incremental burdens on government induced by the TMEP such as emergency response and regulatory oversight. As well, the EconIA ignores how tax revenues may be reduced to the extent that TMEP diverts oil and revenues from other shippers or, as MS (2015) concludes, incremental transportation capacity is created in place of the TMEP if the TMEP is not constructed. Consequently, the estimated $4.5 billion increase in government revenue estimated by the Conference Board of Canada significantly overestimates the net revenue gain to government.

4.5. Inadequate Assessment of Economic, Environmental, and Social Costs

The NEB's assessment of the public interest value of new pipeline applications requires consideration of the potential negative impacts of projects. However, TM considers only the potential benefits of the TMEP on oil price netbacks and economic output and does not include estimates of the economic, environmental, and social costs of the project despite explicit requirements from the NEB to include these costs in the information provided on the public interest. Such costs include:

- government costs of providing infrastructure and services such as emergency response and regulatory oversight to support the pipeline;
- damages and losses to ecosystem goods and services from pipeline and terminal construction and operation;
- air pollution from construction and operation of the pipeline and marine terminal as well as tanker operations;
- GHG emissions from construction and operation of the pipeline and marine terminal as well as tanker operations;
- spill accidents or malfunctions that occur during pipeline, terminal, and tanker operations;
- damages and risks to passive use values incurred by Canadians;
- social costs related to the potential conflict associated with opposition to the project; and
- cultural impacts caused by the disruption of traditional and cultural practices resulting from regular project operations and/or spills.

TM's failure to include and quantify these costs in its assessment is a serious omission that results in an incomplete analysis of the public interest value of the TMEP and is contrary to the public interest requirements of the *NEBA*.

4.6. Incomplete Distributional Analysis of Impacts Affecting Different Stakeholders

Federal government evaluation guidelines recommend the need for analyzing the distribution of impacts of projects and policies across different stakeholder groups. As stated in Treasury Board of Canada Secretariat (TBCS 2007) guidelines:

> *[o]ne must ask, "Who are the winners and who are the losers under the policy?" and "By how much does each class of stakeholders gain or lose?" A stakeholder analysis attempts to allocate the net benefits or losses generated by the policy. The output of the stakeholder analysis contains critical information for decision makers, as it indicates which groups will be the net beneficiaries and which groups will be the net losers and by how much (p. 30).*

The Conference Board of Canada's EconIA prepared for TM (CBC 2015) examines direct, indirect, and induced impacts to GDP, government revenues, and employment from the perspective of the provinces and Canada. The EconIA does not provide a comprehensive analysis of the distribution of potential impacts on First Nations and stakeholder groups (such as households in BC, Alberta, and Canada, crude oil producers, and tanker owners/operators, among others) as recommended in federal government guidelines. Further, the analysis of distributional effects in *Volume 2* identifies only the gross economic benefits of the TMEP and fails to examine the distribution of potential costs that stakeholders incur from the project. Consequently, TM is not able to identify who "wins and loses", nor is TM able to identify appropriate mitigation measures such as adequate levels of compensation to address negative impacts borne by particular societal groups affected by the project such as First Nations.

The absence of a comprehensive evaluation of distributional impacts in the TMEP application prevents decision-makers from assessing the economic, environmental, and social costs and benefits to different groups in Canada and from determining the appropriate balance of these interests in order to assess the public interest of the project consistent with the *NEBA*.

4.7. Inadequate Compensation Plans

An important consideration in the assessment of public interest and analysis of who gains and who loses from projects such as the TMEP is the nature of the compensation system to mitigate economic, environmental, and social costs incurred by specific stakeholders. Here we focus on just one of the many compensation issues: compensation for damages from a potential tanker spill.

Although TM provides an overview of compensation funds in its Contingency Plan (TM 2013b, TERMPOL 3.18), TM has not provided a comprehensive compensation plan that provides details about the process for mitigating and compensating damages incurred by parties impacted by a tanker spill. The Contingency Plan does not define compensable damages, identify compensable parties, specify methods for determining damage claims, identify funding sources to fully cover all damage costs, or specify dispute resolution procedures. Instead, TM defers compensatory responsibility for tanker spills to the International Oil Pollution Compensation Fund (IOPCF) and the domestic Ship-source Oil Pollution Fund, which provide maximum compensation of up to $1.3 billion for tanker spills (TM 2013b, TERMPOL 3.18). It is critical to note, though, that the international and domestic compensation funds only cover damages where a monetary loss can be proven (IOPCF 2011), and consequently many spill damages including environmental damages, social and psychological costs, and passive use damages may not be compensated. Recent evidence shows that compensation actually paid by the IOPCF represented only 5% to 62% of compensation claimed for six large tanker spills (Thébaud et al. 2005).

4.8. 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) considers different pipeline corridors and alternative pump station locations in its environmental and socio-economic assessment in *Volume 5A* and *Volume 5B* and identifies some of the criteria referenced by the NEB (2013c) to evaluate alternatives. However, the TMEP application does 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 MS (2015).

There are a large number of potential transportation projects available other than rail and not all the projects or options are required or needed to meet demand. Consequently it is essential to undertake a comparative evaluation of transportation options to identify which option or combination of options is more cost-effective from an economic, environmental, and social perspective. The US government’s assessment of pipeline proposals provides a good framework for how to undertake comparative evaluation of transportation options.[7]

4.9. No Assessment of Project Trade-offs

A final major deficiency in the TMEP application is that the regulatory application submitted by TM does not present the major trade-offs of the project in terms of its gains and its costs. The TMEP application contains several sections relevant to evaluating the public interest of the project: *Volume 2* of the TMEP application discusses the economic and commercial implications of the project and contains appendices that estimate the benefits of the project, the need for the project, and the direct, indirect, and induced economic impacts; *Volumes 5A, 5B, 5C* and *5D* contain the socio-economic and biophysical impacts of the project; and *Volumes 7* and *Volume 8C* (including the TERMPOL studies) contain important information related to spill risk. However, TM does not synthesize important information from the different volumes of the regulatory application in a centralized evaluative framework to compare costs and benefits of the project and trade-offs that decision-makers must consider in assessing the project's public interest value. Identifying trade-offs between gains from project benefits and losses from project costs is information needed by the NEB to be able to weigh the impacts of a project to determine whether the project is in the public interest (NEB 2010a, p. 1).

4.10. Summary of Major Deficiencies

The methods TM uses to assess whether the TMEP is in the public interest have a number of major weaknesses. The assessment uses gross economic impacts as the primary measure of the contribution of the project to the public interest instead of net impacts, and the method

[7] 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.

incorrectly assumes that economic impacts are a measure of benefits without taking into account the opportunity cost of the labour, capital and other resources it uses. TM's analysis overstates the need for and value of the transportation services it provides. The TM analysis also does not estimate many of the costs of the project (e.g., unused capacity and environmental costs) and does not provide a summary of costs and benefits in a format that allows for identification of trade-offs and comparisons necessary for determining whether the TMEP is in the public interest.

In total we identify 10 major deficiencies related to project need and public interest of the TMEP (Table 4). Accordingly we conclude that TM's application is incomplete and deficient and the application does not provide decision-makers with the information required to make an informed decision on whether the TMEP is needed and in the public interest.

Table 4. Weaknesses in the TMEP Regulatory Application Addressing the NEBA Decision Criteria

Criterion	Description	Deficiency
Project Need	*An analysis of the supply and demand for the pipeline provides the best available information to enable a sound decision of the need for pipeline capacity*	1. Understatement of oil transportation capacity 2. Optimistic crude oil supply forecast 3. No assessment of costs of surplus pipeline capacity
Public Interest	*All relevant economic, environmental, and social costs and benefits to Canadians are estimated using the best available information and analysis to facilitate a rational assessment of public interest impacts*	4. Methodologically unsound forecast of alleged oil price benefit to Canada 5. No analysis and consideration of net as opposed to gross economic impacts 6. Inadequate assessment of economic, environmental, and social costs 7. Incomplete distributional analysis of impacts affecting different stakeholders 8. Inadequate compensation plans 9. No assessment of costs and benefits of alternative projects
	Information is presented in a manner that facilitates the	10. No assessment of project trade-offs

Criterion	Description	Deficiency
	identification of trade-offs among the various impacts to enable a reasoned judgment of whether there is a net benefit	

5. Analysis of Need for TMEP

TM does not provide a comprehensive assessment of oil transportation capacity and demand to assess the need for the TMEP. Such an assessment is essential in evaluating whether the TMEP is needed. To address this deficiency, we provide the following supply and demand analysis. The first step is estimation of available and potential WCSB oil transportation capacity. Existing and proposed transportation projects based on CAPP (2015) data are summarized below (Table 5). To reflect various constraints on pipeline operations, we assume that the transportation system effective capacity is 95% of nameplate capacity.

Table 5. Existing and Proposed Projects (Based on CAPP 2015)

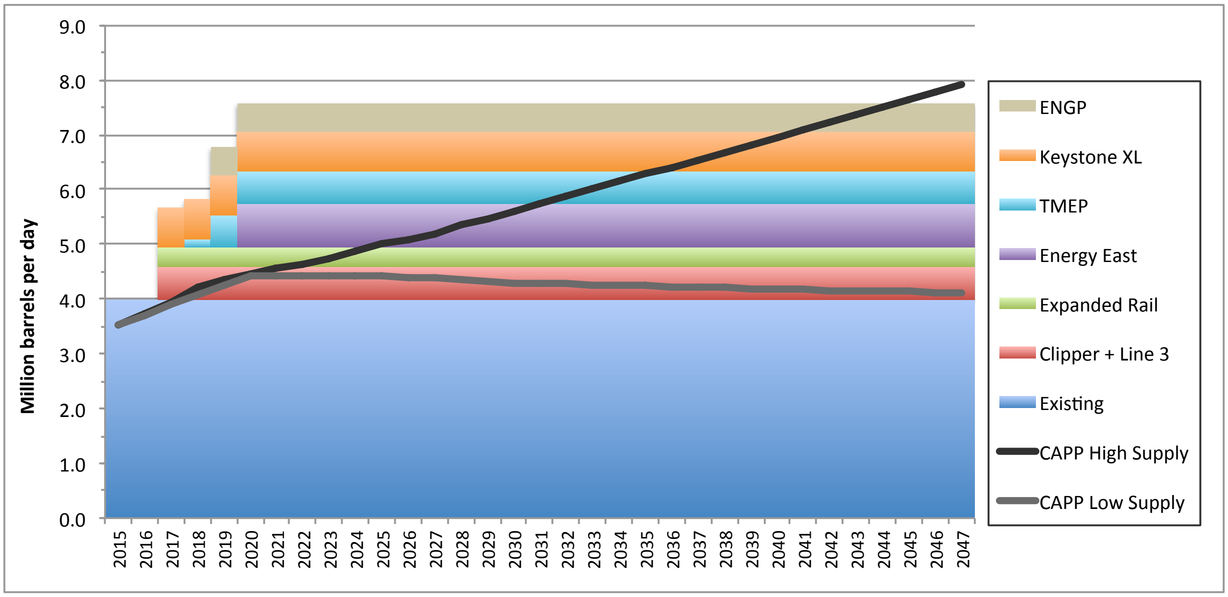
Facility	CAPP (2015) (kbpd)
Enbridge Mainline	2,621
Express/Milk River/Rangeland[1]	490
Trans Mountain	300
Keystone	591
Rail[2]	200
Existing Subtotal	**4,202**
Alberta Clipper Expansion (2015)	230
Line 3 Restoration (2017)	370
Kinder Morgan TMEP (2018)	590
Energy East (2020)	1,100
ENGP (2019)	525
Keystone XL (tbd)	830
Subtotal Existing and Proposed Pipeline	**7,847**
Rail[2] (2018)	350
Total Existing and Proposed Pipeline and Rail	**8,197**

Sources: CAPP (2015). Note. 1. Rangeland and Milk River are included on pipeline maps by CAPP but their capacity is not provided in the CAPP report. Capacity for these two pipelines is from Ensys (2010; 2011). 2. Rail estimates in the table are forecast shipments of oil by rail and are not rail capacity. The 200 kbpd is CAPP's estimated shipments by rail in 2015 and the 350 kbpd increase (total 550 kbpd) is CAPP's mid-point estimate of rail shipments if Keystone XL is not built. If Keystone XL is built we assume rail shipments of 350 kbpd, which is the amount CAPP (2015) forecasts in 2017 before Keystone XL. Actual rail capacity is much higher than forecast rail shipments. According to CAPP (2015), there is currently 776 kbpd of rail capacity for WCSB shipments with significant expansion potential. MS (TM 2015c, p. 12) assumes that rail shipments could grow to 2,255 kbpd by 2038 and rail capacity to 3,870 kbpd by 2038 (MS 2015, p. 43). Therefore if we used rail capacity in our analysis instead of rail shipments, the estimates of surplus capacity would be much higher.

The next step is to forecast demand for WCSB export capacity. Again we rely on CAPP's 2015 forecasts. CAPP provides two supply forecasts: a low growth forecast based on currently operating and under construction projects and a high growth forecast based on currently operating, under construction and new projects. The low growth and high growth CAPP forecasts are essentially the same to 2020 as existing projects under construction are built out and come into production. After 2020, the low growth forecast assumes no additional expansion while the higher growth forecasts adds an additional 577 kbpd by 2025 and 1,288 kbpd by 2030. To estimate the export demand for oil transportation services, refinery consumption from Alberta and Saskatchewan refineries are deducted from the CAPP supply forecasts. Export shipments of refined oil products are then added back in as a demand for transportation services. We also adjust for the proportion of Canadian pipeline space used to ship US Bakken oil by using CAPP's estimates of Bakken shipments on Canadian pipelines. As we discuss in section 6.1, CAPP's estimates of Bakken shipments are high, so this adds an upward bias to the demand for transportation services.

The supply and demand assessment is summarized below (Figure 3). The analysis shows that under both CAPP's high and low growth forecast, some additional capacity is required by 2018, which will consist of completion of the Enbridge Clipper project (230 kbpd) that involves adding pumping capacity to the existing Enbridge Clipper Line and the replacement of Enbridge Line 3, which adds 370 kbpd of capacity. Both of these projects are expected to be in service by 2017. With completion of these two projects, no additional projects are required under CAPP's low growth forecast. Under the higher growth forecast completion of these two projects plus CAPP's forecast rail expansion to 550 kbpd assuming Keystone XL is not built provides sufficient capacity to 2023. In 2023, one new pipeline project (TMEP or Energy East) is required under the higher growth forecast and a second new project will be required around 2029. The analysis shows that the TMEP is not needed until 2023 under the higher growth forecast. If Energy East is built, the TMEP is not needed until 2029. Under the low growth forecast, the TMEP is not required at all during the forecast period to 2048.

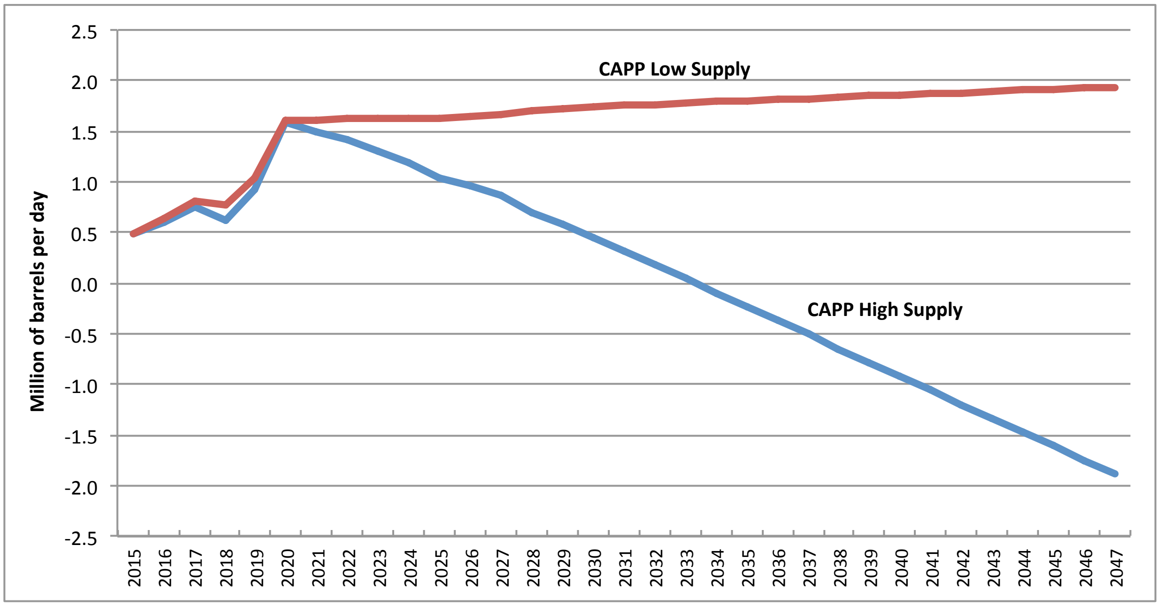
Figure 3. Estimates of Western Canadian Oil Supply Transportation Capacity



Source: Adapted from CAPP (2015). Note: Pipeline capacities reflect nameplate capacities.

We have also estimated surplus capacity under the low and high growth forecast assuming both Energy East and TMEP are approved and built as planned (Figure 4). Under the low growth forecast, surplus capacity increases from 1.6 million bpd in 2020 to over 1.9 million bpd by 2047, which is equivalent to almost four Northern Gateway's worth of empty pipeline space. Under the high growth forecast, surplus capacity peaks at 1.6 million bpd in 2020 and remains until 2034. These estimates of surplus capacity do not include pipeline capacity from ENGP and Keystone XL. If Keystone XL is built, surplus capacity will peak at over 2.0 million bpd in 2020, and surplus capacity will remain under the high growth forecast until 2037.

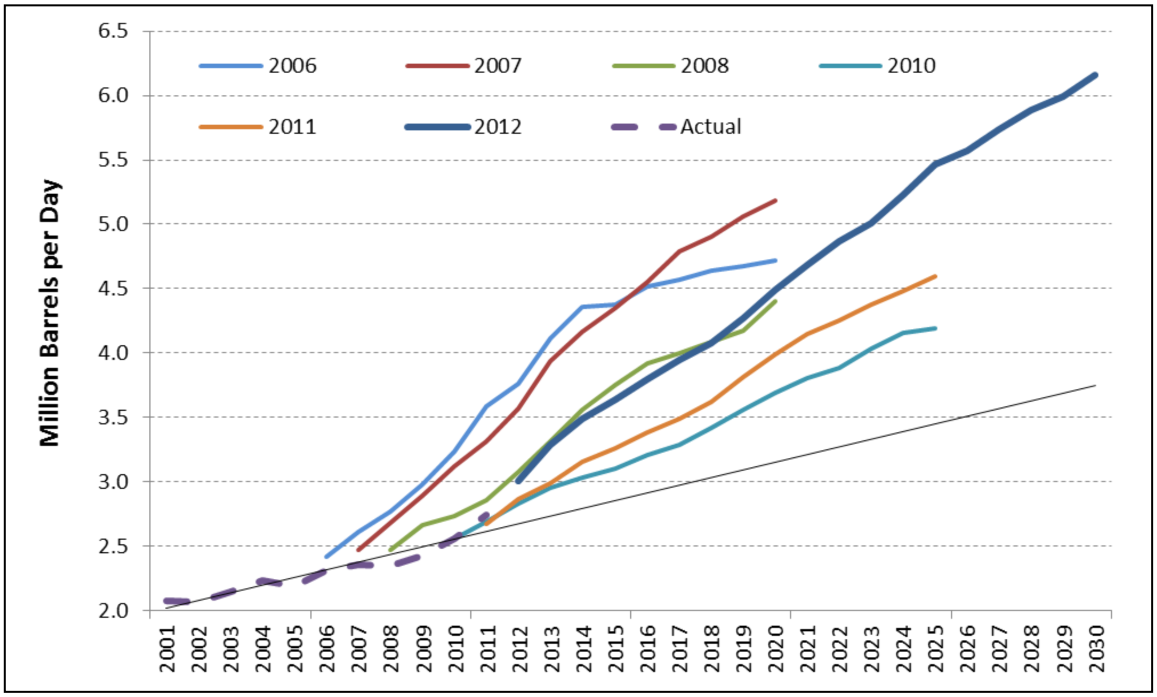
Figure 4. Surplus Capacity Estimates Under CAPP Low and High Supply Forecasts



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

It is important to keep several factors in mind when reviewing these scenarios. First, it is important to note that CAPP's forecasting has been criticized for being overly optimistic. In its review of the Keystone XL pipeline the US government provides a comparison of CAPP forecasts with actual production (Figure 5) and concludes "The CAPP forecasts generally have overestimated potential production compared to the trend of actual production" (USDS 2013, Vol. 1.4-24). The analysis shows the 2006 CAPP forecast is higher than actual production by more than 800 kbpd in 2011 and 2012, and the CAPP 2007 forecast exceeds actual production by about 300 kbpd from 2009 to 2011 (CAPP 2006; CAPP 2007; CAPP 2008; CAPP 2011; CAPP 2012; CAPP 2013). The current 2015 CAPP forecast addresses this uncertainty in forecasting by providing a low and high range. However, CAPP's high growth forecast may still reflect this upward bias.

Figure 5. Comparison of Historical CAPP Forecasts of Canadian Oil Sands Production



Source: CAPP (2006; 2007; 2008 as cited in USDS 2013, Vol. 1.4 p. 1.4-25; 2011; 2012; 2013).

Second, CAPP's 2015 forecast was completed in the Spring of 2015 when it was assumed by many forecasters that the downturn in oil prices was short-term and prices would begin to recover in late 2015 and 2016. The US EIA, for example, forecast in March 2015 that Brent would rise to $75 per barrel in 2016 but now forecasts (October 2015) that Brent will be just over $56 per barrel in 2016 (Table 6).

Table 6. Comparison of US EIA Oil Price Forecasts

Year	US EIA March 2015 (Brent in 2014 US $)	US EIA October 2015 (Brent in 2014 US $)
2014 (actual)	99.00	99.00
2015	59.50	53.82
2016	75.03	56.24

Sources: US EIA (2015a, 2015c).

The International Energy Agency's (IEA) most recent annual energy report (IEA 2015) includes two long-term oil price forecasts: one assumes that oil prices remain below $80 until 2020 and then gradually rise and the second lower price forecast assumes oil prices remain in the $50 to $60 range until 2020 and then gradually rise to $85 by 2048. Under the low price forecast, the

IEA predicts very little expansion in oil production in Canada (IEA 2015, p. 168). The IEA does state that they view the higher price forecast as more likely than the low price forecast. This compares to their previous annual energy review (IEA 2014) in which they forecast oil prices to remain above $100 per barrel throughout the forecast period. Some other analysts also forecast continued low oil prices in the range of $50 to $70 per barrel for the next 10 to 20 years (Wolak 2015).

Another factor contributing to the uncertainty over oil production is climate change policy. Alberta has just announced a major policy change that caps GHG emissions from oil sands at 100 Megatonnes per year, just a 30 Megatonnes per year increase above current emissions and a new carbon tax of $30 per tonne applied to oil sands (Alberta 2015). Additional commitments may be made by the Canadian government as a result of climate change negotiations in Paris. These policies increase the cost of production in Alberta and will likely reduce production below what it would otherwise be, thus further reducing demand for new oil transportation capacity.

These increasingly pessimistic oil price forecasts and new climate change policies are particularly critical for Canadian production because Canadian oil sands production (Figure 6, see Oil Sands) is at the high end of the international cost curve (see also IEA (2013, p.454)). Studies by the Canadian Energy Research Institute (CERI) (2014) estimate that WTI prices (2013 US $) needed to justify oil sands expansion are $85 for *in situ* SAGD projects and $105 for mine projects.[8] While some oil sands projects will have higher or lower supply costs than CERI's average estimates, CERI's analysis shows that many previously planned new greenfield projects in the oil sands are unlikely to be developed at current WTI prices. While some other forecasts have lower cost of production estimates for the oil sands, they also forecast slower growth in WCSB production.[9] Lower oil prices and climate change policies that increase costs will therefore have dramatic impacts on Canadian production (McGlade and Ekins 2015).

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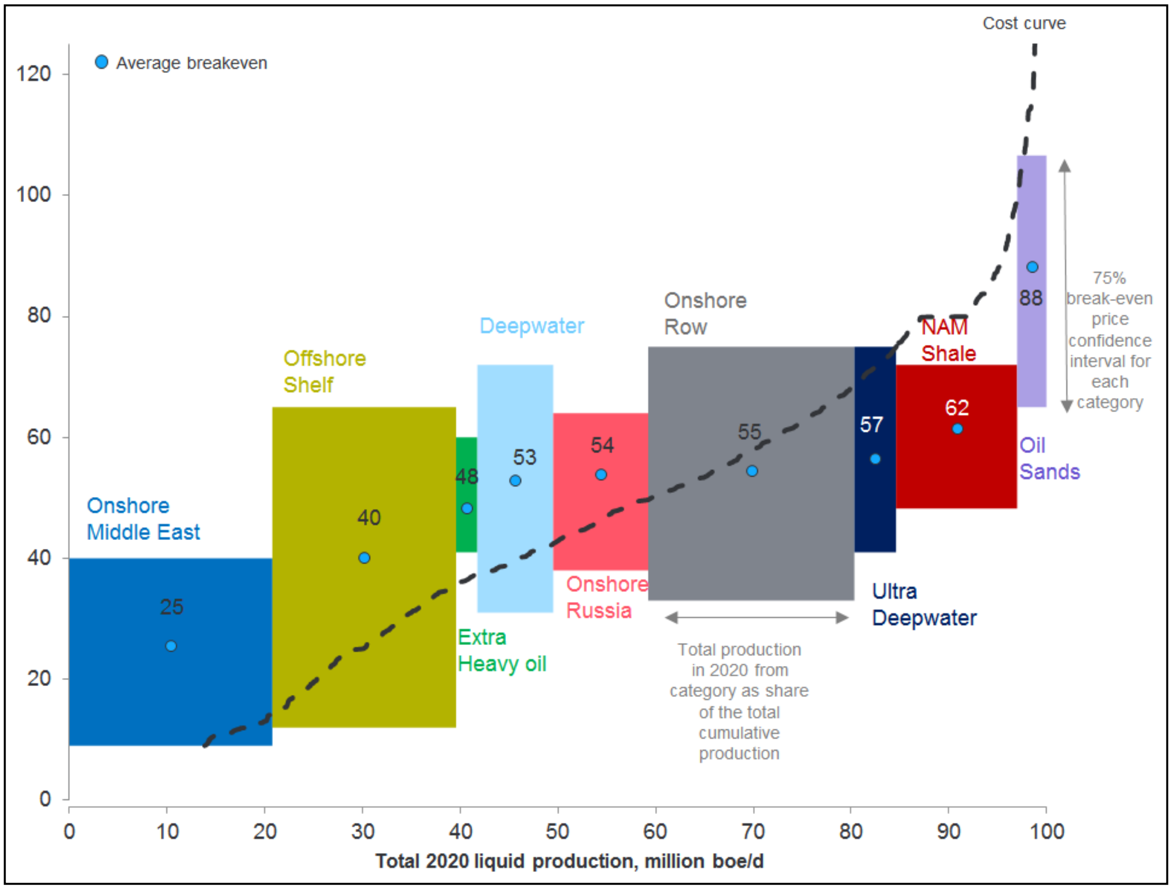
[8] CERI's estimates are based on a US/Canada exchange rate of 0.98, but with the recent decline in the Canadian dollar and potential reductions in costs due to slower rates of expansion, the WTI break-even prices will fall.

[9] Leach (2015) estimates current break-even costs for new *in situ* projects at just under $50 WTI and new mines at about $63 WTI based on lower exchange rates and lower diluent costs. Leach nonetheless anticipates a downward revision in the oil sands production forecasts due to lower prices.

Figure 6. Oil Supply Cost Curve (US $ per barrel)



Source: Rystad Energy Research and Analysis (2015).

Given all these factors it is likely that CAPP's high growth production forecast is too optimistic. Indeed, Alberta producers have already announced cancellation of 17 projects amounting to 1.3 million bpd of capacity (Lewis 2015, p. B1). CAPP's low growth forecast provides a reasonable estimate of the lower bound range of oil production because it is based on currently operating projects plus projects under construction. Projects already under construction have a high probability of being completed and coming into production. However, it is important to note that some producers such as Shell have stopped construction on existing projects such as the 80 kbpd Carmen Creek Project (Shell 2015). If more projects under construction are stopped, it is possible that production could fall below CAPP's low forecast.

What are the implications of this uncertainty for the TMEP? Under the high growth forecast, TMEP is not needed until 2023 (or until 2029 if Energy East is built as planned) and under the low growth forecast it is not needed at all. Given market developments, the high growth forecast seems increasingly less likely and the date that the TMEP capacity may be needed may be later, if at all. It is also possible that oil markets could fully recover and generate sufficient demand to justify construction of the TMEP earlier. If this occurs, there is sufficient lead-time to build the TMEP and/or other transportation infrastructure such as rail to accommodate the demand.

A final issue in assessing need for the TMEP is the existence of shipping contracts. Do the shipping contracts prove that the TMEP is needed and if it is not needed will it get built? These two issues are related. Shipping contracts were signed for TMEP, Keystone XL and Energy East well before the current downturn in oil markets. The signing of take-or-pay contracts obligates shippers to pay the tolls for these pipelines regardless of whether the capacity is needed. This provides the financial rationale to allow the projects to be built thus obligating shippers to divert oil from other transportation facilities to meet their obligations to the new pipelines. The shippers are largely indifferent to the cost because they are able to shift the cost burden onto the other existing transportation facilities that they no longer need. Therefore, the TMEP could be built even if the additional capacity is not required.

The conclusion of the supply and demand analysis is that if the TMEP is not needed at its planned in-service dates and if it is approved there will be a significant surplus capacity. While some degree of surplus capacity is inevitable as new pipeline projects come into operation and 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 proposed projects is unprecedented and will impose a significant cost on Canada. We discuss the implications of this in our benefit cost analysis below.

6. Benefit Cost Analysis of TMEP

In its assessment of the TMEP application, the NEB must recommend whether the TMEP is in the public interest. As stated earlier in 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. In previous decisions, the NEB has applied this test by comparing the burdens of the project to the benefits. In the Northern Gateway decision, for example, the NEB states that "the Panel considers the burdens the project could place on Canadians, and the benefits the project could bring to Canadians" (NEB 2013, p. 8) and "whether present and future generations of Canadians would be better off, with or without, the Enbridge Northern Gateway Project (NEB 2013, p.10).

In section 4.5, we conclude that the TMEP application does not provide an adequate or accurate assessment of costs and benefits. Many costs and burdens of the project are omitted, other costs and benefits are incorrectly estimated, and no effort is made or analytical framework provided to allow for a comparison of costs and benefits to determine if the TMEP will generate a net benefit to Canada. Consequently, the TMEP evidence does not provide the information necessary for the NEB to determine whether the TMEP is in the public interest.

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 and whether present and future Canadians will be better off with or without the TMEP. The best method for assessing the costs and benefits of the TMEP and whether the TMEP generates a net benefit to Canada is benefit cost analysis (BCA). 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 and Alberta (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.[10] 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 project) that will be assessed, (2) determine standing (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. Where applicable we use Canadian benefit cost analysis guidelines published by the federal government (TBCS 2007).

6.1. 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 7. The benefits of the TMEP are: revenues associated with transporting WCSB oil to market; potential increases in oil netbacks and option value by accessing higher value 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 due to the project, costs to BC Hydro due to rates being less than its long run marginal costs, plus external environmental costs such as GHG emissions, potential damages from oil

[10] TM uses a partial BCA that quantifies only the alleged project benefits without the costs.

spills, other environmental and social costs, and costs specific to First Nations.

Table 7. Components of our Benefit Cost Analysis

Component	Benefit	Cost
TMEP Pipeline Operations	Toll revenue	Capital and operating costs of TMEP
Unused Oil Transportation Capacity		Reduced net revenues of impacted transportation capacity
Option Value/Oil Price Netback	Increased netbacks to producers	
Employment	Increased wages and employment generated by TMEP	
Tax Revenue	Net tax revenue gains to government	Net tax revenue loss to government
Electricity		Net loss (incremental costs less revenues) from supplying electricity to TMEP
GHG Emissions		Damage costs from direct TMEP GHG emissions
Other Air Emissions		Damage costs from TMEP air 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 A).

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 facilities (see below). 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. For the base case we use the recommended TBCS (2007) real discount rate of 8%, with sensitivities of 10%, 5%, and 3%. All costs and benefits are reported in 2014 Canadian dollars unless otherwise stated and are estimated over a 30-year operating period.

Our transportation capacity assumptions for Canadian crude oil are based CAPP (2015) *Crude Oil Forecast, Markets & Transportation* and summarized in Table 8. Our estimates are based on the following steps:

- To estimate Enbridge Mainline system capacity, we include pipeline capacity for the Mainline (2,621 kbpd) as well as capacities for the Alberta Clipper expansion (230 kbpd) and Line 3 restoration (370 kbpd). According to CAPP (2015), both of these projects are expected to be in-service before 2018. We deduct shipments of natural gas liquids and refined products (160 kbpd) on Enbridge Line 1, which we estimate based on Wood Mackenzie (2010). We also add CAPP's estimate of Bakken shipments of 225 kbpd on the Enbridge Mainline system.
- We include 550 kbpd of rail capacity in 2018 based on CAPP's (2015) estimate of rail forecast in the absence of Keystone XL. The assumption of 550 kbpd is conservative because: CAPP (2015, p.33) forecasts current rail capacity to be 776 kbpd with potential for significant expansion. MS (2015, p. 43) estimates 2018 rail capacity for WCSB crude at 550 kbpd with a potential to increase to 3,870 kbpd by 2038; rail is increasingly competitive with pipelines for bitumen shipments; and some rail shipments are based on longer-term contracts.
- We deduct 50 kbpd from the TMPL for refined product shipments.
- We include TransCanada Energy East at an available capacity for WCSB oil of 1,100 kbpd as estimated by CAPP (2015) and deduct 300 kbpd of this capacity that could be allocated for Bakken shipments.

Table 8. Transportation Capacity Estimates

Facility	**Our BCA Base Case (kbpd)**
Enbridge Mainline	2,836
Express/Milk River/Rangeland	490
Trans Mountain	250
Keystone	591
Rail	550
Existing Subtotal	**4,717**
Keystone XL	0
ENGP	0
Kinder Morgan TMEP	590
Energy East	800
Subtotal Existing and Proposed Pipeline	**6,107**

Facility	Our BCA Base Case (kbpd)
Proposed Rail	0
Total Existing and Proposed	**6,107**

Sources: CAPP (2015); MS (2015). Note. Our BCA capacity estimates are based on CAPP (2015), which we modify to include: deducting shipments of refined product on Trans Mountain of 50kbpd; deducting shipments of natural gas liquids and refined products on Enbridge Line 1 of 160 kbpd (Wood Mackenzie 2010); deducting Bakken shipments of 225 kbpd from the Enbridge Mainline system capacity; deducting Bakken shipments of 300 kbpd from TransCanada Energy East capacity. Enbridge Mainline capacity estimates include the Alberta Clipper expansion (230 kbpd) and Line 3 Restoration (370 kbpd).

To address uncertainty regarding the proposed expansion of oil transportation infrastructure, we conduct the following sensitivity analyses by making the following alternative assumptions to our base case transportation capacity:

1. Keystone XL added to base case (830 kbpd less 100 kbpd Bakken shipments and reduction in rail of 200 kbpd);
2. ENGP added to base case (525 kbpd);
3. Keystone XL and ENGP added to base case;
4. Rail capped at 200 kbpd; and
5. Energy East removed from base case.

We also conduct a sensitivity analysis based on different assumptions regarding US Bakken shipments on Canadian pipelines. Our base case estimates are from CAPP (2015), which forecasts Bakken shipments of 225 kbpd on the Enbridge Mainline, 300 kbpd on Energy East, and 100 kbpd on Keystone XL (which we include in our Keystone XL sensitivity), for a total of 625 kbpd. CAPP's forecast is higher than that of MS, which assumes US Bakken shipments on Enbridge of 142 kbpd in 2018 declining to zero in 2023 and remaining at zero until the end of the forecast period to 2038 (TM 2015c, p. 8). MS does not include Energy East or Keystone XL in its analysis and thus does not specify any Bakken shipments on these pipelines.

Information on the supply and demand for oil transportation for the Bakken region provided in Table 9 suggests that the CAPP estimate of Bakken shipments on Canadian pipelines is likely too high. Forecasts of Bakken oil production are in the range of 1,400 to 1,700 kbpd by 2020, which may be too high because they do not take into account recent declines in Bakken drilling due to lower prices and declining well productivity (US EIA, 2015b). However, even if Bakken production reaches the high end of the forecast (1,700 kbpd), there will still be over 1,600 kbpd of surplus transportation capacity if all planned projects proceed. Therefore, CAPP's assumption that

625 kbpd (more than half of current Bakken production) will be transported on Canadian pipelines when there is significant excess transportation capacity serving Bakken is a highly optimistic assumption. Consequently, we include a sensitivity analysis that uses MS's forecast of Bakken shipments for Enbridge (TM 2015c, p. 8) of 142 kbpd in 2018 declining to zero kbpd in 2023. In this scenario we also assume that Bakken shipments on Energy East decrease from 300 kbpd to 150 kbpd.

Table 9. Oil Transportation Supply and Demand, Bakken Region

	2015 (kbpd)	2020 (kbpd)
Pipeline Capacity	827	1,766
Rail Capacity	1,490	1,590
Total Transportation Capacity	**2,317**	**3,356**
Production (January 2015)	1,195	1,400 - 1,700
Surplus Transportation Capacity	**1,122**	**1,656 - 1,956**

Sources: North Dakota Pipeline Authority (2015b; 2015a) and Kringstad (2015).

Similar to the MS analysis, we use CAPP's 2015 oil supply forecasts in our BCA. For our base case we use CAPP's (2015) high growth forecast from 2015 to 2030 and use the annual growth rate over this period to estimate supply to 2047. In our sensitivity analysis, we assume 10% higher crude oil supply over the base case for the entire forecast period and, for the lower sensitivity, we use the CAPP's (2015) lower growth forecast. As discussed in section 5, of our report, crude oil supply forecasts from CAPP have historically overestimated actual crude supply and given current market conditions, WCSB production will likely be lower than CAPP's high growth forecast. Refinery consumption from Alberta and Saskatchewan refineries are deducted from the CAPP supply forecasts.

6.2. Costs and Benefits for Trans Mountain

We use capital and operating costs of transporting the oil for the TMEP as specified by TM in its submission: capital costs of $5.5 billion in nominal dollars to be spent over a seven-year period from 2012 to 2018 (or $4.9 billion in 2012 dollars) (CBC 2015; TM 2013b, Vol. 2 App B p. 5); incremental operating costs of $118 million per year (Vol. 5D p. i); and incremental decommissioning costs of approximately $263 million (Vol. 2 p.35).

The benefits accruing to TM are the toll revenues it 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 TMEP will be fully utilized, or at least in accordance with the utilization rate used to determine the cost recovery tolls. 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.[11] We include potential price benefits from shipping on the TMEP in our price benefit section. Also, if the TMEP costs are higher than forecast in the toll hearings there will be a net cost because toll revenues will no longer fully cover costs, and if TMEP costs are lower there will be a net benefit because toll revenues will exceed costs.

Previous pipeline projects indicate that there is a propensity for significant cost escalation, which is consistent with other research on large projects (Flyvbjerg et al. 2003; Gunton 2003).[12] As of October 2015, TM estimates that capital costs for the TMEP will be $6.8 billion, or approximately 25% higher than estimated in the TMEP application (Krugel 2015). TM also notes that it still does not have a firm capital cost estimate and will generate a new estimate after the regulatory decision on its application.

According to TM, shipper's contracts allow for an increase in tolls to reflect higher capital costs up to $6.8 billion, indicating that they are willing to pay to cover increases in capital costs up to this amount. However, if capital costs escalate beyond $6.8 billion, currently negotiated tolls would no longer cover the costs of the TMEP and there would be a net cost to pipeline operations. If costs are lower than the estimate, toll revenues would exceed costs and there would be a net benefit to pipeline operations. To test the impact of changes on capital costs on the net benefit of pipeline operations, we undertake two sensitivities: a 20% increase in capital costs, and a 10% reduction in capital costs. Consistent with industry standard capital cost estimate classifications (e.g. AACE 2011), we use a higher sensitivity for the increase in capital costs than for a decrease

[11] 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.

[12] Estimates of the capital costs of the Enbridge Northern Gateway project increased by about one-third from $5.5 billion (2009$) ($5.9 in 2012$) 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.

in capital costs[13]. Higher capital costs result in a net cost of $792 million while lower costs generate a net benefit of $396 million (net present value).

6.3. Costs of Unused Transportation Capacity

Costs of surplus capacity have been identified as a concern in previous NEB pipeline hearings. In the ENGP hearings, Enbridge (Wright Mansell 2012, p. 144) estimated potential costs of unused capacity of $857 million (2012$), and in the Keystone XL hearings, it was estimated that there would be unused capacity costs of $315-$515 million per year, which would result in increased tolls for shippers (NEB 2010b, p. 24).

There are two components to estimating the costs of surplus capacity: the quantity of unused capacity due to the TMEP 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 6.1, our oil supply forecasts are from CAPP (2015). For our base case we use CAPP's high growth forecast and for our low supply scenario we use CAPP's low growth forecast (CAPP 2015). Our transportation capacity assumptions are also provided in section 6.1. To reiterate we assume existing pipelines, 550 kbpd of rail, and construction of the Energy East and TMEP. Capacity is adjusted for Bakken and refined product shipments on Canadian pipelines and transportation capacity is assumed to be 95% of nameplate capacity. We also include several transportation capacity sensitivity analyses (1. add Keystone XL; 2. add ENGP; 3. add Keystone XL and ENGP; 4. reduce rail from 550 kbpd to 200 kbpd; 5. remove Energy East). Under all scenarios, the construction of TMEP results in surplus capacity. Under CAPP's high growth scenario, the surplus capacity peaks at 1,591 kbpd in 2020 and exists until 2034 in the base case scenario. Under CAPP's low growth forecast, surplus capacity exceeds 1,613 kbpd in 2020 and increases to over 1,935 kbpd by 2047. 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.

The second step in estimating surplus capacity costs is to estimate per unit costs. We use two methods for estimating these costs. The first method is to assume that the toll revenue

[13] AACE classifications for capital costs -30% to +50% for class 3 estimates and -15% to +20% for class 4 estimates.

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 present value of TMEP capital costs are deducted from the overall net benefits to the extent the capital expenditures were not required to move WCSB oil to market.

The second method to estimate unused capacity costs is to estimate more directly the lost net revenue of the unused capacity on existing pipelines resulting from the diversion of oil to the TMEP. This second approach was used by Enbridge 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 by the 590 kbpd that is 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).[14] We use several alternative estimates of net revenue loss per barrel based on different assumptions (Table 10). We use shipments to Chicago for our base case estimate of unused capacity costs. This base case likely underestimates unused capacity costs since shippers are more likely to divert higher cost oil shipments from the 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; shipments on the Enbridge Mainline; and shipments to Chicago under the lower CAPP supply forecast. We also include a sensitivity assuming that Energy East is not available. We note that some shipments may be diverted from rail, which has a lower per barrel net revenue loss. We address this in two ways: first, we estimate the net revenue per barrel based on the assumption that one-half of the diverted oil is from pipelines and the other half from rail;

[14] The net revenue loss estimates for Enbridge will provide a reasonable estimation of the net revenue losses incurred by other shippers. Enbridge data is used for the net revenue loss estimate because much of the oil shipped on TMEP is likely to be diverted from Enbridge, given that Enbridge is the largest shipper, and as oil shipped on competing pipelines and some rail is under long-term contracts while most of the oil shipped on Enbridge is not. 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 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 shipment options.

second, we have included a scenario in which rail is capped at 200 kbpd, which is the estimated current rail shipments for 2015 (CAPP 2015, p. 32).

The net present value of these scenarios ranges from $2.2 to $6.2 billion in unused capacity costs (Table 10). Unused capacity costs incurred by non-Canadians should be omitted as a cost just as increased netback benefits accruing to non-Canadians should be omitted as a benefit. We have not omitted either of these non-Canadian benefits and costs in our analysis due to data limitations. Nonetheless, the base case estimate of $4.4 billion is a conservative estimate of unused capacity costs because it assumes diverted shipments from Chicago instead of the USGC and is based on the CAPP high growth supply forecast.

Table 10. Unused Capacity Costs

Cost Assumption	Unused Capacity Cost (billion $ net present value)
Enbridge Alberta to Chicago toll (base case)	4.4
Enbridge Alberta to Chicago toll (CAPP low supply forecast)	6.2
Enbridge Alberta to Chicago toll (no Energy East)	2.8
Enbridge Mainline Net Revenue	2.2
Enbridge Alberta to Cushing toll	5.6
Enbridge Alberta to Chicago/Rail (50/50)	2.8
TMEP Unneeded Capital Cost Method	2.4

Source: Unused capacity costs are estimated by multiplying the quantity of oil diverted by year by the net revenue per barrel. Net revenue loss is calculated from Enbridge's 2014 annual report (Enbridge 2015 p. 66) for their Canadian mainline based on a three year average (2012-14) of revenue less power costs less one-half of operating and administrative costs. These estimates may underestimate net revenue loss per barrel because they include operating and administrative costs that Enbridge (2015, p. 67) states are relatively insensitive to throughput. 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 mainline operations is multiplied by the toll rate for heavy oil for Enbridge tolls as reported in CAPP (2014, p. 42) and converted to Canadian dollars. The Enbridge Alberta to Chicago/Rail option is estimated by using Enbridge net revenue loss for one-half of the diverted oil and net revenue rail losses estimated by using the operating cost (excluding depreciation) to revenue ratio from CN Rail 2014 applied to the average revenue per barrel for the Enbridge Alberta to Chicago option for the remaining one-half of diverted oil.

6.4. 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 America market (MS 2015, p. 56). As discussed in section 4.3 of this report, there are major deficiencies in the method and assumptions that MS uses to generate its forecast of increased netbacks. Nonetheless it is possible that the TMEP could generate increased returns to producers by providing an option value based on exploiting higher priced oil markets such as Asia from a new oil port on the Pacific.

The existence of oil price market differentials for homogenous types of oil is possible due to shorter-term market constraints but is 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.

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 logistics that result in temporary price differentials (e.g., the glut of oil in Cushing, Oklahoma), the global oil market will erode these differences. As TM's expert and author of MS (2015) stated in NEB hearings on the Northern Gateway Project:

> 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 the world oil market dynamics and would not be prudent[15]. 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 unlikely, there may be short-term price differentials that shippers on the TMEP could take advantage of from a new Pacific port. We test the impact of a potential price premium in a sensitivity analysis. 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 $2.06 (2014 CDN $) per barrel of heavy crude. In the sensitivity, we assume that this price premium is received for each barrel of crude oil shipped on the TMEP to Asia over the 2018 to 2038 forecast period used by MS. 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 likely overstates any price benefit that may accrue from building the TMEP because the assumption of a long-term price premium used in the sensitivity is not evident from past price data and is not consistent with the operation of world oil markets. Further, as MS states, an increase in supply to a regional market will put downward pressure on prices (MS 2015). Consequently, the increased shipment of oil to Asia on the TMEP will work to erode any Asian premium that may exist. In addition, if there is a price benefit, the proportion of the price uplift benefit accruing to non-Canadians should be omitted from the benefits as recommended under federal guidelines (TBCS 2007). However, even if a price premium of $2.8 billion is realized, it is not sufficient to offset the costs of the TMEP and generate a net benefit for Canada.

6.5. Employment Benefits

A potential benefit of the TMEP is providing employment to workers. As discussed in section 4.4 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

[15] 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.

unemployed. However, given recent developments in the energy sector and the potential of TMEP 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 direct labour income for construction and operating employment incomes 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).[16] Total estimated employment benefits for the TMEP range from $77 to $284 million (net present value).

6.6. Benefits to Taxpayers

Incremental tax revenues not offset by incremental government expenditures are a benefit to taxpayers. As discussed earlier in section 4.4 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 any 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.,

[16] 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 38%) is more than double the ratio used for employment benefit estimates in other pipeline projects as the Northern Gateway (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, 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.

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, although a permanent oil price benefit is unlikely 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 estimates from the Conference Board of Canada (CBC 2015). We estimate the net benefit of the incremental tax revenue is $901 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, 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 $242 million (net present value).

6.7. Costs to BC Hydro and BC Hydro Customers

TM estimates that TMEP will consume approximately 1,046 gigawatt-hours (GWh) of electricity per year, 520 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 $85-$100 per megawatt-hour (MWh) (BC Hydro 2013) while the average amount paid by TMEP is $38 per MWh (TM 2014a, p. 110-111), resulting in a net cost to BC Hydro of $52 per

MWh (based on an incremental cost of $90 per MWh), or $27 million per year. The net cost to BC Hydro and BC ratepayers is $257 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.

6.8. Environmental Costs

6.8.1. 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 health and ecosystems. 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). TMEP construction and operations would also emit carbon monoxide, volatile organic compounds, and other hazardous air pollutants including benzene, toluene, ethyl benzene, and xylenes.

TM estimates that some types of air pollution will be reduced with 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 or would have been required as a mitigation measure 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 TMEP proceeds.

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 – 2,157	n/a	n/a	n/a
SO_2	1,582 – 9,655	1,506 – 2,511	1,929 – 2,711	810 – 2,769
NO_X	452 – 19,516	502	1,087 – 1,586	2,139 – 2,638
PM_{10}	1,952 – 33,280	335 – 837	n/a	n/a
$PM_{2.5}$	n/a	1,841 – 5,523	17,138 – 24,967	5,354 – 6,824
VOC	329 – 9,039	502 – 837	n/a	114 – 280

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 2014 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 BC.

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 midpoint average damage costs, a high estimate using the average upper end damage costs and a low estimate using the average lower end damage costs from Table 11. Based on these assumptions, air pollution from the TMEP could cause between $6 and $427 million (net present value) in social damage costs over the life of the project. 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.

6.8.2. Greenhouse Gas Emissions

TM estimates that the TMEP will emit 1,020,000 tonnes of GHG 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 impact 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 also omitted consideration of upstream and downstream GHG emissions from our analysis. However, we note that the production and consumption of oil account for approximately 99% of the GHG emissions associated with oil (IHS CERA 2010). GHG emissions associated with the production and consumption of oil transported on the TMEP are a concern to many Canadians and need to be assessed at some point in the project evaluation process.[17]

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, a recent 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 National Roundtable on the Environment and Economy estimates 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 $111 in 2012 $) by 2020 rising to $300 by 2050.

A third approach to estimating GHG damage costs is to estimate the social cost of GHG damage. In a recent 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

[17] 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.

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 2014). 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 US government (US GAO 2014) recommended cost of $48 per tonne (2014 CDN $), and for our sensitivity we use the upper range US government cost of $137 per tonne (2014 CDN $). 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 $289 million and $916 million (net present value).[18]

6.8.3. 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:

$$\text{Annual expected value} = p*c*q$$

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

[18] 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.

q is the size of the spill (in barrels or hectares).[19]

We use oil spill probability and damage costs estimates for spills based on the findings of Gunton and Broadbent in their oil spill risk assessment report of TMEP (Gunton and Broadbent 2015).[20]

6.8.3.1. 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.[21] The US government publishes tanker and terminal oil spill rates for their OSRA model disaggregated by port and at sea (Anderson et al. 2012). 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 costs understate total costs associated with 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) identify some 27 deficiencies with the TM spill probability estimates, some of which result in an underestimate of spill risk. Also, TM's higher-end (lower probability) tanker spill return period estimates are higher 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.

[19] 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).

[20] We provide only a brief summary of the spill probability and costs assumptions here. For more detailed background consult Gunton and Broadbent (2015).

[21] 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 (Anderson et al. 2012).

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]	0.040	0.071	0.011 (Tanker) 0.045 (Tanker and Terminal)[2]
Mean Size Tanker Spill	39,674 barrels	34,932 barrels	56,700 barrels[3]
Damage Cost[4]	$42,700/barrel	$42,700/barrel	$42,700/barrel (Tanker) $20,649/barrel (Terminal)

Sources: Gunton and Broadbent (2015), Anderson et al. (2012), 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 Wright Mansell's (2012, p. 77) estimate of the average size tanker spill. 4. Costs are based on Wright Mansell (2012, p. 77) updated to 2014 CDN $. Estimation of spill damage costs for the sensitivity scenario sums the cost of at sea spills at $42,700 per barrel and terminal spill costs. Terminal spill costs are estimated by using an annual probability of 0.029 for terminal spills <63 barrels and 0.004 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 $20,649/barrel updated to 2014 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 $42,700 (2014 $). 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. However, we caution that the Wright Mansell estimate of $37,500/barrel may underestimate actual spill costs.

Wright Mansell's spill cost estimate relies on studies from Kontovas et al. (2010) that estimate tanker spill cost data from the IOPCF which itself 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 amount actually claimed (Thébaud et al. 2005).[22] 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.[23] Third, IOPFC data excludes 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 $) is not a conservative estimate.

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.

6.8.3.2. Pipeline Spills

Alternative estimates for pipeline spill probabilities are summarized in Table 13. For our base case we use the probabilities and average size spills based on Pipeline and Hazardous Materials Safety Administration (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.

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[22] 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%.

[23] 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).

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 $167,000 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 $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). The results in an average cost per pipeline spill in our BCA of $3.8 million, which is then adjusted by the probability of a spill to determine the expected value.

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 (2012$)
Leak	$28,098 – $86,456	$12,697 – $167,244	$3,188	n/a	$9,800
Rupture	$6,484 - $16,128	$3,022 – $48,858	$30,750	$60,177	$14,000

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 also acknowledge that to the extent that reduced shipments on other pipelines lower oil spill risk, the net increase in North American oil spills and oil spill damages will be lower than our estimates for the TMEP.[24]

6.8.4. 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 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). 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).

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[24] 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. Also the location and costs of damages will change.

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.[25] Another contingent valuation study from Carson et al. (2004) estimates the amount that households in California would be willing to pay to prevent oil spill damage along the California Coast.[26] The Carson studies are among the most sophisticated contingent valuation studies for assessing passive use values.[27]

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.[28] 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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[25] 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).

[26] 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.

[27] 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.

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

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 2014 Canadian $) by the total number of households in Canada.[29] To provide an order of magnitude estimate of potential WTA values we adjust WTP estimates with the WTA/WTP ratio of 10.4 for public and non-market goods from Horowitz and McConnell (2002). We also provide an estimate of the WTA applied to just BC households and an estimate based on adjusting the WTA for Canadian households for large oil spill probabilities. We use the upper bound WTP for Canadian households for our base case ($ 2.0 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 $1.4 billion based on WTP for Canadian households to a high of $21.1 billion based on WTA for Canadian households (Table 16). Our base case of $2.0 billion (upper bound of WTP for Canadian households) is at the lower end of the range and represents a conservative estimate because it is based on WTP. For our sensitivity analysis we use the mid-point of the WTA range for Canadian households ($17.7 billion).

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)	$1,371 – 2,026
WTA BC households	$2,340
WTA Canadian households (mid-point WTA adjusted for spill probability)[1]	$3,947
WTA Canadian households	$14,261 – 21,073

Note. 1. Expected value estimate is based on US OSRA probability for spills >10,000 barrels applied to the mid-point between the upper and lower bound WTA.

[29] We adjust lower and upper bound WTP values from the Carson et al. (2003) study for inflation, convert US $ to Canadian $, and aggregate the results to reflect the number of households in Canada in 2011 from Statistics Canada data.

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, morals, 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. 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 some 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.

6.8.5. 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 section 6.8 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 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.

6.9. Other Costs

In Appendix A, we list 162 negative impacts associated with the TMEP only a few of which are monetized into 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. We discuss several important impacts of this nature below.

6.9.1. 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.[30] 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 TMEP to First Nations, 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

[30] 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.

in subsistence harvest 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 Aboriginals 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 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).*

6.9.2. 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 pipeline projects in BC (e.g., Justason Market Intelligence 2013). Many interveners including the City of Vancouver, the City of Burnaby, and some First Nations are opposed to the TMEP and there have already been some demonstrations against the TMEP. The ongoing legal and political conflict over the ENGP 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.

6.10. 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 $7.4 billion** (net present value). A large component of the cost is the cost of unused capacity of $4.4 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.[31] The significance of unused capacity costs is not surprising given that the TMEP is forecast to contribute to unused capacity in the Canadian

[31] The precise distribution of unused capacity costs 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.

oil transportation sector to 2034 under our base case assumptions. Based on the lower WCSB oil production forecast in CAPP (2015), there would be surplus capacity over the entire 30-year operating period of the TMEP. 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 TMEP is not built. Environmental costs are significant ($3.1 billion), comprising $289 million for GHG emissions, $85 million for other air pollution, $675 million for oil spills, and an additional $2 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 **$4.6 billion and $23.0 billion**. The highest net cost of $23.0 billion is based on assuming WTA for passive use values, which increases the net cost estimate by $15.6 billion. Lower rail capacity and higher oil production reduce net costs while more projects, lower oil production and higher environmental impacts increase net costs. The lowest net cost of $4.6 billion is based on the assumption of an option value based on an Asian price premium until 2038 that reduces the net cost of the TMEP by about $2.8 billion but is insufficient to compensate for the costs of the project. In sum, there is no scenario in which the TMEP results in a net benefit to Canada.

An obvious question is if the TMEP results in a net cost to Canada, why would it be built? The explanation would seem to be based on the existence of market failures. TM could earn a reasonable return on the TMEP because it has contracts negotiated during a period of more optimistic expectations of oil development that obligate shippers to pay tolls that could financially justify TM’s investment. The costs, however, are externalized onto other parties in the form of unused capacity costs and environmental and other externalities. Therefore, it may be financially feasible for TM to build TMEP even though it imposes a net cost to Canada.

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 would have to 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	0	(792) to 396
Unused Oil Transportation Capacity	(4,381)	(6,233) to (2,173)
Option Value/Oil Price Netback Increase	0	0 to 2,784
Employment	77	77 to 284
Tax Revenue	242	242 to 1,143
Electricity	(257)	No sensitivity
GHG Emissions from Construction and Operation of TMEP and marine traffic in defined study area	(289)	(916) to (289)
Other Air Emissions	(85)	(427) to (6)
Oil Spills	(675)	(1,022) to (310)
Passive Use Damages from Oil Spill	(2,026)	(17,667) to (2,026)
Other Socio Economic, Environmental Costs not estimated	See Appendix A	
Base Case Net Cost	**(7,394)**	**(4,610) to (23,035)**

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

Table 18. TMEP BCA Sensitivity Analysis Results

Scenario	Description	Net Benefit/ (Cost) (million $)
Base Case		(7,394)
Higher TMEP Capital Cost	20% increase	(8,186)
Lower TMEP Capital Costs	10% decrease	(6,999)
Higher Unused Capacity Cost	Diverted shipments from Cushing	(8,638)
Lower Unused Capacity Cost	50% of diverted shipments from rail and 50% from pipelines	(5,863)

Scenario	Description	Net Benefit/ (Cost) (million $)
Unused Capacity Cost based on TMEP capital cost approach		(5,428)
Higher Oil Production	CAPP (2015) high growth forecast + 10%	(6,205)
Lower Oil Production	CAPP (2015) low growth forecast (operating and under construction projects)	(9,246)
Lower Bakken Shipments	MS Bakken shipments for Enbridge and reduction in Bakken shipments on Energy East from 300 to 150 kbpd)	(7,869)
Higher Pipeline Transport Capacity	Three scenarios:	
	i) Add Keystone XL	(8,024)
	ii) Add ENGP	(8,019)
	iii) Add Keystone XL and ENGP	(8,503)
Lower Pipeline Transport Capacity	Remove Energy East	(5,850)
Lower Rail Transport Capacity	Assume current rail capacity (200 kbpd)	(6,835)
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	(4,610)
Higher Employment Benefit	15% of Construction & Operating employment	(7,188)
Higher GHG Emission Damage Cost	Higher damage costs per unit	(8,021)
Higher Air Pollution costs	Higher damage cost per unit	(7,737)
Lower Air Pollution Costs	Lower damage cost per unit and assumed mitigation	(7,315)
Higher Passive Values	WTA for Canadian households	(23,035)
Higher Oil Spill Costs	OSRA in port/at sea tanker spill probabilities (0.071 annual probability)	(7,741)
Lower Oil Spill Costs	TM probability for tanker spills (0.011 annual probability)	(7,030)
Higher Discount Rate (10%)		(6,471)
Lower Discount Rate (5%)		(9,310)

Scenario	Description	Net Benefit/ (Cost) (million $)
Lower Discount Rate (3%)		(11,121)

6.11. 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 supply forecasts will reduce unused capacity while lower oil supply 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). Also, given the lag in adjustment of forecasts to recent price declines, it is likely that current forecasts may be too optimistic.

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 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 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. Some new transportation capacity will be required in the next decade if production exceeds CAPP's low forecast of existing and under construction projects. 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 shutting in of production.[32] There is, for example, surplus rail capacity that can respond quickly to changes in demand. 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 avoid expensive, irreversible investments in pipelines that cannot be justified by 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 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 rail may occur. 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 (Table 10). We have addressed uncertainty over destination points for diverted oil by using a range of unused capacity cost estimates based on different destinations and capping rail in some of the sensitivities. 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 uncertainty is the potential price benefits of shipping on the TMEP relative to other transportation options. To the extent that such a benefit exists, shippers would be willing to pay more for using the TMEP. We addressed this by including a price benefit sensitivity based on an Asian premium and the incremental benefit was not high enough to offset other costs. However, it is challenging to forecast what if any potential benefit may exist for the TMEP relative to other transportation options and the willingness of shippers to pay higher tolls for the TMEP to realize

[32] Increases in production are preceded by increased drilling activity, giving lead time to make transportation adjustments.

these potential benefits is uncertain.

An 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 A). Inclusion of these impacts would increase our environmental cost estimates. There are also environmental costs of shipping oil on other transportation facilities that could to some extent offset some of the increase environmental costs associated with the TMEP. We have not included potential avoided 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 and the results vary appreciably, especially for passive use values. 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 a 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, may significantly underestimate environmental protection values.

7. Conclusion

The NEB has two criteria that need to be satisfied for a project to be recommended: that the project is clearly demonstrated to be needed, and that the project is clearly found to be in the public interest. TM's application states that the project is needed and in the public interest because it will provide pipeline capacity to transport increased oil production from the WCSB, there is demand as evidenced by producers signing contracts to ship on the TMEP, the TMEP will increase netbacks for oil producers, and it will generate significant economic activity.

TM's assessment of the need for the TMEP and impact of the TMEP on public interest is deficient and incomplete in the following respects:

- TM's analysis shows that if the TMEP is not built, there are alternative transportation options to meet the need to transport WCSB oil to market. Therefore the TMEP capacity is not needed to meet WCSB transportation needs.
- TM's conclusion that the TMEP will generate significant benefits relative to other transportation options is based on a questionable methodology, unrealistic assumptions, and is inconsistent with oil market dynamics. Consequently, TM's benefit estimates are unreliable and it is highly unlikely that the TMEP will generate the price benefit estimated by MS.
- TM estimates gross instead of net impacts and incorrectly defines gross economic impacts as benefits without taking into account the opportunity costs of the capital and labour that would be employed by the TMEP.
- TM omits consideration of many of the potential economic, environmental and social impacts of the TMEP in its analysis, contrary to the requirements specified by the NEB.
- TM provides monetary estimates of alleged benefits without providing any monetary estimates of costs and therefore does not provide the information to allow for a comparison of costs and benefits to determine if the TMEP generates a net benefit to Canadians.

To help assess the need and public interest impacts of the TMEP, we completed a multiple account BCA which shows that the TMEP will result in a significant **net cost to Canada ranging**

between $4.6 and $23.0 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 a 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 high growth forecast, construction of the TMEP along with Enbridge Line 3, Enbridge Clipper, and Energy East will result in surplus transportation capacity until 2034. If Keystone XL and Enbridge Northern Gateway are built, there would be surplus capacity beyond 2040. Under CAPP's low production growth forecast, construction of the TMEP along with just Enbridge Line 3 and Enbridge Clipper will result in surplus capacity beyond 2047. This magnitude of potential surplus transportation capacity is unprecedented. The risk of approving the TMEP application is that approval will result in irreversible creation of high cost surplus capacity. The risk of not approving the TMEP application is minimal 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.

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. This is one of the reasons why the NEB regulatory process was created: to address these types of market imperfections and ensure that investments in new transportation are in the public interest.

We conclude that the TMEP does not meet the NEB criteria for project approval, and approving and constructing the TMEP will result in a significant net cost to Canada. We further conclude that the current 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 A: Potential Impacts of the TMEP

Table 19. List of Some Potential Impacts of the TMEP Identified in Trans Mountain's Application.[33]

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

[33] This list is based on TM's application (TM 2013b, Vols. 5 and 7) and is not intended to be a comprehensive list of all potential impacts of the TMEP. Impacts normally deemed as positive impacts are italicized.

Type	Potential Impacts from TMEP
	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 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

Type	Potential Impacts from TMEP
	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 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

Type	Potential Impacts from TMEP
	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. Contribution to provincial and national growth during construction and operations; 54. Employment opportunities during construction and operations 55. Reduced labour availability for other regional industries due to workers taking TMEP-related employment opportunities *56. Increased municipal tax revenue* *57. Increased personal spending by TMEP workers during construction* *58. Combined effect on municipal economies from an increase in municipal tax revenue and increased personal spending by TMEP workers during construction* *59. Increased regional contracting and procurement opportunities* *60. Training opportunities, particularly for Aboriginal communities for skill and capacity development* 61. Disruption to business or commercial establishments

Type	Potential Impacts from TMEP
	in the form of reduced income 62. Disruption to resource-based income or livelihoods
Human Health	63. Effects on mental well-being from demographic changes, changes in income, and changes to culture 64. Effects on alcohol and drug misuse 65. Increase in demand on mental health and addictions services 66. Increase in number of sexually transmitted infections 67. Increase in number of respiratory or gastrointestinal illnesses 68. Increase in stress and anxiety related to perceived contamination 69. Increase in traffic-related injury and mortality 70. Increased demand on hospitals, health care facilities, and emergency medical response services 71. Effects on diet and nutritional outcomes 72. Effects on mental well-being in Aboriginal communities
Marine Resource Use	73. Disruption to marine access and use patterns during construction and operations 74. Alteration of subsistence resources 75. Disturbance to cultural sites including sensory disturbance from noise, air emissions, lighting, and visual during construction and operations 76. Sensory disturbance for commercial, recreation, and tourism users (e.g. noise, lighting, visual, air quality) during construction and operation 77. Change in distribution and abundance of harvested species including marine fish and fish habitat 78. Displacement of commercial, recreational and tourism users around Westridge Marine Terminal during construction and operations

Type	Potential Impacts from TMEP
	79. Change in commercial, recreational and tourism vessel access routes during construction and operations 80. Disruption to subsistence hunting, fishing, and plant gathering activities 81. Disruption to use of travel ways by traditional marine resource users 82. Disturbance to gathering places including increased sensory disturbance for marine users 83. Disturbance to sacred sites 84. Disruption to commercial fishing activities 85. Sensory disturbance (e.g. noise, visual effect, air quality) for commercial fishers, recreational users, and tourism users 86. Change in distribution and abundance of target species for commercial fishers 87. Alteration of existing movement patterns of marine commercial, recreational, and tourism users 88. Increased rail bridge operations 89. Marine vessels collision with built infrastructure, marine facilities or shoreline with a commercial, recreational, or tourism use 90. Marine vessel collisions with marine commercial users, other recreational users, and marine tourism users 91. Marine vessel wake effects on small fishing vessels, recreational vessels and tourism operator vessels 92. Negative recreational and tourism user perspectives of increased project-related marine vessel traffic
Accidents and Malfunctions (terrestrial and marine)	93. Spills of hazardous materials during construction and maintenance potentially resulting in contamination or alteration of surface or groundwater 94. Fires that may adversely affect adjacent property 95. Damage to utility lines that could interrupt services

Type	Potential Impacts from TMEP
	and lead to fires 96. Transportation accidents that could cause injury to people or result in a fire 97. Use of explosives that could cause injury from flying rock 98. Security risk including damage from criminal activity 99. Change in marine water quality from an accidental release of contaminated bilge water 100. Physical contact between a tanker's hull and marine subtidal habitat from vessel grounding 101. Interference with navigation from a vessel grounding 102. Physical injury or mortality of a marine mammal due to a vessel strike 103. Venting of tanker at anchor or in transit 104. Negative recreational and tourism user perspectives of increased project-related marine vessel traffic
Physical Environment	105. Terrain instability due to slumping at watercourse crossings and sidehill terrain 106. Alteration of topography along steep slopes, slopes of watercourse crossings, sidehill terrain, and areas of blasting 107. Acid generation or metal leaching rock
Soil and Soil Productivity	108. Decreased topsoil/root zone material productivity during topsoil/root zone material salvaging 109. 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 110. 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

Type	Potential Impacts from TMEP
	(e.g., maintenance dig activities) during operations, trench subsidence, and soil diseases (i.e., clubroot disease and potato cyst nematodes) 111. Degradation of soil structure due to compaction, rutting, and pulverization of soil and sod 112. Loss of topsoil/root zone material through wind and water erosion 113. Erosion of soil as a result of release of hydrostatic test water on land 114. Loss of topsoil/root zone material from disturbance (e.g., maintenance dig activities) during operations 115. Increased stoniness in surface horizons 116. Bedrock or large rocks within trench depth 117. Disturbance of previously contaminated soil 118. Contamination of soil as a result of release of hydrostatic test water on land 119. Soil contamination due to spot spills during construction
Water Quality and Quantity	120. Instability of trench at locations with high water table 121. Suspended sediment concentrations in the water column during instream activities 122. Erosion from approach slopes 123. Inadvertent instream drilling mud release 124. Alteration or contamination of aquatic environment as a result of withdrawal and release of hydrostatic test water 125. Reduction of surface water quality due to small spill during construction or site-specific maintenance activities 126. Alteration of natural surface drainage patterns 127. Disruption or alteration of streamflow 128. Shallow groundwater with existing contamination

Type	Potential Impacts from TMEP
	encountered during trench construction 129. Areas susceptible to drilling mud release during trenchless crossing construction, sedimentation in the aquifer, and blasting effects 130. Areas with potential artesian conditions 131. Aquifers (including unconfined aquifers) or wells vulnerable to possible future contamination from a spill during construction 132. Areas susceptible to changes in groundwater flow patterns 133. Disruption of shallow groundwater in high permeable materials in proximity to rivers or watercourse crossings with fluvial materials or colluvium in the substrate 134. Disruption of groundwater flow where springs and shallow groundwater are encountered 135. Areas where dewatering may be necessary during pipeline construction activities 136. Impacts to shallow wells
Air Emissions	137. Project contribution to emissions: increase in air emissions during construction and increase in air emissions during site-specific maintenance and inspection activities 138. Dust and smoke during construction
GHG Emissions	139. Increase in carbon dioxide-equivalent emissions 140. Changes in environmental parameters (e.g., increase in global average temperature)
Acoustic Environment	141. Changes in sound level during construction and operation 142. Changes in vibrations during construction and operation
Fish and Fish Habitat	143. Riparian and instream habitat loss or alteration during construction, maintenance, and operation activities 144. Riparian and instream habitat loss or alteration from

Type	Potential Impacts from TMEP
	accidental drilling mud release 145. Contamination from spills during construction and maintenance 146. Increased access to instream habitat during operation 147. Fish mortality or injury during construction 148. Fish mortality or injury due to accidental release of hazardous materials during power line construction 149. Increased suspended sediment concentrations in the water column during instream construction or from accidental mud release 150. Increased access to fish and fish habitat during operations 151. Blockage of fish movements 152. Effects on fish species of concern 153. 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	154. Loss or alteration of wetlands of High Functional, High-Moderate, Low-Moderate and Low Functional Condition (i.e., habitat, hydrology, biogeochemistry) 155. Contamination of wetland function (i.e., habitat, hydrology, biogeochemistry) due to a spill during construction
Vegetation	156. 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 157. Weed introduction and spread
Wildlife and Wildlife Habitat	158. 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

Type	Potential Impacts from TMEP
	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	159. Change in sediment quality during construction 160. Change in water quality during construction or operations
Marine Fish and Fish Habitat	161. Loss of marine riparian, intertidal, and subtidal habitat 162. Decrease in productive capacity of suitable habitat, injury, or mortality of Dungeness Crab 163. Decrease in productive capacity of suitable habitat, injury, or mortality of inshore Rockfish 164. Decrease in productive capacity of suitable habitat, injury, or mortality of Pacific salmon
Marine Mammals	165. Permanent or temporary auditory injury and sensory disturbance of Harbour Seals, Southern resident Killer Whale, Humpback Whale, and Stellar Sea Lion 166. Injury or mortality due to vessel strikes
Marine Birds	167. 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 B: Certificate of Expert's Duty

We, Dr. Thomas Gunton, Dr. Sean Broadbent, Dr. Chris Joseph and Mr. James Hoffele have been engaged on behalf of Tsawout First Nation, Upper Nicola Band and Living Oceans Society to provide evidence in relation to Trans Mountain Pipeline ULC's Trans Mountain Expansion Project application currently before the National Energy Board.

In providing evidence in relation to the above-noted proceeding, we acknowledge that it is our 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 our area of expertise; and
3. to provide such additional assistance as the tribunal may reasonably require to determine a matter in issue.

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

Date: December 1, 2015 Signature: ______________
Dr. Thomas Gunton

Date: December 1, 2015 Signature: ______________
Dr. Sean Broadbent

Date: December 1, 2015 Signature: Chris Joseph
Dr. Chris Joseph

Date: December 1, 2015 Signature: James Hoffele
Mr. James Hoffele

Appendix C: Curriculum Vitaes

Resume

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

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).

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).

Dr. Thomas Gunton: Selected Publications (may 2015)

1. Joseph, Chris, Thomas I. Gunton and Murray Rutherford. 2015. Good Practices for Environmental Assessment. *Impact Assessment and Project Appraisal. (forthcoming).*
2. Gunton, Thomas I. 2015. Natural Resources and Economic Development. *International Encyclopedia of Geography*. D. Richardson and J. Ketchum ed.: Wiley-AAG. (forthcoming)
3. Gunton, Thomas I. 2015. Collaborative Models of Resource Development. *International Encyclopedia of Geography*. D. Richardson and J. Ketchum ed. Wiley-AAG. (forthcoming)
4. Gunton, Thomas, S. Broadbent and M. Sykes. 2015. LNG Development in BC: Issues and Policy Options: Vancouver, BC.
5. Joseph, Chris andThomas I. Gunton. 2015. Cost-benefit Analysis for Energy Project Evaluation: A Case Study of Bitumen Development in Canada. *Journal of Benefit-Cost Analysis* (in preparation).
6. Broadbent, S., Thomas Gunton and Duncan Knowler.2015. Multiple Accounts Evaluation Methodology for Evaluating Pipeline Proposals: A Case Study of the Enbridge Northern Gateway Project. *Journal of Benefit-Cost Analysis* (in preparation).
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8. Gunton, Thomas I. and Sean Broadbent. 2013. *A Spill Risk Assessment of the Enbridge Northern Gateway Project.* Simon Fraser University: Burnaby, BC.
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19. Gunton, Thomas I., Murray Rutherford and Megan Dickinson. 2010. Stakeholder Analysis in Marine Planning. *Environments*. 37: 3: 95-110.
20. Gunton, Thomas I. and Chris Joseph. 2010. Economic and Environmental Values in Marine Planning: a Case Study of Canada's West Coast. *Environments*. 37: 3: 111-127.
21. Dickinson, Megan, Murray Rutherford, and Thomas I. Gunton. 2010. Principles for Integrated Marine Planning: A Review of International Experience. *Environments*. 37: 3: 21-46.
22. Rutherford, Murray, Megan Dickinson and Thomas I. Gunton. 2010. An Evaluation of the National Framework for Marine Planning in Canada. *Environments*. 37: 3: 47-71.
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75. Gunton, Thomas I., G.C. VanKooten, and S. Flynn. 1991. *Role of Multiple Accounts Analysis in Evaluating Natural Resource and Land Use Options.* Background Report for the B.C. Forest Resource Commission, Victoria, B.C..
76. Gunton, Thomas I. *Economic Evaluation of Non-Market Values for Resource and Environmental Planning*.1990. Report for the B.C. Forest Resource Commission, Victoria, B.C.
77. Gunton, Thomas I.1990. "Natural Resource and Primary Manufacturing Industries in Canada: Retrospect and Prospect." in M. H. Watkins ed. *Canada in the Modern World.* New York: Reference Publishers. 71-87.
78. Gunton, Thomas I.1990. "Natural Gas Deregulation in Canada." in *Integrated Energy Markets and Energy Systems.* International Association of Energy Economists, Thirteenth Annual Conference, Copenhagen, Denmark, 1990, 1-27.
79. M'Gonigle, M., Thomas I. Gunton, et al.1990. "Crown Land Use Planning: A Model for Reform." in Calvin Sandborn ed. *Law Reform for Sustainable Development in British Columbia.* Vancouver: Canadian Bar Association 35-46
80. Gunton, Thomas I. and J. Richards. 1990. "Natural Resources and Economic Development." in P. Wilde and R. Hayter eds. *Industrial Transformation and Challenge in Australia and Canada*. Ottawa: Carleton University Press.141-157.
81. Gunton, Thomas I. and I. Vertinsky. 1990a. *Reforming the Decision Making Process for Forest Land Planning in British Columbia*. Final Report for the B.C. Forest Resource Commission, Victoria, B.C. 35 p.
82. Gunton, Thomas I. and I. Vertinsky. 1990b. *Methods of Analysis for Forest Land Allocation in British Columbia*. Final Report for the B.C. Forest Resource Commission, Victoria, B.C.
83. Gunton, Thomas I. and J. Richards. 1989. "Mineral Policy in Western Canada, The Case for Reform." *Prairie Forum Journal.* 14:2:195-209.
84. Gunton, Thomas I. 1989b. *Review of Natural Gas Pricing in Manitoba*. Report to the Manitoba Public Utilities Board.
85. Gunton, Thomas I. 1989c. *The Competitive Price of British Columbia Coal in the Japanese Market.* Report to the Coal Price Arbitration Panel. 22 p.

86. Gunton, Thomas I. and J. Richards. 1987. "Political Economy of Resource Policy." in Thomas I. Gunton and J. Richards eds. *Resource Rents and Public Policy in Western Canada.* Ottawa: Institute for Research on Public Policy. 1-58.
87. Gunton, Thomas I.1989. "Water Exports and the Free Trade Agreement." in A.L.C. de Mestral and D.M. Keith eds., *Canadian Water Exports and Free Trade*. Ottawa: Rawson Academy of Aquatic Science.71-87.
88. Gunton, Thomas I.1989a. *Review of Natural Gas Pricing in Ontario*. Report to the Ontario Energy Board.
89. Gunton, Thomas I.1989c.*The Impact of Alternative Coal Prices on Government Revenues*. Report to the Coal Price Arbitration Panel.
90. Gunton, Thomas I. and J. Richards eds.1987. *Resource Rents and Public Policy in Western Canada.* Ottawa: Institute for Research on Public Policy.
91. Gunton, Thomas I.1987. "Manitoba's Nickel Industry: The Paradox of a Low Cost Producer." in T. I. Gunton and J. Richards eds. *Resource Rents and Public Policy in Western Canada.* Ottawa: Institute for Research on Public Policy. 89-119.
92. Richards, John and T. I. Gunton.1987. "Expectations in Next-Year Country: Natural Resources and Regional Development." *Transactions of the Royal Society of Canada.* V:1: 1-17.
93. Weaver, C. and Thomas I. Gunton.1986. " Evolution of Canadian Regional Policy." In D.J. Savoie ed. *The Canadian Economy, A Regional Perspective*. Toronto: Methuen. 42-76
94. Gunton, Thomas I.1985. "A Theory of the Planning Cycle." *Plan Canada.* 25:2: 40-45.
95. Gunton, Thomas I.1985. "A Practitioner's Guide to Economic and Population Impact Assessment." *Operational Geographer.* 2:1: 15-19.
96. Gunton, Thomas I. 1984. "The Role of the Professional Planner." *Canadian Public Administration.* 27: 4: 399-417.
97. Gunton, Thomas I. 1983. "Recent Issues in Canadian Land Policy." *Canadian Geographer.* 27: 2: 94-206.
98. Hayter, Roger and Gunton, Thomas I. 1983. "Planning for Technological Change: The Case of Discovery Parks in British Columbia." *B. C. Geographical Series.* 40: 27-42.
99. Gunton, Thomas I. 1982. *Resources, Regional Development and Public Policy*. Canadian Centre for Policy Alternatives, Occasional Paper No. 7. Ottawa: Canadian Centre for Policy Alternatives.
100. Weaver, C. and Gunton, Thomas I. 1982. "From Drought Assistance to Mega Projects: Fifty Years of Regional Policy in Canada." *Canadian Journal of Regional Science.* 5:1:5-39.

Sean Broadbent
Curriculum Vitae
April 2015

School of Resource and Environmental Management, Simon Fraser University
TASC I - Room 8405, 8888 University Drive
Burnaby, BC V5A 1S6
Citizenship: Canadian

EDUCATION

PhD, Resource Management, Simon Fraser University, Burnaby, BC 2014
MBA, Business Economics, Oakland University, Rochester, MI 2008
BSc, Management Information Systems, Oakland University, Rochester, MI 2005

RESEARCH EXPERIENCE

Postdoctoral Fellow, Environmental Management Planning Group, Simon Fraser University, Burnaby, BC, 2014 - 2015.
Managed a team of graduate students in a multi-year research project that assesses cumulative effects to economic, environmental, social, and cultural values in First Nations traditional territory.

Doctoral Researcher, Environmental Management Planning Group, Simon Fraser University, Burnaby, BC, 2009 - 2014
Evaluated existing methods used in the regulatory review process to assess impacts from major energy projects and proposed a new methodological approach that integrates economic, environmental, and social values into a comprehensive evaluative framework.
Advisors: Dr. Thomas Gunton, Dr. Murray Rutherford, and Dr. Chad Day.

Senior Researcher, Environmental Management Planning Group, Simon Fraser University, Burnaby, BC, 2009 - 2014
Completed several studies in resource and environmental management including two studies submitted as evidence to the Joint Review Panel for the Northern Gateway Project on behalf of project intervenors.

Master Researcher, School of Business Administration, Oakland University, Rochester, MI, 2006 - 2008

PEER-REVIEWED PUBLICATIONS

Works in progress

1. **Broadbent, S**. and T.I. Gunton (Draft). Multiple Account Benefit Cost Evaluation of the Enbridge Northern Gateway Project, to be submitted to *Journal of Benefit-Cost Analysis*.

2. **Broadbent, S**. and T.I. Gunton (Draft). Evaluation of Risk Assessment in the Planning of Major Energy Projects: A Case Study Evaluation of the Northern Gateway Project, to be submitted to *Risk Analysis*.

3. **Broadbent, S**., T.I. Gunton, and M.B. Rutherford (Early Draft). Evaluation of Economic Impact Assessment Methodologies in the Regulatory Review Process for Major Energy Projects in Canada, to be submitted to *Impact Assessment and Project Appraisal*.

4. **Broadbent, S**. and T.I. Gunton (Early draft). The Cost of the Exon Valdez Oil Spill: A Summary of Economic Impacts, to be submitted to *Environmental and Resource Economics*

5. **Broadbent, S**. and T.I. Gunton (Early draft). Forecasting Spill Risk in Major Project Applications: An Application of the United States Oil Spill Risk Analysis Model to the Northern Gateway Project, to be submitted to *Risk Analysis.*

SELECTED ACADEMIC AND INDUSTRY REPORTS

Lucchetta, M., M. Steffensen, T.I. Gunton and **S. Broadbent.** (Draft) Cumulative Effects Assessment and Management: A Framework for the Metlakatla First Nation. Burnaby, BC: School of Resource and Environmental Management, Simon Fraser University.

Gunton, T.I., **S. Broadbent** and M. Sykes. (Draft). LNG Development in BC: Issues and Policy Options (Update). Burnaby, BC: School of Resource and Environmental Management, Simon Fraser University.

Broadbent, S. (2014). Major Project Appraisal: Evaluation of Impact Assessment Methodologies in the Regulatory Review Process for the Northern Gateway Project. Doctoral Thesis. Burnaby, BC: School of Resource and Environmental Management, Simon Fraser University.

Gunton, T.I. and **S. Broadbent.** (2014). A Preliminary Evaluation of Socioeconomic and Risk Assessment Components of the Kinder Morgan Regulatory Application for the Trans Mountain Expansion Project. Burnaby, BC: School of Resource and Environmental Management, Simon Fraser University.

Gunton, T.I. and **S. Broadbent**. (2013). North Coast Power Authority. Burnaby, BC: School of Resource and Environmental Management, Simon Fraser University.

Gunton, T.I. and **S. Broadbent**. (2013). A Spill Risk Assessment of the Enbridge Northern Gateway Project. Burnaby, BC: School of Resource and Environmental Management, Simon Fraser University.

Gunton, T.I. and **S. Broadbent**. (2012). A Public Interest Assessment of the Enbridge Northern Gateway Project. Report Submitted to the Joint Review Panel for the Enbridge Northern Gateway Project. Burnaby, BC: School of Resource and Environmental Management, Simon Fraser University.

Gunton, T.I. and **S. Broadbent**. (2012). A Review of Potential Impacts to Coastal First Nations from an Oil Tanker Spill Associated with the Northern Gateway Project. Report Submitted to the Joint Review Panel for the Enbridge Northern Gateway Project. Burnaby, BC: School of Resource and Environmental Management, Simon Fraser University.

ACADEMIC CONFERENCE PRESENTATIONS

Gunton, T.I. and **S. Broadbent**. Project Evaluation and Risk Assessment. Symposium conducted at the Aboriginal Law, Environmental Law and Resource Development Conference, Vancouver, BC, December 3, 2014.

AWARDS, FELLOWSHIPS, GRANTS, AND HONOURS

Mitacs Accelerate Postdoctoral Fellowship ($80,000), Simon Fraser University, 2014.
President's PhD Scholarship ($6,250), Simon Fraser University, 2012.
Industrial Research and Development Internship Program ($15,000), Simon Fraser University, 2011.
Social Sciences and Humanities Research Council Doctoral Award (waitlisted), Simon Fraser University, 2011.
Graduate Fellowship ($6,250), Simon Fraser University, 2009.
Beta Gamma Sigma Honor Society, Oakland University, 2008.

Chris Joseph MRM, PhD

Associate, Compass Resource Management

Education and Awards

2006-2013	PhD (Resource Management) School of Resource and Environmental Management, Simon Fraser University (SFU) *Recipient of several scholarships and awards, including Canada Graduate Scholarship – Doctoral (SSHRC) 2006-2009*
2002-2004	Masters of Resource Management School of Resource and Environmental Management, SFU
1994-1998	Bachelor of Science (Honours with Distinction) in Geography University of Victoria

Professional Affiliations

International Association of Impact Assessment
International Association of Impact Assessment – Western and Northern Canada

Summary of Professional Experience

2010 - Present
Associate, Compass Resource Management, Vancouver BC

2000 - Present
Owner, Chris Joseph Photography, Squamish BC

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

2003 – 2010
Sessional Instructor and Teaching Assistant, SFU, Burnaby BC

2005 – 2009
Consultant, Independent, 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

Selected Representative Assignments

Instream Fisheries Research, Facilitation of Gates Creek Sockeye Workshop. Advised on workshop structure and facilitated workshop. (2015).

Gitga'at First Nation, Environmental assessment advisor. Provide advice to the Gitga'at First Nation regarding EA applications and processes. Assignments have included critiquing proponent EA applications, preparing Information Request submissions to EA bodies, and working through issues in EA application content and methodology with proponent consultants. (2013-present).

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 three LNG projects

(Prince Rupert LNG, Aurora LNG, Pacific Northwest LNG) and a detailed economic impact assessment of the Kitimat LNG project. These studies 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 conducted analysis. 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. Wrote final report. (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).

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. Designed a multi-meeting, multi-month process to engage technical experts to gather advice for Port Metro Vancouver 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 Port 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 relevant to decision-making 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 drafting 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).

City of Merritt*, *Water planning and conservation. Researched water conservation tools in support of recommendations to the City of Merritt for their new water plan, including interviewing of water experts in municipalities across BC and ranking of water conservation tools used across BC. Analyzed the City of Merritt's water use data. (2011).

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. Reviewed the potential impacts on the Haida of the proposed NaiKun offshore wind project and provided the Haida Nation with an independent perspective on the potential impacts and financial viability of the project. Provided a critical 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. Research 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).

Select Publications

Joseph, C., T. Gunton, and M. Rutherford. Forthcoming. Good practices for effective environmental assessment. Impact Assessment and Project Appraisal.

Joseph, C., and T.I. Gunton. Submitted Fall 2013 for special issue. Cost-benefit Analysis for Energy Project Evaluation: A Case Study of Bitumen Development in Canada. Journal of Benefit-Cost Analysis.

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.

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.

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.

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.

Gunton, T.I., and C. Joseph. 2006. Toward a National Sustainable Development Strategy for Canada: Putting Canada on the Path to Sustainability within a Generation. Prepared for the David Suzuki Foundation. Vancouver, BC: David Suzuki Foundation. 30pp.

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.

James Hoffele

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EDUCATION

2012–2015	Masters of Resource Management (Planning), Simon Fraser University (SFU), Burnaby, British Columbia
2011–2012	Teacher Education B.Ed. (Junior/ Intermediate), Brock University, St. Catharines, Ontario
2007–2011	Concurrent B.A. Integrated Studies (Honours), Education, Minor in Geography, Brock University, St. Catharines, Ontario

WORK EXPERIENCE

Permitting Coordinator (Co-op) with Infrastructure Sustainability at Port Metro Vancouver, Vancouver
December 2014 – Present

- Coordinating all associated permits and approvals for habitat enhancement projects in accordance with the Port's habitat banking agreement with Fisheries and Oceans Canada.
- Assisting in Environmental Impact Statement development, contract procurement and management, and progress reporting for Roberts Bank Terminal 2 Project.

Junior Project Scientist (Internship) with Air Quality and Climate Change Group at SNC-Lavalin, Vancouver
May 2014 – September 2014

- Conducted analysis and research for projects related to regional air quality, pollutant dispersal, policy analysis, and noise monitoring.
- Learned and applied in-house Port Emission Inventory Tool to analyze greenhouse gas and air contaminant emissions for Prince Rupert Port Authority's 12 terminals.

Environmental Consultant with Dr. Mark Jaccard for City of Vancouver
April 2014 – June 2014, October 2014 – January 2015

- Assessed and estimated the lifecycle greenhouse gas emissions of proposed Trans Mountain pipeline expansion. The report is being used to inform City of Vancouver's motion filed with the National Energy Board to include the economic effects of climate change in its federal review of the project.
- Led and completed a second report for City of Vancouver analyzing the economic impact on the proposed Trans Mountain pipeline expansion if governments enact policy to fulfill their stated climate targets.

Teaching Assistant for Sustainable Energy and Materials Management undergraduate course, SFU, Burnaby
January 2014 – May 2014

- Facilitated three undergraduate tutorials consisting of approximately 20 students each.
- Provided students with an understanding of the human-induced flows of energy and materials as well as the institutional arrangements, decision-making processes and policy mechanisms for fostering the global adoption of more sustainable technologies and behaviors.

Climate Coordinator with Sustainable SFU, Lower Mainland, BC
September 2013 – May 2014

- Promoted climate change action and energy use reduction at SFU through supporting a fossil fuel divestment campaign, assisting with a climate justice conference, and coordinating an energy reduction program in cooperation with Facilities Management and BC Hydro.

Graduate Student Researcher with Energy and Materials Research Group, SFU, Burnaby, BC
September 2012 – September 2014

- Worked with a diverse energy group that uses an energy-economy model (CIMS) to analyze the cost-effectiveness of technologies, strategies, behaviours and policies to increase energy efficiency and mitigate climate change.
- Under the supervision of Dr. Mark Jaccard and using data obtained from multiple energy-economy modeling teams, I conducted an analysis of the likely decline in production of different fossil fuel resources if global temperatures are limited to a 2^{o} C increase.