An Assessment of Spill Risk for the Trans Mountain Expansion Project

by

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Executive Summary

1. The objectives of this report are to evaluate Trans Mountain's (TM) oil spill risk assessments contained in the regulatory application for the Trans Mountain Expansion Project (TMEP), provide estimates of oil spill frequency risk, and estimate potential damage costs of TMEP oil spills.

2. The TMEP consists of two pipelines to ship oil between Edmonton, Alberta and Burnaby, British Columbia. The 1,147-kilometre Line 1 would ship 350 thousand barrels per day of refined products and light crude oils and the 1,180-kilometre Line 2 would have the capability to transport 540 thousand barrels per day of heavy crude. The project proposes to expand the existing Westridge Marine Terminal to three tanker berths that could accommodate an increase in the current number of tankers from 60 per year to 408 tankers per year.

3. The *CEAA 2012* evaluation criterion requires assessment of two components to define risk: the severity of an adverse impact and the likelihood of an adverse impact occurring. This report evaluates the likelihood of an adverse impact resulting from oil spills.

4. TM estimates that any size tanker spill could occur every 46 to 284 years and any size terminal spill could occur every 34 years. For pipeline spills, TM identifies spill frequencies per kilometre per year for separate spill causes but does not estimate the likelihood of a pipeline spill on either Line 1 or Line 2 in the application.

5. This report uses international risk assessment best practices to evaluate TM's methodology for estimating spill rates for the TMEP based on the following rating scale:

   - Fully met: excellent (no weaknesses);
   - Largely met: good (no major weaknesses);
   - Partially met: poor (one major weaknesses); and
   - Not met: very poor (two or more weaknesses).

6. The evaluation of TM's methodology for estimating spill rates concludes that TM's spill risk analysis meets none of the seven best practice criteria (Table ES.1). In total there are 27 major weaknesses in the TM risk analysis for TMEP tanker, terminal and pipeline spills. The results show that TM did not provide the necessary information in the application to enable an accurate assessment of the likelihood of adverse environmental effects resulting from oil spills from the TMEP for decision makers and as required by *CEAA 2012*.

Table ES.1. Results for the Assessment of Risk in the TMEP Application

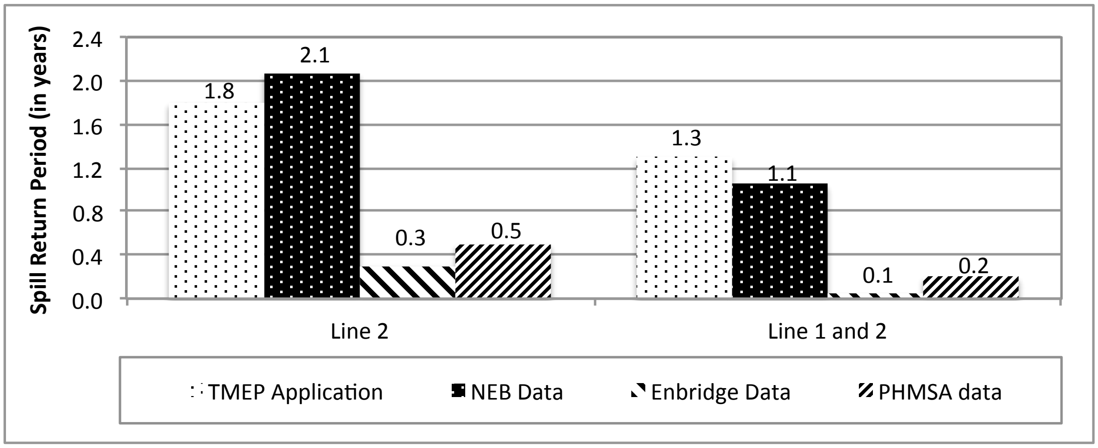
Criterion	Major Weakness	Rating	Result
Transparency *Documentation fully and effectively discloses supporting evidence, assumptions, data gaps and limitations, as well as uncertainty in data and assumptions, and their resulting potential implications to risk*	1. Inadequate description of the model estimating tanker spill return periods 2. Lack of transparency supporting mitigation measures that reduce the likelihood of terminal spills 3. Inadequate evidence supporting the reduction of pipeline spill frequencies	Very Poor	Not Met
Reproducibility *Documentation provides sufficient information to allow individuals other than those who did the original analysis to replicate that analysis and obtain similar results*	Insufficient proprietary data and information required to replicate: 4. MARCS modelling outputs that estimate tanker incident frequencies and consequences for grounding, collision, foundering, and fire/explosion 5. Mitigation measures that reduce spill risk from marine terminal operations 6. Outputs from the analysis of external and internal corrosion pipeline frequencies	Very Poor	Not Met
Clarity *Risk estimates are easy to understand and effectively communicate the nature and magnitude of the risk in a manner that is complete, informative, and useful in decision-making*	7. Inefficient presentation of tanker spill risk estimates 8. Ineffective communication of spill probability over the life of the project 9. Lack of clear presentation of spill risk for TMEP pipeline spills 10. No single spill risk estimate provided for the entire project 11. Inadequate assessment of the likelihood of significant adverse environmental effects consistent with existing law	Very Poor	Not Met
Reasonableness *The analytical approach ensures quality, integrity, and objectivity, and meets high scientific standards in terms of analytical methods, data, assumptions, logic, and judgment*	12. Limited definition of the study area to estimate tanker spill return periods 13. Reliance on tanker incident frequency data that underreport incidents by between 38% and 96% 14. Potential omission of tanker age characteristics in spill likelihood analysis 15. Questionable evidence supporting negligible external and internal corrosion threats to pipeline 16. Inadequate assessment of a worst-case oil pipeline spill 17. Omission of tug traffic that potentially results in an underestimation in spill risk 18. Lack of rigorous analysis supporting revised tanker spill risk estimates	Very Poor	Not Met

Reliability *Appropriate analytical methods explicitly describe and evaluate limitations, sources of uncertainty and variability that affect risk, and estimate the magnitudes of uncertainties and their effects on estimates of risk by completing sensitivity analysis*	19. Lack of confidence intervals that communicate uncertainty and variability in spill risk estimates 20. Lack of sensitivity analysis that effectively evaluates uncertainties associated with spill estimates 21. Lack of risk factor associated with the effective implementation of risk-reducing measures 22. Inadequate statement of uncertainties, limitations, and qualifications in the analysis	Very Poor	Not Met
Validity *Independent third-party experts review and validate findings of the risk analysis to ensure credibility, quality, and integrity of the analysis*	23. Inadequate review and validation of spill risk estimates 24. No justification of the use of the MARCS model to estimate tanker spill risk for the TMEP	Very Poor	Not Met
Stakeholder Participation *Stakeholders participate collaboratively throughout the risk assessment and determine acceptable levels of risk that assess alternative means of meeting project objectives*	25. Lack of stakeholder engagement in a collaborative analysis 26. Failure to define risk acceptability in terms of the needs, issues, and concerns of stakeholders potentially impacted by the project 27. Inadequate assessment and comparison of risks from project alternatives	Very Poor	Not Met

7. We used several widely accepted spill risk methodologies to estimate potential pipeline, terminal, and tanker spill risk for the TMEP. The results of these methodologies are then compared to spill risk results in the TMEP application.

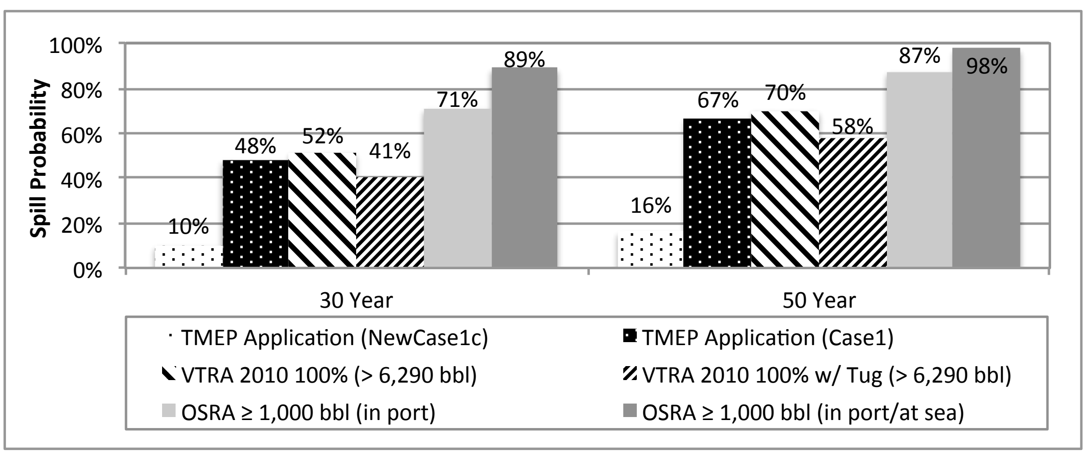
8. Pipeline spill risks are estimated based on recent historical spill frequency data from the National Energy Board, Enbridge liquids pipeline system, and the Pipeline and Hazardous Materials Safety Administration. The spill risk estimates based on these data sources as well as TMEP's own analysis show that spill likelihood is high, with the number of spills for the new Line 2 ranging from 1 to 3 spills every 2 years (Figure ES.1). The comparison of pipeline spill risk for the TMEP shows that TM's unmitigated pipeline spill frequency estimate is similar to the estimate based on data from the National Energy Board, but much lower than spill risk frequencies based on data from Enbridge and the Pipeline and Hazardous Materials Safety Administration. The Enbridge and Pipeline and Hazardous Materials Safety Administration data are based on pipelines that use mitigation measures similar to those proposed by TM for the TMEP. The fact that spill frequency rates forecasted by TM are so much lower than the actual spill rates observed in other pipeline systems, as reported by Enbridge and Pipeline and Hazardous Materials Safety Administration data, that use similar mitigation measures raises doubts about the reliability of the TMEP forecasts.

Figure ES.1. Comparison of Pipeline Spill Frequency



9. Tanker spill risk probabilities based on the TMEP application, the United States Oil Spill Risk Analysis model, and the Vessel Traffic Risk Assessment model are summarised in Figure ES.2. The spill risk estimates from the three different methodologies including the one used by TMEP show a high likelihood of a tanker spill ranging from 58% to 98% over a 50 year operating period. The only outlier result is the TMEP NewCase1c estimate showing a probability of 16%. Given the weaknesses in the methodology used in the TMEP application and the fact that this estimate is an outlier significantly below the estimates based on other methods, the tanker spill risk estimate NewCase1c in the TMEP application is an inaccurate and unreliable estimate of tanker spill risk.

Figure ES.2. Comparison of TMEP Tanker Spill Probabilities

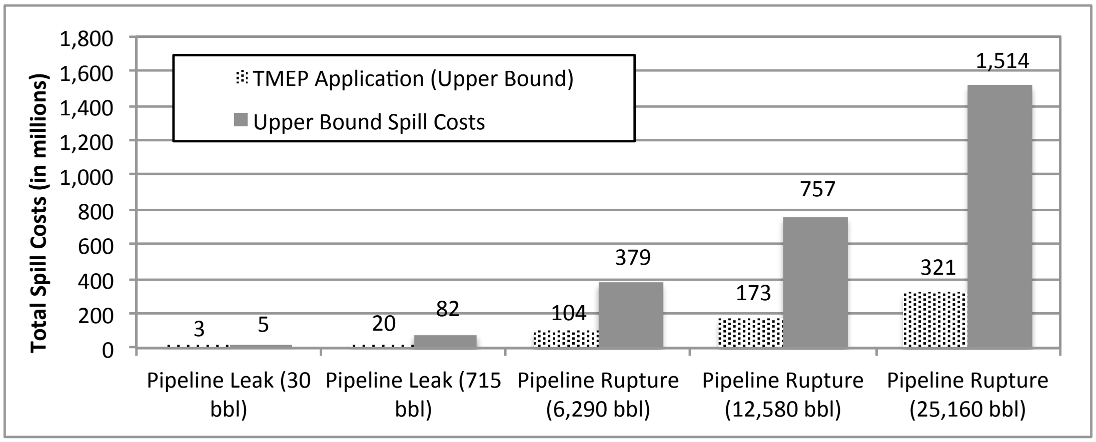


Note: The three methodological approaches for estimating tanker spill probabilities are different and therefore the results are not directly comparable. See Section 5.3 of this report for further discussion of these differences.

10. Potential pipeline, tanker, and terminal spill costs are estimated based on evidence from peer-reviewed literature, government data, regulatory applications, and case studies.

11. Total potential pipeline spill costs range from $5 million to $1.5 billion for a single spill (Figure ES.3). These spill cost estimates are approximately 1.7 to 4.7 times higher (depending on size) than those presented in the TMEP application. Therefore, spill costs in the TMEP application significantly underestimate potential upper bound TMEP pipeline spill costs.

Figure ES.3. Comparison of Upper Bound Pipeline Spill Costs



12. Potential tanker spill costs range from $2.2 to $4.4 billion for a single spill (Table ES.2). If passive use damages are included in the spill cost estimates, the cost of a potential tanker spill could increase up to $25.5 billion. Actual damages would be even higher because many costs such as ecosystem service losses and psychological damages are not included in these estimates. The TMEP application does not provide any estimates of potential tanker spill damage costs.

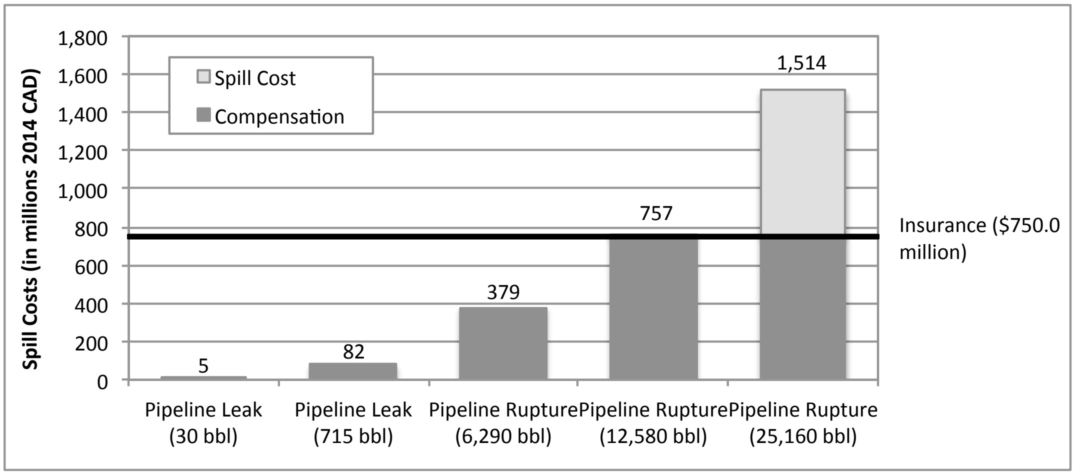
Table ES.2. Potential Spill Cost Estimates for TMEP Tanker Spills

Method	Spill size (bbl)	Potential Spill Costs (in millions)			
		Clean-up	Social and Environmental	Total	Total w/ Passive Use
Mean Outflow	51,891	886	1,330	2,216	3,586 – 23,290
Worst Case Outflow	103,782	1,773	2,659	4,432	5,802 – 25,506

13. Compensation for pipeline spill damages depends on the amount of insurance maintained by the pipeline operator and any other financial assets that the operator could draw upon for compensation purposes. Trans Mountain Pipeline ULC currently maintains general liability insurance of $750 million per year and intends to maintain this level of insurance over the life of the project.

14. In the event of a TMEP pipeline rupture, insurance may be insufficient to fully compensate parties that incur losses from a spill. The shortfall in compensation from a $1.5 billion pipeline spill could total $764 million, which would have to be covered by TMEP (Figure ES.4). TM's ability to cover compensation that exceeds insurance coverage, the details of what will be compensated and how the value of damages requiring compensation will be determined are all unknown.

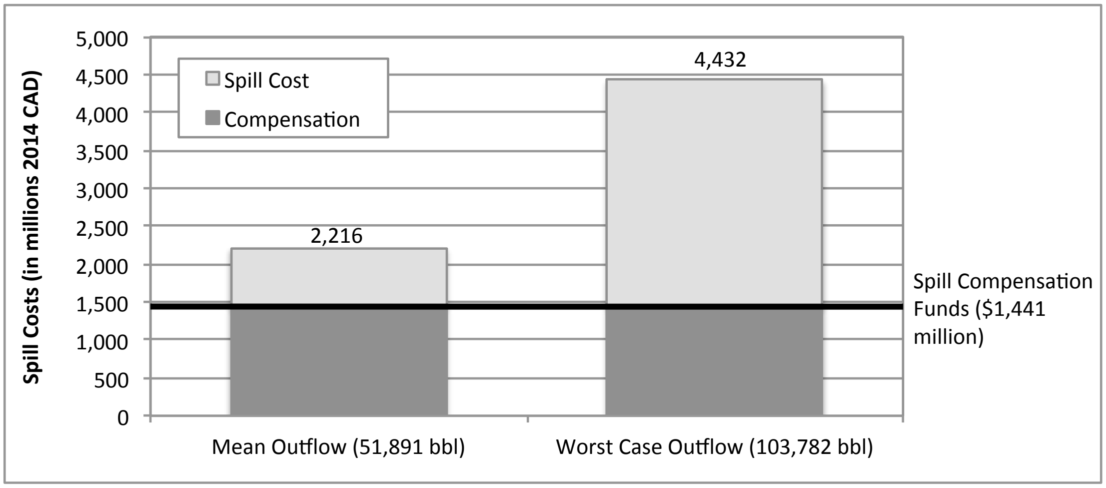
Figure ES.4. Potential Pipeline Spill Costs and Compensation



15. Compensation for a tanker spill is governed by domestic law combined with several international conventions. Under the four-tier system, the total amount available for clean-up, compensation, and natural resource damages from tanker spills in Canada is currently limited to approximately $1.44 billion.

16. Total spill costs could exceed available compensation by over $2.9 billion (Figure ES.5). The compensation shortfall would be higher if passive use damages were included in the spill cost estimates. Consequently, the international and domestic compensation funds are inadequate to cover potential damage costs from a large tanker spill along the TMEP route.

Figure ES.5. Potential Tanker Spill Costs and Compensation



17. TM has not provided in the application a comprehensive mitigation and compensation plan to provide assurance to the Canadian public that TM will be fully responsible for all spill clean-up and damage costs from a tanker, terminal, or pipeline spill along the TMEP route. The elements of a comprehensive compensation plan include:

- defining compensable and non-compensable damages;
- identifying eligible and ineligible parties for compensation;
- specifying methods for determining and evaluating damage claims;
- identifying timelines for impacted parties to receive compensation;
- identifying funding sources to fully cover all damage costs;
- requiring the project proponent to accept unlimited liability for all damages resulting from the project;
- specifying dispute resolution procedures;
- establishing an independent monitoring process to assess ongoing impacts;
- specifying a legally binding and independent arbitration process to determine damages; and
- providing financial support for First Nations and stakeholders to participate in the monitoring and compensation process.

18. TM has not assessed the likelihood of significant adverse environmental effects as required by the *CEAA 2012*. In its application, TM (2013, Vol. 1 p. 1-59) states "Potential effects of credible worst case and smaller spills discussed in Volume 7 and 8A are not evaluated for significance because these represent low probability, hypothetical events". The probability of oil spills is high and therefore TM should have assessed the adverse impacts of spills as required by *CEAA 2012.*

19. The conclusions of this report are as follows:

I. The TMEP application does not provide an accurate assessment of the likelihood of adverse environmental impacts resulting from oil spills as required by the *CEAA*.

TM's spill risk analysis contains 27 major weaknesses. As a result of these weaknesses, TM does not provide an accurate assessment of the likelihood of oil spill risk associated with the TMEP. Some of the key weaknesses include:

- Ineffective communication of spill probability over the life of the project;
- Lack of confidence ranges for spill risk estimates;
- Inadequate sensitivity analysis of spill risk estimates;
- No presentation of the combined spill risk for the entire project;
- Reliance on tanker incident frequency data that underreport incidents by up to 96%;
- Incomplete assessment of the significance of oil spills; and
- Inadequate disclosure of information and data supporting key assumptions that were used to reduce spill risk estimates.

II. TM's own analysis shows spill likelihood for the TMEP is high (99%)

TM's spill risk estimates show that the combined likelihood of an oil spill from the TMEP is high (99%) (Table ES.3). The individual spill probabilities for the specific types of spills, that is tanker (16 – 67%), terminal (77%), and pipeline (99%) spills, understate the likelihood of spills associated with the TMEP because of the methodological weaknesses in the TM analysis.

Table ES.3. Probabilities for TMEP Tanker, Terminal, or Pipeline Spills

Type of Spill	Spill Probability over 50 Years
Tanker Spill	16 – 67%
Terminal Spill	77%
Pipeline Spill	99%
Combined Spills	99%

III. The likelihood of an oil spill from the TMEP is high

The probabilities of oil spills from the TMEP are estimated using a range of widely accepted methods. The estimates show that the likelihood of spills is high. For pipeline spills, data from the National Energy Board, the Enbridge liquids pipeline system, the Pipeline and Hazardous Materials Safety Administration and the TMEP application show that a spill is highly likely to occur (99%). The Pipeline and Hazardous Materials Safety Administration methodology is the standard methodological approach for estimating spill risk in the United States and the method may provide the most reliable estimates of potential spill risk for the TMEP.

The United States Oil Spill Risk Analysis model and the Vessel Traffic Risk Assessment methodology estimate that there is a high likelihood of a tanker spill (58% to 98%) (Figure ES.2). Tanker spill risk estimates in the TMEP application range from 16% to 67% depending on mitigation measures (Figure ES.2). The low end of TMEP estimates of 16% is an outlier significantly below the estimates based on other methods. Therefore, given the methodological deficiencies in TM's oil spill risk assessment and the fact that TM's low end estimates are significantly below the estimates generated by other methodologies, the low end spill risk estimates in the TMEP application should not be relied on as accurate estimates of tanker spill risk.

IV. TM underestimates the upper bound damage costs of a pipeline spill and provides no estimates of the damage costs of a tanker spill

Total potential pipeline spill costs range from $5 million to $1.5 billion for a single spill, which is 1.7 to 4.7 times higher than the upper bound spill costs estimated in the TMEP application. Therefore, spill costs in the TMEP application cannot be relied on as accurate estimates of upper bound costs. TM provides no estimates of the potential damages resulting from a tanker oil spill.

V. Potential spill costs from the TMEP could exceed available compensation

The comparison of potential pipeline and tanker spill damages to available compensation shows that existing mechanisms could provide inadequate compensation after a spill. Based on Trans Mountain's liability insurance of $750 million, we estimate that potential pipeline spill costs for a 25,160 barrel rupture could exceed this insurance by $764 million for a single spill. For a tanker spill, a worst-case spill of 103,782 barrels could exceed available compensation from domestic and international spill compensation funds by $2.9 billion. The government's recent plans to remove the liability cap for the domestic compensation fund could be insufficient to cover all tanker spill costs in this worst-case scenario. As a result, British Columbians and Canadians could incur those spill costs that are not compensated.

VI. Overall Conclusion

The overall conclusion of this report is that:

1. TM's application contains major methodological weaknesses that do not provide an accurate assessment of the degree of risk associated with the TMEP;
2. There is a high probability of oil spills from the TMEP ; and
3. Pipeline or tanker spills from the TMEP could result in significant damage costs that exceed existing compensation schemes.

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List of Acronyms

Bbl	Barrel
Bbbl	Billion barrels
BC	British Columbia
BOSCEM	Basic Oil Spill Cost Estimation Model
CAD	Canadian dollars
CEAA	Canadian Environmental Assessment Act
COS	California oil spill
DNV	Det Norske Veritas
EVOS	Exxon Valdez oil spills
IOPCF	International Oil Pollution Compensation Fund
Kbpd	Thousand barrels per day
KM	Kinder Morgan
LRFP	Lloyd’s Register Fairplay
MARCS	Marine Accident Risk Calculation System
NEB	National Energy Board
NGP	Northern Gateway Project
Nm	Nautical miles
OSRA	Oil Spill Risk Analysis
PHMSA	Pipeline and Hazardous Materials Safety Administration
SQRA	Semi-quantitative risk assessment
TM	Trans Mountain
TMEP	Trans Mountain Expansion Project
TMPL	Trans Mountain Pipeline
US	United States
USD	United States dollars
VTRA	Vessel Traffic Risk Assessment
WTA	Willingness to accept
WTP	Willingness to pay

1. Introduction

This report assesses the risk of accidental spills for the Trans Mountain Expansion Project (TMEP). The specific objectives of this study are to:

1. Evaluate spill risk assessments contained in the TMEP application;
2. Estimate pipeline and tanker spill risks associated with the TMEP;
3. Compare the results of different spill risk assessment methodologies with those from the TMEP application; and
4. Review potential spill costs from the TMEP and compare these costs with existing insurance and compensation schemes.

Chapter 2 of the report provides an overview of the TMEP, while Chapter 3 summarizes the oil spill risk assessments completed by Trans Mountain (TM) and its consultants. Chapter 4 contains an evaluation of the oil spill risk assessments in the TMEP application using best practices for risk assessment and discusses the results of this evaluation in terms of the project approval criterion in the *Canadian Environmental Assessment Act* (*CEAA 2012)*. Chapter 5 reviews alternative spill risk assessment methods, applies these methods to estimate risks from the TMEP, and compares the results with results from the TMEP application. Chapter 6 provides a literature review of potential spill costs, applies these spill cost estimates to the TMEP, and compares potential spill costs from the TMEP with insurance coverage maintained by TM and international and domestic compensation funds. Chapter 7 summarizes our findings and conclusions.

All dollar figures in this report are reported as 2014 Canadian dollars (CAD) unless otherwise stated. Conversions were made using annual inflation data from the United States (US) Bureau of Labor Statistics (USBLS 2015) and the Bank of Canada (BOC 2015b) and using currency exchange information from the Bank of Canada (BOC 2015a).

This report has been prepared in accordance with our duty as experts to assist: (i) Tsawout First Nation, Upper Nicola Band and Tsleil-Waututh Nation 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 "A".

1.1. Authors

Dr. Gunton (lead author) is currently Full Professor and Director of the Resource and Environmental Planning Program at Simon Fraser University, where he teaches advanced graduate courses in resource and environmental planning and policy. He has more than 35 years of professional experience in the natural resource and environmental management field 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.

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 redesign of the regulatory and royalty system for oil and gas development (including design and implementation of the BC Oil and Gas Commission), and new air pollution regulations. He also worked as the chief negotiator for BC on a number of major resource development projects including Alcan's Kemano completion project (including finalizing an energy agreement) and design of a new oil and gas royalty system. He has been an expert witness for various regulatory agencies including the National Energy Board, the Ontario Energy

Board, the Manitoba Public Utilities Commission and the BC Arbitration Panel providing evidence on natural resource markets and natural resource policy.

Dr. Gunton has a PhD in Planning from the University of British Columbia specializing in public policy and a Masters degree in Planning from the University of Waterloo specializing in natural resource policy and development. He has published over 80 articles in refereed journals on natural resource policy and has won numerous research grants competitions from national granting agencies to fund his research. For the last decade he has been working on assessing the environmental, social and economic risks and impacts of energy projects in BC including the proposed Enbridge Northern Gateway Pipeline (ENGP) for which he completed a benefit-cost study, environmental impact and oil spill risk analysis assessment. He appeared as an expert witness before the NEB hearings on the ENGP testifying on the environmental impacts, risks and economic costs and benefits of the ENGP. His full resume is attached as Appendix “B”.

Dr. Sean Broadbent has a PhD from the Simon Fraser University in Resource and Environmental Management, where he took senior graduate courses in economics, ecological science, risk analysis and environmental planning. His PhD thesis was a multiple accounts benefit cost analysis and oil spill risk assessment evaluation of the proposed Enbridge Northern Gateway Project, which was nominated for Canadian Association for Graduate Studies - UMI Distinguished Dissertation Award and received an award of outstanding merit by external examiners. He has a Masters of Business Administration in Business Economics, (*Beta Gamma Sigma*) and a Bachelor of Science in Management Information Systems from Oakland University. Dr. Broadbent has worked as a consultant for over seven years on a variety of resource and environmental projects in BC including preparing reports on the Enbridge Northern Gateway submitted to the NEB hearings and reports on LNG development. His full resume is attached as Appendix “B”.

2. Overview of the Trans Mountain Expansion Project

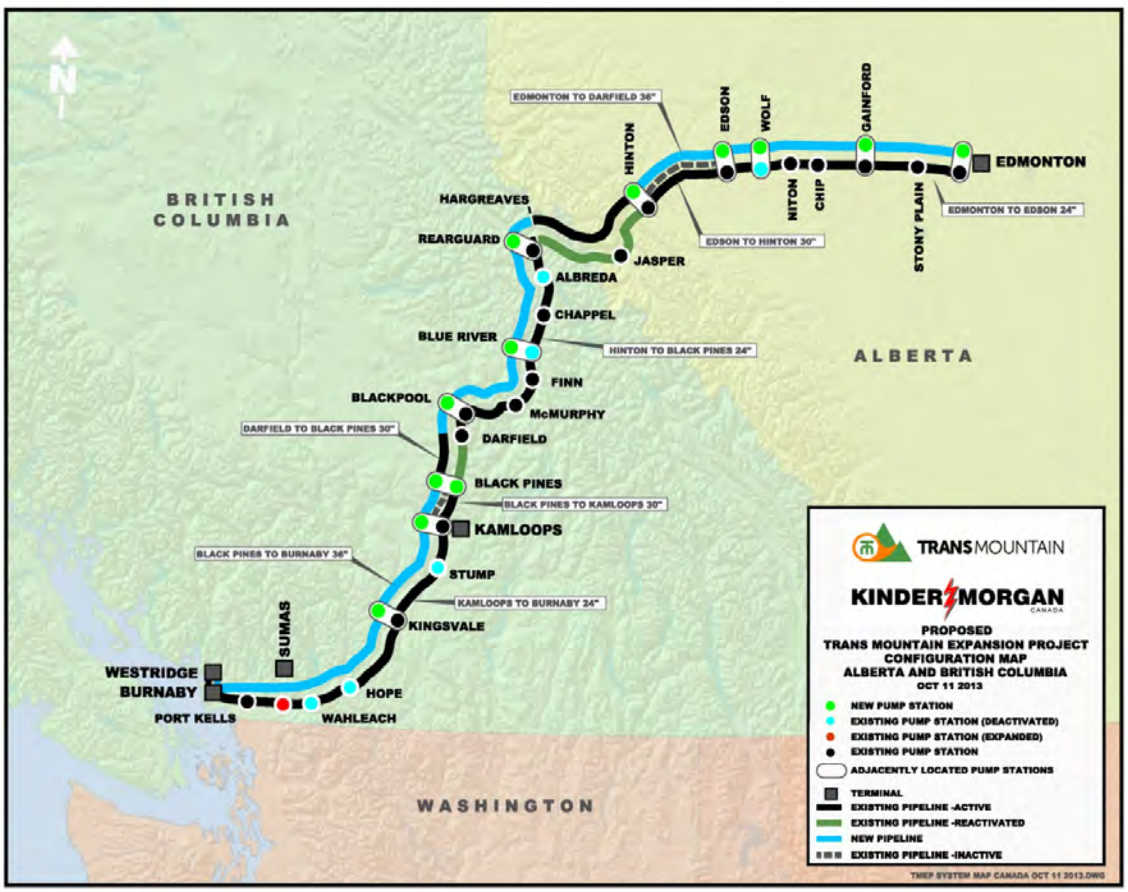
The TMEP is a proposal to expand the existing Trans Mountain Pipeline (TMPL) that has been operating since 1953. According to TM, the purpose of the TMEP is "to provide additional transportation capacity for crude oil from Alberta to markets in the Pacific Rim including BC [*British Columbia*], Washington State, California, and Asia" (TM 2013, 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 2013, Vol. 2 p. 2-12). The TMEP would consist of two independently operated pipelines. The first line (Line 1) is a 1,147-km pipeline with the capability of transporting 350 kbpd (TM 2013, Vol. 4A p. 4A-2-3). Line 1 would use mostly existing TMPL pipeline and reactivated pipeline that was previously deactivated 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 2013, 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 2013, 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 2013, Vol. 4A p. 4A-2). The proposed route for the TMEP largely parallels the existing TMPL route (Figure 1). The proposed TMEP route begins at the Edmonton Terminal, continues west to Hinton, Alberta where it passes through the Hargreaves Trap Site on the west side of Mount Robson Provincial Park and continues south towards the Community of Blue River (KM 2013 Vol. 5A). The proposed TMEP route continues south along the North Thompson River valley, across the Thompson River and down to Merritt (KM 2013, Vol. 5A). From Merritt, the TMEP would continue to the District of Hope and to the Lower Mainland of BC where it would cross the City of Chilliwack, the City of Abbotsford, the Township of Langley, the City of Surrey, and the City of Burnaby to reach Burnaby Terminal and Westridge Marine Terminal on Burrard Inlet (TM 2013, Vol. 5A). The TMEP would include an additional 12 new pump stations, new storage tanks, and other components to support Lines 1 and 2 (TM 2013, Vol. 4A p. 4A-3).

Figure 2.1. Proposed Pipeline Route



Source: TM (2013 Vol. 2 p. 2-15).

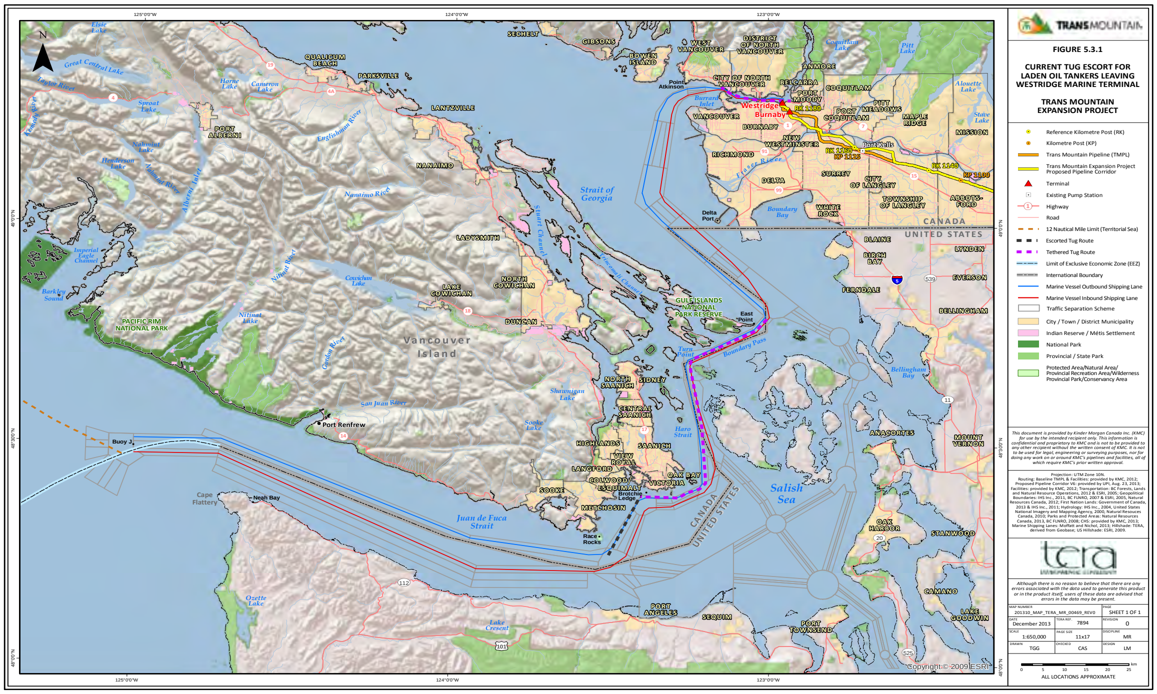
2.1.2. Terminal

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 consisting of three berths, each having the capability to handle Aframax tankers (TM 2013, Vol. 1 p. 1-11; 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 2013, 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 2013, Termpol 3.15 p. 22; Vol. 4A p. 4A-3). According to TM (2013, Vol. 2 p. 2-27), 630 of the 890 kbpd in system capacity delivered to the marine terminal would be for shipment.

2.1.3. Tanker

The TMEP would increase existing tanker traffic from the TMPL of five vessels loaded with heavy crude oil per month to 34 vessels per month (TM 2013, Vol. 2 p. 2-27), or an annual increase from 60 tankers to 408 tankers. Tankers accessing Westridge Marine Terminal would be Panamax (less than 75,000 deadweight tonnes) or Aframax (75,000 to 120,000 deadweight tonnes) tankers, which are the current class of tankers calling at the terminal for the TMPL (TM 2013, Vol. 8A p. 8A-68; 71). Tankers would use between two and four tethered tugs to navigate the Vancouver Harbour Area (TM 2013, Termpol 3.15 p. 12). TM would not own or operate the tankers calling at Westridge Marine Terminal (TM 2013, Vol. 2 p. 2-27) and thus the tanker owner would be liable to pay costs associated with an oil tanker spill (TM 2013, Vol. 8A p. 8A-52). TMEP tankers travelling inbound and outbound to Westridge Marine Terminal would use existing marine transportation routes (TM 2013, Vol. 8A p. 8A-67). Sailing west-east, tankers would enter the 12 nautical mile (nm) limit of the territorial sea of Canada, follow the Juan de Fuca Strait by Race Rocks, through Boundary Pass, Haro Strait, and the Strait of Georgia into English Bay and through the First and Second Narrows to Westridge Terminal (TM 2013, Termpol 3.15 p. 11-17).

Figure 2.2. Proposed TMEP Tanker Routes



Source: TM (2013).

3. Summary of Oil Spill Risk Assessment

3.1. Introduction

Regulatory approval of the TMEP requires the applicant to demonstrate that the proposed project satisfies decision criteria pursuant to the *CEAA 2012*. The key criterion in the decision of whether or not to approve a project under the *CEAA 2012* is the likelihood that the project will cause significant adverse environmental effects that cannot be justified in the circumstances. Although there are many impacts of the TMEP that should be assessed to determine if they cause significant adverse environmental effects, we focus on only one potential adverse impact: an oil spill. TM provides separate spill likelihood estimates for tanker, terminal, and pipeline spills in its regulatory application for the TMEP and we summarize the methodologies that TM and its consultants use to estimate spill likelihood in this section. This summary, which provides the basis for the evaluation in Chapter 4, relies on the following components of the TMEP regulatory application:

- *Volume 7: Risk Assessment and Management of Pipeline and Facility Spills* including appendices;
- *Risk Update* that contains several attachments including the *Failure Frequency Assessment Report, Trans Mountain Expansion Project Quantitative Geohazard Frequency Assessment, Line 2 Consequence Report,* and *Tabulated Risk Results for the Trans Mountain Expansion Project;*
- *Termpol Study No. 3.15: General Risk Analysis and Intended Methods of Reducing Risk* and appendices by Det Norske Veritas; and
- *Trans Mountain Response to Information Requests regarding the TERMPOL Report and Outstanding Filings from National Energy Board* that contains revised tanker spill risk estimates.

3.2. Pipeline Spills

The oil spill semi-quantitative risk assessment (SQRA) was submitted in *Volume 7* of the TMEP application in 2013. In a response to an information request from the National Energy Board (NEB), TM agreed to provide results from its risk assessment in a *Risk Update* that informs the risk-based design process for TMEP Line 2 and the new Westridge delivery pipelines (Dynamic Risk 2014a, pdf p. 7). The SQRA submitted in *Volume 7* of the application in 2013 and the Pipeline SQRA submitted in 2014 in response to the information request from the NEB appear to use similar methodological approaches. We summarize the 2014 Pipeline SQRA since it represents the most recent version.

The Pipeline SQRA prepared by Dynamic Risk estimates risk as the product of quantitative estimates of the likelihood of pipeline failure and qualitative, index-based, values for the consequences of a failure (Dynamic Risk 2014a, pdf p. 11). Dynamic Risk derives the first component of risk (i.e. failure frequencies) in a threat assessment that identifies potential threats associated with the TMEP. These threats include external corrosion, internal corrosion, third party damage, human error during operations, material defects, construction defects, and geotechnical, geological, and hydrological failures (Dynamic Risk 2014a, Att. A, p. 3). Equipment failures are not included in the *Threat Assessment* because they will be assessed as part of a separate facilities risk assessment (Dynamic Risk 2014a, Att. A, p. 4). The *Threat Assessment* uses two approaches to determine failure likelihood estimates for different threats: (1) industry incident statistics from the Pipeline and Hazardous Materials Safety Administration

(PHMSA) in the US, and; (2) a reliability methods approach that uses a limit state model[1] describing failure conditions for the mechanism under consideration.

Dynamic Risk examines the frequency of spills from external corrosion using a reliability approach based on an in-line inspection dataset that represents a modern pipeline and design details of the TMEP pipeline (i.e. diameter, wall thickness, and operating pressure, among others) (Dynamic Risk 2014a, Att. A, p. 8). Dynamic Risk chooses in-line inspection data from Kinder Morgan's 36-inch Tennessee Gas Pipeline (Dynamic Risk 2014a, Att. A, p. 8) in part because this pipeline uses Fusion Bond Epoxy which is the same coating type planned for TMEP. The reliability approach models the response of pipeline materials and design to anticipated growth in corrosion rates (TM 2013, Vol. 7 p. 7-11). The results of the modelling show that the unmitigated failure probability is zero during the first 11 years of operation after which the failure frequency increases to measurable levels (Dynamic Risk 2014a, Att. A, p. 12). To estimate potential pipeline failures from internal corrosion, Dynamic Risk reviews evidence from Penspen (2013), Alberta Innovates (2011), and NAS (2013) that shows diluted bitumen is no more corrosive than other heavy crudes (Dynamic Risk 2014a, Att. A, p. 14-16). Dynamic Risk also references the analysis it completed for the Northern Gateway Project (NGP) section 52 application based on in-line inspection data from Enbridge's NPS 36-inch Line 4 that showed no evidence of internal corrosion (Dynamic Risk 2014a, Att. A, p. 16). Dynamic risk states that pre-emptive measures could be implemented to address corrosion before it became a critical flaw size (Dynamic Risk 2014a, Att. A, p. 16). Thus, Dynamic Risk concludes the failure probability of internal corrosion is

[1] A limit state model represents conditions that interfere with the functionality of a system (in this case pipelines). According to Dynamic Risk (TM 2013, Vol. 7 App. A p. 2-3), limit state functions contain variables representing failure conditions for the pipeline system and at least one of these variables is characterized as a probability density function. Modeling techniques such as Monte Carlo analysis can then be used to calculate the probability of a pipeline failure for a specific damage mechanism. Dynamic Risk notes that probability density functions are not available for all pipeline threats and uses the limit state models approach in the TMEP regulatory application to estimate failure frequencies for external corrosion and third party damage.

negligible and that it expects no significant internal corrosion on the TMEP (Dynamic Risk 2014a, Att. A, p. 16).

To estimate the failure frequency associated with third party damage, Dynamic Risk models potential pipeline failures resulting from excavation damage. The approach, based on Chen and Nessim (1999), estimates the failure frequency based on the frequency of the pipeline incurring a hit by an excavator and the probability of pipeline failure from the hit (Dynamic Risk 2014a, Att. A, p. 17). The approach relies on a fault tree model that identifies the event, conditions, and probabilities of the impact frequency from a third party in conjunction with design, installation, and operations data for TMEP (Dynamic Risk 2014a, Att. A, p. 20). Failure probabilities, given an excavator impacts a pipeline, are estimated using Monte Carlo analysis (Dynamic Risk 2014a, Att. A, p. 21). Dynamic Risk compares the resulting failure frequencies of 3.9E-05 to 5.7E-05 with failure frequencies from the PHMSA data for excavation damages of 5.412E-05 suggesting that the results of their analysis are consistent with empirical data. Dynamic Risk estimates that the percentages of leaks and ruptures resulting from third party damages to pipelines are 75% and 25%, respectively (Dynamic Risk 2014a, Att. A, P. 31).

Dynamic Risk estimates pipeline spill frequencies for human error, manufacturing defects, and construction defects based on PHMSA data for incidents involving large-diameter, onshore pipelines that occurred between 2002 and 2009. For incidents of human error during operations, Dynamic Risk adjusts the baseline PHMSA failure frequency to account for TMEP operations that would address causal factors of pipeline failures from human error (Dynamic Risk 2014a, Att. A, p. 32). Dynamic Risk derives the adjustment factors from an Operational Management Systems Questionnaire administered during the Threat Assessment Workshop and the adjustment results in a 72% decrease in the failure frequency for human error. Dynamic Risk does not adjust baseline PHMSA failure frequencies for manufacturing defects and construction defects.

BGC Engineering uses SQRA to estimate threats to the TMEP from geotechnical, geological, and hydrological failures. The assessment evaluates the potential for each type of geohazard identified to result in a loss of containment (BGC Engineering 2014, p. ii). The evaluation includes a review of maps (soil, topographic, and hydrological), pipeline alignment sheets, incident reports detailing ground movements, hydrological and geological events, as well as floods, studies, texts, and engineering reports (Dynamic Risk 2014a, Att. A, p. 34). The geohazard assessment identifies a total of 4,281 potential hazards that have an unmitigated range of 1.0E-02 to 1.0E-10 events per year (BGC Engineering 2014, p. ii).

Table 3.1. TM's Summary of Pipeline Failure Threats and Likelihoods

Cause	Failure Frequency (per km-year)		Leak/Rupture (% of failures)	Source
	Baseline	Adjusted		
External Corrosion	n/a	n/a	n/a	Reliability Approach
Internal Corrosion	n/a	n/a	n/a	Literature Review / NGP
Third Party Damage	5.41E-05	3.90E-05 to 5.70E-05	75/25	Reliability Approach
Human Error (Operations)	7.84E-05	2.22E-05	80/20	Historical PHMSA spill data
Material Defects	5.88E-05	n/a	67/33	Historical PHMSA spill data
Construction Defects	7.84E-05	n/a	87/13	Historical PHMSA spill data
Geohazards	1.00E-02 to 1.00E-10	n/a	0/100	Geohazard Assessment

Source: Compiled from BGC Engineering (2014), Dynamic Risk (2014a). Note, the geohazard frequency assessment measures loss of containment as a full-bore rupture (BGC Engineering 2014, p. 6-7) and thus 100% of failures from geohazards represent a full-bore rupture. Percentage of leaks and ruptures for human error, material defects, and construction defects calculated based on Dynamic Risk (2014a).

Dynamic Risk uses a qualitative approach to estimate the second component of risk (i.e. consequences of a spill) (Dynamic Risk 2014a, Att. C, p. 5). The qualitative approach uses a weighted scoring system that evaluates spill impacts depending on the outflow volume and the environmental characteristics in the specific location of the spill (Dynamic Risk 2014a, Att. C, p. 5). Specifically, the weighted scoring system produces a consequence score for watercourse spills, which is a function of outflow volume, watercourse sensitivity, and drinking water as well as a consequence score for non-watercourse spills that depends on the outflow volume and land-use severity such as whether the land-use is remote, agricultural, or residential, among others (Dynamic Risk 2014a, Att. C). The consequences scores for watercourses (ranging from 10 to 100) and non-watercourses (ranging from 1 to 10) are estimated for each km of the proposed

TMEP corridor and multiplied by the total failure frequency for each km in order to estimate the environmental risk score per km of the TMEP.

Dynamic Risk observes several trends from the preliminary results of its SQRA for Line 2 (Dynamic Risk 2014a, pdf p. 22). First, natural hazards are the largest contributor to overall failure frequency in each of the 174 highest risk scores. Second, high consequence scores are the principal contributor to risk for many segments. Third, internal and external corrosion are the lowest contributors to total failure frequency. Dynamic Risk notes that the risk assessment presents unmitigated results and that the incorporation of mitigation measures will reduce failure likelihood and/or consequences and thus reduce risk (Dynamic Risk 2014a, pdf p. 23).

To estimate spill outflow volumes from a pipeline release, TM (2013, Vol. 7 p. 7-72; 94) relies on spill outflow modelling that identifies hypothetical pipeline spill scenarios. In *Volume 7*, TM identifies four worst-case spill scenarios that release between 1,250 and 2,700 m^3 or approximately 7,862 to 16,982 barrels (bbl) of crude oil. In Appendix G of *Volume 7*, Dr. Ruitenbeek identifies two pipeline leak scenarios of 30 and 715 bbl and four pipeline rupture scenarios between 6,290 and 25,160 bbl (TM 2013, Vol. 7, App G p. 24). In the *Risk Update*, a model uses 2,298 spill points along 12 different pipeline segments to estimate potential oil spill volumes (Galagan et al. 2014, p. 9). The model outputs the minimum, maximum, and mean volumes that remain on land, evaporate, enter rivers, enter lakes, and that reach open water (Galagan et al. 2014, p. 12). The analysis estimates a maximum of 21,225 bbl of oil from a spill could end up on land, while a maximum of 26,367 bbl and 25,920 bbl could enter rivers and lakes, respectively (Table 3.2). The expected average spill volumes for each category are much lower than the maximum.

Table 3.2. TM Estimated Oil Spill Outflow Volumes

Category	Volume Released (in bbl)		
	Minimum	Maximum	Mean
Oil Retained on Land	0	21,225	1,627
Oil Evaporated	0	1,326	121
Oil Entering Rivers	0	26,367	6,797
Oil Entering Lakes	0	25,920	736
Oil Reaching Open Water	0	7,554	12

Source: Adapted from Galagan et al. (2014, p. 12).

3.3. Terminal Spills

TM commissioned the *Termpol 3.15* study from Det Norske Veritas (DNV) that quantitatively evaluates spill risk for TMEP operations at Westridge Marine Terminal in Burnaby, BC. To estimate terminal spills, DNV assesses the frequency of oil spills during cargo transfer operations and spills while the tanker is berthing, unberthing, or at berth. DNV estimates the frequency of these incident types as well as the consequences should an accident occur. DNV then combines the frequency and consequence assessment to estimate the risk of a terminal spill.

DNV identifies typical causes of spills during cargo transfer operations that include overfilling of cargo tanks, damage to loading arms or piping from external effects such as mooring failure or operator error, and leaks from loading arms or piping from internal effects such as corrosion or fatigue (TM 2013, Termpol 3.15 p. 62). DNV uses incident frequencies for cargo transfer operations from European terminal accident statistics to estimate incident frequencies for Westridge Terminal (Table 3.3). For each type of cargo transfer incident, DNV adjusts incident frequencies to account for risk reducing measures that include oil booms deployed around the tanker, emergency shutdown valves for pipelines, overfilling detection, and a Loading Master for each loading tanker, among others (TM 2013, Termpol 3.15 p. 62-63). The net effect of the mitigation measures is a 58% reduction in spill risk from loading operations (Table 3.3). DNV estimates incident frequencies as return periods, or the number of years between spill events.

Table 3.3. Unadjusted and Adjusted Frequencies for Spills per Loading Operations

Cause	Unadjusted Spill Frequency	Reduction Factor	Adjusted Spill Frequency	Return Period
Defect in loading arm	5.1E-05	20%	4.08E-05	24,510
Cargo control equipment failure	5.1E-06	20%	4.08E-06	245,098
Vessel piping system or pump failure	7.2E-06	20%	5.76E-06	173,611
Human failure	7.2E-06	20%	5.76E-06	173,611
Mooring failure	3.8E-06	80%	7.60E-07	1,315,789
Cargo tank overfilling	1.2E-04	80%	2.40E-05	41,667
All causes	1.94E-04	58%	8.12E-05	12,321

Source: Adapted from TM (2013, Termpol 3.15 p. 62-63).

DNV estimates the frequency that another vessel strikes a TMEP tanker while the tanker is berthed at Westridge Terminal. The incident frequency of a vessel strike is based on the frequency of TMEP tanker loading operations, the average time of each loading operation (24 hours), and how often vessels with sufficient size to penetrate the hull of a TMEP tanker pass the berth (TM 2013, Termpol 3.15 p. 64). DNV estimates striking probabilities for tankers berthed at Westridge Terminal using incident frequencies from a 2006 study it completed for striking frequencies that occur at different port types around the world (TM 2013, Termpol 3.15 p. 64). Since Burrard Inlet is 0.7 nm wide where Westridge Terminal is situated, DNV uses a base frequency of 9.0E-06 (or return period of 111,111 years) that corresponds to the striking frequency for fjords or narrow channels from the DNV (2006) study (TM 2013, Termpol 3.15 p. 64). DNV adjusts the base frequency for a vessel striking a TMEP tanker based on several factors that include the limited amount of traffic forecast to pass Westridge Terminal (50% reduction) and the terminal design that protects 1 of 3 berths from a vessel strike (33% reduction) (TM 2013, Termpol 3.15 pp. 64-65). After accounting for the amount of time the 408 tankers loading at the terminal will be berthed and the 420 vessels of sufficient size to damage a TMEP tanker that will pass the terminal, DNV estimates a striking frequency of 1.4E-03 per year or once every 707 years (TM 2013, Termpol 3.15 p. 65).

DNV also estimates the likelihood that a TMEP tanker anchored at one of the four anchorage locations near the terminal is struck by another vessel. DNV uses the same incident frequency for the likelihood that a tanker is struck at berth based on the DNV (2006) study and assumes that 50% of ballast tankers and 35% of laden tankers go to anchorage (TM 2013, Termpol 3.15 p. 65). The frequency that a tanker is struck at anchorage is dependent on the frequency that TMEP tankers go to anchorage, the average time a tanker is anchored (24 hours), and the frequency of passing vessels. Consequently, DNV estimates that a striking of a tanker at anchorage is 7.4E-04 per year (1,351 years) assuming 143 laden tankers anchor per year.

The consequence assessment for cargo transfer operations and a TMEP tanker struck at berth provides an estimate of the volume of oil spilled from such incidents. To estimate the consequences of cargo transfer operations, DNV first estimates the distribution of spills from loading incidents for medium and small spills. DNV then calculates the potential volume of a spill from loading operations based on the transfer rate, spill detection time, and emergency shutdown time (TM 2013, Termpol 3.15 p. 73). From these specifications, DNV determines a credible worst-case oil spill at Westridge Terminal of 103 m^3 (648 barrels or bbl) if there is a large rupture in one loading arm lasting 4 minutes (TM 2013, Termpol 3.15 p. 74). DNV estimates that a leak (instead of a rupture) of a loading arm would result in a spill volume of less than 10 m^3 (63 bbl) (TM 2013, Termpol 3.15 p. 74). The likelihood of a vessel striking a tanker at berth is estimated by the same methodological approach used to estimate the spill volume from a tanker collision (see next section) although the potential spill volumes are assumed to be lower (50% of laden) because the tanks are not fully loaded until the vessel leaves the berth (TM 2013, Termpol 3.15 p. 74). DNV does not summarize spill volumes for a TMEP tanker struck by a passing vessel except in graphical form (see Figure 38 in TM 2013, Termpol 3.15 p. 74).

DNV estimates oil spill risk for cargo transfer operations and a tanker striking at berth or anchorage by combining incident frequencies and consequences and compares spill risk results for different cases. According to DNV (TM 2013, Termpol 3.15 p. 43), Case 0 assumes the TMEP does not proceed and that other marine vessel traffic increases in 2018 without the TMEP. Under this scenario, there are 60 tankers per year from the TMPL. Case 1 assumes the TMEP proceeds, increasing TMPL traffic from 60 to 408 tankers per year, and there is an escalation in other marine traffic to 2018 equivalent to the increase in traffic in Case 0. Thus, the difference between Case 0 and

Case 1 is the increase in TMEP tanker traffic. For loading operations, DNV estimates a return period of 34 years for TMEP spills less than 10 m^3 which is a 580% increase from the return period of 234 years estimated without TMEP (see Table 3.4 Case 0 versus Case 1) (TM 2013, Termpol 3.15 p. 81). DNV compares its spill risk estimates for cargo transfer operations with the database of historical TMPL spills at Westridge Terminal kept since 1961 and shows that actual terminal spills occurred once every 25 years, which is a significantly higher risk than its forecast of one spill every 234 years based on the TMPL and increases in marine traffic until 2018 (Case 0) (TM 2013, Termpol 3.15 p. 81). However, DNV notes that the spill volumes associated with the two historical spills were lower than the spill volume threshold considered as small in the global database (TM 2013, Termpol 3.15 p. 81). For a tanker struck at berth or anchorage causing a 16,500 m^3 (103,782 bbl) spill, DNV estimates a return period of 50,000 years for the TMEP (Case 1) or over a 350% increase compared to a spill every 227,270 years for the TMPL (Case 0) (TM 2013, Termpol 3.15 p. 81).

Table 3.4. Annual Frequencies and Return Periods for Terminal Spills

Spill Type (Size)	Case 0 (No TMEP; 2018 traffic)	Case 1 (TMEP; 2018 traffic)
Loading operation spill (<10 m^3)		
Annual spill frequency	4.3E-03	2.9E-02
Return period	234 years	34 years
Loading operation spill (<100 m^3)		
Annual spill frequency	6.0E-04	4.1E-03
Return period	1,655 years	234 years
Tanker struck at berth (16,500 m^3)		
Annual spill frequency	4.4E-06	2.0E-05
Return period	227,270	50,000

Source: Adapted from TM (2013, Termpol 3.15 p. 81). Note: annual spill frequencies for tanker struck at berth estimated from return periods.

3.4. Tanker Spills

DNV also prepared an oil spill risk assessment for TMEP tanker operations. DNV uses its Marine Accident Risk Calculation System (MARCS), a risk management tool that combines shipping traffic, data describing the marine environment, and data describing shipping operations to estimate tanker incident frequencies for collision, powered and drift grounding, foundering, and fire and explosion (TM 2013, Termpol 3.15 p. 8). An overview of the MARCS model is provided in Appendix 1 of the *Termpol 3.15* study. The methodological approach estimating tanker spill risk includes the following components: (1) system definition; (2) hazard identification; (3) assessment of incident frequency; (4) assessment of oil spill consequences, and; (5) oil spill risk results based on incident frequency and consequence assessment (TM 2013, Termpol 3.15 pp. 3-4).

The risk assessment begins by defining the system that includes route description (see section 2.1.3 for a description of the tanker route), vessel handling, tanker specification, and environmental data, among other characteristics. TMEP would use Aframax (80,000 to 120,000 deadweight tonnes) and Panamax (50,000 to 80,000 deadweight tonnes) class double-hull tankers to transport oil from Westridge Terminal (TM 2013, Termpol 3.15). Tankers would use between two and four tethered tugs to navigate the Vancouver Harbour Area (TM 2013, Termpol 3.15 p. 12). Environmental parameters in the MARCS model consist of visibility, wind characteristics, shoreline types, and seabed types in the study area. Poor visibility, which DNV defines as less than 2 nm visibility, is greatest near Tofino where visibility is less than 2 nm 14% of the year (TM 2013, Termpol 3.15 p. 26). According to wind roses in the study area, winds are expected to be calm or fresh most of the time (TM 2013, Termpol 3.15 pp. 26-28). Seabed types in the area range from rock to mud and DNV estimates the probability of encountering a rocky hard shoreline in the event that a tanker grounds along the sailing route between 10% and 90% (0.1 to 0.9) in the study area (TM 2013, Termpol 3.15 p. 29).

DNV held a hazard identification workshop with 43 experts from government and industry to identify hazards and navigational complexities along the tanker sailing routes (TM 2013, Termpol 3.15 App. 2 pp. 12-13). The one-day workshop asked participants to describe causes of marine incidents based on their local knowledge (TM 2013, Termpol 3.15 p. 31). Experts identified hazards for each of the seven segments of the tanker route. Three of the segments of the tanker route were rated as average, one segment was rated as below average, and two segments were identified with above average hazards. Segment 2, the Vancouver Harbour Area, was rated as above average because of draft and tidal restriction obstructions from the First and Second Narrows and the high density of vessels in the harbour (TM 2013, Termpol 3.15 App. 2 p. 12). Segment 5, Boundary Pass and Haro Strait, was also rated above average due to limited sea room navigational channel restriction (TM 2013, Termpol 3.15 App. 2 p. 12).

The MARCS model incorporates shipping traffic to and from the Westridge Terminal using three different cases. Case 0 (i.e. 60 loading operations per year for TMPL) and Case 1 (i.e. 408 loading operations per year for TMEP) are described in the previous section. Case 2 assumes the TMEP proceeds at 408 tanker transits per year and other marine traffic increases to 2028 (TM 2013, Termpol 3.15 p. 34). In all scenarios, DNV estimates marine vessel traffic to increase between 0 and 2% per year between 2012 and 2030. Non-TMEP tanker traffic from Pacific Coast Terminals, Neptune Terminals, and the Suncor petroleum terminal is expected to grow up to 4% per year between 2012 and 2018 along the tanker route to Westridge Terminal (TM 2013, Termpol 3.15 p. 35; TM 2013, Termpol 3.2 p. 46).

DNV estimates tanker incident and spill frequencies for collision, powered and drift grounding, foundering, and fire and explosion using the MARCS model (TM 2013, Termpol 3.15 p. 43). The MARCS model relies on historical ship accident data from Lloyd's Register Fairplay (LRFP) from 1990 to 2000 and the analysts do not incorporate any adjustments to the ship accident data into the model (TM 2015b). Incident frequencies represent the likelihood of an accident that may or may not result in a spill whereas a spill represents the likelihood that an incident releases cargo, which DNV estimates based on the ship structure, grounding on rocky shore versus soft shore, wave and wind effects, and ship momentum (in the case of collisions) (TM 2013, Termpol 3.15 p. 48). DNV accounts for risk controls that reduce risk in its incident and spill frequencies, which include vessel traffic service, pilotage, escort and tethered tugs for a portion of the route, and ship vetting, among others (TM 2013, Termpol 3.15 p. 40). DNV attempts to quantify the effect of these mitigation measures in Appendix 4 of the *Termpol 3.15* study.

For each of the three cases, Table 3.5 shows incident and spill frequencies in the entire study area for all accident types and compares frequencies for Trans Mountain tankers to all other traffic within the traffic lanes used by Trans Mountain tankers.

According to DNV (TM 2013, Termpol 3.15 p. 45), TMEP tankers are expected to have an incident once every 4.8 years based on forecasted 2018 vessel traffic (compared to one every 0.6 years for all traffic). A tanker incident is expected to result in a spill of any size once every 46 years based on 2018 marine traffic (TM 2013, Termpol 3.15 p. 49), or approximately 10% of the time a tanker incident occurs. The TMEP increases spill frequency 6.8 times relative to the status quo (i.e. TMPL operating at 60 tanker transits per year), while a spill from TMEP tankers could be involved in 63% of potential oil spills from tanker and barge traffic in the study area based on 2018 traffic (TM 2013, Termpol 3.15 p. 48). Similar to its risk assessment for terminal operations, DNV estimates incident and spill frequencies as return periods.

Table 3.5. Incident and Spill Return Periods for All Accident Types in the Project Study Area

Scenario	Incident (in years)		Any Size Spill (in years)	
	Trans Mountain Tanker	All Traffic	Trans Mountain Tanker	Overall Tanker and Barge Traffic
Case 0 (No TMEP; 2018 traffic)	32.6	0.07	309	62
Case 1 (TMEP; 2018 traffic)	4.8	0.06	46	29
Case 2 (TMEP; 2028 traffic)	4.7	0.06	45	27

Source: TM (2013, Termpol 3.15 p. 45; 49). Note: spills represent any size spill

DNV also assesses incident and spill return periods for TMEP tankers in different segments (Table 3.6). According to DNV, a spill from TMEP tankers could occur once every 530 to 580 years in the inner harbour that includes the area between Westridge Terminal and the First Narrows under Lion’s Gate Bridge. DNV also estimates a return time of 59 to 60 years for a tanker spill that occurs in TMEP tanker sailing lanes, which it defines as the area between English Bay and the Juan de Fuca Strait.

Table 3.6. Incident and Spill Return Periods for All Accident Types in Particular Segments

Segment Area	Scenario	TMEP Return Period (in years)	
		Incident	Spill
Inner Harbour	Case 0	129.5	3,697
	Case 1	19.0	580
	Case 2	18.6	530
TMEP tanker sailing lanes	Case 0	49.9	410
	Case 1	7.3	60
	Case 2	7.2	59
Total Study Area	Case 0	32.6	309
	Case 1	4.8	46
	Case 2	4.7	45

Source: TM (2013, Termpol 3.15 p. 45; 49). Note: spills represent any size spill

DNV assesses possible risk control measures in addition to those risk control measures incorporated into the analysis. DNV remodels Case 1 (TMEP with 2018 traffic) with improved risk controls that include: (Case 1a) extended tug escorts for the entire sailing out to Juliet Buoy, and; (Case 1b) extended tug escort and moving exclusion zone for the entire route to Juliet Buoy (TM 2013, Termpol 3.15 p. 52). According to DNV (TM 2013, Termpol 3.15 p. 54), extending the tug escort reduces oil spill frequency between 46% and 91% depending on the segment of the tanker route relative to spill frequencies for Case 1. Extending the tug escort and incorporating a moving exclusion zone that prevents other vessels from entering a zone around the tanker during transit further reduces oil spill frequencies between 14% and 68% for each segment compared to spill frequencies for extending the tug escort (TM 2013, Termpol 3.15 p. 56).

DNV completes a consequence assessment that examines vessel damage and volume of oil spilled from a tanker accident travelling to and from Westridge Terminal (TM 2013, Termpol 3.15 p. 66). DNV estimates the conditional spill probability and spill size distribution for bottom and side damages by modelling spill outflow from an Aframax tanker with Naval Architecture Package software (TM 2013, Termpol 3.15 p. 66). The software simulates damage to the tanker’s outer and inner hulls at a variety of damage penetration depths and opening sizes (TM 2013, Termpol 3.15 p. 66). The method calculates spill probabilities for grounding and collision spills ranging between 0 and 35,000 m^3 (or 0 to 220,000 bbl) (TM 2013, Termpol 3.15 pp. 68-69). From the modelling, DNV estimates a mean outflow and credible worst-case scenario outflow for grounding and collision accidents resulting in a spill (Table 3.7). The mean outflow, which represents the 50% largest outflow, ranges between 5,700 and 8,250 m^3 (approximately 35,800 to 51,900 bbl) for a grounding or collision accident, whereas the credible worst case outflow, which represents the 10% highest outflow, ranges from 15,750 to 16,500 m^3 (approximately 99,000 to 103,800 bbl) per incident type. DNV does not consider a total loss of the vessel since there has not been a total loss involving a double hull tanker to date (TM 2013, Termpol 3.15 p. 70).

Table 3.7. Oil Spill Volume Outflow

Accident Type	Mean Outflow (m^3)	Worst Case Outflow (m^3)
Grounding	5,700	15,750
Collision	8,250	16,500

Source: TM (2013, Termpol 3.15 p. 68-69). Note: Grounding accident assumes bottom impact whereas collision accident assumes side impact.

DNV combines oil spill frequencies with oil spill outflows to estimate spill likelihood for mean and credible worst-case oil spills. According to DNV (TM 2013, Termpol 3.15 p. 77-78), the return period for a 8,250 m^3 tanker spill is 91 years based on forecasted 2018 vessel traffic and the return period increases to 456 years for a 16,500 m^3 spill (Table 3.8). If TM extends tug escorts for the entire tanker sailing and implements an exclusion zone around the tanker (Case 1b), DNV estimates a return period of 473 years for the mean case and 2,366 years for the worst-case spill scenario. DNV concludes from its assessment of tanker spill risk that:

> …the regional increase in oil spill risk caused by the expected increase in oil tanker traffic to Trans Mountain Westridge Marine Terminal is low, and the region is capable of safely accommodating the additional one laden crude oil tanker per day increase that will result from the Project (TM 2013, Termpol 3.15 p. 98).

Table 3.8. Return Periods for Oil Cargo Spill Risk for Entire Study Area

Accident Type	Return Period (in years)	
	Mean Outflow (8,250 m^3)	Worst-Case Outflow (16,500 m^3)
Case 0 (No TMEP; 2018 traffic)	619	3,093
Case 1 (TMEP; 2018 traffic)	91	456
Case 1a (Tug extension)	265	1,326
Case 1b (Tug extension/exclusion zone)	473	2,366

Source: TM (2013, Termpol 3.15 p. 77). Note: All cases in the table represent the use of tug escorts. Case 1 uses tug escorts for portions of the sailing route including the Second Narrows Movement Restricted Area, Vancouver harbor area through the First Narrows, Boundary Pass, and Haro Strait (TM 2013, Termpol 3.15 p. 19). Case 1a extends tug escorts for the entire tanker sailing out to Juliet Buoy. Case 1b extends tug escort and moving exclusion zone for the entire route to Juliet Buoy.

In a response to an information request from the NEB, DNV recalculates spill likelihood based on refinements to the risk control measures for the project. These refinements are developed from additional research into vessel traffic services, tanker drift simulations, tug escort simulations, collision risk, and escort and rescue tug capabilities (TM 2015a, pp. 17-26). DNV restates Case 0 and Case 1 (referred to as NewCase 0 and NewCase 1) according to these refinements and revises Case 1b, the scenario that extends tug escorts for the entire tanker sailing and implements an exclusion zone around the tanker, following a review of these mitigation measures by the Termpol Review Committee. The Termpol Review Committee did not endorse the moving tanker exclusion zone since it determined current regulations are adequate to accommodate the increase in TMEP tanker traffic (TM 2015a, p. 16). As a result, NewCase 1c does not include the moving tanker exclusion zone but instead reflects enhanced situational awareness practices for tankers leaving Westridge Terminal that include security broadcasts informing other vessels of the tanker's movement, a public education campaign, notices to international mariners describing enhanced situational awareness practices, the use of tethered and untethered escort tugs, and the use of sound signals by tugs in the event a tanker comes in close quarters with another vessel (TM 2014a, pp. 1-2). According to TM, the refined risk control measures decrease tanker spill risk for any size spill from 46 to 90 years in the base case and from 236 to 284 years when the moving tanker exclusion zone is replaced with enhanced situational awareness practices.

Table 3.9. Revised Return Periods for Oil Tanker Spills

Spill Size	Oil Cargo Spill Return Periods (in years)					
	Case 0	NewCase 0	Case 1	New Case1	Case 1b	NewCase 1c
Any Size	310	613	46	90	236	284
Mean Worst Case	619	1,227	91	180	473	568
Credible Worst Case	3,093	6,135	456	901	2,366	2,841

Source: TM (2015a). Note: TM does not define Mean Worst Case and Credible Worst Case oil spills in the response to the information request although the definitions of these spills are likely derived from the spill outflow analysis in the Termpol 3.15 study. If this is correct, a mean worst case spill is 8,250 m^3 and a credible worst case spill is 16,500 m^3.

4. Evaluation of Spill Risk Assessments

4.1. Introduction

The following chapter evaluates spill risk assessments in the TMEP regulatory application. Our assessment examines whether risk assessments for tanker, terminal, and pipeline spills adequately assess the likelihood of significant adverse environmental effects as required in the *CEAA 2012*. To achieve this objective, we evaluate risk assessments estimating return periods for tanker, terminal, and pipeline spills in the TMEP application. Risk studies evaluated include:

- *Volume 7: Risk Assessment and Management of Pipeline and Facility Spills* and appendices;
- *Risk Update* that contains several attachments including the *Failure Frequency Assessment Report, Trans Mountain Expansion Project Quantitative Geohazard Frequency Assessment, Line 2 Consequence Report,* and *Tabulated Risk Results for the Trans Mountain Expansion Project;*
- *Termpol Study No. 3.15: General Risk Analysis and Intended Methods of Reducing Risk* and appendices; and
- *Trans Mountain Response to Information Requests regarding the TERMPOL Report and Outstanding Filings from National Energy Board*.

We evaluate spill risk assessments in the TMEP application with best practice criteria for risk assessment (Table 4.1). The best practices are based on a comprehensive review and synthesis of best practices by Broadbent (2014) of the international risk assessment literature. Over 50 peer-reviewed journal articles, government reports, published books, industry association studies, and other sources were reviewed. Best practice criteria based on this synthesis and review compiled by Broadbent (2014) were reviewed by experts in risk assessment and were published in the author's doctoral thesis. We use these best practices in our evaluation of the TMEP application in order to identify any weaknesses that may reduce the quality of information provided to decision-makers evaluating the likelihood of significant adverse environmental effects. We consider weaknesses as opportunities to improve the risk assessments so that decision-makers have the necessary information to judge the likelihood of significant adverse environmental effects.

Table 4.1. Best Practices for Risk Assessment

Criterion	Description
Transparency	Documentation fully and effectively discloses supporting evidence, assumptions, data gaps and limitations, as well as uncertainty in data and assumptions, and their resulting potential implications to risk
Reproducibility	Documentation provides sufficient information to allow individuals other than those who did the original analysis to replicate that analysis and obtain similar results
Clarity	Risk estimates are easy to understand and effectively communicate the nature and magnitude of the risk in a manner that is complete, informative, and useful in decision-making
Reasonableness	The analytical approach ensures quality, integrity, and objectivity, and meets high scientific standards in terms of analytical methods, data, assumptions, logic, and judgment
Reliability	Appropriate analytical methods explicitly describe and evaluate limitations, sources of uncertainty and variability that affect risk, and estimate the magnitudes of uncertainties and their effects on estimates of risk by completing sensitivity analysis
Validity	Independent third-party experts review and validate findings of the risk analysis to ensure credibility, quality, and integrity of the analysis
Stakeholder Participation	Stakeholders participate collaboratively throughout the risk assessment and determine acceptable levels of risk that assess alternative means of meeting project objectives

Source: Broadbent (2014) based on synthesis of international best practices literature on risk assessment

We qualitatively evaluate the risk assessments with a four-point scale that assesses the degree to which each best practice criterion is met. Any weaknesses identified in the assessment are categorized as minor or major. Major weaknesses are considered to have a material effect influencing the quality of information that decision-makers use to make a decision. The four-point scale consists of the following categories:

- Fully met: excellent (i.e. no weaknesses);
- Largely met: good (i.e. no major weaknesses);
- Partially met: poor (i.e. one major weaknesses); and

- Not met: very poor (i.e. two or more weaknesses).

Spill risk requires assessing the two components of risk: the magnitude of an adverse impact and the likelihood that an adverse impact will occur. Our evaluation focuses on the latter component of risk, the likelihood that an adverse impact (i.e. spills) will occur. While we do not include an assessment of the magnitude of adverse impacts in this study, we refer to our previous research on oil spills that concludes that large spills cause significant adverse environmental effects (Gunton and Broadbent 2012) and we note that independent analyses prepared on behalf of the US and Canadian governments conclude that small oil spills can have significant adverse environmental impacts. The first study prepared for Transport Canada by WSP (2014) evaluates spill risk along the BC coast and determines that spills as small as 10 m^3 (62 bbl) could cause significant damage in the Vancouver and Victoria areas and up to 24 nm west of Vancouver Island. The second study from the US Department of the Interior assessing impacts of potential oil spills in Cook Inlet, Alaska, an area with similar characteristics as the BC study area, concludes that an oil spill as small as 238 m^3 (1,500 bbl) could have significant adverse environmental impacts (US DOI 2003).

4.2. Evaluation of TMEP Spill Risk Assessments

4.2.1. Transparency

Criterion: Documentation fully and effectively discloses supporting evidence, assumptions, data gaps and limitations, as well as uncertainty in data and assumptions, and their resulting potential implications to risk.

There are three major weaknesses related to transparency in the methods estimating spill return periods in the TMEP regulatory application. These include:

1. Inadequate description of the model estimating tanker spill return periods.

DNV provides an overview of the MARCS model in Appendix 1 of the *Termpol 3.15* study. The overview identifies data inputs to the model, describes how the model calculates the frequency of serious accidents, and briefly discusses how MARCS evaluates the consequences in terms of cargo loss (TM 2013, Termpol 3.15 App. 1). However, the overview of MARCS in the *Termpol 3.15* study does not provide the source code for the model, does not compare the MARCS model with other spill risk models, omits any discussion of the historical performance of the model, and does not discuss how different informational inputs, parameter values, and datasets impact the results of the model. The consequence assessment portion of the MARCS model, which estimates conditional spill probabilities based on spill quantities for bottom and side damages for groundings and collisions based on the Naval Architecture Package software, does not provide the raw data used to perform the analysis and does not provide sufficient information describing the nature of the original data used in the analysis such as its assumptions, data gaps, and limitations.

Further, DNV does not clearly and comprehensively explain how it ascribes probabilities in the fault tree analysis underlying the MARCS model. As discussed in Appendix 1 of the *Termpol 3.15* study, the MARCS model applies a probability value for a collision or grounding obtained from fault tree analysis. However, there is no discussion of how DNV determines these probabilities such as the decision-making or expert judgment process and the data used by experts to assign probability values to the events that comprise a fault tree analysis. Since the MARCS model is the main tool for estimating tanker spill return periods in the TMEP application, it is very important for risk assessors to effectively disclose all specifications of the model in a transparent manner. A high level of transparency is particularly important when risk results inform a decision that has the potential to negatively impact human life, property, or the environment (CSA 1997; IALA 2008), as in the case of the TMEP.

2. Lack of transparency supporting mitigation measures that reduce the likelihood of terminal spills

The second major weakness concerning transparency relates to incident frequencies at the marine terminal and the mitigation measures that DNV claims will significantly reduce spill risk. To estimate cargo transfer accidents at Westridge Terminal, DNV uses incident frequencies for cargo transfer operations at European terminals obtained from DNV's internal QRA handbook (TM 2013, Termpol 3.15 p. 62). DNV does not include the internal QRA handbook in an appendix file nor does DNV describe the data underlying incident frequencies such as any assumptions in the dataset, the number of terminals included, the number and types of incidents included, the specific jurisdictions covered by the dataset, or the types of risk-reducing measures that characterize terminal operations in the data. DNV then incorporates technological and operational risk controls that will be implemented at Westridge Terminal claiming these measures will reduce spill frequencies up to 80% for particular accident types (TM 2013, Termpol 3.15 p. 63). DNV does not provide supporting evidence in the form of technical reports or data on the performance of these risk controls to justify the magnitude of reduction associated with their implementation at Westridge Terminal. Further, since DNV does not describe the original dataset for cargo transfer incidents, particularly terminal operations captured in the data, there is the potential for double-counting mitigation measures that will be implemented at the Westridge Terminal but may already be reflected in the DNV dataset. The lack of data transparency prevents any verification to ensure that mitigation measures are not double-counted in the data.

To estimate the likelihood that a vessel strikes a tanker at berth at Westridge Terminal, DNV obtains the incident frequency from a confidential study it prepared in 2006 estimating the annual striking frequency for ports in various locations (TM 2013, Termpol 3.15 p. 64). Similar to the risk reducing measures for cargo transfer operations, DNV does not describe the dataset from which the incident frequency is derived nor does DNV include a copy of the confidential study in an appendix. DNV also includes a risk-reduction factor of 50% for the likelihood that a vessel will strike a tanker while at berth at Westridge Terminal by claiming that "the limited amount of traffic forecast to pass the marine terminal in the very well monitored and managed Vancouver Harbour leads to a further reduction of the base frequency by 50%" (TM 2013, Termpol 3.15 p. 64). DNV does not provide adequate documentation to justify reducing the risk of a tanker strike by half.

3. Inadequate evidence supporting the reduction of pipeline spill frequencies

In the *Risk Update*, Dynamic Risk determines that the risk from corrosion is negligible. For external corrosion, Dynamic Risk uses in-line inspection data from Kinder Morgan's Tennessee Gas Pipeline to predict that the failure frequency is zero for the first 11 years and concludes that external corrosion features would be detected before reaching a critical size due to planned in-line inspections every 5 years. For internal corrosion, Dynamic Risk relies on current research showing that diluted bitumen is no more corrosive than other heavy crudes and references the analysis it completed for the NGP section 52 application based on in-line inspection data from Enbridge's 36-inch Line 4 that showed no evidence of internal corrosion (Dynamic Risk 2014a, Att. A, p. 16). Based on these observations a failure frequency of zero is used to estimate internal and external corrosion from the TMEP (Dynamic Risk 2014a, Att. C, pdf pp. 11-37).

The analysis for external and internal corrosion has several weaknesses related to transparency. First, there is inadequate information describing the nature of the original in-line inspection data used in the analysis such as its assumptions, data gaps, limitations, or whether the data was in any way altered or transformed. Second, the in-line inspection dataset and the results of the Monte Carlo simulation are not included as an appendix file that would allow individuals to analyze the data independently. Third, there is no comparison of the results of the analysis with external and internal corrosion frequencies from PHMSA, even though Dynamic Risk undertook a comparison for other damage causes. According to PHMSA data for onshore crude oil mainline pipes 16 inches in diameter and larger, external corrosion and internal corrosion accounted for 15.5% and 25.4%, respectively, of all pipeline incidents between January 2002 and July 2012 (USDS 2014, App. K, p. 14). Combined, these corrosion incidents represent a failure frequency of 1.0E-04 per mile-year, or approximately 0.07 incidents per year (return period of 13 years) if applied to Line 2 of the TMEP[2]. Therefore, the reduction of corrosion risk to zero in the TMEP application is a questionable and material change that requires extensive justification documenting the effectiveness of the proposed measures in their role to effectively neutralize the threat of external and internal corrosion in modern pipelines. No such documentation is provided in the TMEP application.

There is also inadequate transparency related to adjustments made in the *Risk Update* to reduce spill risk from human error during operations. Dynamic Risk adjusts the baseline PHMSA failure frequency to account for TMEP operations that would

[2] Estimated based on 29 external and internal corrosion incidents recorded by the PHMSA from January 2002 to July 2012 for onshore, crude oil mainline pipelines with a 16-inch or larger diameter and 287,665 miles of pipeline (USDS 2014, App. K, p. 14). Estimates for TMEP based on 1,180 km of pipe converted to 733 miles.

address causal factors of pipeline failures from human error (Dynamic Risk 2014a, Att. A, p. 32). Dynamic Risk derives the adjustment factor from an Operational Management Systems Questionnaire administered during the Threat Assessment Workshop appended to Volume 7. The survey asked Workshop participants to assign a score to a series of questions related to the design and operation of the TMEP. According to Dynamic Risk, the results of the questionnaire scored 56.5 out of a possible 73 points or 77.3% and this score is used in an equation to estimate an adjustment factor. The adjustment factor reduces the PHMSA incident frequency of 7.836E-5 to 2.219E-5 failures per km-year, resulting in a 72% decrease in the failure frequency for human error. Although the survey method used to adjust the PHMSA incident frequency follows an approach described by Muhlbauer (2004) to incorporate the potential for human error in risk assessment, the author states that a drawback of this index-based approach is the subjectivity of the scoring. Indeed, Muhlbauer (2004, p. 24) states “Extra efforts must be employed to ensure consistency in the scoring and the use of weightings that fairly represent real-world risks.” The description provided by Dynamic Risk of the use of survey results to adjust the PHMSA failure frequency does not describe any efforts undertaken to ensure consistency in the scoring. Further, since the adjustment factor reduces PHMSA pipeline spill data, it is important to ensure that the scores in the survey do not double count any measures that are already captured in the PHMSA data since the data includes operations from modern pipelines. Therefore, additional information must be provided on the methodological approach of the survey. This information should include a description of the basis of comparison survey respondents used when scoring the design and operation of the TMEP relative to PHMSA data and whether participants completed individual surveys and how these data were aggregated or whether the participants agreed on the overall score for each question and the process used to facilitate this consensus-based approach as well as the process undertaken when participants did not agree on overall scores.

*Evaluation: There are three major weaknesses related to the transparency criterion and thus this criterion is **not met**.*

4.2.2. Reproducibility

Criterion: Documentation provides sufficient information to allow individuals other than those who did the original analysis to replicate that analysis and obtain similar results.

The TMEP regulatory application provides an overview of the methodologies estimating spill frequencies and return periods for tanker, terminal, and pipeline spills in a fairly straightforward manner. However, authors of the risk assessments for tanker, terminal, and pipeline spills provide insufficient information to reproduce results in the application. As suggested in the previous section, inadequate transparency prevents individuals other than the original analysts from replicating the following components of TMEP spill risk and each component represents a major weakness related to reproducibility:

1. MARCS modelling outputs that estimate tanker incident frequencies and consequences for grounding, collision, foundering, and fire/explosion;
2. Mitigation measures that reduce spill risk from marine terminal operations;
3. Outputs from the analysis of external and internal corrosion pipeline frequencies.

We acknowledge the difficulty in replicating certain results, such as the consequence assessment of tanker spill volumes and pipeline corrosion failure probabilities based on random sampling from methods such as Monte Carlo simulation. However, proprietary data and the computer code for the Monte Carlo simulation model should be included in an appendix or separate data report in order to allow an independent party to conduct similar tests and compare results with those included in the TMEP regulatory application.

*Evaluation: There are three major weaknesses related to the reproducibility criterion and thus this criterion is **not met**.*

4.2.3. Clarity

Criterion: Risk estimates are easy to understand and effectively communicate the nature and magnitude of the risk in a manner that is complete, informative, and useful in decision-making.

Methodologies that calculate and present spill likelihood in the TMEP regulatory application do not provide a clear assessment of the likelihood of spill occurrence. There are five major weaknesses related to clarity in the methodological approach for estimating return periods for TMEP tanker, terminal, and pipeline spills:

1. Inefficient presentation of tanker spill risk estimates

DNV recalculates tanker spill likelihood based on refinements to the risk control measures and provides these revised estimates in a response to an information request from the NEB. The updated tanker spill risk estimates are developed from additional research into vessel traffic services, tanker drift simulations, tug escort simulations, collision risk, and escort and rescue tug capabilities (TM 2015a, pp. 17-26). The refined risk control measures decrease tanker spill risk for any size spill from 46 to 90 years in the base case and from 236 to 284 years with enhanced situational awareness practices.

Although DNV revises its tanker spill risk estimates, it does not update or re-issue the *Termpol 3.15* study that contains the original estimates of tanker spill risk so that First Nations, stakeholders have all the relevant information in a single study. Instead, DNV recalculates return periods in a series of tables in response to an information request from the NEB that replace the information in the *Termpol 3.15* study and references studies that it uses to revise spill estimates. Failure to update the original Termpol 3.15 study with the revised spill estimates may create confusion among First Nations and stakeholders regarding which estimates are the correct ones, whether there were changes to the original methodology estimating revised tanker spill risk, and whether sections of the *Termpol 3.15* are still relevant or if these sections of the original study must also be updated along with the revised estimates. As the risk assessment literature states, the presentation and organization of risk results should improve understanding for all parties involved in a risk assessment process (NRC 1996; US EPA 1998). Characterizing risk in a clear manner promotes learning and improves understanding that enables First Nations and stakeholders to meaningfully participate in the process (NRC 1996). Therefore, failing to update the main spill risk report for tanker spills and providing tanker spill risk estimates in a single document do not promote learning and understanding among First Nations and stakeholders since the studies estimating tanker spill risk are not presented and organized in an efficient and user-friendly manner.

2. Ineffective communication of spill probability over the life of the project

FEARO (1994, p. 193) and TC (2001, p. 3-14) instruct the proponent to calculate the likelihood of a spill as a probability of occurrence and FEARO references the importance of estimating impacts over the life of the project and determining risk acceptability. In the discussion of the duration and frequency of significant adverse environmental effects, the FEARO suggests the importance of estimating the likelihood of future effects that is consistent with evaluating impacts over the life of the project. Indeed, the FEARO states:

> Long term and/or frequent adverse environmental effects may be significant. Future adverse environmental effects should also be taken into account. For example, many human cancers associated with exposure to ionizing radiation have long latency periods of up to 30 years. Obviously, when considering future adverse environmental effects, the question of their likelihood becomes very important (FEARO 1994, p. 190).

TM expresses the likelihood of a spill as a return period rather than the probability of a spill over the life of the project, which presents a major weakness in the communication of spill estimates to decision-makers. Return periods incorrectly imply that an oil spill event will occur only once throughout the recurrent interval when in fact the event can occur numerous times or not at all. Return periods also do not communicate the probability of a spill during the operational life of the project as suggested by FEARO (1994, p. 190). Stating return periods instead of probability of a spill over the life of a project communicates different perceptions of risk. Indeed, the risk assessment literature states that probabilities presented as percentages more effectively communicate risk compared to other formats, which leads to a more accurate perception of risk (NRC 2007; Cuite et al. 2008; Budescu et al. 2009). Kunreuther et al. (2014) confirm this finding and highlight the importance of communicating risk to homeowners considering buying insurance for protection against low-probability, high-consequence events such as natural disasters. Kunreuther et al state:

> Research shows that homeowners can be persuaded to consider insurance simply by recharacterizing the risks they face. Property owners in a flood-prone area are far more likely to take the flood risk seriously if they are informed that there is a greater than 1-in-5 chance (precisely 22 percent) of at least one flood occurring in the next 25 years, instead of learning that they are in a “one-in-100-year flood plain” (as defined by the Federal Emergency Management Agency). These two probabilities are equal, but they don’t seem the same to homeowners (Kunreuther et al. 2014).

3. Lack of clear presentation of spill risk for TMEP pipeline spills

The oil spill SQRA in *Volume 7* and in the *Risk Update* do not clearly present spill risk for the TMEP pipeline. In the *Threat Assessment* in Appendix A of *Volume 7*, TM presents individual failure frequencies on a km-year basis derived from PHMSA data and other methods used to estimate particular types of pipeline incidents. TM does not combine failure frequencies for individual incidents to represent an incident frequency for all failure types, does not adjust the km-year failure frequencies to reflect the length of both Line 1 and Line 2 of the TMEP pipelines, and does not combine failure frequencies for both pipelines in order to estimate overall pipeline spill frequency for the TMEP. Similarly in the Risk *Update*, TM estimates an individual failure frequency per km-year for various types of incidents and provides failure frequencies for each 1-km segment of the TMEP Line 2 in Attachment D as well as for the TMPL in the *TMPL Risk Results* study (Dynamic Risk 2014b). However, there is no estimation of the overall likelihood of a pipeline leak or rupture from TMEP Line 1 or Line 2. Although we acknowledge the importance of estimating spill risk at fine scales such as 1 km increments to capture the unique characteristics associated with each segment, the overall risk of the pipelines should also be estimated in order to communicate the likelihood of pipeline spills to decision-makers.

To address the aforementioned weaknesses, we adjust spill frequencies provided by TM in Attachment D of the *Risk Update* and *TMPL Risk Results* study for the length of Line 1 and Line 2 of the TMEP (Table 4.2). We then restate failure frequencies for both lines as return periods consistent with the rest of the TMEP application to estimate a spill return period for Line 1 and Line 2 of 4.1 years and 1.8 years, respectively. Combined, the risk results in the TMEP application show that a pipeline spill could occur on either Line 1 or Line 2 every 1.3 years (TM 2015c, 2.01-2.02). The pipeline spill risk assessments show that a spill is more likely to occur on the new Line 2 compared to the over 60-year old Line 1 and this appears to be driven by the inclusion of failure frequencies for geohazards in the risk assessment for Line 2. According to Dynamic Risk (2014b, pdf p. 13), the risk assessment for Line 1 does not include failure estimates for geohazards since these threats are being managed through the Natural Hazards Management Program. Failure frequencies and return periods for Line 1 represent the likelihood of a leak or rupture whereas failure frequencies and return periods for Line 2 represent the likelihood of a rupture (TM 2015c). We note that spill likelihood for Line 2 would be higher if failure frequencies for external and internal corrosion incidents were non-negligible risks in the *Threat Assessment*.

Table 4.2. Frequency and Return Periods for TMEP Pipeline Spills

Cause	Failure Frequency (per year)		Return Period (in years)		
	Line 1	Line 2	Line 1	Line 2	Combined
External Corrosion	2.61E-04	0	3,827	n/a	3,827
Internal Corrosion	8.21E-07	0	1,218,461	n/a	1,218,461
Manufacturing Defects	n/a	1.94E-02	n/a	52	52
Construction Defects	4.85E-02	9.68E-03	21	103	17
Third-Party Damage	1.17E-01	1.03E-02	9	97	8
Incorrect Operations	7.85E-02	4.39E-03	13	228	12
Geohazards	n/a	5.09E-01	n/a	2	2
Total	2.44E-01	5.53E-01	4	2	1

Source: Computed from Dynamic Risk (2014a; 2014b; 2014c).

Moreover, the pipeline oil spill SQRA in *Volume 7* does not evaluate the risk of non-pipebody spills such as spills from pump stations or storage tanks. In its response to NEB Information Request 1.98, TM provides facilities risk assessments for the

Edmonton Terminal, Sumas Tank Farm, Burnaby Terminal, Westridge Marine Terminal, Westridge Marine Terminal Ship Loading Portion, as well as preliminary qualitative risk assessments for proposed terminal facilities (i.e. Edmonton Terminal, Sumas Terminal, Burnaby Terminal, Westridge Marine Terminal) and proposed pump stations. The facilities risk assessments provide separate risk estimates for each of the Edmonton Terminal, Sumas Tank Farm, Burnaby Terminal, Westridge Marine Terminal, Westridge Marine Terminal Ship Loading Portion, while the qualitative risk assessments for terminal facilities and pump stations assign numerical risk scores to various categories without estimating the overall risk for each individual facility (McCutcheon 2013b; 2013c; 2013a; 2013d; 2014). Therefore, risks associated with non-pipebody spills are not effectively communicated in the regulatory application and this prevents decision-makers from assessing the level of risk associated with TMEP pipeline spills. In the response to the information request, TM states that it will complete final risk assessments for facilities after it completes detailed design and engineering for the TMEP in mid 2016 (TM Response to NEB IR No. 1, p. 481), which is after the NEB submits its recommendations to the Governor in Council.

4. No single spill risk estimate provided for the entire project

A major weakness in the TMEP regulatory application is TM's failure to estimate spills for the entire project. The *Termpol 3.15* study, *Volume 7,* and the *Risk Update* present separate spill risk estimates for tanker, terminal, and pipeline operations. TM does not combine separate spill likelihood estimates to demonstrate the likelihood of a spill from all potential spill sources. By presenting separate spill return periods for individual components of the project instead of the entire project, TM does not provide decision makers with the overall spill risk information necessary to assessing risk and for applying the *CEAA 2012* decision criterion. When findings in the TMEP application are restated as the probability of a spill over the operational life of the project instead of return periods[3], the conclusion based on TM's own analysis is that the probability of a

[3] We use the following formula to convert annual probabilities to probabilities over a 30- and 50-year period: $1 - ((1 - P)^n)$, where P is the annual probability and n is the number of years.

spill for the entire TMEP inclusive of tanker, terminal and pipeline spills is 99%[4] (Table 4.3). The estimates in Table 4.3 may underestimate spill probabilities because they omit spills associated with pipeline components such as pump stations and storage tanks. The estimates may also underestimate spills due to the other weaknesses in the TM spill risk assessments.

Table 4.3. TM's Estimate of Spill Probabilities Based on the TMEP Regulatory Application

Type of Spill		Probability over 30 Years	Probability over 50 Years
Tanker Spill	Any size	10.0% – 48.3%	16.2% – 66.7%
Terminal Spill	Spill <10 m^3	58.6%	77.0%
Pipeline Spill	Leak	99.9%	99.9%
Tanker, Terminal, or Pipeline Spill		99.9%	99.9%

Source: Computed from TM (2013, Termpol 3.15); Dynamic Risk (2014a; 2014b; 2014c); TM (2015a; 2015b; 2015c) Note: Pipeline spill represents probability of spills on both Line 1 and Line 2 of the TMEP pipeline. See footnote 4 for calculations. Note that these estimates are confirmed by TM in TM (2015b) sections 2.02 – 2.04.

5. Inadequate assessment of the likelihood of significant adverse environmental effects consistent with existing law

TM has not assessed the likelihood of significant adverse environmental effects as required by the *CEAA 2012*. In its application, TM (2013, Vol. 1 p. 1-59) states "Potential effects of credible worst case and smaller spills discussed in Volume 7 and 8A are not evaluated for significance because these represent low probability, hypothetical events". This approach evaluates the likelihood of significant adverse environmental effects prior to determining the significance of these adverse effects. This contravenes existing regulatory guidance from the Canadian Environmental Assessment Agency and fails to provide decision-makers with the necessary information to assess malfunctions

[4] Spill probabilities calculated based on the following: (1) any size tanker spill of 284 years (NewCase 1c) and 46 years (Case 1) from TM (2015a); (2) terminal spills <10 m^3 of 34 years from TM (2013, Termpol 3.15); and (3) Pipeline spills for Line 1 and Line 2 of 4 years and 2 years, respectively, from Dynamic Risk (2014a; 2014b; 2014c). Spill likelihood estimates were confirmed by TM in response to information requests (TM 2015b; 2015c).

or accidents as required under the *CEAA 2012*. Regulatory guidance documents from NEB (2013) and FEARO (1994) defines a framework for determining whether a project is likely to cause significant adverse environmental effects that consists of the following sequential steps:

1. Deciding whether the environmental effects are adverse;
2. Deciding whether the adverse environmental effects are significant, and;
3. Deciding whether the significant adverse environmental effects are likely (NEB 2013, p. 4A-38; FEARO 1994, p. 187).

This framework, which TM uses in Volumes 5A, 5B, and 8A of its application to assess potential environmental and socioeconomic effects from routine operations, identifies the order in which the likelihood of significant adverse environmental effects should be assessed. It is not clear why TM applies the NEB (2013) and FEARO (1994) framework to assess routine operations yet does not use it to evaluate the likelihood of significant adverse effects of a spill.

Furthermore, TM's rationale for not evaluating the significant adverse environmental effects from spills is based on the erroneous assumption that spills are unlikely. TM does not define the term "likelihood" in its environmental and socioeconomic assessment in Volumes 5A, 5B, and 8A of its application even though TM characterizes impacts as likely or unlikely and assesses likelihood as high or low. Thus it is unclear what definition TM uses in its statement that spills "…represent low probability. TM estimates return periods to make judgments on the likelihood of spills. As discussed earlier in this section, return periods do not permit a reasonable judgement of the likelihood of significant adverse environmental effects because they do not represent nor communicate the probability of spill occurrence over the life of the project. As Table 4.3 shows, the probability of any size tanker spill over the life of the TMEP is as high as 67% and the probability of a pipeline spill is 99%. Spill probabilities of this magnitude are clearly likely events and consequently the environmental impacts should have been fully assessed.

*Evaluation: There are five major weaknesses related to the clarity of communication of risk criterion and thus this criterion is **not met**.*

4.2.4. Reasonableness

Criterion: The analytical approach ensures quality, integrity, and objectivity, and meets high scientific standards in terms of analytical methods, data, assumptions, logic, and judgment.

The methodological approach estimating spill likelihood for the TMEP contains seven major weaknesses related to the reasonableness criterion. These include:

1. Limited definition of the study area to estimate tanker spill return periods

DNV calculates return periods for tanker spills based on a limited study area. DNV assesses spill likelihood consistent with the Termpol Review Process that focuses on marine shipping within the Territorial Sea of Canada (TC 2001, p. 1-1). However, section 5 of the *CEAA 2012* requires the consideration of environmental effects that would occur outside Canada (CEAA S.C. 2012, c. 19, s. 52). Although DNV's analysis complies with federal guidance, there is no rationale provided for excluding the open water area outside the Territorial Sea of Canada where a tanker spill may occur.

The limited study area within the Territorial Sea of Canada compares with a recent spill risk assessment study from WSP (2014) commissioned by Transport Canada. The WSP (2014) study examines spill risk affecting Canada's three coasts in three different zones at various distances from the shoreline. These zones are defined by Canada's *Oceans Act* (S.C. 1996, c. 31) and include the Territorial Sea (i.e. nearshore zone between 0 and 12 nm from shore), the Contiguous Zone (i.e. the intermediate zone between 12 and 24 nm from shore), and the Exclusive Economic Zone (i.e. deep-sea zone between 24 and 200 nm from shore) (WSP 2014 p. 2; 11). The WSP study identifies different types of risks in the Contiguous and Exclusive Economic Zones compared to the Territorial Sea as well as different environmental sensitivities among the various zones. These different risks and environmental conditions should be considered in the DNV analysis of potential TMEP tanker incidents that extend beyond the 12-nm limit from shore used in the tanker spill risk assessment.

If the DNV analysis were to estimate tanker incidents outside the 12-nm limit associated with the Territorial Sea of Canada, the methodology should incorporate sailing distances beyond the sailing routes identified in the *Termpol 3.15* study. One option for estimating potential effects outside Canada is to use the Exclusive Economic Zone that extends 200 nm from land defined in Canada's *Oceans Act* (S.C. 1996, c. 31) and prescribed by the United Nations Convention on the Law of the Sea (UN General Assembly 1982) as a boundary since surface waters in the Exclusive Economic Zone beyond the 12-nm Territorial waters are considered international waters. Accordingly, the DNV analysis would need to incorporate an additional 188 nm per tanker sailing per year or a total of over 65,000 nm for 348 laden tanker sailings in order to estimate incidents within the Exclusive Economic Zone extending from the BC coast[5]. Another option to estimate potential effects outside Canada is to use the entire sailing distances to export markets in Asia. For example, one-way sailing distances from Vancouver to Shanghai, China are approximately 5,110 nm (Sea Distances undated) or 4,950 nm more per tanker than the 160 nm sailing route within the BC study area. Based on 348 more oil tankers sailing the outbound laden portion of their voyage to China, one-way distance shortfalls amount to over 1.7 million nm per year. Therefore the DNV analysis in the TMEP application omits between 65,000 and 1.7 million nm per year where a tanker incident could occur. Excluding the full length of shipping routes in the analysis of TMEP tanker incidents results in an underestimate of the oil spill risk. The full length of shipping routes should be included in the analysis to provide decision-makers with a more accurate assessment of the risk of adverse environmental effects of the TMEP outside Canada as specified in *CEAA 2012.*

2. Reliance on tanker incident frequency data that underreport incidents by between 38% and 96%

Literature in peer-reviewed sources suggests that vessel accident data reported in the LRFP database, which analysts use in the Termpol 3.15 study to determine tanker

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[5] This represents a minimum estimate since it assumes tankers sail a straight line from the 12-nm limit to the 200 nm limit of the Economic Exclusion Zone.

incident frequencies, underestimate actual tanker incident frequencies. Hassel et al. (2011) examine the LRFP database for underreporting of foundering, fire/explosion, collision, wrecked/stranded, contact with a pier, and hull/machinery accidents for merchant vessels exceeding 100 gross tonnes registered in particular states (flag states) including Canada, Denmark, Netherlands, Norway, Sweden, United Kingdom, and the US from January 2005 to December 2009. Using various statistical methods, the researchers estimate that reporting performance by LRFP ranges between 4% and 62% for select flag states compared to actual accident occurrences. In effect, this suggests that as few as one in 25 accidents were reported in the LRFP database for a particular flag state over a five-year period. In the best-case scenario for accidents involving Canadian vessels, the LRFP database reports 69% of all accidents and thus omits nearly one-third (31%) of all accidents occurring for vessels with a Canadian flag (Hassel et al. 2011).

A separate study conducted by Psarros et al. (2010) observes similar underreporting in the LRFP database for accidents from vessels registered in Norway. Based on an analysis of accident data for merchant vessels exceeding 100 gross registered tonnage from February 1997 to February 2007, the researchers estimate that at best only one in three (30%) accidents that occurred are reported in the LRFP database. Thus, the LRFP database has no record for 70% of accidents from vessels registered in Norway over a 10-year period. Furthermore, Psarros et al. (2010) observe that the effect of the vessel's size on reporting performance is insignificant and that the seriousness of an accident does not have a significant effect on the likelihood of an accident being reported. The relationship between incident frequency underreporting in the LRFP database and spill frequency calculations in the TMEP risk assessment is unknown due to lack of proprietary data provided by risk assessors in the Termpol 3.15 study.

To address underreporting, Hassel et al. (2011) suggest that statistical accident data should be accompanied by adjustments such as correction factors, safety margins, or expert judgment. In the Termpol 3.15 study, risk assessors did not adjust data derived from the LRFP database to incorporate any uncertainties associated with LRFP data. Best practice requires risk assessors to, at a minimum, disclose the known issue of incomplete LRFP data in a transparent manner and describe why they did not adjust the data accordingly. The failure of risk assessors to acknowledge deficiencies in LRFP data and make adjustments to correct for underreporting is particularly surprising given that, at the time the article documenting underreporting was published (2010), the authors of that article were employees of the same organization that prepared the Termpol 3.15 study.

3. Potential omission of tanker age characteristics in spill likelihood analysis

An important consideration in assessing the future spill risk of TMEP tankers transiting to and from Westridge Terminal is the relative incident frequencies among different age classes of tankers. A recent study from Eliopoulou et al. (2011) examines the relationship between tanker age and accidents in tanker casualty data from the LRFP database after the *Oil Pollution Act* of 1990. The authors determine that incident rates for non-accidental structural failure (also known as foundering) vary significantly depending on the age of the double-hull tanker. Indeed, non-accidental structural failure tanker incidents for double-hull tankers ranging between 16 and 20 years are over 2.5 times higher compared to tankers aged 11 to 15 years and over 4 times higher compared to tankers aged 6 to 10 years. In 2009, Eliopoulou et al. (2011) estimate that the average age of double hull tankers in the worldwide operational fleet was between 4 and 8 years. Papanikolaou et al. (2009) estimate that, due to the young age of the worldwide tanker fleet, non-accidental structural failures could become significant after 2020, which corresponds to the operational period of the TMEP. It is unclear whether the DNV analysis in the *Termpol 3.15* study incorporates the potential increase in non-accidental structural failures in its modelling for TMEP tanker incidents since DNV does not explicitly describe any adjustments corresponding to an increase in foundering incidents. The omission of such an increase has the potential to significantly underestimate future tanker incident rates for non-accidental structural failures.

4. Questionable evidence supporting negligible external and internal corrosion threats to pipeline

As described in section 4.2.1, the pipeline SQRA determines that threats to TMEP Line 2 from external and internal corrosion are negligible. However, the conclusion to use zero as a representative failure frequency for external and internal corrosion relies on questionable evidence. First the analysis in the *Risk Update* concluding that external and internal corrosion are negligible for the TMEP depends on a representative pipeline to evaluate each type of corrosion. For external corrosion, Dynamic Risk selects the Tennessee Gas pipeline because it uses the same coating technology (i.e. Fusion Bond Epoxy) that the TMEP would use and for internal corrosion, Dynamic Risk references a study it completed for the NGP that uses in-line inspection data for Enbridge Line 4. According to Dynamic Risk these pipelines are selected due to their alleged representativeness of the TMEP. However, Dynamic Risk does not provide sufficient evidence to conclude that the performances of the Tennessee Gas and Enbridge Line 4 pipelines are representative of the expected performance of TMEP Line 2 since information comparing candidate pipelines to the TMEP was not provided. This information should include the following data for all potential candidate in-line inspection datasets considered for the analysis: installation year; type of coating; summary of operating standards; years the in-line inspection were complete; an overview of the corrosion management system; quality of the in-line inspection dataset; corrosion features detected by in-line inspection; and any leaks or spills resulting from corrosion. A more reasonable approach than relying on in-line inspection data for a representative pipeline would be to use in-line inspection datasets from many modern pipelines, including those that have experienced corrosion events, in order to capture a wider sample of modern pipelines operating in various conditions and that reflect a variety of corrosion management programs.

Second, the conclusion that external and internal corrosion are not a threat to modern pipelines such as the TMEP is not supported by existing data. As previously mentioned, external corrosion and internal corrosion accounted for over 40% of all pipeline incidents between January 2002 and July 2012 for onshore crude oil mainline pipes 16 inches in diameter and larger (USDS 2014, App. K, p. 14). Since these data include older pipelines as well as modern pipelines, it is reasonable to assume that most of these corrosion incidents occurred on older pipelines that do not use modern coatings and technologies to reduce spills. However, an analysis of publically available incident data reveals that corrosion incidents occur on modern pipelines, which Dynamic Risk

(2014a, Att. A, p. 33) defines as pipelines installed since 1980. According to PHMSA data from January 2002 to November 2014, there were a total of 39 corrosion incidents that resulted in a release of crude oil from the pipebody of onshore pipelines installed since 1980[6]. Of these 39 incidents, 10 were caused by external corrosion on pipes with some form of protective coating on the exterior of the pipe and 29 incidents were caused by internal corrosion. The 2002-2014 PHMSA data also shows that corrosion accounted for the majority of crude oil releases that occurred on crude oil pipelines installed since 1980. According to the data, crude oil releases resulting from corrosion represented 71% of all incidents that occurred on onshore, crude oil pipelines installed since 1980[7]. Due to incomplete pipeline mileage data in the PHMSA database for pipelines installed in particular years, a failure frequency for external and internal corrosion cannot be estimated for modern pipelines.

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[6] To undertake this analysis, we use the following data files from PHMSA: (1) Hazardous Liquid Accident Data - January 2002 to December 2009 (PHMSA 2014a); and (2) Hazardous Liquid Accident Data - January 2010 to November 2014 (PHMSA 2014b). We use pipelines installed since 1980 since, according to Dynamic Risk (2014a, Att. A, p. 33), these pipelines represent a cut-off for modern pipeline materials, design, and installation practices.

[7] Filtering the PHMSA (2014a) Hazardous Liquid Accident Data from January 2002 to December 2009 for all causes of crude oil releases that occurred from the pipe of onshore pipelines installed since 1980 shows a total of 33 incidents from the following: external corrosion (6); internal corrosion (17); excavation (8); natural forces (1); and other (1). Similarly, filtering the PHMSA (2014b) Hazardous Liquid Accident Data from January 2010 to November 2014 for all causes of crude oil releases that occurred from the pipe of onshore pipelines installed since 1980 shows a total of 23 incidents from the following: external corrosion (4); internal corrosion (13); excavation (5); natural forces (1). Combined, both of these data sets result in the following estimate of 56 total incidents that occurred from 2002 to 2014: corrosion (40); excavation (13); natural forces (2); and other (1). Note that the total number of corrosion incidents of 40 is higher than 39 referenced in the text since the former includes a crude oil release from external corrosion on a pipeline that did not have a coating whereas the latter estimate of corrosion omits this incident. Further note that the 71% of corrosion events estimated with PHMSA (2014a; 2014b) data differs from the 40% estimated by USDS (2014, App. K) since the latter includes pipelines with a 16-inch diameter or larger installed in any year.

Table 4.4. Historical Spills Caused by Corrosion for Crude Oil Pipelines Installed Since 1980 in the PHMSA Database (2002-2014)

Year of Incident	External Corrosion Installation Year (Number of Spills)	Internal Corrosion Installation Year (Number of Spills)	Total Spills
2002	1982 (1)	1982 (1); 1993 (1)	3
2003		1981 (1); 1994 (1); 1995 (1); 1996 (1)	4
2004	1990 (1); 1994 (1); 2000 (1)	1991 (1)	4
2005		1991 (1); 1992 (3)	4
2006		1981 (1)	1
2007	1999 (1)	1991 (1)	2
2008		2000 (1)	1
2009	1989 (1)	1981 (1); 1985 (1)	3
2010	1982 (1)	2001 (1)	2
2011		1985 (1); 1994 (1); 1999 (1)	3
2013	1982 (1); 2012 (1); 2013 (1)	1986 (4); 1995 (2); 2012 (1)	10
2014		1990 (2)	2
Total	10	29	39

Source: Calculated from PHMSA (2014a; 2014b). Note: The data in the External and Internal Corrosion columns represent the year in which the pipe was installed and the number of spills that occurred in parentheses.

Third, it is unclear if the updated Pipeline SQRA evaluates corrosion, particularly external corrosion, for each km of pipe. In its analysis of external corrosion, Dynamic Risk states that it estimated the probability of failure for each dynamic segment (Dynamic Risk 2014a, Att. A, pp. 11-12). However, Dynamic Risk does not provide adequate evidence that the unique environmental characteristics of each segment of the pipeline were taken into consideration and incorporated into the analysis of potential threats causing external corrosion. According to Baker and Fessler (2008, p. 14), several environmental factors affect external corrosion for onshore, buried pipelines including characteristics of the soil such as moisture contents, drainage, salt contents, oxygen contents, and aeration. According to the authors, the type of soil also affects the rate at which a pipeline coating deteriorates and rocky soils can puncture the pipeline coating whereas heavy clay soils can separate the coating from the pipe as the soil expands and contracts. Although soils and soil maps were evaluated in the assessment of geohazards along the proposed pipeline route for the TMEP, there is no reference of the soil types as they relate to the potential for external corrosion. Indeed, the *Quantitative Geohazard Frequency Assessment* in Attachment B of the *Risk Update* states “External corrosion is not addressed in this geohazards assessment and is being addressed as part of the overall risk assessment” (BGC Engineering 2014, p. 12).

5. Inadequate assessment of a worst-case oil pipeline spill

In the pipeline oil spill SQRA in *Volume 7*, TM models spill outflow volumes based on a worst-case full-bore rupture. Under this scenario, TM uses a time interval of ten minutes prior to the control room operator shutting down the pump and closing the valves (TM 2013, Vol. 7 p. 7-16). During this 10-minute period, the control room operator would verify alarms and the pump stations would continue to operate (TM 2013, Vol. 7 p. 7-16). TM states:

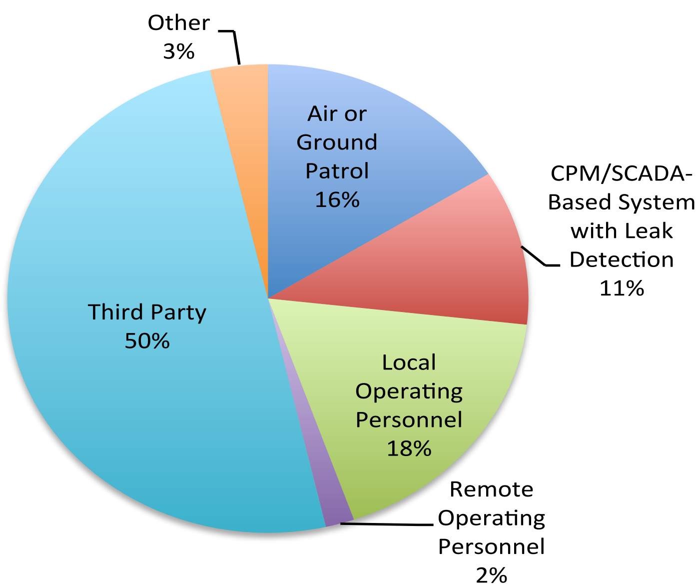
> As ten minutes is a worst case duration for a partial line break or moderate leak where it is not immediately obvious that the pipeline has experienced a failure, the use of a ten minute time interval for a readily identifiable catastrophic rupture is conservative since a trained Control Centre Operator (CCO) will recognize the event immediately” (TM 2013, Vol. 7 p. 7-16.).

The assumption that a control room operator will detect and take action to address the spill within 10 minutes is not supported by recent pipeline spill data. Analysis of PHMSA data shows that, of the 56 spills detected between 2002 and 2014 from the pipebody of onshore crude oil pipelines installed since 1980, the majority (50%) were detected by a third party[8]. According to the PHMSA data, only 11% of the reported

[8] To undertake this analysis, we filter PHMSA (2014a) data from 2002-2009 and PHMSA (2014b) data from 2010 to 2014 for onshore, crude oil pipelines installed after 1980 that experience a spill on the mainline pipe. The PHMSA (2014a) data identifies the following number of spills (in brackets) for each detection method: Third party (17); Air Patrol or ground surveillance (3); CPM/SCADA-based system (4); Local operating personnel (7); Remote operating personnel (1); Other (1). The PHMSA (2014b) data identifies the following number of spills (in brackets) for each detection method: Third party that caused the accident (4); Notification from public (7); Air Patrol (3); Ground Patrol (3); CPM/SCADA-based system (2); Local operating personnel (3); Other (1). Since the detection categories differ between the 2002-2009 and 2010-2014 datasets, we use the spill detection categories in Figure 4.1 based on input from a representative of the PHMSA (Keener 2015).

spills were detected by pipeline control rooms that contained leak-detection software, alarms, and monitoring systems and a further 18% of spills were detected by local operating personnel (Figure 4.1). These observations based on the PHMSA data are supported by independent analysis on the detection of pipeline spills from Sider (2014)[9]. Any spills detected outside the control room would very likely increase the volume of oil released from a spill since the news of the spill would need to be communicated back to the pipeline operator and the control room before a shutdown sequence is initiated.

Figure 4.1. Crude Oil Pipeline Spills Detected from 2002-2014 (PHMSA)



Source: Computed from PHMSA (2014a; 2014b)

Furthermore, spills can release a significant volume of oil even when leak detection systems function properly. For example, the Exxon pipeline spill in Mayflower, Arkansas released 5,000 bbl of oil after control room operators detected a drop in pressure after 90 seconds and began the 16-minute long process of shutting down the

[9] In a review of PHMSA data for 251 hazardous liquids pipeline spills that occurred from 2010 to 2013, Sider (2014) determines that only 19.5% of the reported spills were detected by pipeline control rooms that contained leak-detection software, alarms, and monitoring systems. On-site employees (29.1%) and local residents (26.3%) were much more likely to detect pipeline spills compared to control room operators (Sider 2014).

pipeline (Sider 2014). Similarly, a pipeline can release significant volumes of oil when control room operators do not detect a spill as was the case with the 20,000-bbl diluted bitumen spill that shutdown sections of the Kalamazoo River near Marshall, Michigan in July 2010 (NTSB 2012). Enbridge control room operators failed to detect or attempt to shutdown the ruptured pipeline for 17 hours even though monitoring systems repeatedly sounded alarms and displayed low-pressure readings (NTSB 2012). These observations suggest that there is no basis for TM's assumption that 10 minutes is a worst-case time duration to shutdown the TMEP pipeline.

6. Omission of tug traffic that potentially results in an underestimation in spill risk

The traffic forecast in section 5 of the Termpol 3.15 study appears to omit the increase in escort tug traffic that would accompany the increase in TMEP tanker traffic in the study region. The comparison of predicted vessel nm data in the study area with and without the TMEP shows no increase in vessel nm for vessels in the "other" category, which according to DNV includes tugs that are predominantly escort tugs and harbour tugs that assist large vessels (Table 4.5). TM has agreed to require the use of tug escorts along the entirety of the route (TC 2014a). Therefore, the traffic forecast in the MARCS model potentially underestimates tug traffic by at least 111,020 nm (i.e. the difference between Case 1 and Case 0 assuming each tanker has one escort) and this omission is likely higher since some segments of the tanker route would use two or three tugs per TMEP tanker. Vessel traffic is a major component of the MARCS model and thus the potential omission of tug traffic likely results in an underestimation of spill risk associated with collision accidents in the study region.

Table 4.5. Comparison of Vessel Nautical Miles With and Without the TMEP

Vessel Category	Vessel Nautical Miles in Study Area in 2018		
	Without TMEP (Case 0)	With TMEP (Case 1)	Difference
TMEP Tankers	19,143	130,163	+ 111,020
Other Vessels	1,607,429	1,607,429	0

Source: TM (2013, Termpol 3.15).

7. Lack of rigorous analysis supporting revised tanker spill risk estimates

DNV incorporates risk reduction factors in its assessment of revised tanker spill risk. These risk reduction factors include a 20% reduction associated with the use of vessel traffic services and a 28% decrease in collision risk from the use of tug escorts and enhanced situational awareness that includes Securité Broadcasts, a public education campaign, notices to industry, and adherence to International Regulations for Preventing Collisions at Sea (DNV 2014a; 2014b). There are several weaknesses related to the analytical methods, data, assumptions and judgment used to quantify risk reduction measures.

To estimate potential risk reductions from Vessel Traffic Services, DNV evaluates studies of the use of Vessel Traffic Services in other regions and uses these reference studies to estimate a risk reduction factor of 20% for TMEP tanker spill risk. To compare local Vessel Traffic Services with Vessel Traffic Services used internationally, DNV conducts interviews with the Canadian Coast Guard Marine Communications and Traffic Services. However, DNV does not describe the interview process it undertook with Canadian Coast Guard personnel. It is unclear how DNV used interview responses to compare local Vessel Traffic Services to those services in the reference studies. There is insufficient information or data to support DNV’s assertion that local Vessel Traffic Services are within the range of world-wide applications since there is no direct link identified between questions asked to assess local Vessel Traffic Services capabilities and the reference studies. This comparison of local Vessel Traffic Services with the services assessed in the reference studies is essential to confirm the validity of the risk reduction assumptions. There is a wide range of Vessel Traffic Services in operation; there are over 500 Vessel Traffic Services operating worldwide and these systems vary by the types of technologies (e.g. VHF-based, basic radar-based, tracking radar-based, and transponder-based) and locations including port and coastal (DNV 2014b, p. 5).

DNV acknowledges that some of the reference studies used to estimate risk reduction factors from Vessel Traffic Services are more than 20 years old, more recent studies show smaller risk reducing effects of Vessel Traffic Services, and there is a large variation in the effects of Vessel Traffic Services in the different studies (DNV 2014b, p. 12). DNV also acknowledges that hazards (e.g. complexity of coastline and the tanker routes, complexity of commercial shipping traffic, fishing and leisure craft activity, weather, tides, etc.) in specific areas are an important consideration in the range of Vessel Traffic Services effectiveness, yet there is no comprehensive evaluation and comparison of hazards between the reference studies and the TMEP study area. Furthermore, all reference studies used by DNV represent the risk reducing effects from newly-introduced Vessel Traffic Services, not the effect of existing Vessel Traffic Services over time (DNV 2014b, p. 11). There is no rationale provided by DNV for selecting the Vessel Traffic Services studies that it relies on to deduce risk reduction factors. Since Vessel Traffic Services in the study region may be existing services already provided by the Canadian Coast Guard, the risk-reducing effects of Vessel Traffic Services for TMEP tanker incidents are likely to be lower than those estimated by DNV.

TM completed an assessment of the proposed tug escort regime which included manoeuvring assessments of proposed tug escorts in the Georgia and Juan de Fuca Straits and an evaluation of local tug escort capabilities (LANTEC 2014a; 2014b). Neither of these studies quantifies risk reduction factors for tug escorts on collision or grounding incidents. Instead, the risk reducing effects of tug escorts are estimated in *The Effect of Enhanced Situational Awareness on Collision Risk* along with other risk reduction factors for enhanced situational awareness. In this five-page document, DNV estimates the proportion of accidents that could be prevented using enhanced situational awareness. The percentages are derived from a confidential study completed by DNV in 1996 of 38 collisions on large vessels that occurred internationally from 1956 to 1963. From this confidential study, DNV concludes: (1) 28% of vessels involved in collisions were unaware of other ships; (2) 33% of vessels involved in collisions had an awareness of other ships but were unaware of the risk; and (3) 9% of vessels involved in collisions engaged in hazardous behaviour such as accepting a close passing distance or expecting the other ship to stay clear (DNV 2014a, pp. 2-3). There is no discussion of the particular incidents referenced in the study and no data, analysis, assumptions, or methodology to explain how the percentages were derived. DNV appears to arbitrarily assume that enhanced situational awareness could prevent collisions half the time, without providing any rationale. Therefore, DNV concludes that enhanced situational awareness activities could reduce collisions by 28% (DNV 2014a, p. 3). DNV acknowledges that the method for estimating risk reductions factors for enhanced situational awareness is uncertain due to the old dataset, the difficulty identifying the specific causes of the collisions, and the arbitrary assumption that these measures will be effective half the time (DNV 2014a, p. 3). Despite these significant uncertainties, DNV uses the 28% reduction factor even though the study identifies values as low as 12% based on other approaches (DNV 2014a, p. 5).

Furthermore, DNV does not discuss the relationship between the data used to estimate risk reduction factors and the historical international tanker data from LRFP that it uses in the MARCS model to estimate tanker incidents. Specific considerations that should be explicitly discussed when incorporating risk reduction factors include the types of Vessel Traffic Services, tugs, and enhanced situational awareness practices represented in the historical international tanker data from LRFP and how these mitigation measures compare with those used to reduce tanker spill risk in the MARCS model. This analysis is required to ensure that the potential benefits of risk-reduction factors are not double-counted in the data.

*Evaluation: There are seven major weaknesses related to the reasonableness criterion and thus this criterion is **not met**.*

4.2.5. Reliability

Criterion: Appropriate analytical methods explicitly describe and evaluate limitations, sources of uncertainty and variability that affect risk, and estimate the magnitudes of uncertainties and their effects on estimates of risk by completing sensitivity analysis.

The methodological approach estimating spill return periods in the TMEP regulatory application contains four major weaknesses related to the reliability criterion:

1. Lack of confidence intervals that communicate uncertainty and variability in spill risk estimates

The methodologies estimating tanker, terminal, and pipeline spill risk for the TMEP provide point estimates that fail to characterize and communicate uncertainty and variability in the methodological approach. Contrary to recommendations in FEARO (1994, p. 193) to include confidence limits as a measure of scientific uncertainty when deciding the likelihood of significant adverse environmental effects, there are no confidence intervals for any of the spill estimates or failure frequencies for tanker, terminal, and pipeline operations in the *Termpol 3.15* study*, Volume 7*, and the *Risk Update* as well as their corresponding appendices. Confidence intervals provide a measure of the accuracy of a calculated value and describe the uncertainty surrounding an estimate. Failure to present confidence intervals understates risk by implying that there is little or no uncertainty in spill estimates when the uncertainty may be high. Without confidence intervals, decision-makers lack the necessary information for assessing the environmental risks of the TMEP. Providing confidence intervals is standard scientific practice when presenting outcomes from statistically driven models.

2. Lack of sensitivity analysis that effectively evaluates uncertainties associated with spill estimates

The various studies addressing spill likelihood submitted for the TMEP regulatory application exclude comprehensive sensitivity analyses that measure the uncertainty of spill estimates in a meaningful way. The analysis of terminal spill risk in the *Termpol 3.15* study and pipeline spill risk in *Volume 7* and the *Risk Update* do not contain sensitivity analyses for spill estimates, while the sensitivity analysis for tanker spill risk in the *Termpol 3.15* study provides a limited evaluation of the sensitivity of key input parameters on return periods. To test the sensitivity of tanker spill risk, DNV changes one key input parameter, improved risk control measures, by extending the use of escort tugs to cover the entire route and by creating an exclusion zone for tankers. Their analysis asserts that both parameter changes significantly reduce spill risk associated with the TMEP from 91 years to between 265 and 473 years for the mean volume outflow. DNV did not examine changes in critical parameters such as incident frequencies, conditional spill probabilities, environmental data, and traffic data to determine their effect on spill likelihood. With regards to traffic data, van Dorp and Merrick (2014) describe specific uncertainties and difficulties associated with predicting future traffic in their study *Preventing Oil Spill from Large Ships and Barges in Northern Puget Sound and Strait of Juan de Fuca*:

> This study does not attempt to predict the future of vessel traffic in the study area. Such predictions are often made based on observable trends in the traffic levels or projections of potential economic changes and their possible impacts on traffic levels. As we have seen in the last decade, predicting global economic changes is difficult and unpredictable

> economic changes can lead to unforeseen changes in traffic levels and reversals in previously observed trends. This means predictions can prove to be inaccurate, particularly in the medium to long term (van Dorp and Merrick 2014, p. 89)

The challenge of forecasting marine traffic far into the future as described by Van Dorp and Merrick (2014) illustrates the importance of testing the underlying uncertainty with a sensitivity analysis that captures a reasonable range of the variability in data inputs.

An example in the tanker spill risk assessment of a missed opportunity to undertake sensitivity analysis is the potential increase in the number of tankers resulting from the substitution of Panamax for Aframax tankers. The tanker spill risk assessment in the Termpol 3.15 study assumes that the 408 TMEP tankers calling on Westridge Marine Terminal would all be Aframax tankers (TM 2013, Termpol 3.15, p. 34). Although the TMEP application acknowledges the potential increase in the number of tankers of 2 to 3 per month for a 25% Panamax tanker class substitution, the risk assessment in the Termpol 3.15 study does not evaluate the potential increase in risk from this increase in tankers. The TM risk assessment does not examine any potential increase associated with any tanker class substitution even though this substitution could increase tanker traffic from the TMEP by a theoretical maximum of approximately 96 to 144 tankers per year or an increase of 24% to 35% compared to the 408 Aframax tankers assumed in the application (Table 4.6).

Table 4.6. Potential Increase in TMEP Tanker Traffic from Substitution

Tanker Substitution	Monthly Increase in Tanker Loadings	Annual Increase in Tanker Loadings	Total Number of Tankers (per year)	Percentage Increase to Base Case
25%	2 – 3	24 – 36	432 – 444	6 – 9%
50%	4 – 6	48 – 72	456 – 480	12 – 18%
75%	6 – 9	72 – 108	480 – 516	18 – 26%
100%	8 – 12	96 – 144	504 – 552	24 – 35%

Source: Computed from TM (2013, Vol. 8A).

Since incident frequencies, conditional spill probabilities, environmental data, and traffic data parameters are multiplied together, any uncertainty propagates through to the final estimate of spill likelihood and could result in significant changes to tanker spill return periods. Thus, the uncertainty of these critical parameters must be tested individually with a comprehensive sensitivity analysis to evaluate their effect on spill return periods. In addition to evaluating changes to individual parameters, it is important to assess any synergistic effects from changing multiple inputs at once to evaluate how return periods react to various inputs. The sensitivity analysis for tanker spill in the *Termpol 3.15* study does not assess the impact of simultaneously changing multiple parameters.

3. Lack of risk factor associated with the effective implementation of risk-reducing measures

Another consideration related to reliability of spill risk results in the TMEP application concerns mitigation measures that purportedly reduce risk without incorporating a risk factor to account for the implementation of risk management measures. The *Termpol 3.15* study and oil spill SQRA in *Volume 7* identify mitigation measures that authors claim will significantly reduce tanker, terminal, and pipeline spill likelihood. Ensuring effective implementation of mitigation measures is the responsibility of TM, the NEB, and Transport Canada. The NEB is responsible for regulating oil and gas that moves through interprovincial and international pipelines while Transport Canada is responsible for regulating oil shipments by rail and ship. The enforcement and monitoring record of the NEB and Transport Canada raises serious concerns regarding the effectiveness of implementing risk management initiatives. According to an audit performed by the Commissioner of the Environment and Sustainable Development (2011, p. 10), nearly two-thirds (64%) of the compliance verification files reviewed by the NEB identified deficiencies and only 7% of those files provided evidence the NEB followed up with companies to determine if deficiencies were corrected. Further, 100% of the emergency response plans reviewed had deficiencies and there was a follow-up to address the deficiencies in only one case (CESD 2011, p. 11). The same report determined that Transport Canada had not taken sufficient action to address non-compliance since 53% of the completed inspection files reviewed during the audit had instances of non-compliance and 73% of these files had incomplete or missing evidence that corrective action was taken (CESD 2011 p. 10). Further, Transport Canada had not verified many emergency response plans submitted by regulated companies and had given only temporary approval to nearly half of the plans established by companies shipping dangerous products (CESD 2011 p. 10).

The weak monitoring record of the NEB and Transport Canada suggests that any mitigation measures identified in the TMEP regulatory application to reduce spill likelihood and minimize spill damage must include a risk analysis of the likelihood of implementation failure. It should be accompanied by a detailed implementation plan that clearly outlines a comprehensive monitoring and verification program. If TM does not adequately implement mitigation measures and the NEB and Transport Canada fail to take corrective action, spill likelihood has the potential to significantly underestimate risks because they assume effective implementation of all risk-reducing measures.

4. Inadequate statement of uncertainties, limitations, and qualifications in the analysis

A common weakness in all risk assessment documents in the TMEP regulatory application is a lack of discussion of the limitations of the analysis and any qualifications that decision-makers must keep in mind when evaluating the results. TM and its consultants do not explicitly state many of the limitations and qualifications related to the uncertainties in tanker and pipeline spill risk. For example, DNV does not clearly summarize uncertainties associated with its MARCS model in the *Termpol 3.15* study and how these uncertainties alter the risk results. By comparison, DNV provides a detailed discussion of the uncertainties in the results of its assessment of spill risk in the Aleutian Islands in a study entitled *Aleutian Islands Risk Assessment Phase A - Preliminary Risk Assessment* (DNV and ERM 2010). In this study, DNV identifies and describes the following uncertainties inherent in its application of the MARCS model to assess spill risk in the Aleutian Islands: (1) input data, particularly with regards to the quantity and location of traffic data; (2) representation of input data into risk models such as how ship types are categorized as well as seasonal and temporal variation in meteorological data; (3) how risk models represent reality, and; (4) risk parameters used in the risk models, particularly the ship collision model (DNV and ERM 2010, p. 42-45). Similarly, although Dynamic Risk provides an overview of the reliability method approach it uses to derive failure frequencies in its *Threat Assessment* in *Volume 7* and in the *Risk Update*, there is no comprehensive description of the uncertainties and limitations associated with the reliability method approach that reduces external and internal corrosion to negligible levels. All methodological approaches contain uncertainties that affect the reliability of the results, such as variability, randomness, lack of knowledge, data gaps, and disagreements or lack of consensus in the scientific community over various theories or models (NRC 1996; US EPA 1998; Aven 2011). Failure to characterize uncertainty by explicitly stating the limitations and qualifications of the analysis conceals important background information that provides context to decision-makers and increases the likelihood that decisions will be made with imprecise, incomplete, or misleading risk estimates (NRC 1994; Aven 2010; 2011).

*Evaluation: There are four major weaknesses related to the reliability criterion and thus this criterion is **not met**.*

4.2.6. Validity

Criterion: Independent third-party experts review and validate findings of the risk analysis to ensure credibility, quality, and integrity of the analysis.

There are two major weaknesses in the TMEP regulatory application related to the validity of the risk analysis:

1. Inadequate review and validation of spill risk estimates

There is no evidence to suggest that the majority of findings in the *Termpol 3.15* study and oil spill SQRA in *Volume 7* were peer reviewed or validated by independent experts. The methodological approach in the *Termpol 3.15* study solicited experts to identify and evaluate hazards that influence tanker and terminal risk during the hazard identification workshop (TM 2013, Termpol 3.15 App. 2-3) and used experts to identify risk control measures that reduce spill risk (TM 2013, Termpol 3.15 App. 4). However, these two components represent only a portion of the data used when estimating return periods for tanker spills. There appears to be no expert peer review and validation of important findings related to incident frequencies, conditional probabilities, traffic and environmental data, as well as return periods for tanker and terminal spills.

Dynamic Risk held a workshop of experts to discuss threats to the TMEP pipeline system and complete the Operational Management Systems Questionnaire. However, there is no evidence suggesting that experts validated the failure frequencies identified in the *Threat Assessment* in *Volume 7* and in the Risk Update. Independent peer review of a risk assessment ensures analysts use suitable data, methods, and models, reviews all assumptions to ensure their credibility, ensures the analysis is reproducible, and checks all assumptions and uncertainties to ensure they are acknowledged and documented in the risk assessment (IALA 2008). The failure to provide third party, peer, independent review and validation of spill estimates for the TMEP is a serious weakness and does not satisfy the best practice for validity that characterizes a quality risk assessment.

2. No justification of the use of the MARCS model to estimate tanker spill risk for the TMEP

When there are multiple empirically validated models available, risk assessment practitioners should use a range of models instead of selecting a single best- guess model (Cox 2012). As Cox (2012) notes, the use of multiple models typically produces better results than a single best-guess model and provides a range of possible risk estimates. DNV does not justify the use of the MARCS model as an appropriate tool to measure TMEP tanker spill risk. Although DNV compares the findings of the MARCS model to other models, DNV does not complete an evaluation of alternative spill risk models, apply these models to the TMEP, and compare the models and their results. Many other spill risk models exist such as the methodological approach DNV used for the NGP, the Oil Spill Risk Analysis model developed by the US Department of the Interior and currently in use by the US Bureau of Ocean Energy Management, and the Vessel Traffic Risk Assessment model developed by academics at the George Washington and Virginia Commonwealth Universities. Failure by TM to complete a comprehensive comparative analysis of TMEP spill risk using a range of risk models and failure to justify the use of the MARCS model relative to alternative models is a major deficiency that compromises the credibility of the results and deprives decision-makers of the information they need to judge the risk of the project.

The lack of justification of the use of the MARCS model raises legitimate concerns whether the model's spill risk estimates accurately assess risk. In the *Termpol 3.15* study, DNV compares its frequency estimate for any size TMEP tanker spill of 0.0005 spills per shipyear to data for the global frequency of oil spills over 7 tons (approximately 50 bbl) between 2002 and 2011 from the International Tanker Oil Pollution Federation data (0.0016 spills per shipyear). The observed tanker spill frequency from the International Tanker Oil Pollution Federation is three times higher than the spill frequency predicted by the MARCS model for TMEP tanker spills and nearly four times higher than the spill frequency of 0.00041 spills per shipyear estimated by DNV in the revised NewCase 1c scenario. The fact that TM’s tanker spill forecasts are so much lower than recorded spill risk performance raises serious doubts whether such significant reductions can be achieved with the additional mitigation measures proposed by TM to reduce spill risk. This is particularly so since 2002 – 2011 data from the International Tanker Oil Pollution Federation already includes mitigation measures used in ports worldwide such as double-hull tankers, tug usage, vessel traffic services, pilots, and navigational aids, among others Also as discussed in section 4.2.4, the historical data underreports actual spills and incidents. If historical data were corrected for underreporting, the difference between TMEP hypothetical spill risk forecasts and actual spill risks would be even greater.

The TMEP spill frequency for Case 1 (0.0025 spills per shipyear) and the revised NewCase 1 (0.00128 spills per shipyear) are closer to the recorded global oil spill frequency of 0.0016 spills per shipyear from the 2002 – 2011 International Tanker Oil Pollution Federation data. Therefore, spill frequency estimates in Case 1 and NewCase 1 without the enhanced mitigation measures are likely more accurate estimates of potential spill risk than Case1b and NewCase1c for the TMEP because they are more consistent with recorded historical spill performance. Again we caution that recorded historical data underreports actual incidents. We note that DNV compares the results of the MARCS model with spill risk in the Danish Strait, but this comparison cannot accurately be used to compare relative tanker spill risk in each jurisdiction[10].

*Evaluation: There are two major weaknesses related to the validity criterion and thus this criterion is **not met**.*

4.2.7. Stakeholder Participation

Criterion: Stakeholders participate collaboratively throughout the risk assessment and determine acceptable levels of risk that assess alternative means of meeting project objectives.

Methods estimating spill return periods in the TMEP regulatory application contain three major weaknesses related to the stakeholder participation criterion:

1. Lack of stakeholder engagement in a collaborative analysis

DNV and Dynamic Risk held workshops to engage in discussions about spill risk for tanker and pipeline operations. The DNV workshop identified route hazards and navigational complexities along the tanker sailing routes (TM 2013, Termpol 3.15 App. 2 pp. 12-13) whereas the Dynamic Risk workshop reviewed potential threats to the pipeline system (TM 2013, Vol. 7 App. A p. ii). Although DNV and Dynamic Risk included experts and stakeholders in the workshops, the processes described in each risk assessment suggest that neither constituted a collaborative approach that, according to Busenberg (1999), involves groups working collectively to establish and

[10] DNV compares TMEP tanker incident frequencies with tanker incident frequencies in the Danish Strait and concludes that the annual incident frequency for tankers in the Danish Strait is 32 times higher for collisions and 8 times higher for groundings compared to TMEP tanker incidents in Case 1 (TM 2013, Termpol 3.15 p. 60). Yet, it is unclear whether the comparison incorporates the higher marine vessel traffic volumes that DNV (TM 2013, Termpol 3.1.5 p. 60) acknowledges exist in the Danish Strait compared to the TMEP study area. The analysis suggests that DNV compares the absolute number of tanker incidents per year since DNV states there is "…an average of 2 tanker collisions and 3.25 tanker grounding per year" (TM 2013, Termpol 3.15 p. 60) without referencing the number of incidents per nm or shipyear. A more accurate approach would be to compare the number of incidents on a nm basis that incorporates differences in vessel traffic and distances sailed by tankers in each region. Thus DNV does not provide an accurate comparison that accounts for differences in tanker traffic between the Danish Strait and the TMEP study area.

guide a research team where stakeholders have the ability to make adjustments to the research as it proceeds. The goal of such a collaborative analysis is to create a single study that is accepted by all stakeholder groups (Busenberg 1999). One example of a collaborative analysis is the spill risk study prepared by Van Dorp and Merrick (2014) for the Washington State Puget Sound Partnership entitled *VTRA 2010 Final Report: Preventing Oil Spills from Large Ships and Barges In Northern Puget Sound & Strait of Juan de Fuca*. The study engaged stakeholders representing government, Native American tribes, industry, and environmental groups and the project was overseen by an advisory/steering committee that included representatives from all of these groups. Stakeholders met every other month in meetings that were open to the public and stakeholders helped define the scope of the research, including which impacts to model in the analysis of oil spill risk. The *VTRA 2010 Final Report* is the outcome of the collaborative approach used by Van Dorp and Merrick (2014).

2. Failure to define risk acceptability in terms of the needs, issues, and concerns of First Nations and stakeholders potentially impacted by the project

An important part of stakeholder participation in risk assessment is determining an acceptable level of risk. Risk acceptability is a value judgment that depends on the needs, issues, concerns, perspectives, and knowledge of interested and affected parties potentially exposed to the risk (Fischhoff et al. 1984; NRC 1996; CSA 1997; Eduljee 2000; IALA 2008). While experts in risk assessment focus on technical analysis of data, laypeople tend to emphasize value-laden concerns such as the distribution of risks and benefits, the possibility of a catastrophic event, or their degree of personal control over the activity (IALA 2008). The importance of First Nations and stakeholders providing the context in which acceptable levels of risk are measured requires that risk assessment be viewed as a participatory process informed by technical analysis rather than a technical exercise in which First Nations and stakeholders occasionally intervene (Fiorino 1989). Thus, risk assessment process should determine acceptable levels of risk in a structured, participative decision-making process by First Nations and stakeholders that include those likely to be directly affected by the proposed activity.

TM’s method in the risk assessments for the TMEP all define risk in technical terms that limit risk analysis to data, methods, and assumptions of the analysts preparing the assessment and do not incorporate the goals, objectives, and concerns of First Nations and stakeholders potentially impacted by risk. The *Termpol 3.15* study concludes that "…the regional increase in oil spill risk caused by the expected increase in oil tanker traffic to Trans Mountain Westridge Marine Terminal is low, and the region is capable of safely accommodating the additional one laden crude oil tanker per day increase that will result from the Project" (TM 2013, Termpol 3.15 p. 98). To make this conclusion, DNV references the modernization of the Westridge Terminal, the comparatively lower traffic volumes on sailing routes used by tankers, and TM's plans to implement additional safety enhancements (TM 2013, Termpol 3.15 p. 98), all of which are represented in the spill risk model for TMEP tanker spills. DNV also compares TMEP tanker spill rates to other locations, particularly the global frequency of tanker spills as reported by the International Tanker Oil Pollution Federation and tanker spills in the Danish Strait, and concludes that tanker spill risk associated with the TMEP is lower in both cases (TM 2013, Termpol 3.15 pp. 59-60). If TMEP spill risk is comparable to other jurisdictions does this mean that it is acceptable? The answer is unequivocally no. Different regions and different First Nations and stakeholders will have different risks and different tolerances. The fact that a certain level or type of risk is accepted in one region does not mean that it will be accepted elsewhere. As FEARO (1994) states acceptable risk is based on many factors including social values. The definition of acceptable risk for the TMEP must be based on the values of those impacted and not the norms of other jurisdictions.

Similarly, the pipeline oil spill SQRAs in *Volume 7* and in the *Risk Update* inadequately assess and define risk acceptability in terms of the needs, issues, and concerns of First Nations and stakeholders potentially impacted by the project. TM measures spill risk according to an algorithm that combines the quantitative failure frequency with the qualitative consequences of a pipeline rupture (TM 2013, Vol. 7 p. 7-18). TM then states that risk from the preliminary design of the pipeline will be reviewed and evaluated to determine whether risk objectives are met (TM 2013, Vol. 7 p. 7-18) without providing reference to the parties that will be involved in evaluating risk and the specific objectives that define risk acceptability. In the Risk Update, *Dynamic Risk* uses the principle of reducing risk to as low as reasonably practicable whereby risk is reduced to a point of diminishing returns in the expenditure of risk reduction measures (Dynamic Risk 2014, pdf p. 27). This approach to reducing risk overlooks the value judgment of how First Nations and stakeholders perceive the acceptability of risks of the project. Instead, it focuses on weighing risk against the cost of mitigation measures. Risk acceptability should materialize from an open dialogue with First Nations and stakeholders that builds trust and provides confidence in the results. Determining acceptable levels of risk should rely on an iterative process beginning with informed consultations early in the process and continuing throughout the process to assess and address any residual risk after appropriate mitigation measures have been proposed (IALA 2008).

3. Inadequate assessment and comparison of risks from project alternatives

Another major weakness concerns TM's inadequate approach to evaluating risks associated with alternative approaches to meeting the objective of the TMEP. According to TM, the objective of the TMEP 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 2013, Vol. 1 p. 1-4). In its evaluation of alternatives, TM does not adequately consider risks associated with alternative project configurations, and does not examine and compare risks associated with possible project alternatives beyond simply reconfiguring the TMEP. In *Volume 5A* and *Volume 5B* of the TMEP application, TM evaluates alternative corridors for pipeline routing through Alberta and BC. Although the site selection assessment evaluates many factors, it does not quantify risks associated with each alternative such that the relative risk can be compared among different configurations of the project. Further, TM does not identify nor compare the risks associated with viable alternatives that meet the stated purpose of the project. There are viable alternatives to shipping crude oil from the Western Canadian Sedimentary Basin to market and the relative risk of these alternatives should be evaluated based on a risk profile for each alternative that enables a comparison of the risks of each candidate project. Failure of TM to complete a comprehensive comparison of the viable project alternatives deprives First Nations, stakeholders and decision-makers with the information they need to assess relative risks and determine if the risks of adverse environmental effects of the TMEP are acceptable and whether they meet the conditions for project approval under the *CEAA 2012*.

Evaluation: There are three major weaknesses related to the criterion for stakeholder participation and thus this criterion is ***not met***.

4.3. Summary of Major Weaknesses

Table 4.7 summarizes the results of our evaluation of the quality of risk assessments in the TMEP regulatory application with best practices. The results show 27 major weaknesses in the TMEP application, and none of the seven best practices for risk assessment being met by TM. Weaknesses identified in the qualitative assessment suggest that the TMEP regulatory application does not provide the best available information to assess whether the project meets the *CEAA 2012* criterion for likelihood of significant adverse environmental effects. The tanker, terminal, and pipeline risk assessments completed for the TMEP do not provide an accurate and complete assessment of the degree of risk associated with the project, do not fulfill the requirements of the *CEAA 2012*, and do not provide decision makers with reliable information to evaluate the risks of oil spills from the TMEP.

Table 4.7. Results for the Qualitative Assessment of Risk in the TMEP Regulatory Application

Criterion	Major Weakness	Rating	Result
Transparency *Documentation fully and effectively discloses supporting evidence, assumptions, data gaps and limitations, as well as uncertainty in data and assumptions, and their resulting potential implications to risk*	1. Inadequate description of the model estimating tanker spill return periods 2. Lack of transparency supporting mitigation measures that reduce the likelihood of terminal spills 3. Inadequate evidence supporting the reduction of pipeline spill frequencies	Very Poor	Not Met
Reproducibility *Documentation provides sufficient information to allow individuals other than those who did the original analysis to replicate that analysis and obtain similar results*	Insufficient proprietary data and information required to replicate: 4. MARCS modelling outputs that estimate tanker incident frequencies and consequences for grounding, collision, foundering, and fire/explosion 5. Mitigation measures that reduce spill risk from marine terminal operations 6. Outputs from the analysis of external and internal corrosion pipeline frequencies	Very Poor	Not Met
Clarity *Risk estimates are easy to understand and effectively communicate the nature and magnitude of the risk in a manner that is complete, informative, and useful in decision-making*	7. Inefficient presentation of tanker spill risk estimates 8. Ineffective communication of spill probability over the life of the project 9. Lack of clear presentation of spill risk for TMEP pipeline spills 10. No single spill risk estimate provided for the entire project 11. Inadequate assessment of the likelihood of significant adverse environmental effects consistent with existing law	Very Poor	Not Met
Reasonableness *The analytical approach ensures quality, integrity, and objectivity, and meets high scientific standards in terms of analytical methods, data, assumptions, logic, and judgment*	12. Limited definition of the study area to estimate tanker spill return periods 13. Reliance on tanker incident frequency data that underreport incidents by between 38% and 96% 14. Potential omission of tanker age characteristics in spill likelihood analysis 15. Questionable evidence supporting negligible external and internal corrosion threats to pipeline 16. Inadequate assessment of a worst-case oil pipeline spill 17. Omission of tug traffic that potentially results in an underestimation in spill risk 18. Lack of rigorous analysis supporting revised tanker spill risk estimates	Very Poor	Not Met

Reliability *Appropriate analytical methods explicitly describe and evaluate limitations, sources of uncertainty and variability that affect risk, and estimate the magnitudes of uncertainties and their effects on estimates of risk by completing sensitivity analysis*	19. Lack of confidence intervals that communicate uncertainty and variability in spill risk estimates 20. Lack of sensitivity analysis that effectively evaluates uncertainties associated with spill estimates 21. Lack of risk factor associated with the effective implementation of risk-reducing measures 22. Inadequate statement of uncertainties, limitations, and qualifications in the analysis	Very Poor	Not Met
Validity *Independent third-party experts review and validate findings of the risk analysis to ensure credibility, quality, and integrity of the analysis*	23. Inadequate review and validation of spill risk estimates 24. No justification of the use of the MARCS model to estimate tanker spill risk for the TMEP	Very Poor	Not Met
Stakeholder Participation *Stakeholders participate collaboratively throughout the risk assessment and determine acceptable levels of risk that assess alternative means of meeting project objectives*	25. Lack of stakeholder engagement in a collaborative analysis 26. Failure to define risk acceptability in terms of the needs, issues, and concerns of stakeholders potentially impacted by the project 27. Inadequate assessment and comparison of risks from project alternatives	Very Poor	Not Met

5. Application of Alternative Spill Risk Assessment Methods

5.1. Introduction

This chapter provides spill risk estimates for TMEP tanker, terminal, and pipeline operations. The estimates are based on several different, widely-accepted methodological approaches. The chapter contains three major components. First, we provide a description of the various spill risk assessment methodologies used to assess spill risk for the TMEP. Second, we estimate potential tanker, terminal, and pipeline spill probabilities for the TMEP using methods described in the previous step. Third, we compare the results of the spill risk assessment methodologies in order to gain an understanding of how methods in the TMEP application compare with other spill risk methods.

5.2. Pipeline Spill Risk

5.2.1. National Energy Board

The NEB regulates international and interprovincial oil and gas pipelines (NEB 2015b). As of 2013, the NEB regulated approximately 73,000 km of oil and gas pipelines in Canada (NEB 2015a). The NEB provides pipeline performance and spill statistics in its *Focus on Safety and Environment* released in 2011. The NEB has not provided an update to this study since it was released in 2011.

5.2.1.1. Overview of Method

Historical spill frequency data from the NEB pipeline system represents pipebody and operational leaks between 2000 and 2009. A pipebody leak is any leak from the body of the pipe and includes cracks and pinholes. Operational leaks are leaks from pipeline components such as valves, pumps, and storage tanks (NEB 2011). The NEB uses a spill size classification of greater than 1.5 m^3 (9 bbl) for pipeline failures since this is the minimum amount of liquid released that must be reported to the NEB (NEB 2011, p. 13). Spills represent liquid pipelines that include crude oil, refined products, and natural gas liquids (NEB 2011, p. 4), and the NEB does not disaggregate the data based on these different liquids or the year of installation of the pipes. Recent evidence suggests that pipeline spill rates presented in Table 5.1 could be higher since 2009 in part due to a greater awareness among companies about spill reporting requirements (Hildebrandt 2013). NEB spill data are not categorized by pipeline technologies or pipeline age to allow for a direct comparison of newer to older pipelines.

Table 5.1. NEB Historical Spill and Volume Data (2000-2009)

Pipeline Component	Number Spills	Pipeline Distance (km-years)	Incident Rate (per km-year)	Total Spill Volume (m^3)	Average Volume per Leak (m^3)
Pipebody Spills (>1.5 m^3)	16	148,804	0.00011	6,420	401
Operational Spills	411	148,804	0.00276	3,744	9
Spills (<1.5 m^3)	*366*	*148,804*	*0.00246*	*n/a*	*n/a*
Spills (>1.5 m^3)	*45*	*148,804*	*0.00030*	*n/a*	*n/a*

Source: NEB (2011); Computed from NEB (2011). Note: NEB (2011) does not provide specific estimates for the number of incidents per km-year or the average volume of liquid leaked per spill and thus these values were computed based on the NEB (2011) data.

5.2.1.2. Application of Method to TMEP

NEB pipeline spill frequency data from 2000 to 2009 for pipebody and operational releases are used to estimate potential spill frequency for the TMEP. Applying these inputs to TMEP results in a combined spill frequency for spills > 1.5 m^3 (9 bbl) or 0.95 spills per year, which represents a spill return period of one year (Table 5.2). Operational releases are more likely to occur than pipebody releases although the average volume per leak for pipebody releases is higher than the average volume per leak for operational spills.

Table 5.2. Potential Spill Estimates for TMEP based on NEB Data

Pipebody and Operational Spills	NEB Incident Rate (per km-year)	Annual Spill Frequency	Spill Return Period (in years)
Line 1 (1,147 km)	0.00041	0.47	2
Line 2 (1,180 km)	0.00041	0.48	2
Combined (2,327 km)	0.00041	0.95	1

Source: Computed from NEB (2011).

5.2.2. Enbridge Pipeline Spill data

Enbridge operates the largest pipeline system in Canada and transports the majority of crude oil out of the Western Canadian Sedimentary Basin to markets in North America (Enbridge undated). Enbridge claims that the company is ”… recognized as an industry leader in pipeline safety and integrity, ensuring that regardless of age, our pipelines are safe” (Enbridge undated, pdf p. 7). Enbridge submitted spill frequencies for its pipeline system during the regulatory review process for the NGP. Due to Enbridge’s experience shipping crude oil and its claimed leadership in pipeline safety, we apply spill frequencies from the Enbridge pipeline system to the TMEP.

5.2.2.1. Overview of Method

According to historical spill data submitted by Enbridge to the Joint Review Panel for the NGP from 1998 to 2010, a total of 771 reportable spills occurred on the system releasing a total of 170,099 bbl, or an average of 221 bbl per spill (Enbridge 2012). The historical spill data from Enbridge does not categorize spills as occurring on the body of the pipe or from components such as valves or tanks and does not classify spills as leaks or ruptures. Further, the spill data for the Enbridge liquids pipeline system are not broken down by pipeline technologies or pipeline age to allow for a direct comparison of newer to older pipelines. However, Enbridge increased the length of its pipeline by over 10,900 km in annual capacity from 2002 to 2010 yet the rate of spills during this period increased suggesting that the spill rate for the Enbridge liquids pipeline system does not appear to be sensitive to the average age of the pipeline system.

Table 5.3. Historical Pipeline Spill Data for Enbridge Liquids Pipeline System

Year	Length of Pipeline (km)	Reportable Spills	Volume Spilled (bbl)	Spills per Thousand KM of Pipeline	Average Volume per Spill (bbl)
1998	13,632	39	9,831	2.86	252
1999	14,655	54	28,763	3.68	533
2000	15,178	43	7,481	2.83	174
2001	15,324	27	25,673	1.76	951
2002	16,328	46	14,681	2.82	319
2003	16,812	58	6,377	3.45	110
2004	18,412	64	3,114	3.48	49
2005	18,409	70	9,825	3.80	140
2006	19,522	62	5,435	3.18	88
2007	19,629	59	13,756	3.01	233
2008	20,786	80	2,681	3.85	34
2009	22,843	89	8,360	3.90	94
2010	24,613	80	34,122	3.25	427
Total	236,143	771	170,099	3.26	221

Source: Enbridge (2012). Note: Volume spilled per spill calculated from Enbridge (2012) data.

5.2.2.2. Application of Method to TMEP

Application of Enbridge's spill rate data for its liquid pipeline system to proposed shipments on the TMEP produces an estimate of over 7 pipeline spills that could occur from Line 1 and Line 2 in any given year. Based on the average spill volume of 221 bbl per spill, 7.6 spills per year could result in 1,676 bbl spilled in a year.

Table 5.4. Potential Spill Estimates for TMEP based on Enbridge Data

	Spills per Thousand KM	Spill Frequency	Return Period (in years)	Average Volume Spilled Per Year (bbl)
Line 1 (1,147 km)	3.26	3.7	0.3	826
Line 2 (1,180 km)	3.26	3.9	0.3	850
Combined (2,327 km)	3.26	7.6	0.1	1,676

Source: Computed from Enbridge (2012).

5.2.3. US Environmental Impact Assessment Methodology: Pipeline and Hazardous Materials Safety Administration

The US State Department recently completed an environmental assessment of the proposed Keystone XL Pipeline as part of the legal requirements for pipeline approval (USDS 2014). The methodology is based on using historical spill volumes, incident causes, and incident frequencies in the US using pipeline incident data from the Pipeline and Hazardous Materials Safety Administration (PHMSA). PHMSA is part of the US Department of Transportation and is responsible for the safe and secure transportation of hazardous materials including crude oil by pipeline (USDS 2014, Vol. 4.13, p. 4.13-10). PHMSA gathers data and information on hazardous liquid pipeline systems that operate in the US (USDS 2014, Vol. 4.13, p. 4.13-8). In this section, the PHMSA methodology is used to estimate pipeline spill risk for the TMEP. The *Risk Update* for the TMEP application relies partly on PHMSA pipeline spill data and we discuss the similarities and differences as they relate to the PHMSA data used in the Keystone XL *Final Supplemental Environmental Impact Statement.*

5.2.3.1. Overview of Method

PHMSA collects information on reportable spills including the date of the incident, the type of hazardous liquid associated with the incident, the volume of liquid released, the source of the spill in the pipeline system, the size of the pipeline, and the cause of the incident (USDS 2014, Vol. 4.13, pp. 4.13-8-9). PHMSA also collects data on the total length (in miles) of pipelines operating in the US (USDS 2014, Vol. 4.13, pp. 4.13-8-9). The PHMSA dataset identifies serious and significant incidents[11] (USDS 2014, Vol. 4.13, p. 4.13-10).

The PHMSA dataset in the Keystone XL *Final Supplemental Environmental Impact Statement* uses crude oil pipeline incident data from January 2002 through July

[11] A serious incident is one in which there is a fatality or injury that requires hospitalization whereas a significant incident is defined as an incident involving one of the following; $50,000 or more in total costs (measured in 1984 dollars); highly volatile liquid releases of 5 bbl or more or other liquid releases of 50 bbl or more; or liquid releases resulting from an unintentional fire or explosion (USDS 2014, Vol. 4.13, p. 4.13-10).

2012 (USDS 2014, App. K, p. 3). According to USDS (2014, App. K, p. 2), these data are most applicable to estimate incidents from new state of the art pipelines such as Keystone XL. The dataset is divided into two main categories: (1) spills from the mainline pipe (i.e. pipe body); and (2) spills from pipeline system components, which include breakout tanks, pumping stations, and valves, among other discrete elements (USDS 2014, Vol. 4.13 p. 4.15). The data show that the majority of the 1,692 counted incidents that occurred during 2002 – 2012 occurred on pipeline components other than the mainline pipe (1,027 compared to mainline pipe incidents of 321) (Table 5.5). During this period, the top five causes of these 1,692 incidents from onshore crude oil pipeline spills were equipment malfunction (31.9%), internal corrosion (16.6%), unspecified corrosion (11.4%), incorrect operations (9.5%), and manufacturing or construction (8.7%)[12] (USDS 2014, App. K, p. 11).

The Keystone XL *Final Supplemental Environmental Impact Statement* estimates incident frequencies for pipeline components and the mainline pipe on an incident per mile-year (i.e. pipeline miles per year) basis whereby the number of historical incidents is divided by the number of pipeline miles-years in the PHMSA data (Table 5.5). Crude oil mainline pipe incidents are divided into different categories based on the diameter of the pipeline on which the incident occurred, thus permitting an incident frequency for different size pipelines. Of the 321 crude oil mainline pipe incidents, 71 occurred on pipes with a diameter of 16 inches or larger, while the balance of incidents occurred on smaller pipes or pipes for which the diameter was not provided (USDS 2014, App. K p. 4). The analysis also divides the PHMSA dataset into three discrete spill volume categories: (1) 0-50 bbl, (2) greater than 50 to 1,000 bbl; and (3) greater than 1,000 bbl, and provides an estimate of the average spill volume for each pipeline component.

[12] Remaining causes include outside force (6.5%), external corrosion (6.4%), weather or natural force (4.1%), and unspecified (5.0%) (USDS 2014, App. K, p. 11).

Table 5.5. PHMSA Historical Spill Incident and Volume Data (2002-2012)

Pipeline Component	Number of Spills	Pipeline Mileage (mile-years)	Incident Rate (per mile-year)	Spill Volume Distribution			Average Spill Volume (in bbl)
				0-50 bbl	>50-1,000 bbl	>1,000 bbl	
Mainline Pipe	321	537,295	0.00059	56%	35%	9%	401.7
> 16" Pipe	*71*	*287,665*	*0.00025*	*38%*	*36%*	*26%*	*1,116.0*
Tanks	93	537,295	0.00017	51%	30%	19%	1,720.0
Valves	25	537,295	0.00005	89%	11%	0%	33.7
Other Elements	909	537,295	0.00169	84%	14%	2%	172.5
Unspecified	344	537,295	0.00064	n/a	n/a	n/a	n/a
All Elements	1,692	537,295	0.00313	79%	17%	4%	264.6

Source: USDS (2014, Vol. 4.13 pp. 4.13-17-18; App. K). Note: The Mainline Pipe category represents spills from all pipe diameter sizes in the PHMSA dataset and the >16-inch category represents a subset of the Mainline Pipe category. The unspecified category represents incomplete data in the PHMSA database including blanks, unknown, miscellaneous, and other (USDS 2014, App. K, p. 3).

The TMEP application also uses PHMSA data to estimate pipeline spill frequencies in the *Risk Update* although there are several important differences. First, the *Risk Update* uses PHMSA pipeline spill data from 2002 to 2009 whereas the USDS uses a more complete spill dataset from January 2002 through July 2012. Second, the *Risk Update* only uses PHMSA data to estimate failure frequencies for human error during operations, material defects, and construction defects whereas the USDS relies on failure frequencies from the PHMSA dataset for all spill causes including external and internal corrosion, as well as outside forces and weather or natural forces. Third, Dynamic Risk adjusts PHMSA failure frequency data for pipeline spills caused by human error during operations, while the PHMSA data in the Keystone XL application is unadjusted.

5.2.3.2. Application of Method to TMEP

Potential spills that could occur from the TMEP are estimated using incident rates from the Keystone XL Final Supplemental Environmental Impact Statement that relies on PHMSA historical data between 2002 and 2012 for onshore crude oil pipelines (Table 5.6). For spills associated with the mainline pipeline, the incident frequency for pipes with a diameter of 16 inches or larger is used since the majority of newly constructed pipeline for the TMEP will have a diameter of 36-inches (TM 2013, Vol. 1 p. 1-3). For the rest of the pipeline system (i.e. tanks, valves, and other components), spill incident frequencies for all pipe diameters are used since the PHMSA incident frequency data in the Keystone XL *Final Supplemental Environmental Impact Statement* are not disaggregated for system components based on pipe diameter[13]. PHMSA data from the Keystone XL *Final Supplemental Environmental Impact Statement* indicate that any size spill from the mainline pipe or pipeline system (i.e. tanks, valves, or other components) could occur at least once a year (return period of 0.2 years) on Line 1 and Line 2 of the TMEP (Table 5.6). Spill frequency is higher on Line 2 compared to Line 1 since Line 2 is a longer pipeline (Table 5.7).

Table 5.6. Potential Spill Estimates for TMEP based on PHMSA Data (Aggregated Line 1 and Line 2)

Pipeline Component	PHMSA Incident Rate (per mile-year)	Annual Incident Frequency	Spill Return Period (in years)			
			Any Size	0-50 bbl	>50-1,000 bbl	>1,000 bbl
Mainline Pipe (>16”)	0.00025	0.36	3	7	8	11
Pipeline System	0.00190	2.76	0.4	0.4	2	10
Tanks	*0.00017*	*0.25*	*4*	*8*	*13*	*21*
Valves	*0.00005*	*0.07*	*15*	*17*	*135*	-
Other	*0.00169*	*2.45*	*0.4*	*0.5*	*3*	*20*
Unspecified	0.00064	0.93	1	n/a	n/a	n/a
Total	0.00279	4.05	0.2	0.4	2	5

Source: Calculated from USDS (2014, Vol. 4.13 p. 4.13-17-18; App. K). Note: The Mainline Pipe category represents spills from >16-inch pipelines. The total does not reflect volume distribution data for unspecified incidents since this category represents incomplete data in the PHMSA database.

[13] As a result, the total incident frequency of 0.00279 in Table 5.6 is different than the total incident frequency in Table 5.5 because the incident frequency of 0.00279 includes the incident rate for mainline pipes greater than 16-inches (i.e. 0.00025) as opposed to the incident rate for all pipeline diameters (i.e. 0.00059)

Table 5.7. Potential Spill Estimates for TMEP based on PHMSA Data (Disaggregated Line 1 and Line 2)

Pipeline Component	PHMSA Incident Rate (per mile-year)	Annual Incident Frequency	Spill Return Period (in years)			
			Any Size	0-50 bbl	>50-1,000 bbl	>1,000 bbl
Line 1	0.00279	1.99	0.5	0.9	4	11
Line 2	0.00279	2.05	0.5	0.8	4	10
Combined	0.00279	4.05	0.2	0.4	2	5

Source: Calculated from USDS (2014, Vol. 4.13 p. 4.13-17-18; App. K). Note: Data represents spills from >16-inch pipelines, the pipeline system, and unspecified spills.

5.3. Tanker Spill Risk

5.3.1. Oil Spill Risk Analysis Model

The US government developed a model that it uses to evaluate oil spill risk for US oil and gas exploration and development. The Oil Spill Risk Analysis (OSRA) model was developed in 1975 by the US Department of the Interior and is a well-established methodology that the US government uses to estimate oil spill occurrence probabilities for platform, pipeline, and tanker spills, as well as the chances of spills detrimentally impacting environmental resources. The OSRA model has been refined and tested in many applications and peer reviewed journal publications and is the model used by the Bureau of Ocean Energy Management to assess oil spill risk (Smith et al. 1982).

The OSRA model has been used in several specific applications for the Outer US Continental Shelf. The Bureau of Ocean Energy Management typically prepares an environmental impact statement for offshore lease areas and a component of the environmental impact statement is an evaluation of potential oil spill risk over the life of the projects under consideration (Anderson and LaBelle 1990). The US federal government used the OSRA model to examine spill probabilities associated with the development of offshore resources in the Beaufort Sea in northern Alaska (US DOI 1997), Cook Inlet in southern Alaska (US DOI 2003), and the Gulf of Mexico (US DOI 2002; 2007a), and examined development on the Pacific Outer Continental Shelf off the coast of California (US DOI 2000b), and oil and gas development on the Eastern Gulf of Mexico Outer Continental Shelf (US DOI 1998), and other development and exploration activities in the Beaufort Sea (US DOI 2000a; 2007b). The US government continues to use the OSRA model and it is useful to apply the model to the TMEP.

The OSRA model consists of three main components: (1) probability of spills occurring; (2) trajectory simulation of spills; and (3) combined spill probabilities and trajectory simulations (Smith et al. 1982). The probability assessment developed by the US Department of the Interior uses a per-volume methodology that relies on historical spill occurrences for platform, pipeline, and tanker operations and volume of oil handled. A fundamental component of this forecasting method is defining an appropriate exposure variable. Smith et al. (1982) conclude that spill occurrence estimates “depend fundamentally on the estimated amount of oil to be produced” (p. 20) and recommend volume as the key variable due to the variable’s simplicity and predictability. Similarly Lanfear and Amstutz (1983) suggest that the volume of oil handled is “… the most practical exposure variable for predicting oil spill occurrences as a Poisson process” (p. 359). More recently, Anderson et al. (2012) and Anderson and LaBelle (2000) support Smith et al. (1982) and Lanfear and Amstutz (1983) in the recommendation of volume as the exposure variable in the OSRA because it satisfies two important criteria: (a) volume is easy to define; and (b) volume is a quantity that can be estimated based on historical volumes of oil handled.

The OSRA assumes that spills occur independently of each other as a Poisson process. Spill occurrence conforms to a Poisson process for three reasons: (1) no spill can occur when the volume of oil produced or transported is equal to zero; (2) the record shows that spill events are independent of each other over time and volume in that the number of spills does not depend on the previous number of spills; and (3) the number of events in any interval are Poisson distributed and this process has stationary increments (Anderson and LaBelle 2000; Anderson et al. 2012). Smith et al. (1982) describe the probability (*P*) of a specific number of spills (*n*) in the course of handling *t* barrels where λ is the rate of spill occurrence:

$$P(n) = \frac{(\lambda t)^n e^{-\lambda t}}{n!}$$

The above formula bases the rate at which spills occur (λ), which is typically expressed as the mean number of spills per billion barrels (Bbbl) of oil handled, on historic spill occurrence data per volume of oil produced/transported (Anderson and LaBelle 2000; Anderson et al. 2012). The Bureau of Safety and Environmental Enforcement collects tanker spill data from the US Coast Guard and from international sources, and manages a database that provides spill rate data for tanker spills that occur at sea and in port (Anderson et al. 2012). Tanker spill rates are also based on data from the US Department of Commerce, the US Army Corps of Engineers, and British Petroleum's *Statistical Review of World Energy* (Anderson et al. 2012). Anderson and LaBelle (2000) and Anderson et al. (2012) estimate tanker spill rates for spills ≥ 1,000 bbl (159 m^3) since the authors submit that spills of this size are more likely to be reported compared to smaller spills and the historical data are considered more comprehensive than data for spills less than 1,000 bbl. Separate spill rates for tanker spills are presented for spills that occur at sea and in port. Spills that occur in port are defined as those spills that occur in harbours or at piers where the spill contacts land. Spills that occur at sea are offshore spills that may or may not contact land and any forecasting of spills at sea would need to be simulated using trajectory models to estimate the fate and behaviour of the spilled oil (Anderson and LaBelle 1994; 2000)[14]. Spill rates developed by Anderson et al. (2012) and Anderson and LaBelle (1990; 1994; 2000) have been regularly updated and improved to reflect changes in spill rates over time.

5.3.1.1. Application of Method to TMEP

We estimate potential spill probabilities for oil spills from TMEP tanker operations based on the OSRA model. The approach to estimating spill probabilities with the OSRA model includes three main steps:

1. Obtain historical spill rate data for the type of transportation, type of location, and general magnitude of spill;
2. Estimate the volume of oil and condensate handled for three time periods (annual, 30 years, and 50 years); and

[14] The Exxon Valdez spill in 1989 is classified by Anderson et al. (2012) as a spill that occurred at sea even though the oil released from the tanker contacted land. Therefore, the definition of spills that occurred at sea does not assume that oil will not contact land.

3. Calculate spill probabilities with the OSRA model based on data from steps (1) and (2).

Anderson et al. (2012) provide the most recent historical spill rate data for use in the OSRA model for international tanker spills and spills from tankers transporting Alaska North Slope crude oil (Table 5.8). In their recent report, Anderson et al. (2012) note the significant decline in tanker spill rates, which they attribute to regulatory changes since the 1990s, improving safety and requiring double hull tankers. Anderson et al. (2012) do not estimate confidence intervals for spill rates. We estimate 95% confidence intervals for the international tanker spill data in their study[15].

Table 5.8. Oil Tanker Spill Rates in International and Alaskan Waters

Spill Size	Source Data	Time Period	Number of Spills	Volume (Bbbl)	Mean Spill Rate (per Bbbl)		
					In Port	At Sea	Combined
≥ 1,000 bbl (≥ 159 m^3)	International	1994-2008	59	185.8	0.18	0.14	0.32
	Alaska	1989-2008	4	8.7	0.35	0.11	0.46
≥ 10,000 bbl (≥ 1,590 m^3)	International	1994-2008	20	185.8	0.04	0.07	0.11
	Alaska	1989-2008	1	8.7	-	0.12	0.12
≥ 100,000 bbl (≥ 15,900 m^3)	International	1994-2008	6	185.8	0.02	0.01	0.03

Source: Anderson et al. (2012). Note: 95% Confidence intervals computed from Anderson et al. (2012) include the following for combined international tanker spills in port and at sea: ≥ 1,000 bbl (159 m^3) spills (0.19 – 0.44); ≥ 10,000 bbl (1,590 m^3) spills (0.03 – 0.18); and ≥ 100,000 bbl (15,900 m^3) spills (<0.01 – 0.07). Consistent with Anderson et al. (2012), a dash indicates that there were no spills observed and the spill rate was not calculated.

Anderson et al. (2012) also estimate average spill sizes that correspond to spill size categories in Table 5.8. For international tanker spills ≥ 1,000 bbl (159 m^3) that occurred between 1989 and 2008, the average spill sizes in port and at sea were 39,674

[15] For international tanker spill data. Anderson et al. (2012) provide the number of spills for each size of tanker spill and the volume of crude oil handled for each year from 1974 to 2008. This information is required to estimate 95% confidence intervals for tanker spill rates. Anderson et al. do not provide comparable data for tanker spills associated with shipments departing Valdez, Alaska between 1989 and 2008 and thus we are unable to estimate confidence intervals for these data.

and 28,915 bbl, respectively, or a combined 34,932 bbl for tanker spills that occurred either in port and at sea. During the same period, international tanker spills ≥ 10,000 bbl (1,590 m^3) reported average spill sizes in port and at sea of 173,401 and 53,580 bbl, respectively, or a combined 95,517 bbl for tanker spills that occurred either in port or at sea.

The second step in applying the OSRA model is to estimate the volume of oil to be transported by TMEP tanker traffic on an annual basis and over the 30- and 50-year life of the project. According to TM (2013, Vol. 2 p. 2-27), 630 of the 890 kbpd in system capacity would be for shipment via the marine terminal, which equates to approximately 230.0 million bbl per year. We estimate that over a 30-year and 50- year operating period, an export volume of 630 kbpd represents nearly 4.6 Bbbl and 11.5 Bbbl, respectively, of oil transported by tankers.

In the third step, we use spill rates for tanker spills and the volume of oil that would be transported by TMEP tanker traffic as inputs to the OSRA model and estimate spill probabilities. Our application of the OSRA model uses the following spill occurrence rates from Anderson et al. (2012) to provide a range of potential tanker spill probability estimates for the TMEP:

- Spills in international waters between 1994 and 2008, which represent worldwide spills from modern tanker operations in the last 15 years of the Bureau of Ocean Energy Management database; and
- Spills associated with shipments departing Valdez, Alaska between 1989 and 2008 that represent the last 20 years of modern tanker traffic transporting Alaskan crude oil.

5.3.1.1.1. Potential Annual TMEP Tanker Spill Risk

The OSRA model suggests that a TMEP tanker spill ≥ 1,000 bbl could occur every 10 to 14 years while the tanker is either in port or at sea (Table 5.9). Spill risk decreases to a spill every 37 to 40 years for a tanker spill ≥ 10,000 bbl and 145 years for a tanker spill ≥ 100,000 bbl. Confidence intervals at the 95% level are presented in the footnote to Table 5.9.

Table 5.9. Estimates of Potential Annual TMEP Tanker Spill Return Periods

Spill Size	Source Data	Return Period (in years)		
		In Port	At Sea	Combined
≥ 1,000 bbl (≥ 159 m^3)	International	25	32	14
	Alaska	13	40	10
≥ 10,000 bbl (≥ 1,590 m^3)	International	109	63	40
	Alaska	-	37	37
≥ 100,000 bbl (≥ 15,900 m^3)	International	218	435	145

Source: Computed from Anderson et al. (2012). Note: Confidence intervals computed from Anderson et al. (2012) include the following return periods for combined international tanker spills in port and at sea: ≥ 1,000 bbl (159 m^3) spills (10 – 23 years); ≥ 10,000 bbl (1,590 m^3) spills (24 – 139 years); and ≥ 100,000 bbl (15,900 m^3) spills (60 – n/a years). Consistent with Anderson et al. (2012), a dash indicates that there were no spills observed and the spill rate was not calculated.

5.3.1.1.2. Potential Spill Risk Over a 30-Year Period

The OSRA model estimates that the probability of a TMEP oil tanker spill occurring in port or at sea based on the international tanker spill data is 89.0% for oil spills ≥ 1,000 bbl. Spill probabilities for larger TMEP tanker spills based on the international data are 53.2% for spills ≥ 10,000 bbl, and 18.7% for spills ≥ 100,000 bbl over a 30-year period. Spill probabilities estimated based on the Alaska tanker spill data are slightly higher than those estimated based on the international data.

Table 5.10. Estimates of Potential TMEP Tanker Spill Risk Probabilities Over 30 Years

Spill Size	Source Data	Spill Probability over 30 Years (%)		
		In Port	At Sea	Combined
≥ 1,000 bbl (≥ 159 m^3)	International	71.1	61.9	89.0
	Alaska	91.1	53.2	95.8
≥ 10,000 bbl (≥ 1,590 m^3)	International	24.1	38.3	53.2
	Alaska	-	56.3	56.3
≥ 100,000 bbl (≥ 15,900 m^3)	International	12.9	6.7	18.7

Source: Computed from Anderson et al. (2012). Note: Confidence intervals computed from Anderson et al. (2012) include the following probabilities for combined international tanker spills in port and at sea: ≥ 1,000 bbl (159 m^3) spills (73.4 – 95.3%); ≥ 10,000 bbl (1,590 m^3) spills (19.5 – 71.9%); and ≥ 100,000 bbl (15,900 m^3) spills (0.1 – 39.6%). Consistent with Anderson et al. (2012), a dash indicates that there were no spills observed and the spill rate was not calculated.

5.3.1.1.3. Potential Spill Risk Over a 50-Year Period

Over a 50-year operating period, the OSRA model estimates that the probability of an oil spill ≥ 1,000 bbl occurring in port or at sea is 97.5% based on international tanker spill rates (Table 5.11). Spill probabilities for larger TMEP tanker spills based on the international data are 71.8% for spills ≥ 10,000 bbl, and 29.2% for spills ≥ 100,000 bbl over a 50-year period. Similar to spill probabilities estimated over a 30-year period, probabilities over 50 years based on the Alaska tanker spill data are slightly higher than those estimated based on the international data.

Table 5.11. Estimates of Potential TMEP Tanker Spill Risk Probabilities Over 50 Years

Spill Size	Source Data	Spill Probability over 50 Years (%)		
		In Port	At Sea	Combined
≥ 1,000 bbl (≥ 159 m^3)	International	87.4	80.0	97.5
	Alaska	98.2	71.8	99.5
≥ 10,000 bbl (≥ 1,590 m^3)	International	36.9	55.3	71.8
	Alaska	-	74.8	74.8
≥ 100,000 bbl (≥ 15,900 m^3)	International	20.5	10.9	29.2

Source: Computed from Anderson et al. (2012). Note: Confidence intervals computed from Anderson et al. (2012) include the following probabilities for combined international tanker spills in port and at sea: ≥ 1,000 bbl (159 m^3) spills (89.0 – 99.4%); ≥ 10,000 bbl (1,590 m^3) spills (30.3 – 87.9%); and ≥ 100,000 bbl (15,900 m^3) spills (0.1 – 56.8%). Consistent with Anderson et al. (2012), a dash indicates that there were no spills observed and the spill rate was not calculated.

There are several considerations to applying the OSRA model to estimate potential tanker spills for the TMEP. The principal consideration relates to the model's reliance on historical data to estimate future tanker spill rates. There have been improvements in safety that resulted in a reduction in tanker spill rates over time (Anderson and LaBelle 2000; Anderson et al. 2012) and thus historical rates may not accurately reflect future risk. Tanker spill rates in the future could continue to decline as a result of further mitigation measures and regulatory requirements, could remain static due to diminishing returns from previous regulatory and technological improvements, or could increase as a result of an aging tanker fleet (Papanikolaou et al. 2009). We do not attempt to predict future changes in average tanker spill rates over the operational life of the TMEP and we recognize that reliance on historical data is a consideration in the application of many models predicting the occurrence of future events. Second, average historical data may not reflect the unique characteristics of the project environment that may affect risk such as unusual hazards or special mitigation measures. We attempt to mitigate this weakness by using tanker spill data from Alaska, which may increase the likelihood that data more accurately reflect the unique risks of the Pacific coastal region. Furthermore, Alaska data for the 1989 to 2008 period includes mitigation measures similar to those proposed for the TMEP such as escort tugs. Third, Anderson et al. (2012) do not estimate confidence intervals for tanker spill rates. Although Anderson and LaBelle (2000) determine 95% confidence intervals for spill rates, the recent update by Anderson et al. (2012) only provides the mean estimate for spill rates. We partially address this by estimating 95% confidence intervals for the international tanker spill data based on data in the Anderson et al. (2012) study. However, Anderson et al. (2012) do not provide comparable data for spills associated with shipments departing Valdez, Alaska between 1989 and 2008 and thus we are unable to estimate confidence intervals for these data.

5.3.2. Vessel Traffic Risk Assessment 2010

The Vessel Traffic Risk Assessment (VTRA) 2010 is a spill risk assessment completed in 2014 for the Puget Sound Partnership. The purpose of the VTRA 2010 study is to assess potential changes in marine spill risk in the Puget Sound and Salish Sea and to provide information to decision-makers on the mitigation actions that could be taken to address an increase in spill risk in the region (van Dorp and Merrick 2014). The VTRA method was initially developed in 1996 and researchers at the George Washington and Virginia Commonwealth Universities have continually updated the model since its initial development (van Dorp and Merrick 2014). The VTRA model has been used in numerous applications including the Prince William Sound Risk Assessment, the Washington State Ferries Risk Assessment, the Exposure Assessment of the San Francisco Bay ferries, and the VTRA 2005 study that evaluates marine spill risk in Washington State and BC. The VTRA method has been peer-reviewed by the National Research Council as well as by experts in the area of expert elicitation design and analysis (van Dorp and Merrick 2014). Further, the VTRA methodology including data use and model assumptions has been peer-reviewed in the academic literature (Harrald et al. 1998; Grabowski et al. 2000; Merrick et al. 2000; van Dorp et al. 2001; Jason et al. 2002; Merrick et al. 2003; van de Wiel and van Dorp 2011).

The VTRA 2010 study uses a collaborative approach to evaluating spill risk. The study engaged stakeholders to participate in bi-monthly meetings that were open to the public and the study was guided by a steering committee that included members of the Puget Sound Harbor Safety Committee (van Dorp and Merrick 2014). The steering committee/advisory group also included members representing federal, state, and First Nation interests as well as members from the marine shipping industry, petroleum industry, labour union, and an environmental representative (van Dorp and Merrick 2014).

5.3.2.1. Overview of Method

The VTRA analyses the amount of time that particular classes of vessels travel through an area and the frequency of accidents and oil losses from these vessel type. The VTRA 2010 models the chain of events that could lead to a spill from a vessel, the components of which include situations, incidents, accidents, and an oil spill. The first step in the chain (i.e. situations) describes interactions in which an accident can occur in the study region. The study region includes portions of the Washington outer coast, the Strait of Juan de Fuca, and the approaches to and passages through the San Juan Islands, Puget Sound, and Haro Strait/Boundary Pass. The VTRA maritime simulation model attempts to recreate conditions in the study region related to the operation of vessels and environmental factors. Vessel operations modeled in the VTRA include the type of vessel (e.g. tanker, chemical carrier, fishing vessel, passenger ship, etc.), the route travelled by an individual vessel, the length of the route travelled, and the average speed of the vessel. Environmental factors modeled include wind, fog, and currents derived from the National Climactic Data Center. The simulation model replays traffic and environmental conditions and then counts and records these conditions every minute over a period of a year for those situations in which an accident could occur.

Incidents are events that precede an accident and are estimated in the VTRA model based on historical data. There are four main types of incidents captured in the model: propulsion losses; total steering losses; loss of navigational aids; and human errors. The impact of each of these incident types on the occurrence of accidents is evaluated through an examination of the records for each accident that occurred inside the study area (van Dorp and Merrick 2008, p. 44). Maritime casualty and incident records from January 1995 to December 2005 were reviewed and cross-validated from 13 maritime organizations including the US Coast Guard Marine Incident Database, the Washington State Department of Ecology, and Lloyd’s List Marine Intelligence Unit Portal, among others (van Dorp and Merrick 2008, App. A, p. a-5). This analysis of incident data is used to estimate the probability of each incident type in the VTRA simulation model with the exception of human errors, which are estimated based on an error analysis of accidents (van Dorp and Merrick 2008, p. 44). Incident rates in the model are subsequently converted to an incident rate per unit of time that the vessel is on the water.

Accidents in the VTRA include collisions between two vessels, powered and drift groundings, and allisions. To assess accidents, the VTRA model uses expert judgment and historical accident data. The incident-accident data described in the previous step provides an estimate of the frequency of accidents, however there is insufficient data in the study area to determine how each variable recorded by the simulation model (i.e. proximity to other vessels, types of vessels, location, and environmental factors) affects the chance of an accident (van Dorp and Merrick 2008, p. 45). To address this lack of specific data in building its accident probability model, the VTRA uses expert elicitation from tanker masters, tug masters, Puget Sound pilots, Coast Guard VTS operators, and ferry masters in order to assess the difference in accident probability between similar scenarios (van Dorp and Merrick 2008, pp. 45-46). For example, experts are asked the difference in risk between unrestricted and restricted visibility in the event a tanker is meeting a ferry (van Dorp and Merrick 2008, pp. 45-46). Since expert elicitation provides an estimate of relative differences in risk, the total number of accidents is estimated in the VTRA by calibrating the accident probability model to reflect the number of historically observed accidents in the geographic region. Thus incident and accident rates estimated by the VTRA model in the base case coincide with historical incident and accident rates in the region.

An oil outflow model for collision and grounding accidents is the basis for the fourth component in the chain of events, an oil spill. The outflow model links input variables (e.g. hull design, displacement and speed, striking vessel displacement and speed, and the angle of both vessels) to output variables (e.g. the extent of damage to the tanker). The outflow model produces an estimate of an oil outflow volume that totals the capacity of tank compartments damaged from an accident.

What-If scenarios that represent planned projects in the study area are incorporated into the VTRA model by including the traffic level impacts of these planned projects. The VTRA 2010 project steering committee selected the following projects based on the criteria that they were in advanced stages of a permitting process: (1) the Gateway bulk carrier terminal, which would add 487 bulk carriers; (2) the TMEP, which would add 348 crude oil tankers; (3) the combination of proposed changes at Delta port, which includes coal, grain, and container terminal expansions that combined would add 348 bulk carriers and 67 container vessels; and (4) all three scenarios operating concurrently, which would increase traffic by 1,250 vessels (van Dorp and Merrick 2014, p. 33).

The results of the VTRA 2010 model provide an estimate of potential changes in accident frequency and oil outflow. In the model, the accident frequency is driven by the amount of time a vessel moves through the study area (referred to as vessel time of exposure) and potential oil losses are driven by the amount of time a cubic metre of oil moves through the area (referred to as oil time of exposure). The VTRA compares accident and oil outflow estimates measured for What-If scenarios to the base case in order to estimate the relative change in the risk of accidents and oil loss in the study area.

The VTRA 2010 study estimates significant increases in accident and oil spill risk if the Gateway bulk carrier terminal, the TMEP, and proposed changes at Delta port proceed. If all three projects become operational, the model estimates an 18% increase in the potential accident frequency and a 68% increase in total potential oil loss compared to the base case for all focus vessels (i.e. bulk carriers, container vessels, other cargo vessels, chemical carriers, articulated tug barges, oil barges, and tankers) (van Dorp and Merrick 2014, p. 103). For the addition of TMEP alone (referred to as Scenario R in the study), the VTRA 2010 estimates an increase in potential accident frequency of 5% and an increase in potential oil loss of 36% compared to the base case (van Dorp and Merrick 2014, p. 102). The majority of the increases in potential oil outflow from the TMEP are in the Haro Strait/Boundary pass waterway (+17.3%) and the East Strait of Juan de Fuca waterway (+10.6%).

Table 5.12. Selected Results of VTRA 2010 Study

Scenario	Percentage Change (to Base Case)	
	Accident Frequency	Oil Loss
Gateway Expansion (+487 bulk carriers)	+12%	+12%
TMEP (+348 tankers)	+5%	+36%
Delta Port Expansion (+348 bulk carriers / +67 container vessels)	+6%	+4%
Combined Expansion Scenario (Gateway / TMEP / Delta Port)	+18%	+68%
Risk Mitigation Measures	-29%	-44%

Source: van Dorp and Merrick (2014). Note: The base case in the VTRA uses 2010 vessel traffic data in the study region. The Risk Mitigation Measures scenario compares relative accident frequency and oil loss to the Combined Expansion Scenario. The portfolio of risk mitigation measures includes articulated tug barges following one-way Rosario regime, escorting on Haro-Strait/Boundary Pass routes, escorting on Rosario routes, a 17-knot max speed rule applied to container vessels, a 50% reduction in human error for oil barges, and bunkering support for Gateway vessels.

The VTRA model also implements risk mitigation measures to evaluate their effect on the base case scenario. Risk mitigation measures incorporated into the model include double hull fuel tank protection for cargo vessels, an additional person on the bridge of oil barges, speed limits for container ships, and escort vessels on certain route segments, among others (van Dorp and Merrick 2014, pp. 113-117). The VTRA 2010 study estimates that if this portfolio of risk mitigation measures is implemented in the study region, the increase in accident frequency and oil loss from the three projects can be mitigated. Indeed, the model evaluates the maximum potential benefit of the mitigation measures and determines a potential decrease in potential accident frequency and oil loss of 29% and 44%, respectively, for the scenario in which the Gateway, TMEP, and Delta port are operational (van Dorp and Merrick 2014, pp. 131-132). The VTRA does not evaluate the effect of proposed risk mitigation measures on accident frequency and oil loss specifically for the TMEP scenario.

5.3.2.2. Application of Method to TMEP

As discussed in the previous section, the VTRA 2010 focuses on relative comparisons among accident types, oil outflow categories, what-If scenarios, and waterways and does not provide an estimate of absolute spill risk values. Due to the interest in spill risk values for the TMEP, Merrick and van Dorp (2015) prepared a supplemental analysis to the VTRA 2010 study that estimates spill return times for a range of spill sizes for various scenarios. One of these scenarios compares the return times for tanker focus vessels in the base case with the addition of 348 TMEP tankers (i.e. Scenario R). We note that the supplemental analysis evaluates the uncertainty distribution of average return times and, since the estimates in the analysis represent the median values of the distributions, the average return times may be higher or lower than the median estimates.

According to the supplemental analysis, potential return times for a tanker spill range from 82 to 2,971 years in the base case depending on the volume of oil released from the collision or grounding accident (Table 5.13). The analysis shows that when 348 tankers from the TMEP are added to the base case in Scenario R, spill risk increases to between 53 and 1,836 years depending on the spill risk size category. From these ranges, we estimate return times for any spill over 6,260 bbl of 43 years for the base case, which increases to 25 years for Scenario R[16]. Since the supplemental analysis does not provide an estimate of the average return time specifically for TMEP tankers, we estimate these return times by taking the difference between the base case and Scenario R. Based on this approach, we estimate potential return times for TMEP tankers of 150 to 4,806 years with an overall return time of 57 years for all tanker spills greater than 6,290 bbl. This overall return time would be lower if tanker spills less than 6,290 bbl were incorporated into the analysis. We note that the supplemental analysis prepared by Merrick and van Dorp (2015) does not evaluate the effect of proposed risk mitigation measures from van Dorp and Merrick (2014) on TMEP spill return periods and thus return times for mitigated tanker spills are not available.

[16] We acknowledge that there are qualifications to our approach that must be considered and that the return period may be different if calculated directly using the VTRA model. To estimate tanker spills greater than 6,290 bbl, we sum the inverse of the return times for each discrete spill size category. One consideration estimating the return time using this approach is Jensen's Inequality in probability and statistics (van Dorp 2014a). Jensen's Inequality states that for non-linear relationships between inputs and outputs, the average of the outputs is not equal to the output of the average inputs. Jensen's inequality applies to the VTRA because of the non-linear relationships between inputs and outputs in the model and thus the outputted overall return times would not be equal to the return time calculated based on averaging the inputs. Nonetheless, the overall return time represents an approximation in lieu of computing a tanker spill return time for spills greater than 6,290 bbl using the VTRA 2010 model.

We also estimate potential TMEP tanker spill probabilities over the 30- and 50-year life of the project based on return times from Merrick and van Dorp (2015). Our estimate of the likelihood of a TMEP tanker spill greater than 6,290 bbl ranges from 41.1% to 58.6% over a 30- and 50-year period, respectively, although this estimate based on Merrick and van Dorp (2015) is subject to the considerations described in footnote 16. We acknowledge that the range of spill probabilities for spills greater than 6,290 bbl computed from the VTRA 2010 model could differ from those presented in Table 5.13.

Table 5.13. Potential Return Times for TMEP Tanker Spill based on VTRA 2010

Potential Oil loss	Median Average Return Time (in years)			TMEP Spill Probability	
	Base Case	Base Case + TMEP	Estimated TMEP	30 Years	50 Years
6,290 – 15,725 bbl	82	53	150	18.2%	28.4%
15,725 – 31,449 bbl	200	74	117	22.6%	34.8%
31,449 – 47,174 bbl	477	387	2,051	1.5%	2.4%
47,174 – 62,898 bbl	941	502	1,076	2.8%	4.5%
62,898 – 78,623 bbl	481	417	3,134	1.0%	1.6%
78,623 – 94,347 bbl	2,971	1,836	4,806	0.6%	1.0%
over 94,347 bbl	1,765	1,107	2,969	1.0%	1.7%
Greater than 6,290 bbl	43	25	57	41.1%	58.6%

Source: Merrick and van Dorp (2015); computed form Merrick and van Dorp (2015). Note: The supplemental analysis does not estimate spill risk for tanker spills greater than 1,000 m^3 and spill probabilities for all spill size categories as well as for spills greater than 1,000 m^3; we calculate these spill risk estimates and probabilities based on Merrick and van Dorp (2015).

Several qualifications should be noted that affect the accuracy of the TMEP tanker spill estimates generated from the VTRA model. First, the VTRA 2010 study area, which includes portions of the Washington outer coast, the Juan de Fuca Strait, and approaches to/passages through the San Juan Islands, Puget Sound, and Haro Strait/Boundary Pass, does not include Canadian waters north of the Canada-US border since this was not part of the study's mandate (van Dorp and Merrick 2014). The waters not included in the VTRA 2010 study correspond to roughly half the portion of segment 4 and all of segments 3, 2, and 1 for the TMEP tanker route defined by DNV in section 3 of its Termpol 3.15 study or approximately 27% of the nm of the entire route. Therefore return times in Table 5.13 represent potential oil loss along approximately 73% of the

TMEP tanker route. The spill risk for potential oil losses from TMEP tankers would be higher if estimated along the entire tanker route. If we assume that average tanker spill risk from the VTRA supplemental analysis is the same along the entire TMEP tanker route, this results in an increase in spill risk from a return time of 57 years to 42 years for a spill greater than 6,290 bbl[17]. A return time of 42 years corresponds to spill probabilities of 52% and 70% over a 30- and 50-year period, respectively. Second, the VTRA supplemental analysis does not evaluate tanker accidents and oil spills that occur from foundering, fire or explosions and incorporating these types of accident causes would further increase the risk of TMEP tanker spills. Third, the VTRA study does not estimate the impact of proposed mitigation measures on TMEP tankers and thus the mitigated return period for TMEP tankers based on the VTRA model is unknown. Applying the 28% reduction factor from DNV (2014a) for the use of tug escorts and enhanced situational awareness to the estimated return period of 42 years along the entire TMEP route suggests that a potential order of magnitude estimate based on the VTRA model for a mitigated tanker spill could be 58 years, corresponding to a 58.1% probability of a tanker spill over a 50 operating period[18]. Fourth, by attempting to isolate the increase in spill risk from the TMEP, the analysis of TMEP tanker spill risk does not capture indirect effects associated with the increase in TMEP tankers to the study region (van Dorp 2015). For example, spill risk estimates for the TMEP in Table 5.13 do not represent the potential increase in accidents associated with interactions among non-TMEP vessels, such as chemical carriers and container vessels, when the number of TMEP tankers increases by 348 vessels. As the VTRA 2010 shows, the relative changes in accident frequency and potential oil loss are significant when all vessel types are considered.

[17] Risks along the excluded portion may be higher or lower than the average for the route assessed and therefore the risks for the entire TMEP tanker route may be higher or lower than this estimate.

[18] This general order of magnitude estimate assumes that the 28% reduction factor from DNV (2014a) is an accurate estimate of the impact of this mitigation measure and can be applied to the VTRA model.

5.4. Comparison of Spill Risk Assessment Methods

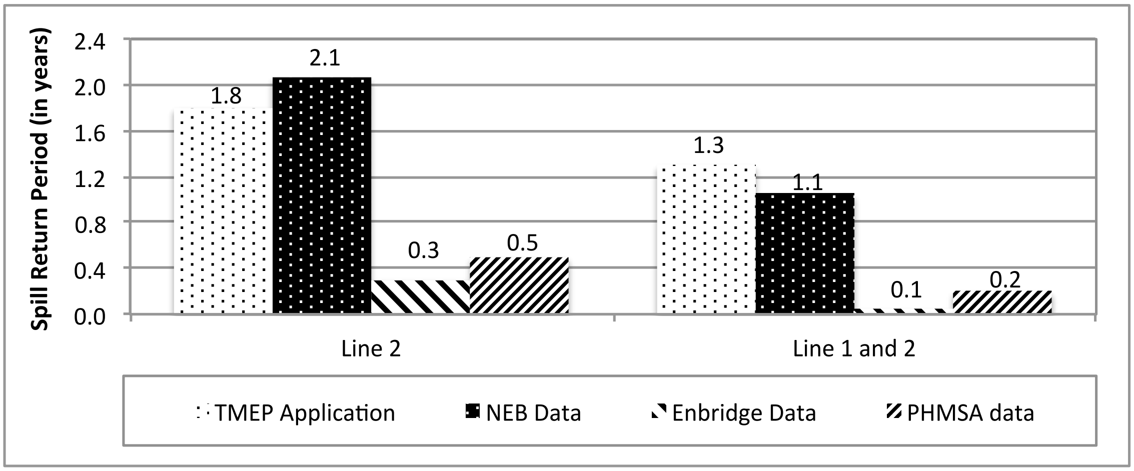
5.4.1. Pipeline Spill Risk

The TMEP application and spill estimates based on NEB, Enbridge, and PHMSA data all show that the likelihood of a pipeline spill is high (Table 5.14). Indeed, every methodological approach estimates a 99.9% chance of a spill over 30- and 50-year periods. The methods provide different return period estimates ranging from a spill every 0.2 years to a spill every 4 years. According to TM, the 2-year return period for a Line 2 rupture estimated in the TMEP application represents unmitigated spill risk. However, TM provides no “mitigated” pipeline rupture return period estimates (TM 2015c). Therefore we are not able to compare mitigated spill risk return periods from the TMEP application with other methodological approaches. Nonetheless, the comparison in Figure 5.1 shows that TM’s unmitigated pipeline spill risk estimate is lower than most spill rates from other data sources even though the other estimates are based on historical data from Enbridge, the NEB, and PHMSA that include mitigation measures similar to those proposed by TM for the TMEP.

Table 5.14. Comparison of Pipeline Spill Risk Estimates for TMEP

Method	Size and Type of Spill	Return Period (in years)	Spill Probability over 30 Years (%)	Spill Probability over 50 Years (%)
TMEP Application	Line 1 Leak or Rupture	4	99.9	99.9
	Line 2 Rupture	2	99.9	99.9
	Line 1 or Line 2 Spill	1	99.9	99.9
NEB (2000-2009)	Line 1 spill (> 9 bbl)	2	99.9	99.9
	Line 2 spill (> 9 bbl)	2	99.9	99.9
	Line 1 or Line 2 spill (> 9 bbl)	1	99.9	99.9
Enbridge (1998-2010)	Line 1 spill (any size)	0.3	99.9	99.9
	Line 2 spill (any size)	0.3	99.9	99.9
	Line 1 or Line 2 spill (any size)	0.1	99.9	99.9
PHMSA (2002-2012)	Line 1 spill (any size)	0.5	99.9	99.9
	Line 2 spill (any size)	0.5	99.9	99.9
	Line 1 or Line 2 spill (any size)	0.2	99.9	99.9

Figure 5.1. Comparison of Pipeline Spill Return Periods



As discussed in the previous section, all methodological approaches have strengths and weaknesses. The method used in the TMEP application omits spills associated with external and internal corrosion and does not estimate the overall likelihood of a spill along the length of the pipeline. Spill risk estimates for the TMEP based on datasets from the NEB, Enbridge, and the PHMSA all represent average pipeline operations that may not capture any potential unique characteristics of the TMEP that increase or decrease spill risk. However, the standard methodology in US pipeline risk assessments (such as for Keystone XL) is to use recent historical data. Based on these considerations, the PHMSA data may provide the most reasonable estimates of potential spill risk for the TMEP for several reasons. First, PHMSA data was used to estimate potential spill risk for the Keystone XL in the *Final Supplemental Environmental Impact Statement* and thus withstood the scrutiny of experts involved in the pipeline review process administered by the US Department of State. Second, the PHMSA dataset is large and represents a range of different pipeline technologies, operating environments, and corporate safety practices from various pipeline operators. While the comprehensiveness of the PHMSA dataset could be considered a weakness due to the effects of averaging, it also represents a strength since the data uses a large sample size of pipeline operations over a more than 10-year period instead of relying on the performance of a single pipeline. Third, the PHMSA data represents raw data that does not include subjective downward adjustments to pipeline spill rates and the data also include types of spill causes omitted from the TMEP application (i.e. external and internal corrosion). Fourth, the PHMSA data incorporates potential spills from tanks, valves, and other pipeline system components whereas the TMEP application does not include these risks together with its spill estimates. Therefore, the PHMSA data may more accurately represent potential pipeline spill risk for the TMEP compared to other methods evaluated in this study.

5.4.2. Terminal and Inner Harbour Spill Risk

Due to our client's interest in potential spill likelihood in the Vancouver harbour area of the tanker route, we compare spill risk in the harbour estimated with the different methodological approaches. To estimate spill risk in the Vancouver harbour area in the TMEP application, we combine the likelihood of a spill occurring in the Inner Harbour (defined as the region of the tanker route from English Bay to Westridge Terminal in Termpol 3.15) and spill likelihood at the marine terminal. We also provide the risk of a spill occurring in the port estimated with the OSRA model (i.e. spills that occur in harbours or at piers according to Anderson et al. (1994; 2000)).

The comparison shows that spill probabilities over 30- and 50-year periods are relatively similar for both methodologies. The TMEP application estimates a 83.0% likelihood of a spill in the harbour over a 50-year period whereas the OSRA model estimates a spill probability of 87.4%. It is important to note several differences in definitions between the two models. First the two models use different size categories: the estimates in the TMEP application include all size spills while the OSRA model includes only spills ≥ 1,000 bbl. Second, the TMEP application estimates are for a clearly defined geographic area while the OSRA model is for the "port" which is defined more generally as the area in which a spill will reach land (Anderson et al. 1994; 2000). For these reasons the spill estimates from the two models are not directly comparable.

Table 5.15. Comparison of Return Periods and Spill Probabilities for TMEP Terminal and Inner Harbour Spills

Method	Size and Type of Spill	Return Period (in years)	Spill Probability (%)	
			30 Years	50 Years
TMEP Application	Any size tanker spill (Inner Harbour)	580	5.0	8.3
	Terminal spill < 63 bbl	34	58.6	77.0
	Terminal spill < 629 bbl	234	11.6	18.6
	Spill in Inner Harbour (terminal or tanker)	29	65.5	83.0
OSRA Model (International)	Tanker spill in port ≥ 1,000 bbl	25	71.1	87.4
	Tanker spill in port ≥ 10,000 bbl	109	24.1	36.9

Note: Spill probabilities for TMEP application computed based on return periods from TM (2013, Termpol 3.15) and Trans Mountain (2015). The Inner Harbour in the TMEP application represents segments 1 and 2 in the Termpol 3.15 study; this corresponds to the geographic region between English Bay and Westridge Terminal. The category Spill in Inner Harbour estimated based on the TMEP application represents a terminal spill < 63 bbl, a terminal spill <629 bbl, and any size tanker spill that occurs in the Inner Harbour. Spill probabilities for OSRA model computed from Anderson et al. (2012).

5.4.3. Tanker Spill Risk

The TMEP application, the OSRA model, and the VTRA all estimate a potentially high likelihood of a tanker spill from the TMEP. The TMEP application estimates that a tanker spill of any size could occur between 46 and 284 years. Since return periods in the TMEP application estimate the amount of time between spills and not the chance of a spill over the life of the project, we convert return periods to spill probabilities. From these conversions, we estimate the probability of a tanker spill of any size over a 30-year period is 10.0% to 48.3% and over a 50 year period is 16.2% to 66.7%. Our analysis with the OSRA model estimates that a tanker spill ≥ 1,000 bbl that occurs in port or at sea has a 89.0% chance of occurring over a 30-year operating period and a 97.5% chance of occurring over a 50-year period. Based on the supplemental analysis from Merrick and van Dorp (2015), we estimate a 57-year return period for a spill >6,290 bbl, which equates to spill probabilities of 41.1% and 58.6% over 30- and 50-year periods, respectively, although these probabilities increase to 51.6% and 70.2% when we estimate spill risk for 100% of the TMEP route. Applying the 28% reduction factor for tug mitigation based on DNV (2014a) results in a general order of magnitude of a 58 year return period based on the VTRA methodology.

Table 5.16. Comparison of Return Periods and Spill Probabilities for TMEP Tanker Spills

Method	Size and Type of Spill	Return Period (in years)	Spill Probability (%)	
			30 Years	50 Years
TMEP Application	Any size tanker spill	46 – 284	10.0 – 48.3	16.2 – 66.7
	Any size tanker spill (in harbor)	580	5.0	8.3
	Mean tanker spill (35,900 bbl or 51,900 bbl)	91 – 568	5.1 – 28.2	8.4 – 42.4
	Worst case tanker spill (99,100 bbl or 103,800 bbl)	456 – 2,841	1.1 – 6.4	1.7 – 10.4
	Any size tanker or terminal spill	20 – 31	62.8 – 78.7	80.8 – 92.4
OSRA Model (International)	Tanker spill in port ≥ 1,000 bbl	25	71.1	87.4
	Tanker spill at sea ≥ 1,000 bbl	32	61.9	80.0
	Tanker spill in port/at sea ≥ 1,000 bbl	14	89.0	97.5
	Tanker spill in port/at sea ≥ 10,000 bbl	40	53.2	71.8
	Tanker spill in port/at sea ≥ 100,000 bbl	145	18.7	29.2
VTRA	TMEP spill greater than 6,290 bbl (73%)	57	41.1	58.6
	TMEP spill greater than 6,290 bbl (100%)	42	51.6	70.2
	TMEP spill greater than 6,290 bbl (tug mitigation)	58	40.6	58.1

Note: Spill probabilities for TMEP application computed based on return periods from TM (2013, Termpol 3.15) and Trans Mountain (2015). The Inner Harbour in the TMEP application represents segments 1 and 2 in the Termpol 3.15 study; this corresponds to the geographic region between English Bay and Westridge Terminal. Spill probabilities for tanker spill of 35,900 bbl or 51,900 bbl represent mean outflow for grounding and collision, respectively. Spill probabilities for tanker spill of 99,100 bbl or 103,800 bbl represent worst case outflow for grounding and collision, respectively. Spill probabilities for VTRA 2010 any size spill computed based on return period from Merrick and van Dorp (2015). Spill probabilities for OSRA model computed from Anderson et al. (2012).

Comparing the spill risk estimates from the different methodologies is challenging due to the different methodological approaches and results representing different spill size categories for each method. We have attempted to increase the comparability of spill risk estimates by converting all outputs into return periods and probabilities over the life of the project.

As discussed in section 4.2, the methodology used in the TMEP application contains many weaknesses including the transparency of the methods and data, the reasonableness of the analytical approach, and the lack of uncertainty analysis, among others. Moreover, the revised estimates rely on insufficient evidence to further reduce tanker spill risk estimates suggesting that the higher spill risk estimates in the *Termpol 3.15* study of 46 years for any size tanker spill may be a more accurate estimate of potential spill risk. Despite these weaknesses, the MARCS model has been continuously updated by DNV to address weaknesses such as those identified by the National Academy of Sciences and has been used in several applications to estimate tanker spill risk. Further, the method incorporates regional specific data and attempts to incorporate information provided by individuals with local knowledge.

The methodology of the OSRA model has been peer-reviewed when published in the academic literature and the method uses as inputs raw historical tanker spill data. Consequently, tanker spill risk estimates derived from the OSRA model rely on international tanker spill rates that are not adjusted to the unique characteristics of the TMEP project area, which may increase or decrease risk relative to the international averages. We have also used tanker spill data from Alaska, which may better represent risk conditions on the Westcoast of Canada and Northwest US, although we acknowledge that Alaska data does not necessarily represent the risks of the TMEP, which may be higher or lower. The OSRA model also uses different definitions of spills than the TMEP application[19].

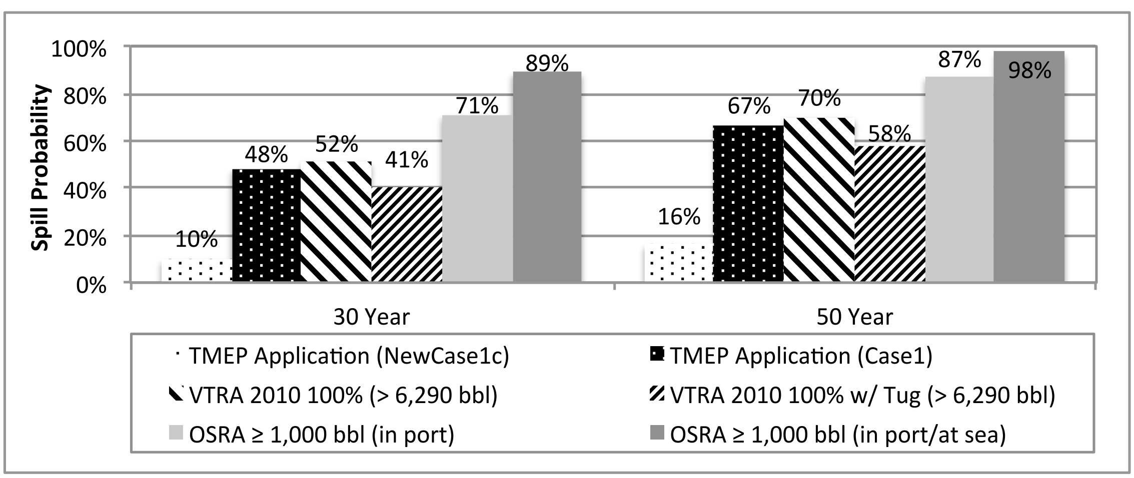
The VTRA 2010 model uses a methodology that assesses potential changes in system-wide risks. The method has been peer-reviewed by the National Research Council and by experts in the academic literature. However, the VTRA 2010 study does not isolate incremental risk for particular projects such as the TMEP and instead examines the increase in risk when projects are added to the base case. Further, the VTRA 2010 study focuses on a study area that represents approximately 73% of the TMEP tanker route and thus does not assess the entire spill risk for the TMEP. We have attempted to adjust the VTRA results to include the entire TMEP tanker route, although

[19] The OSRA model estimates spill rates based on spills that occur at sea and in port, with the latter category defined as those spills that occur in harbours or at piers and contacts land (Anderson and LaBelle 1994; 2000). Alternatively, the TMEP application estimates malfunctions from the equipment loading tankers such as overfilling of cargo tanks and damage to loading arms or piping.

this adjustment assumes equal risk on the excluded portion as on the portion assessed in the VTRA. We have also attempted to adjust the VTRA results for tug mitigation along the entire route. Consequently, the adjusted estimates may overstate or understate the risk for the entire route. The VTRA study also focuses on groundings and collisions and does not estimate potential tanker spills associated with foundering, fire, or explosion.

The estimates from DNV are at the low end of the range of estimates and the OSRA estimates are at the upper end of the range of estimates. The comparison of strengths and weaknesses for each method suggests that there is no single best guess estimate of potential spill risk from the increase in TMEP tankers. However, given the weaknesses in the DNV methodology and the fact that the DNV estimates are outliers significantly below the estimates based on other methods, we conclude that the DNV estimates should not be relied upon as an accurate estimate of tanker spill risk. This comparison demonstrates the importance of a more collaborative process that encourages stakeholder participation in the risk assessment. Risk assessment should be viewed as a participatory process informed by technical analysis whereby First Nations and stakeholders define risk acceptability, provide input into the analysis and research, and develop a single study that has the support of all stakeholder groups.

Figure 5.2. Comparison of TMEP Tanker Spill Probabilities



Note: The probability estimates from the different models are not directly comparable because they are based on different minimum spill sizes, geographic zones and mitigation measures. OSRA results exclude all spills <1000 bbl and VTRA results exclude spills < 6,290 bbl and exclude 27% of the tanker route. Mitigation measures also vary by model result.

6. Potential Spill Clean-up and Damage Costs

6.1. Introduction

In this chapter we review pipeline, tanker, and terminal spill costs from several sources including peer-reviewed literature, government data, regulatory applications, and case studies. This review also identifies qualifications and limitations of the different spill cost estimates. From this review we identify upper bound estimates of potential spill costs for the TMEP and compare these costs with upper bound estimates in the TMEP application.

6.2. Review of Selected Pipeline Spill Costs and Compensation

To estimate a range of potential pipeline spill costs, we rely on information and data from the TMEP regulatory application, the Basic Oil Spill Cost Estimation Model (BOSCEM) from Etkin (2004), PHMSA accident reports, and spill cost estimates from the Enbridge Line 6B spill in Marshall, Michigan.

In Appendix G of Volume 7 of the TMEP application, Ruitenbeek estimates potential clean-up and damage costs of an oil spill from the TMEP. The analysis of spill costs examines several data sources including a study from Etkin (2004) entitled *Modeling Oil Spill Response and Damage Costs*, International Oil Pollution Compensation Fund (IOPCF) data (Kontovas et al. 2010), Natural Resource Damage Assessment in Washington State, a study by Anielski (2012) evaluating ecosystem goods and services along the NGP right-of-way, and Atlantic Canada spill costs from Transport Canada. Ruitenbeek relies on spill clean-up costs from Etkin (2004) to estimate a range of potential spill clean-up costs and applies a damage cost multiplier of 1.5 to clean-up costs to estimate potential damage costs. Spill costs depend on several factors including spill size, whether the area of the spill is high-consequence, and other factors such as remoteness of spill, water exposure, and type of clean-up, among others. Updating the analysis in TM (2013, Vol. 7, App. G, p. 24) by Dr. Ruitenbeek to 2014 CAD results in overall, upper bound clean-up and damage costs ranging from $28,098 to $86,456 per bbl for pipeline leaks and $6,484 to $16,128 per bbl for pipeline ruptures. Potential spill sizes for leaks and ruptures are estimated in Appendix G of Volume 7 of the TMEP application based on PHMSA data and spill outflow modelling in Volume 7, respectively.

Table 6.1. Summary of Pipeline Spill Costs Per Bbl from TMEP Application

Type of Spill	Expected Upper Bound Pipeline Spill Costs per bbl		
	Clean-up	Damage Costs	Total Costs
Leak (30 bbl)	34,582	51,873	86,456
Leak (715 bbl)	11,239	16,859	28,098
Rupture (6,290 bbl in HCA)	6,451	9,676	16,128
Rupture (12,580 bbl in HCA)	3,584	5,376	8,960
Rupture (12,580 bbl)	2,594	3,890	6,484
Rupture (25,160 bbl)	2,594	3,890	6,484

Source: TM (2013, Vol. 7, App. G, p. 24). Note: HCA = High Consequence Area. Spill cost estimates from TMEP application converted to 2014 (CAD).

The study from Etkin (2004) entitled *Modeling Oil Spill Response and Damage Costs* develops the BOSCEM to estimate oil spill costs (Etkin 2004, p. 1). The spill cost estimates in BOSCEM were developed based on an analysis of data for spill response, socioeconomic, and environmental damage costs from historical spill case studies, spill trajectory, and impact analysis (Etkin 2004, p. 2). BOSCEM incorporates specific factors that influence spill costs including the amount spilled, the type of oil, the response methodology and its effectiveness, impacted medium (e.g. open water, wetland, grassland, rock, etc.), socioeconomic value based on location of spill, freshwater vulnerability, habitat/wildlife sensitivity, and type of location (Etkin 2004, p. 1). Based on these cost modifiers, BOSCEM estimates three distinct spill cost categories: (1) response costs; (2) socioeconomic damage costs; and (3) environmental damage costs. The three spill cost categories can be summed to estimate total spill costs.

We use two scenarios to demonstrate the range of potential estimates associated with heavy oil spill costs from Etkin (2004). The lower bound estimates use the minimum values for all cost modifiers in the BOSCEM for response, socioeconomic, and environmental costs, while the upper bound estimates use the maximum values for all cost modifiers in the BOSCEM[20]. The results show that potential spill cost estimates based on Etkin (2004) represent a wide range (Table 6.2). Total costs range from $3,022 per bbl for the largest spill size category to $167,244 for spills between 24 and 238 bbl. We then compare these estimates to the upper bound costs provided in the TMEP application. The comparison shows that the "upper bound" costs in the TMEP application are up to $86,034 less per bbl than upper bound costs for spill size categories computed using the maximum values for all cost modifiers in Etkin (2004) (Table 6.3). The TMEP application therefore does not present an accurate estimate of Etkin's (2004) upper bound costs.

Table 6.2. Estimated Spill Costs Per Bbl Based on Etkin (2004)

Spill Size	Pipeline Spill Costs per bbl		
	Response (Clean-up)	Socioeconomic and Environmental	Total Costs
Less than 12 bbl	9,461 – 42,973	3,235 – 34,839	12,697 – 77,813
12 - 24 bbl	9,431 – 42,778	5,860 – 88,907	15,291 – 131,685
24 - 238 bbl	9,400 – 42,583	7,569 – 124,662	16,970 – 167,244
238 - 2,380 bbl	8,149 – 40,043	4,883 – 74,089	13,032 – 114,132
2,380 - 23,800 bbl	3,144 – 17,482	2,197 – 31,375	5,341 – 48,858
More than 23,800 bbl	1,099 – 8,497	1,923 – 27,453	3,022 – 35,950

Source: Computed from Etkin (2004). Note: See footnote 20 for a description of the values used in BOSCEM.

[20] Ranges represent lower bound values and upper bound values based on the following values for modifiers in BOSCEM: (1) Lower bound values include 50% mechanical response costs for heavy oils, location modifier = 0.5 (pavement/rock), socioeconomic cost modifier = 0.1 (none), freshwater modifier = 0.4 (industrial), and wildlife modifier = 0.4 (urban/industrial); and (2) Upper bound values include 0% mechanical response costs for heavy oils, location modifier = 1.6 (wetlands), socioeconomic cost modifier = 2.0 (extreme), freshwater modifier = 1.7 (wildlife use), and wildlife modifier = 4.0 (wetlands). All values adjusted for increases in inflation from 2002 to 2014 and exchange rate.

Table 6.3. Comparison of Spill Cost Estimates Per Bbl in TMEP Application and Costs Based on Etkin (2004)

Comparable Spill Size Category	Total Upper Bound Pipeline Spill Costs per bbl		
	Etkin (2004)	TMEP Application	Difference
24 - 238 bbl	167,244	86,456	(80,788)
238 - 2,380 bbl	114,132	28,098	(86,034)
2,380 - 23,800 bbl	48,858	16,128	(32,730)
More than 23,800 bbl	35,950	6,484	(29,466)

Note: Spill costs from TM (2013, Vol. 7, App. G) updated to 2014 CAD.

We provide a second estimate of potential spill costs based on PHMSA data. The PHMSA collects information on pipeline leaks and ruptures from operators that submit accident reports spills[21]. Information collected includes the type of spill (leak or rupture) as well as costs associated with the spill that include: (1) public and non-operator private property damage; (2) commodity lost; (3) operator's property damage and repairs; (4) operator's emergency response; (5) operator's environmental

[21] PHMSA (2011, p. 20) defines a leak as "… a failure resulting in an unintentional release of the transported commodity that is often small in size, usually resulting in a low flow release of low volume, although large volume leaks can and do occur on occasion" and a rupture as "… a loss of containment that immediately impairs the operation of the pipeline. Pipeline ruptures often result in a higher flow release of larger volume. The terms "circumferential" and "longitudinal" refer to the general direction or orientation of the rupture relative the pipe's axis. They do not exclusively refer to a failure involving a circumferential weld such as a girth weld, or to a failure involving a longitudinal weld such as a pipe seam. (Precise measurement of size – e.g., micrometer – is not needed. Approximate measurements can be provided in inches and one decimal.)"

remediation; and (6) other costs (PHMSA 2012). PHMSA sums these six categories to estimate total property damages from a spill[22].

To estimate spill costs from the PHMSA data, we use the most current dataset available from the PHMSA (2014b) from January 2010 to November 2014[23]. We filter the data for crude oil releases from onshore pipelines and components including pumps, terminals, tanks, and other equipment. During, this period, there is spill cost data for 649 leaks and 24 ruptures that resulted in crude oil releases of 91,323 bbl and 42,216 bbl, respectively. For these leaks and ruptures, pipeline operators reported total costs of $291.1 million and $1,298.1 million, respectively, or an average of approximately $3,188 per bbl for leaks and $30,750 per bbl for ruptures (Table 6.4). PHMSA data for ruptures during this period include cost estimates for the Enbridge Line 6B spill in Marshall, Michigan.

[22] According to PHMSA (2011), categories contain the following types of costs: (1) Public and non-operator private property damage includes physical damage to the property of others, cost of environmental investigation and remediation of site, laboratory costs, costs for engineers, scientists, and others; (2) Commodity lost includes the cost of the commodity that was not recovered; (3) Operator's property damage and repairs includes physical damage to the property of the operator such as replacement value of the damaged pipe and repair costs associated with restoring property to its predefined level of service such as excavation, materials, and labor costs, among others; (4) Operator's emergency response includes costs to return the accident site to a safe state and costs to contain, control, mitigate, recover, and remove the commodity from the environment including materials, labor, and supplies; (5) Operator's environmental remediation includes those costs associated with engineering, scientists, laboratory work, and the installation, operation and maintenance of recovery systems over the long-term; and (6) Other costs that include any and all costs not identified in the previous five categories.

[23] Spill cost data from the 2002-2009 PHMSA dataset were not included since the dataset includes a large proportion of crude oil pipeline spills that are not categorized as either leak or rupture. Indeed, 78.9% of the onshore, crude oil pipeline spills that reported damage costs from 2002 to 2009 were uncategorized. Therefore, given that we are trying to estimate pipeline spill costs for leaks and ruptures, we did not include PHMSA data from 2002-2009.

Table 6.4. Summary of Spill Costs from PHMSA 2010 – 2014

Cost Category	Leaks (All)		Ruptures (All)	
	Total Costs	Per bbl	Total Costs	Per bbl
Non-operator property damage	21,475,540	235	40,355,048	956
Commodity lost	4,514,642	49	1,237,887	29
Property damage/repairs	56,761,520	622	15,760,557	373
Emergency response	88,339,406	967	420,990,945	9,972
Environmental remediation	109,877,204	1,203	779,744,754	18,471
Other costs	10,156,543	111	40,040,215	948
Total property damage	291,124,854	3,188	1,298,129,407	30,750

Source: PHMSA (2014b). Note: Spill costs from PHMSA (2014b) converted to 2014 CAD. Per bbl spill costs represent average values.

Spill costs from PHMSA are likely conservative for numerous reasons. First, PHMSA uses an estimate of $841 million for the Enbridge Line 6B cost, which is significantly lower than the most recent estimates of $1.21 billion (Enbridge 2014). Including the $369 million in additional costs for the Enbridge Line 6B spill would increase the per bbl spill cost for ruptures from $30,750 to approximately $40,400. Second, it is unclear to what degree spill costs from PHMSA include all relevant socioeconomic 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 proportion of total environmental costs are covered by the remediation expenses. For example, excluded damage costs could include compensatory damages to the public for the lost 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 monetary worth that individuals ascribe to the protection or preservation of resources or psychological costs associated with factors such as stress and dislocation of impacted parties.

The Enbridge Line 6B can be used to provide a third estimate of potential, upper bound pipeline spill costs. On July 25, 2010, the Enbridge Lakehead Line 6B ruptured in a wetland in Marshall, Michigan releasing approximately 843,444 gallons (20,074 bbl) of bitumen crude oil (NTSB 2012). The oil saturated the wetlands and eventually flowed into Talmadge Creek and the Kalamazoo River (NTSB 2012). As of September 30, 2014, Enbridge estimates that its total costs associated with the Line 6B spill are $1.21 billion (Enbridge 2014). The cost estimate consists of $551.6 million in response personnel and equipment, $227 million in environmental consultants, and $429.4 million in professional, regulatory, and other expenses (Enbridge 2014, p. 19). Total costs from the Line 6B release amount to $60,177 per bbl of crude oil spilled (Table 6.5). While more analysis is required to determine explanatory variables for the high reported costs associated with the Enbridge Line 6B spills, some factors may be the type of oil spilled (bitumen) which may be harder to clean up and the fact that the oil impacted a high value aquatic environment, stronger clean-up standards (given the high profile of the spill) and more accurate reporting of costs (again due to the higher profile of the spill). Furthermore, Enbridge states that it may incur future costs from the spill from regulatory agencies, fines and penalties, and litigation and claim settlement expenditures (Enbridge 2014). There are approximately 10 actions or claims against Enbridge in federal and state courts related to the Line 6B spill, including actions seeking class status (Enbridge 2014, p. 21).

Table 6.5. Summary of Spill Costs from Enbridge Line 6B Spill

Cost Category	Total Costs (in millions)	Cost per bbl
Response personnel and equipment	551.6	27,478
Environmental consultants	227.0	11,308
Professional, regulatory, and other	429.4	21,391
Total costs	1,208.0	60,177

Source: Enbridge (2014). This is an estimate of spill costs as of 2014 and final spill costs may be higher.

The review of selected studies estimating pipeline spill costs demonstrates that estimates in TM (2013, Vol. 7, App. G) based on Etkin (2004) do not represent upper bound estimates as claimed (Table 6.6). The TMEP application estimates total upper bound spill costs of $16,128 per bbl for pipeline ruptures, which is well below the upper bound estimate of $48,858 per bbl from Etkin (2004), the $30,750 per bbl average from PHMSA, and the $60,177 per bbl in spill costs for the 20,074-bbl spill from Enbridge Line 6B spill. The upper bound spill cost estimate of $86,456 per bbl for leaks in the TMEP application is below Etkin’s upper bound estimate of $167,244 but well above the

PHMSA average. Therefore based on this comparison, estimates in the TMEP application should not be considered as upper bound estimates of pipeline spill costs.

Table 6.6. Summary of Spill Cost Estimates Per Bbl for Pipeline Leaks and Ruptures

Type of Spill	TMEP Application (Volume 7)	BOSCEM (Etkin 2004)	PHMSA 2010-2014 (PHMSA 2014b)	Enbridge Line 6B (Enbridge 2014)
Leak	28,098 – 86,456	12,697 – 167,244	3,188	n/a
Rupture	6,484 -–16,128	3,022 – 48,858	30,750	60,177

Note: Etkin (2004) does not categorize spill costs as leaks and ruptures and we estimate the range of these values based on spill outflow estimates in TM (2013 Vol. 7, App. G) that categorize spills of 715 bbl and less as leaks and spills of 6,290 bbl and greater as ruptures.

6.3. Review of Selected Terminal Spill Costs

The analysis by Dr. Ruitenbeek in Volume 7 of the TMEP application uses cost estimates based on Etkin (2004) to estimate potential spill costs associated with a marine terminal spill. Marine terminal spill costs depend on several factors including spill size, whether the area of the spill is high-consequence, and other factors such as remoteness of spill, water exposure, and type of clean-up, among others. However, in the case of terminal spills, Dr. Ruitenbeek applies a damage cost multiplier of 0.85 to clean-up costs in order to estimate potential damage costs. The multiplier of 0.85 for terminal spill costs is lower than the factor of 1.5 for pipeline spills and is based on the multiplier for terminal spill costs derived from Transport Canada cost data for Atlantic Canada (TM 2013, Vol. 7, App. G, p. 17). For a 103 m^3 (648 bbl) spill at the marine terminal, the author estimates upper bound clean-up costs of $11,000 (2013 CAD) per bbl and damage costs of $9,350 (2013 CAD) per bbl resulting in overall potential spill costs of $20,350 (2013 CAD) per bbl (Table 6.7).

To estimate potential spill costs associated with a 103 m^3 (648 bbl) spill, we use the BOSCEM developed by Etkin (2004) and rely on default values for all cost modifiers for response, socioeconomic, and environmental costs. We use default settings because the default location for the BOSCEM represents open water/shore, which is consistent with the nearshore water exposure value used in the analysis in TM (2013, Vol. 7, App. G)[24]. The results show that potential spill cost estimates based on Etkin (2004) of $48,772 are more than double the upper bound costs estimated in the TMEP application for a terminal spill of 103 m^3 (648 bbl).

Table 6.7. Summary of Potential Terminal Spill Costs Per Bbl

Cost Category	Expected Terminal Spill Costs per bbl	
	TMEP Application	Etkin (2004)
Clean-up	11,162	21,914
Damage Costs	9,487	26,858
Total Costs	20,649	48,772

Source: Computed from Etkin (2004); TM (2013, Vol. 7, App. G, p. 24). Note: Spill costs from the TMEP application represent upper bound costs for a spill that occur in a high consequence area and are converted to 2014 CAD. See footnote 24 for a description of the values used in BOSCEM.

6.4. Review of Selected Tanker Spill Costs

We estimate potential tanker spill costs from several sources including an analysis of spill cost data from the IOPCF, the regulatory application for the NGP, and case studies from two large tanker spills (i.e. the Exxon Valdez oil spill, or EVOS, and Prestige oil spill). Kontovas et al. (2010) estimate oil spill costs based on data from the IOPCF. In their analysis, the authors use the compensation paid to claimants to represent the cost of an oil spill. Kontovas et al. (2010) obtain IOPCF compensation information for 84 spills that occurred between 1979 and 2006 and complete regression analyses of clean-up costs and total costs. Cost categories in the dataset analyzed by Kontovas et al. (2010) include clean-up, preventative measures, fishery-related costs,

[24] Default values for modifiers in BOSCEM include: 10% mechanical response costs for heavy oil spills between 10,000 and 100,000 gallons (238 and 2,380 bbl), location modifier = 1.0 (open water/shore), socioeconomic cost modifier = 0.7 (moderate), freshwater modifier = 0.9 (non-specific), and wildlife modifier = 1.5 (river/stream).

tourism-related costs, farming-related costs, other loss of income, other damage to property, and environmental damage/studies. The regression analyses of the spill costs estimate an average per tonne oil spill clean-up cost of $1,639 in 2009 United States dollars (USD) and an average per tonne total spill cost of $4,118 (2009 USD), suggesting that socioeconomic and environmental damage costs represent the difference between these two costs with an average of $2,479 (2009 USD) per tonne. Converting the Kontovas et al. (2010) estimates from 2009 USD per tonne to 2014 CAD per bbl based on changes in the consumer price index over that period, the average annual exchange rate, and oil conversion factors, we estimate total spill costs of approximately $685 per bbl (Table 6.9).

Table 6.8. Summary of Spill Costs Per Bbl from Kontovas et al. (2010)

Cost Category	Spill Cost Estimates per bbl
Clean-up	272
Damages	412
Total	685

Source: Computed from Kontovas et al. (2010). Note: Figures from Kontovas et al. (2010) converted to 2014 CAD.

There are several weaknesses to the Kontovas et al. (2010) spill cost estimates. 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 in the case of large spills (Thébaud et al. 2005)[25]. Second, IOPCF payments are limited by maximum pay out limits set by the funds and therefore only compensate a portion of total spill damages if damages exceed the fund limits[26]. Third, IOPFC data excludes several types of damage costs including non-market use values

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

[26] For example, claimants in the 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).

and passive use values. Fourth, tanker spill cost data represent world averages that are not adjusted for locational 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).

Spill cost estimates prepared by Wright Mansell for Enbridge's NGP application represent a second estimate of potential tanker spill costs. In the section 52 application for the NGP, WM (2012) reviews various spill cost estimates for spill damages potentially resulting from a tanker spill on the North Coast of BC. Studies of offshore oil spill costs reviewed by WM (2012) include TC (2007), Psarros et al. (2009), and Kontovas et al. (2010). Based on their review, WM estimates clean up costs of $17,082 per bbl and uses a 1.5 multiplier from Kontovas et al. (2010) to estimate additional environmental damage costs of $25,623 per bbl (both costs adjusted from 2012 and 2014). WM claims that total costs of $42,706 per bbl spilled are conservative (i.e. at the upper end of the range) since they represent an upper bound estimate based on the review of the literature.

Table 6.9. Summary of Spill Costs Per Bbl from WM (2012)

Cost Category	Spill Cost Estimates per bbl
Clean-up	17,082
Damages	25,623
Total	42,706

Source: Computed from WM (2012). Note: Figures from WM (2012) converted to 2014 CAD.

The study by Hotte and Sumaila (2014) on potential tanker spill costs from the NGP to British Columbians represents another source of spill costs estimates. The authors use economic impact assessment methodology that measures the direct, indirect, and induced effects to ocean-based industries including commercial fishing, port activities, ferry transportation, and marine tourism from a medium (63,000 bbl) and high (257,000 bbl) impact spill. To estimate these impacts, the authors rely on tanker spill information from the Exxon Valdez spill. The study measures economic effects from a spill on total output, employment, and gross domestic product and does not include potential costs associated with spill response and clean-up activities, social, cultural, and ecological impacts, and damages to passive use values. The authors present spill cost estimates as present values discounted over a 50-year period (Table 6.10).

Table 6.10. Summary of Total Spill Costs from Hotte and Sumalia (2014)

Industry	63,000 Bbl Spill			257,000 Bbl Spill		
	Output	Person Years	GDP	Output	Person Years	GDP
Commercial Fishing	37 – 185	247 – 1,032	18 – 91	40 – 187	268 – 1,465	20 – 92
Port Activities	0 – 0	0 – 0	0 – 0	3 – 50	21 – 374	2 – 26
Ferry Transportation	2 – 5	21 – 59	1 – 3	2 – 6	27 – 80	2 – 5
Marine Tourism	4 – 7	131 – 223	5 – 8	46 – 78	1,336 – 2,460	52 – 92
Total	43 – 198	399 – 1,314	24 – 102	91 – 322	1,652 – 4,379	75 – 214

Source: Computed from Hotte and Sumaila (2014). Note: Output and GDP from study are adjusted to represent millions of 2014 CAD. The range represents low and high estimates provided by the authors.

We make adjustments to spill costs from Hotte and Sumaila (2014) in order to estimate spill costs per bbl that are comparable with other costs described in this section. First, we convert present value losses to gross domestic product from ocean-based industries to undiscounted estimates over a 50-year period. Second, we estimate clean-up costs based on the ratio of clean-up costs to social and environmental costs from WM (2012). Based on these adjustments to the Hotte and Sumaila study, we estimate that total spill costs per bbl could range from $6,090 to $11,877 depending on the size of the spill (Table 6.11). We acknowledge that spill costs would likely be higher since they represent market values for four ocean-based industries and omit damages to social, cultural, ecological, and passive use values. We further acknowledge that these costs represent potential spill impacts to the North Coast region of British Columbia and costs to the Lower Mainland would likely be higher due to the larger and more diversified economy compared to the North Coast.

Table 6.11. Estimated Upper Bound Spill Costs Per Bbl based on Hotte and Sumaila (2014)

Cost Category	63,000 Bbl Spill	257,000 Bbl Spill
Estimated Clean-up	4,751	2,436
Economic Costs	7,126	3,654
Total	11,877	6,090

Source: Computed from Hotte and Sumaila (2014). Note: Clean-up costs estimated based on the ratio of clean-up costs to damage costs of 0.67 from WM (2012).

Evidence submitted to the Joint Review Panel for the Northern Gateway Project by Gunton and Broadbent (2012) represent a third estimate of potential spill costs. Gunton and Broadbent (2012) summarize costs from the EVOS based on a review of the literature and describe a range of costs from the EVOS associated with a decrease in economic activity, sociocultural impacts, clean-up activities, and non-use natural resource damages. The authors estimate the economic costs to commercial fisheries based on the Cohen (1995) study that estimates the accident’s impact on commercial fisheries in southcentral Alaska and the damages claimed by local commercial fishermen in a class action lawsuit (Duffield 1997). EVOS costs to recreational fishing, a separate cost category than commercial fishing, are estimated from a study by Carson and Hanemann (1992) that uses travel cost methodology to estimate the economic impacts from a decrease in recreational fishing activity associated with the spill. The net negative impact to the tourism industry in Alaska was estimated based on a study prepared by the McDowell Group (1990) and the authors estimate wildlife damages from the cost to replace, relocate, and rehabilitate wildlife impacted by the EVOS as described by ARI (1993) and Brown (1992). Sociocultural costs are estimated based on court claims made by Alaska natives for reductions in usable pounds of all wild foods as well as property damages to sites with cultural and heritage significance injured by the EVOS estimated based on McAllister 1992 (as cited in EVOSTC 1994). Gunton and Broadbent estimate oil spill and clean-up activities and costs using reported costs spent by Exxon as reported in Duffield (1997) and EVOSTC (2009).

Converting spill costs to 2014 CAD results in total costs of the EVOS based on Gunton and Broadbent of $4,349.6 to $5,824.2 million and average costs of $16,859 to $22,575 per bbl based on the EVOS size of 258,000 bbl (Table 6.12)[27]. We note that the methods used to estimate EVOS spill costs have a conservative bias and therefore actual costs are likely higher (see Gunton and Broadbent 2012, pp. 69-85 for a more comprehensive discussion of the limitations and qualifications of EVOS studies). For example, if the 1.5 multiplier of clean-up costs to socioeconomic and environmental costs from Kontovas et al. (2010) is applied to EVOS spill costs of $3,939.6 million, socioeconomic and environmental costs could total $5,909.4 million thus increasing total potential spill costs from the EVOS to $9,849 million or approximately $38,174 per bbl.

Table 6.12. Summary of Economic Costs of the EVOS

Cost Category	Total Economic Costs (in millions)	Costs per bbl
Commercial Fishing	301.1 – 1,474.9	1,167 – 5,717
Recreational Fishing	7.2 – 98.2	28 – 381
Tourism	37.5	145
Wildlife Damages	48.8 – 227.3	189 – 881
Subsistence Use	14.1 – 45.4	55 – 176
Cultural and Heritage Impacts	1.5	6
Spill Clean-up Activities	3,939.6	15,270
Total	4,349.6 – 5,824.2	16,859 – 22,575

Source: Computed from Gunton and Broadbent (2012). Note: Figure adjusted for inflation from 2010 CAD to 2014 CAD.

[27] The degree to which this estimate includes potential double-counting is unknown. It is possible that a portion of the costs incurred by recreational fishers are captured in the costs to the tourism industry. Similarly, it is also possible that some portion of wildlife damage costs are captured in passive use damages as well as cleanup costs. It is not possible to estimate whether or not this is the case and what portion this might be. We note that costs for tourism, recreational fishing, and wildlife damages represent a relatively small proportion of total costs in Gunton and Broadbent (2012) and thus any potential double-counting is unlikely to have a large effect on overall costs

Liu and Wirtz (2006) use an economic model to measure environmental damages from the Prestige oil spill in Spain. The Prestige tanker suffered hull damage on November 13, 2002 off the Spanish Coast and broke apart six days later releasing approximately 63,000 tonnes (461,800 bbl) of oil (ITOPF undated). The authors evaluate five cost categories that they claim cover the overall direct and indirect costs of an oil spill, which include: (1) environmental damages; (2) socio-economic losses; (3) research costs associated with assessment and monitoring; (4) clean-up costs; and (5) other cost categories. Liu and Wirtz (2006, p. 55) estimate the following damage costs associated with the Prestige oil spill: (1) €603.6 million in environmental damages; (2) between €633.58 and €6,734.4 million in short- and long-term socioeconomic damages; (3) €10 million in research costs; (4) €1,000 million in clean-up costs; and (5) €0.51 million in other costs. The authors estimate overall costs of the Prestige oil spill of approximately €8,500 million in the long-term, which equal approximately $14,441.1 million in total long-term costs after converting costs to 2014 CAD (Table 6.13). At the time of the incident, spill damage costs exceeded available payments. Liu and Wirtz (2006, p. 56) estimate that payments of €172 million from the 1992 Fund and Civil Liability Convention represented approximately 2% of total oil spill costs. Thus society incurred the remaining 98% of costs associated with the Prestige oil spill.

Table 6.13. Summary of Spill Cost Estimates for Prestige Oil Spill

Cost Category	Total Costs (in millions)	Costs per bbl
Environmental Damages	1,044.1	2,261
Long-term Socioeconomic Losses	11,649.1	25,226
Research Costs	17.3	37
Clean-up Costs	1,729.8	3,746
Other Costs	0.9	2
Total	14,441.1	31,272

Source: Computed from Liu and Wirtz (2006). Note: Figures from Liu and Wirtz (2006) converted to 2014 CAD.

The studies reviewed demonstrate that there is a wide range of potential spill cost estimates for damages caused by tanker spills. Based on these studies, spill clean-up costs range from $3,746 to over $17,082 per bbl and damage costs range from $4,447 to $27,526 per bbl. Estimates from WM (2012) represent the highest potential costs of the studies reviewed at $42,706 per bbl. Spill cost estimates from Kontovas et al. (2010) are not included in Table 6.14 since these spill costs derived from IOPCF data represent only compensation paid to claimants and do not represent all potential spill costs. As Kontovas et al. (2010 p. 4) state "…we further note that admissible claims cannot be paid in full, especially in the case of large spills…" and Thebaud et al. (2005) found that compensation paid to claimants from the IOPCF in the case of six major oil spills represented between 5% and 62% of compensation claimed while Liu and Wirtz conclude that compensation costs represent only 2% of total damage costs. We also note that spill costs vary significantly depending on the location of the spill and thus spill costs in the Georgia Strait could be higher or lower than those identified in Table 6.14. As Vanem et al. (2008) point out, spill costs depend on the type of oil spilled, the physical, biological, and economic characteristics of the location of the spill, the amount of oil spilled, weather and sea conditions, the time of year of the spill, the effectiveness of clean-up response technologies, and the management and control of response operations. The average spill clean-up cost per tonne spilled in North America is among the highest in the world and is over 1.5 times higher than the weighted global average (Vanem et al. 2008).

Table 6.14. Summary of Potential Spill Cost Estimates Per Bbl for a Tanker Spill

Cost Category	Estimated Potential Spill Cost per bbl			
	NGP Application (WM 2012)	NGP Spill (Hotte and Sumaila 2014)	EVOS (Gunton and Broadbent 2012)	Prestige (Liu and Wirtz 2006)
Clean-up	17,082	4,751	15,270	3,746
Damages	25,623	7,126	4,447	27,526
Total	42,706	11,877	19,717	31,272

Note: Spill cost estimates for the EVOS represent median values for the lower and upper bound estimates.
Note: WM (2012) refers to non-clean-up costs as damage costs. Hotte and Sumaila (2014) do not estimate costs from damages to social, cultural, ecological, and passive use values.

6.4.1. Review of Potential Passive Use Damages

Passive use values reflect the worth that people ascribe to the protection or preservation of natural resources and the environment that they may not directly use (Freeman 2003; Kramer 2005). There are many issues and challenges in estimating passive values and in some cases for some First Nations and stakeholders monetary estimation may not be possible or appropriate. Nonetheless there is a consensus that passive values exist and should be taken into account in decision making.

One method for estimating passive use values is to ask individuals what they would be willing to pay to prevent the loss or the amount an individual would be willing to accept in compensation to incur the loss. The valuation based on willingness to accept (WTA) a loss is generally much higher than the willingness to pay (WTP) to prevent a loss (Horowitz and McConnell 2002). Determining which measure - WTA or WTP - to use is therefore an important consideration that depends on the reference point that individuals use to value the underlying good or service (Knetsch 2005; Zerbe and Bellas 2006; Shaffer 2010). Knetsch (2005) argues that the appropriate measure of value depends not on legally defined property rights but on individual perceptions of entitlement associated with changes affecting the availability of public goods. In this sense, if individuals regard the reference point for valuing public goods as the current conditions of the resource, a decrease in current conditions should be measured by the amount of compensation individuals would be willing to accept for the loss, whereas any improvement in current conditions should be measured by the amount individuals would pay for the gain (Knetsch 2005; Shaffer 2010). For an oil spill, the logical reference point is the status quo prior to the spill, or the absence of a spill in the study region, and thus the loss in welfare from a spill should be measured by the compensation individuals would require in order to accept the adverse impacts of a spill (Knetsch 2005). Carson et al. (2003) agree that WTA compensation for an environmental loss from a spill represents a more appropriate measure of value than WTP to prevent a loss.

To estimate potential passive use damages for the TMEP, we rely on existing studies estimating WTP to prevent oil spills and adjust WTP estimates to reflect WTA compensation for a spill. Although the conventional assertion was that individuals value gains and losses the same (Willig 1976; Diamond et al. 1993), empirical evidence indicates that an individual's WTA compensation for a change that is perceived as a loss is substantially larger than an individual's WTP to prevent the loss (Rutherford et al. 1998; Horowitz and McConnell 2002; Knetsch 2005). Horowitz and McConnell (2002) evaluated 45 studies with WTA/WTP ratios and found that WTA values were 10.4 times higher than WTP values for environmental benefits. To provide an estimate of potential

WTA values we adjust WTP estimates with this WTA/WTP ratio from Horowitz and McConnell (2002).

We estimate potential passive use values for the TMEP using benefit transfer methodology and two studies estimating WTP to prevent oil spills in Alaska and California. The first study completed by Carson et al. (1992), and updated by Carson et al. (2003), estimates that US residents would be willing to pay between \$4.9 and \$7.2 billion (1991 USD) to prevent another oil spill similar to the Exxon Valdez disaster[28]. In the *ex ante* contingent valuation study, Carson et al. (1992; 2003) asked respondents across the US how much they would pay in the form of a one-time federal tax to implement a program that would prevent a possible second EVOS over the next ten years. In order to provide a concrete illustration of measures that could be implemented to make the contingent valuation study plausible to the survey respondents, the survey describes an escort ship program whereby Coast Guard ships would escort tankers through Prince William Sound. The Carson et al. (1992) study is widely considered among the most sophisticated contingent valuation studies for assessing damages to non-use natural resources (ARI 1993). The study uses methodological best practices that withstood the scrutiny of the courts and independent experts[29].

The second contingent valuation study from Carson et al. (2004) estimates the amount that households in California would be willing to pay to prevent oil spills along

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[28] The Exxon Valdez ran aground on Bligh Reef on March 24, 1989 releasing 258,000 bbl 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 EVOS have yet to recover (EVOSTC 2010).

[29] Best practices include a comprehensive pretesting program to refine the survey instrument, rigorous probability sampling to capture a representative sample of the US population, in-person interviews, double-bounded discrete choice WTP questions, detailed description of the program inclusive of photographs and maps, and checks of respondents to ensure their comprehension (Carson et al. 2003). 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.

the California Coast[30]. Similar to the EVOS study, this *ex ante* investigation asked respondents how much they would pay for a one-time tax to implement a ship escort program that would prevent/contain oil spills over the next ten years until all tankers have double-hulls. The California oil spill (COS) study also implemented methodological best practices similar to the EVOS study that include a comprehensive pretesting phase and pilot study, probability sampling to represent the California population, the use of in-person interviews, visual aids refined during the pretesting phase, and the use of advanced statistical techniques to evaluate WTP.

The EVOS and COS studies determine similar estimates for the amount individuals would be willing to pay to prevent an oil spill. The EVOS study by Carson et al. (2003) estimates a lower bound Turnbull mean WTP value of $53.60 per household and an upper bound value of $79.20 (both in 1991 USD). The COS study by Carson et al. (2004) estimates a lower bound Turnbull estimate of $76.45 (in 1995 USD). Adjusted for inflation to 1995, the EVOS WTP estimates range between $59.98 and $88.62, the interval of which includes the COS study estimate of $76.45. The underlying populations are an important distinction between the EVOS and COS studies (Table 6.15). The EVOS study evaluates WTP for US households while the COS study evaluates WTP for California households and so the populations represented in the studies are different.

[30] Carson et al. (2004) do not define the volume of oil spilled in the COS 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.

Table 6.15. Comparison of EVOS and COS Studies

Study Feature	EVOS Study	COS 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 recovery 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).

We use benefit transfer to estimate Canadians' valuation of potential passive use damages from an oil spill on the BC Coast. Transferring values from one study area to another is a widely-used and accepted methodological approach when there is insufficient time and resources to complete an original valuation study (Brouwer 2000; Boardman et al. 2011). Selecting the study site from which to transfer values to the policy site is an important step in benefit transfer methodology to reduce transfer error (Boyle and Bergstrom 1992; Desvousges et al. 1992). Values should be obtained from studies that rely on adequate data, sound economic methods and correct empirical techniques (Desvousges et al. 1992). Further, the study and policy site should have similar characteristics (Desvousges et al. 1992) and the non-market commodity valued at the study site should be identical to the policy site (Boyle and Bergstrom 1992). The EVOS study by Carson et al. (2003) is a good study to rely on to estimate passive values because it uses methodological best practices, measures WTP to prevent a spill, which is also the non-market commodity of interest to measure passive use values for the TMEP, and the study area has similar biophysical and socioeconomic characteristics to those of the TMEP area.

We transfer passive use values from the EVOS study that determines household WTP values at a national scale in the US since protecting the BC coast from an oil spill will have value to all Canadians. We adjust household level lower and upper bound mean WTP estimates from Carson et al. (2003) to 2014 CAD based on changes in the consumer price index and aggregate the data to reflect the number of households in Canada[31]. We estimate that Canadian households could be willing to pay a total of between $1.4 and $21.1 billion to avoid a tanker spill in BC. The low value of $1.4 billion reflects the lower bound WTP value from Carson et al. (2003) whereas the high value of $21.1 billion represents passive use values based on the WTP from Carson et al. (2003) adjusted for the WTA/WTP ratio of 10.4 from Horowitz and McConnell (2002).

Table 6.16. Potential Passive Use Damages from a Tanker Spill

Cost Category	Low Value - WTP (in billions)	High Value - WTA (in billions)
Passive use damages	$1.4	$21.1

Source: Computed from Carson et al. (2003).

There are several qualifications to transferring this assessment of passive use values from the EVOS to the TMEP. First, the calculations of passive use reflect the values, morals, and attitudes of American society after the EVOS and are based on WTP values to prevent a major oil spill in Alaska, not BC. Nonetheless, transferring values from other jurisdictions provides an approximate measure of passive use values in the absence of an original valuation study for the BC coast. Canadians may value passive use damages higher or lower than Americans. Second, we do not adjust WTP values transferred from Carson et al. (2003) for higher median household incomes in Canada even though Carson et al. (2003) observe a strong association between higher incomes and a higher WTP to prevent another EVOS. Median household income in Canada in 2012 is 24% higher than the inflation-adjusted median household income in

[31] We adjust lower and upper bound WTP values from the Carson et al. (2003) study for inflation, convert USD to CAD, and aggregate the results to reflect the number of households in Canada in 2011 (Statistics Canada 2012). We acknowledge that there may be some degree of double-counting in the passive use values since British Columbians also hold use values for the area impacted by a spill. Although we have not estimated the potential amount of double-counting, we believe this amount is likely to be small.

the US in 1990[32]. Third, the original EVOS study did not estimate individuals' WTA compensation for an environmental loss from a spill and we estimate WTA values based on the WTA/WTP ratio for public goods from Horowitz and McConnell (2002). The WTA compensation for passive values for oil spills could be higher or lower than our estimate based on WTA/WTP ratios observed by Horowitz and McConnell (2002). Fourth, Carson et al. (2003) characterize oil spill damages as short term in their survey. In the EVOS study, the description of the effects of an oil spill that would occur in the absence of a program to prevent oil spill damages states that the environment would recover within 5 years (Carson et al. 2004, p. 194). The research shows, in fact, that the environment has not recovered. According to the EVOSTC (2010), only 10 of the 32 environmental and human resource categories monitored have recovered 20 years after the oil spill. Given that potential, passive use damages from a TMEP oil tanker spill could persist longer than stated in the EVOS study survey based on the EVOS actual recovery rates, passive use damages could be higher than those estimated by Carson et al. (2003). Fifth, we assume that only Canadians hold passive use values for the region potentially impacted by a TMEP tanker spill. However, citizens outside Canada may be willing to pay to prevent a tanker spill on the west coast of BC, which would further increase passive use values. Finally, for some individuals, First Nations and stakeholders there may be no amount of monetary payment that could compensate for oil spill damages.

[32] According to US census data, the median US household income in 1990 was $29,943 ($52,573 in 2012 USD) (USBC 1992). The latest available Canadian census data (2011) shows a median household income of $64,730 ($65,268 in 2012 USD) (Statistics Canada 2013) or 24% higher than the inflation-adjusted US household income at the time of the EVOS. Given the higher household incomes in Canada, it is possible that Canadians would be willing to pay more to protect the BC coast from an oil spill compared to the EVOS study. Furthermore, opposition to the project may further increase household WTP to prevent a spill.

6.5. Potential Clean-up and Damage Costs for TMEP Pipeline, Terminal and Tanker Spills

To estimate potential upper bound pipeline spill costs from the TMEP, we use spill volume scenarios contained in the TMEP Application and spill cost data discussed in the previous section. *Volume 7* in the TMEP application identifies two pipeline leak scenarios of 4.8 m^3 (30 bbl) and 113.7 m^3 (715 bbl) and three pipeline rupture scenarios of 1,000 m^3 (6,290 bbl), 2,000 m^3 (12,580 bbl), and 4,000 m^3 (25,160 bbl) (TM 2013, Vol. 7, App. G, p. 24). For pipeline leak costs, we use upper bound spill cost data from Etkin (2004) of $167,244 for spills between 24 and 238 bbl and $114,132 for spills between 238 and 2,380 bbl. For pipeline ruptures, we use spill cost data from the Enbridge Line 6B spill in Marshall Michigan totalling $60,177 per bbl, which constitute costs from response personnel and equipment, environmental consultants, professional, regulatory, and other costs[33]. Potential spill costs for TMEP pipeline leaks could range between $5 and $82 million and costs for a pipeline rupture could range from $379 to $1,514 million depending on the size of the spill (Table 6.17). These costs are more conservative than worst-case costs estimated by Goodman and Rowan (2014) of $2 to $5 billion for a pipeline rupture.

[33] We note that the cost categories associated with spill costs from the Enbridge Line 6B spill are not directly compatible with cost categories form Etkin (2004). In order to estimate the cost for ruptures in Table 6.13, we make the following assumptions regarding the spill cost data for Enbridge Line 6B: (1) costs of $27,478 per bbl associated with response personnel and equipment are categorized as clean-up costs; (2) costs of $32,699 per bbl from environmental consultants, professional, regulatory, and other costs are categorized as social and environmental costs. We caution that actual spill costs in each category may differ although the overall cost per bbl of $60,177 would remain unchanged.

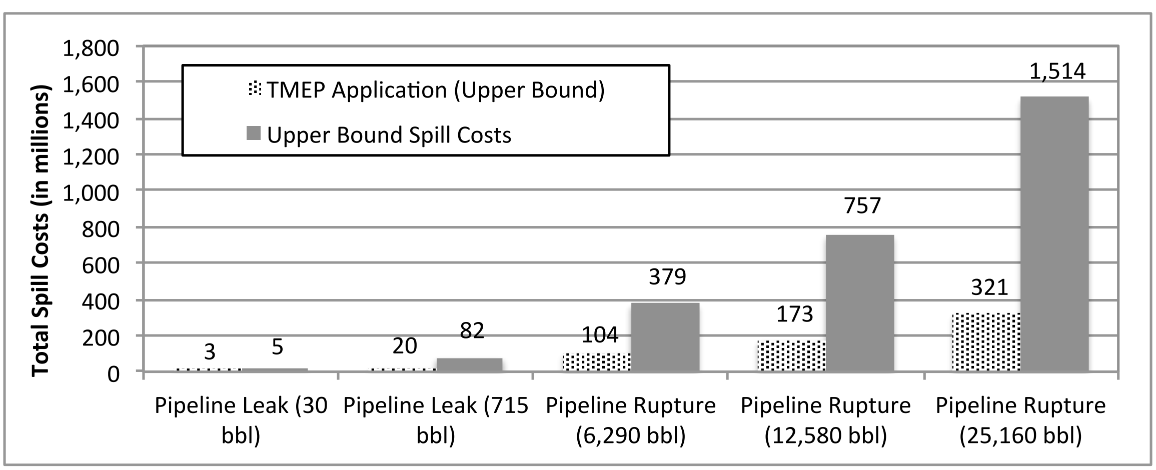
Table 6.17. Potential Spill Cost Estimates for TMEP Pipeline Spills

Method	Potential Spill Costs (in millions)			
	Spill size (bbl)	Clean-up	Social and Environmental	Total
Pipeline Leak (Median)	30	1.3	3.7	5.0
Pipeline Leak (Mean)	715	28.6	53.0	81.6
Pipeline Rupture of 1,000 m^3	6,290	172.8	205.7	378.5
Pipeline Rupture of 2,000 m^3	12,580	345.7	411.3	757.0
Pipeline Rupture of 4,000 m^3	25,160	691.4	822.7	1,514.1

Source: Computed from Etkin (2004); TM (2013, Vol. 7, App. G); Enbridge (2014). Note: Total spill costs estimated from spill cost data for leaks from Etkin (2004) and ruptures for Enbridge Line 6B (Enbridge 2014). See footnote 33 for a discussion of how we incorporate spill cost data from the Enbridge Line 6B spill into the range of estimates.

The estimates in Table 6.17 are significantly higher than those presented in the TMEP application. According to Volume 7, Appendix G, the upper bound costs for a pipeline rupture adjusted for inflation range from $104 to $321 million. Using the same spill volumes from the TMEP application, the upper bound spill cost estimates based on Etkin and Enbridge Line 6B are nearly five times higher than those presented in the TMEP application. Spill costs in the TMEP application do not provide an accurate upper bound of potential pipeline spill costs as suggested in Appendix G of *Volume 7*.

Figure 6.1. Comparison of Upper Bound Pipeline Spill Costs



To estimate the potential spill costs associated with a spill at the marine terminal we use a spill volume estimate of 648 bbl provided in the TMEP Application (TM 2013, Termpol 3.15). As we discuss in section 6.3, Dr. Ruitenbeek estimates potential upper bound spill costs of $20,649 (2014 CAD) per bbl, which results in costs of $13.4 million for a 648 bbl spill. We estimate a terminal spill cost using the default values for the BOSCEM, which represent the open water/shore setting for the response cost modifier. The default value for the BOSCEM produces an estimate of total costs of $48,772 per bbl for a spill between 238 and 2,380 bbl. Applying default spill costs from Etkin (2004) results in potential terminal spill costs of $32 million for a rupture (Table 6.18).

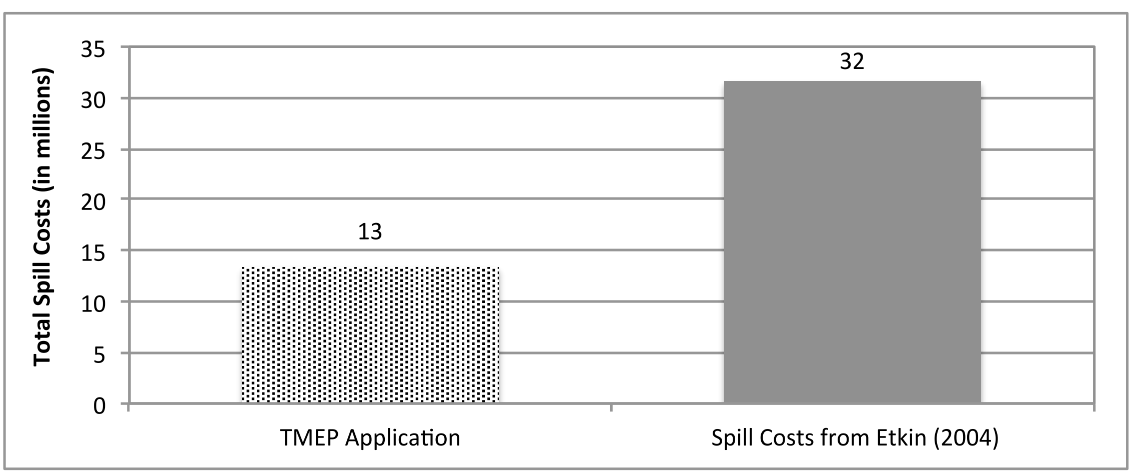
Table 6.18. Potential Spill Cost Estimates for TMEP Terminal Spill

Method	Potential Spill Costs (in millions)			
	Spill size (bbl)	Clean-up	Social and Environmental	Total
Worst Case Terminal Rupture	648	14.2	17.4	31.6

Source: Computed from Etkin (2004); TM (2013, Vol. 7 App. G). Note: Total spill costs estimated from spill cost data from Etkin (2004).

Total spill costs based on Etkin (2004) are significantly higher than the spill costs estimated in the TMEP application (Figure 6.2). Both cost estimates use a spill volume of 648 bbl for a rupture at the marine terminal and thus the only difference in these estimates is the spill cost per bbl. TM (2013, Vol. 7 App. G, p. 17) refers to spill costs of $13 million for a rupture as a maximum estimate although default values in the BOSCEM clearly show that spill costs could increase by a factor of two.

Figure 6.2. Comparison of Terminal Spill Costs with TMEP Application



TM does not provide an estimate of tanker spill costs in the TMEP application. To estimate potential tanker spill costs, we rely on spill size estimates from the TMEP application and spill cost data from WM (2012). WM (2012) estimates clean-up and damage costs of $42,706 (2014 CAD) per bbl, which applied to the mean and worst case outflows from the TMEP application result in spills costs of $2.2 to $4.4 billion per spill. These costs do not include the values that individuals ascribe to the protection or preservation of resources that they will never use. As discussed in the previous section, passive use values could range between $1.4 and $21.1 billion. Including passive use damages in the spill cost estimates for tanker spills results in total costs of up to $25.5 billion for a single spill.

Table 6.19. Potential Spill Cost Estimates for TMEP Tanker Spills

Method	Spill size (bbl)	Potential Spill Costs (in millions)			
		Clean-up	Damage	Total	Total w/ Passive Use
Mean Outflow	51,891	886	1,330	2,216	3,586 – 23,290
Worst Case Outflow	103,782	1,773	2,659	4,432	5,802 – 25,506

Source: Computed from Carson et al. (2003); WM (2012); TM (2013, Termpol 3.15). Total spill costs estimated from spill cost data from WM (2012). Lower passive use values based on WTP and higher values based on WTA.

6.6. Compensation for Spill Damages

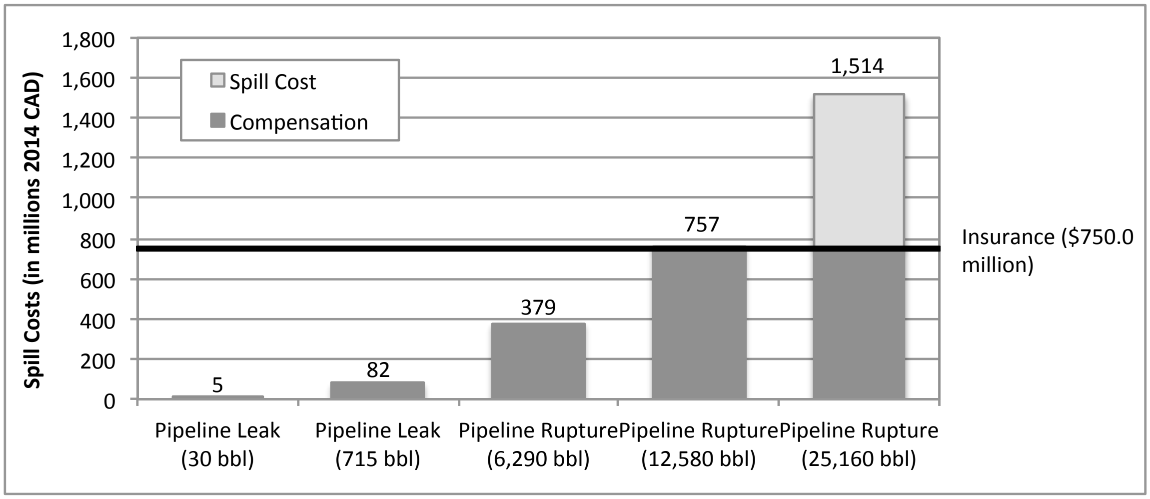
6.6.1. Pipeline Spills

Section 75 of the *National Energy Board Act* requires pipeline companies to fully compensate all damages resulting from their operations. Compensation in the event of a pipeline spill is the result of negotiations between individuals claiming a loss and the pipeline operator to determine an appropriate level of compensation acceptable to both parties. In the event that negotiations between claimants and the pipeline operator fail to result in any settlement, Section 90 of the *National Energy Board Act* establishes an arbitration process and the appointment of a federal arbitration tribunal to settle disputes arising from damages claims. Although there is no theoretical limit on pipeline operator's liability for spill clean-up and damages to individuals, their property, and the environment, compensation could be limited by the company's available insurance and financial position.

Compensation for pipeline spill damages depends on the amount of insurance maintained by the pipeline operator and any other financial assets that the operator could draw upon for compensation purposes. According to TM (2013, Vol. 7, p. 7-186), Trans Mountain Pipeline ULC currently maintains general liability insurance of $750 million per year and intends to maintain this level of insurance over the life of the project. Losses and claims that exceed insurance limits could be compensated using Trans Mountain's cash from operations, issuance of debt, commercial paper, credit facility draws, expected future access to capital markets, or by selling off its assets (TM 2013, Vol. 7, App. G, p. 5). TM (2013, Vol. 7, p. 7-186) states that it expects to have an additional $3.2 billion in equity when the TMEP is complete that could be available to compensate spill damages. In 2013, the federal government introduced Bill C-46, the *Pipeline Safety Act*, that if passes would require pipeline companies to have $1 billion in clean up funds available to respond to spills (NRCan 2014).

The TMEP insurance of $750 million could provide sufficient coverage in the event of smaller pipeline leaks but may not fully compensate parties that incur losses from larger pipeline ruptures (Figure 6.3). In the case of the largest pipeline rupture of 25,160 bbl modeled in the TMEP application, the shortfall in compensation could total $764 million for a $1.5 billion pipeline spill, which would have to be covered by TMEP. Although TMEP is able to cover some damage liabilities, the maximum capacity of TMEP to cover compensation exceeding insurance coverage is unknown. A second concern is that the details of what will be compensated and how the value of damages requiring compensation will be determined is also unknown. Concerns regarding this uncertainty over compensation requirements were expressed following the Enbridge Line 6B spill. During congressional hearings held by the US government after the Enbridge Line 6B spill in Marshall, Michigan, Representative Shauer from the state of Michigan pointed out that many spill-affected citizens in his district were denied some or all of their compensation claims by Enbridge (Hearing on Enbridge Pipeline Oil Spill in Marshall, Michigan 2010). Although the Enbridge Line 6B spill occurred in a different jurisdiction under different regulators, the incident illustrates potential issues with uncertainties in compensation after a large pipeline spill.

Figure 6.3. Potential Pipeline Spill Costs and Compensation



6.6.2. Tanker and Terminal Spills

The current compensation scheme for oil pollution damages resulting from tanker spills in Canada consists of domestic law combined with several international conventions. Spills at the marine terminal would also be compensated under Canadian and international laws if the spill originates from the ship, whereas the terminal operator would be responsible for spills resulting from terminal operations (TM 2013, Vol. 7, App. G). Compensation for oil pollution damage in Canada is largely governed by the *Marine Liability Act*, which incorporates several international conventions into Canadian law including the 1992 International Convention on Civil Liability for Oil Pollution Damage (Civil Liability Convention), the 1992 International Convention on the Establishment of an International Fund for Compensation for Oil Pollution (1992 Fund), and the 2003 International Oil Pollution Compensation Supplementary Fund (Supplementary Fund) (SSOPF 2014a). Canada also has a domestic compensation fund for oil pollution known as the Ship-Source Oil Pollution Fund (SSOPF 2014b). Under the four-tier system where each of the first three tiers provides a maximum amount of compensation, the total amount available for clean-up, compensation, and natural resource damages is limited to approximately $1.44 billion (Table 6.20). In situations where there is proof of intent to cause natural resource damages, the Civil Liability Convention states that liability will not be limited to the maximum compensation under the four-tier system (Boulton 2010). However, in the unlikely event that there is no limited liability, additional compensation may not be available because recovering damages over and above the ship owner's insurance limits depends on the ship operator's corporate assets which may be insufficient to cover additional costs (Boulton 2010). Independent tanker operators, which are common throughout the industry, may only have the ship as an asset and will not be in a position to provide additional compensation (Boulton 2010).

Table 6.20. Summary of Compensation Scheme for Oil Pollution Damages

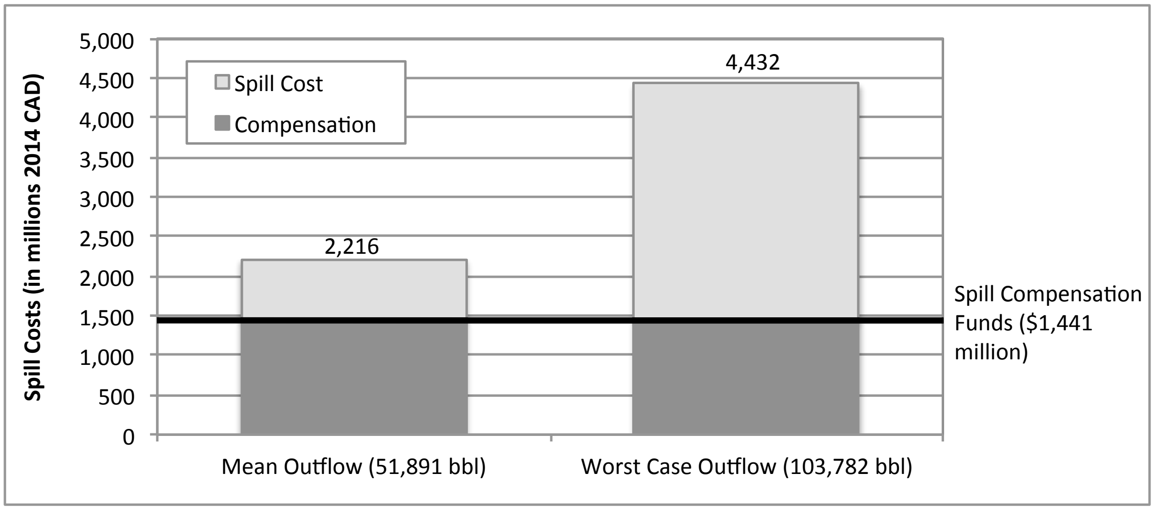
Tier	Maximum Compensation (in millions)
The Civil Liability Convention	152.96
The 1992 Fund - International Oil Pollution Compensation Fund	345.90
The Supplementary Fund - International Oil Pollution Compensation Fund	932.06
The Ship-Source Oil Pollution Fund	162.75
Total Available Compensation	1,440.70

Source: SSOPF (2014b).

The international and domestic compensation funds described above would likely provide sufficient compensation in the event of smaller tanker spills. However, the compensation funds may be inadequate in the event of larger tanker spills (Figure 6.4). Indeed, spill costs estimated based on spill volumes from the TMEP application and costs from WM (2012) show that total spill costs could exceed available compensation by up to $2.9 billion. In May 2014, the Canadian government announced its plan to allow the entire balance of the Ship-source Oil Pollution Fund of $400 million to be available for compensation in the event of a spill (TC 2014b). Even if the full balance of the Ship-source Oil Pollution Fund was available, there still could be inadequate compensation in the event of an oil spill. Removing the limit on the Ship-source Oil Pollution Fund would increase potential compensation provided by the domestic and international compensation scheme from $1,440.7 million to $1,677.9 million. This level of spill compensation would leave a shortfall of over $2.7 billion in uncompensated damages that would not be covered (Figure 6.4). If additional damage costs such as passive use damages and ecosystem services damages are included, the shortfall would be even higher. Canada's Federal Tanker Safety Expert Panel recommended that the limit of liability within the Ship-source Oil Pollution Fund should be removed and that, in the event that a spill exhausts the Fund's current reserve of $400 million, the

Canadian government should borrow additional funds to pay claimants and reinstate levies to replenish the Fund (Houston et al. 2013, p. 31).

Figure 6.4. Potential Tanker Spill Costs and Compensation



The resolution of spill damage compensation itself has the potential to generate large costs to impacted parties. Difficulties and uncertainties in reconciling resolution and 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). A major source of this stress was a ruling by the Federal Court in response to the claim by Natives that the EVOS caused economic damages beyond losses from reduced subsistence harvest. Specifically, Alaskan Natives asserted that the oil spill caused injury to their culture and subsistence lifestyle, which is different from that of non-Native Alaskans, and sought compensatory damages for these injuries (Fall et al. 2001). A court decision rejected the Natives claim on the basis that the subsistence lifestyle of Alaskan Natives is not unique from all Alaskans and that Alaska Natives suffered damages no different than non-Natives (Fall et al. 2001). Years later, the Federal Court of Appeals rejected an appeal launched by the Native class, stating that that there was no basis in law for awarding cultural claims (Fall et al. 2001). Although Exxon paid $20 million for lost subsistence uses out of court, the verdict against compensatory damages for culture and subsistence lifestyle was very painful for villagers to accept (Miraglia 2002) and produced high-levels of stress for individuals attempting to recover from oil spill damages (Picou and Gill 1996 as cited in Fall et al. 2001).

The provision of adequate compensation to mitigate economic, environmental, and social costs from a potential tanker spill is an important consideration in the assessment of the public interest of the TMEP. Although TM provides an overview of compensation funds in its Contingency Plan (TM 2013, Termpol 3.18), TM has not provided a comprehensive compensation plan that provides details about the process for mitigating and compensating damages incurred by impacted parties. 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 and specify dispute resolution procedures. Instead, TM defers compensatory responsibility for tanker spills to the IOPCF and the domestic Ship-source Oil Pollution Fund, which we show are inadequate in the case of large oil spills (Figure 6.4). The potential inadequacy of the international and domestic funds to compensate for all damages shifts the shortfall in damage costs to third parties impacted by the damages or to taxpayers.

TM does not provide a comprehensive mitigation and compensation plan to provide assurance to the Canadian public that TM will be fully responsible for all spill clean-up and damage costs from a tanker, terminal, or pipeline spill. The elements of the detailed comprehensive compensation plan include:

- defining compensable and non-compensable damages;
- identifying eligible and ineligible parties for compensation;
- specifying methods for determining and evaluating damage claims;
- identifying timelines for impacted parties to receive compensation;
- identifying funding sources to fully cover all damage costs;
- requiring the project proponent to accept unlimited liability for all damages resulting from the project;
- specifying dispute resolution procedures;
- establishing an independent monitoring process to assess ongoing impacts;
- specifying a legally binding and independent arbitration process to determine damages; and
- providing financial support for First Nations and stakeholders to participate in the monitoring and compensation process.

TM also has a social responsibility and obligation to ensure that parties potentially impacted by a spill are satisfied with mitigation and compensation strategies prior to the construction and operation of the TMEP. Consequently, TM should be required to outline a process for obtaining stakeholder approval of its compensation plans prior to project approval.

7. Conclusion

This report evaluates spill risk assessment methods in the TMEP regulatory application. We evaluate the TMEP regulatory application using best practice criteria for risk assessment in order to assess whether the application provides adequate information to enable a reasoned judgment of the likelihood of significant adverse environmental effects from oil spills under the *CEAA 2012*. We also estimate pipeline and tanker spill risks associated with the TMEP using other well accepted risk assessment methodologies, compare the results of these different spill risk assessment methodologies with those from the TMEP application, and compare potential spill costs from the TMEP with existing insurance and compensation schemes. Based on our analysis we conclude:

1. The TMEP application does not provide an accurate assessment of the likelihood of adverse environmental impacts resulting from oil spills as required by the *CEAA*

TM's spill risk analysis contains 27 major weaknesses. As a result of these weaknesses, TM does not provide an accurate assessment of the degree of risk associated with the TMEP. Some of the key weaknesses include:

- Ineffective communication of spill probability over the life of the project;
- Lack of confidence ranges for spill risk estimates;
- Inadequate sensitivity analysis of spill risk estimates;
- No presentation of the combined spill risk for the entire project;
- Reliance on tanker incident frequency data that underreport incidents by up to 96%;
- Incomplete assessment of the significance of oil spills, and;
- Inadequate disclosure of information and data supporting key assumptions that were used to reduce spill risk estimates.

2. TM's analysis shows spill likelihood for the TMEP is high (99%)

TM's spill risk estimates show that the likelihood of an oil spill from the TMEP is high (99%) (Table 7.1). The individual spill probabilities for the specific types of spills, that is tanker (16 – 67%), terminal (77%), and pipeline (99%) spills, understate the likelihood of spills associated with the TMEP because of the methodological weaknesses in the TM analysis.

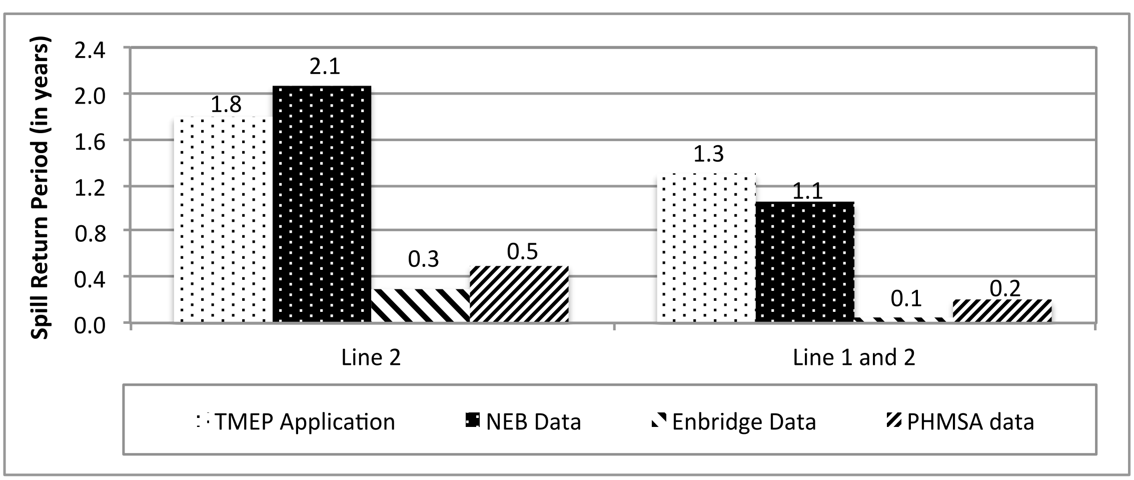
Table 7.1. Probabilities for TMEP Tanker, Terminal, or Pipeline Spills (50 Years)

Type of Spill	Spill Probability over 50 Years
Tanker Spill	16 – 67%
Terminal Spill	77%
Pipeline Spill	99%
Combined Spills	99%

3. The likelihood of an oil spill from the TMEP is high

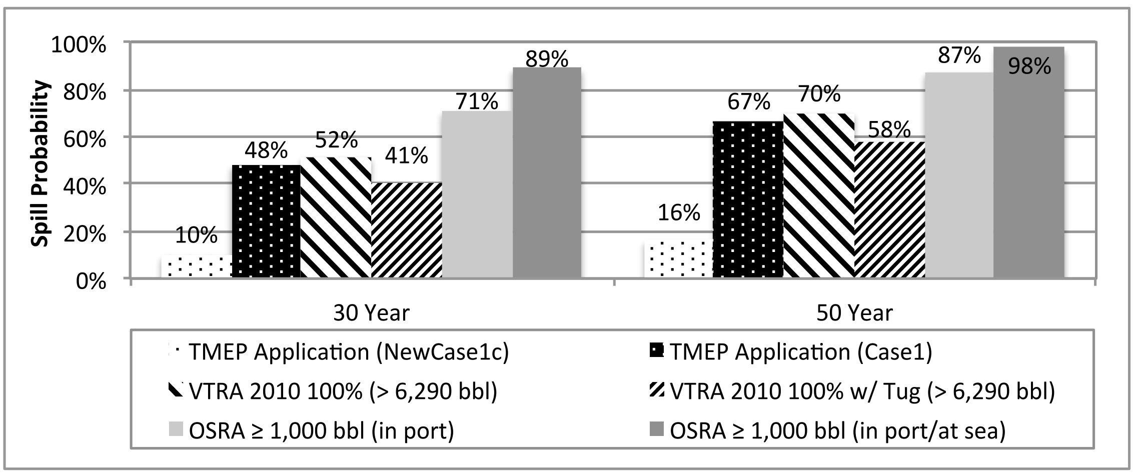
Several different, widely accepted methodological approaches for estimating spill likelihood for the TMEP all show that likelihood of spills is high. For pipeline spills, data from the NEB, the Enbridge liquids pipeline system, and the PHMSA show that a spill is highly likely to occur (Figure 7.1). The PHMSA methodology is the standard methodological approach for estimating spill risk in the US and the method may provide the most reasonable estimates of potential spill risk for the TMEP.

Figure 7.1. Comparison of Pipeline Spill Return Periods



Tanker spill risk probabilities based on the TMEP application, the OSRA model, and the VTRA model are summarised in Figure 7.2. The spill risk estimates from the three different methodologies including the one used by TMEP show a high likelihood of a tanker spill ranging from 58% to 98% over a 50 year operating period. The only outlier result is the TMEP NewCase1c estimate showing a probability of 16%. Given the weaknesses in the methodology used in the TMEP application and the fact that this estimate is an outlier significantly below the estimates based on other methods, the tanker spill risk estimate NewCase1c in the TMEP application is an inaccurate and unreliable estimate of tanker spill risk.

Figure 7.2. Comparison of TMEP Tanker Spill Probabilities



4. TM significantly underestimates the upper bound damage costs of a pipeline spill and provides no estimates of the damage costs of a tanker spill

Total potential pipeline spill costs range from $5 million to $1.5 billion for a single spill, which is 1.7 to 4.7 times higher than the upper bound spill costs estimated in the TMEP application. Spill costs in the TMEP application are unreliable estimates of upper bound costs. TM provides no estimates of the potential damages resulting from a tanker oil spill.

5. Potential spill costs from the TMEP could exceed available compensation

The comparison of potential pipeline and tanker spill damages to available compensation shows that existing mechanisms could provide inadequate compensation to affected individuals after a spill. Based on Trans Mountain's liability insurance of $750 million, we estimate that potential pipeline spill costs for a worst-case 25,160 bbl rupture could exceed this insurance by $764 million for a single spill. For a tanker spill, a worst-case spill of 103,782 bbl could exceed available compensation from domestic and international spill compensation funds by $2.9 billion. The federal government's recent plans to remove the liability cap for the domestic compensation fund could be insufficient to cover all tanker spill costs in this worst-case scenario. As a result, British Columbians and Canadians could incur those spill costs that are not compensated.

6. Overall Conclusion

The overall conclusion of this report is that:

1. TM's application contains major methodological weaknesses that do not provide an accurate assessment of the degree of risk associated with the TMEP;
2. There is a high probability of oil spills from the TMEP (99%); and
3. Pipeline or tanker spills from the TMEP could result in significant damage costs that exceed existing compensation schemes.

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TM. (2015c). Trans Mountain Response to Upper Nicola Band Information Request No. 2 *in Trans Mountain Expansion Project Section 52 Application to the National Energy Board*: Trans Mountain.

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Appendix A: Certificate of Expert's Duty

We, Dr. Thomas Gunton and Dr. Sean Broadbent, of Simon Fraser University, Burnaby, B.C., have been engaged on behalf of Tsawout First Nation, Upper Nicola Band and Tsleil-Waututh Nation 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: May 25, 2015 Signature: thomas gunton Digitally signed by thomas gunton DN: cn=thomas gunton, o=sfu, ou=REM, email=gunton@sfu.ca, c=CA Date: 2015.05.25 16:18:37 -07'00'

Dr. Thomas Gunton

Date: May 25, 2015 Signature:

Dr. Sean Broadbent

Appendix B: 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)
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Curriculum Vitae

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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.