



Trans Mountain Pipeline ULC



Trans Mountain Expansion Project

An Application Pursuant to Section 52 of the National Energy Board Act

December 2013

Volume



Project Overview, Economics
& General Information

NATIONAL ENERGY BOARD

IN THE MATTER OF

**the *National Energy Board Act*,
R.S.C. 1985, c. N-7, as amended, (“*NEB Act*”)
and the Regulations made thereunder;**

AND IN THE MATTER OF

**the *Canadian Environmental Assessment Act, 2012*,
S.C. 2012, c. 37, as amended,
and the Regulations made thereunder;**

AND IN THE MATTER OF

**an application by Trans Mountain Pipeline ULC
as General Partner of Trans Mountain Pipeline L.P.
(collectively “Trans Mountain”)
for a Certificate of Public Convenience and Necessity and
other related approvals pursuant to Part III of the *NEB Act***

**APPLICATION BY TRANS MOUNTAIN FOR APPROVAL OF
THE TRANS MOUNTAIN EXPANSION PROJECT**

December 2013

**To: The Secretary
The National Energy Board
444 — 7th Avenue SW
Calgary, AB T2P 0X8**

Trans Mountain Expansion Project

Application Pursuant to Section 52 of the *National Energy Board Act*

Guide to the Application

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Transmittal - Letter to the National Energy Board	
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Volume 2	Project Overview, Economics and General Information
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Volume 5A	Environmental and Socio-Economic Assessment – Biophysical
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Volume 5C	Environmental and Socio-Economic Assessment – Biophysical Technical Reports
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Section 3.0	Project Need and Economic Feasibility	Appendix C	Direct Evidence of John J. Reid of Concentric Energy Advisors, Inc., to the National Energy Board
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ABBREVIATIONS AND ACRONYMS

This table lists the abbreviations and acronyms used in this volume of the application.

Term	Meaning
AB	Alberta
AESRD	Alberta Environment and Sustainable Resource Development
AFUDC	Allowance for Funds Used During Construction
ALR	Agricultural Land Reserve
bb/d	barrels per day
BC	British Columbia
BC OGC	BC Oil and Gas Commission
CCO	control centre operator
CEA	Canadian Environmental Assessment
CN	Canadian National
CO ₂	carbon dioxide
CPCN	Certificate of Public Convenience and Necessity
DFO	Fisheries and Oceans Canada
ESA	Environmental and Socio-Economic Assessment
ESD	emergency shut-down
FOTS	fibre optic transmission system
GDP	Gross Domestic Product
HDD	horizontal directional drill
IHS	IHS Global Canada Limited
IOS	Individual Ownership Sketch
KMC	Kinder Morgan Canada Inc.
KMP	Kinder Morgan Energy Partners, L.P.
KP	kilometre posts
NEB	National Energy Board
<i>NEB Act</i>	<i>National Energy Board Act</i>
NPS	nominal pipe size
OD	outside diameter
OMS	Operations Management System
PMV	Port Metro Vancouver
POD	Pattern of Dealing
PPA	Pacific Pilotage Authority
RK	reference kilometre
RMLBV	remote mainline block valve
SARA	<i>Species at Risk Act</i>
SCADA	Supervisory Control and Data Acquisition
TERMPOL	Technical Review Process of Marine Terminal Systems and Transshipment Sites
the Project	Trans Mountain Expansion Project
TMEP	Trans Mountain Expansion Project
TMPL	Trans Mountain Pipeline
TMPL system	Trans Mountain pipeline system
Trans Mountain	Trans Mountain Pipeline ULC
TUC	Transportation/Utility Corridor
TWS	temporary workspace
US	United States
WCMRC	Western Canada Marine Response Corporation

Term	Meaning
WCSB	Western Canadian Sedimentary Basin

NEB FILING MANUAL CHECKLIST

CHAPTER 3 – COMMON INFORMATION REQUIREMENTS

Filing #	Filing Requirement	In Application? References	Not in Application? Explanation
3.1 Action Sought by Applicant			
1.	Requirements of s.15 of the Rules.	Volume 1 Section 1.1	---
3.2 Application or Project Purpose			
1.	Purpose of the proposed project.	Volume 2 Section 1.1	---
3.4 Consultation			
		Volumes 3A,3B,3C; Volumes 5A, 5B Section 3; Volume 8A Section 3	--
3.4.1 Principles and Goals of Consultation			
1.	The corporate policy or vision.	Volume 3A Section 1.2.1 Volume 3B Section 1.2.1	--
2.	The principles and goals of consultation for the project.	Volume 3A Section 1.2.2 Volume 3B Section 1.2.2 Volume 5A Section 3.2.1 Volume 5B Section 3.2.1	--
3.	A copy of the Aboriginal protocol and copies of policies and principles for collecting traditional use information, if available.	Volume 3B Section 1.3.5	--
3.4.2 Design of Consultation Program			
1.	The design of the consultation program and the factors that influenced the design.	Volume 3A Section 1.3 Volume 3B Section 1.3 Volume 5A Section 3.1.1, 3.2.2 Volume 5B Section 3.1.1, 3.2.2	--
3.4.3 Implementing a Consultation Program			
1.	The outcomes of the consultation program for the project.	Volume 3A Section 1.7 Volume 3B Section 1.5 Table 1.5.1 Volume 5A Section 3.1.5, 3.2.4 Volume 5B Section 3.1.5, 3.2.4	--
3.4.4 Justification for Not Undertaking a Consultation Program			
2.	The application provides justification for why the applicant has determined that a consultation program is not required for the project.	N/A	N/A
3.5 Notification of Commercial Third Parties			
1.	Confirm that third parties were notified.	Volume 2 Section 3.2.2	--
2.	Details regarding the concerns of third parties.	Volume 2 Section 3.2.2	--
3.	List the self-identified interested third parties and confirm they have been notified.	N/A	N/A
4.	If notification of third parties is considered unnecessary, an explanation to this effect.	N/A	N/A

CHAPTER 4 – SECTIONS 4.1 AND 4.2: COMMON REQUIREMENTS FOR PHYSICAL PROJECTS

Filing #	Filing Requirement	In Application? References	Not in Application? Explanation
4.1 Description of the Project		Volume 2	--
1.	The project components, activities and related undertakings.	Volume 2 Section 2.0; Volume 4A	--
2.	The project location and criteria used to determine the route or site.	Volume 2 Section 4.0; Volume 4a	--
3.	How and when the project will be carried out.	Volume 2 Section 2.3; Volume 4B Section 2.0	--
4.	Description of any facilities, to be constructed by others, required to accommodate the proposed facilities.	N/A	N/A
5.	An estimate of the total capital costs and incremental operating costs, and changes to abandonment cost estimates.	Volume 2 Section 2.9	--
6.	The expected in-service date.	Volume 2 Section 1.1; Volume 4B Section 2.1	--
4.2 Economic Feasibility, Alternatives and Justification			
4.2.1 Economic Feasibility			
1.	Describe the economic feasibility of the project.	Volume 2 Section 3.5	--
4.2.2 Alternatives			
1.	Describe the need for the project, other economically-feasible alternatives to the project examined, along with the rationale for selecting the applied for project over these other possible options.	Volume 2 Section 3.0; Volume 8A Section 2.2	--
2.	Describe and justify the selection of the proposed route and site including a comparison of the options evaluated using appropriate selection criteria.	Volume 2 Section 4.0; Volume 8A Section 2.2	--
3.	Describe the rationale for the chosen design and construction methods. Where appropriate, describe any alternative designs and methods evaluated and explain why these other options were eliminated.	Volume 2 Section 4.0; Volume 8A Section 2.2	--
4.2.3 Justification			
1.	Provide a justification for the proposed project	Volume 2 Section 3.4	--

GUIDE A – A.1 ENGINEERING

Filing #	Filing Requirement	In Application? References	Not in Application? Explanation
A.1.1 Engineering Design Details			
1.	Fluid type and chemical composition.	Volume 4A Section 3.1.1	--
2.	Line pipe specifications.	Volume 4A Section 3.2.8	--
3.	Pigging facilities specifications.	Volume 4A Section 3.3.1, 3.3.2	--
4.	Compressor or pump facilities specifications.	Volume 4A Section 3.4	--
5.	Pressure regulating or metering facilities specifications.	Volume 4A Section 3.5	--
6.	Liquid tank specifications, or other commodity storage facilities.	Volume 4A Section 3.4	--
7.	New control system facilities specifications.	Volume 4A Section 3.3	--
8.	Gas processing, sulphur or LNG plant facilities specifications.	N/A	N/A
9.	Technical description of other facilities not mentioned above.	N/A	N/A
10.	Building dimensions and uses.	Volume 4A Section 3.3, 3.4, 3.5	--
11.	If project is a new system that is a critical source of energy supply, a description of the impact to the new system capabilities following loss of critical component.	N/A	N/A
A.1.2 Engineering Design Principles			
1.	Confirmation project activities will follow the requirements of the latest version of CSA Z662.	Volume 4A Section 2.2	--
2.	Provide a statement indicating which Annex is being used and for what purpose	Volume 4A Section 2.3	--
3.	Statement confirming compliance with OPR or PPR.	Volume 4A Section 2.1	--
4.	Listing of all primary codes and standards, including version and date of issue.	Volume 4A Section 2, Table 5.1.1	--
5.	Confirmation that the project will comply with company manuals and confirm manuals comply with OPR/PPR and codes and standards.	Volume 4A Section 2.6, Table 5.1.2	--
6.	Any portion of the project a non-hydrocarbon commodity pipeline system? Provide a QA program to ensure the materials are appropriate for their intended service.	N/A – all hydrocarbons	N/A
7.	If facility subject to conditions not addressed in CSA Z662: <ul style="list-style-type: none"> • Written statement by qualified professional engineer • Description of the designs and measures required to safeguard the pipeline 	Volume 4A Section 2.9	--
8.	If directional drilling involved: <ul style="list-style-type: none"> • Preliminary feasibility report • Description of the contingency plan 	Volume 4A Section 2.12	--
9.	If the proposed project involves the reuse of materials, provide an engineering assessment in accordance with CSA Z662 that indicates its suitability for the intended service.	Volume 4A, Section 2.7	--
10.	If new materials are involved, provide material supply chain information, in tabular format.	Volume 4A Section 2.7	
11.	If reuse of material is involved, provide an engineering assessment in accordance with CSA Z662 that indicates its suitability for the intended service.	Volume 4A, Section 2.7	--
A.1.3 Onshore Pipeline Regulations			
1.	Designs, specifications programs, manuals, procedures, measures or plans for which no standard is set out in the OPR or PPR.	--	Existing standards will be followed
2.	A quality assurance program if project non-routine or incorporates unique challenges due to geographical location.	--	No unique challenges
3.	If welding performed on a liquid-filled pipeline that has a carbon equivalent of 0.50% or greater and is a permanent installation: <ul style="list-style-type: none"> • Welding specifications and procedures • Results of procedure qualification tests 	--	Welding on liquid filled pipe will not be conducted

GUIDE A – A.2 ENVIRONMENTAL AND SOCIO-ECONOMIC ASSESSMENT

The following table identifies where information requested in the National Energy Board (NEB) Filing Manual Guide A – A.2 Environmental and Socio-economic Assessment checklist may be found in the various volumes of the Application for the Trans Mountain Expansion Project.

Filing #	Filing Requirement	In Application? References	Applicable Marine Transportation Elements	Not in Application? Explanation
A.2.5 Description of the Environmental and Socio-Economic Setting				
1.	Identify and describe the current biophysical and socio-economic setting of each element (<i>i.e.</i> , baseline information) in the area where the project is to be carried out.	Volume 5A: ESA - Biophysical • Sections 5.0 and 6.0 Volume 5B: ESA - Socio-Economic • Sections 5.0 and 6.0 Volume 5C: ESA - Biophysical Technical Reports Volume 5D: ESA - Socio-Economic Technical Reports	Volume 8A: Marine Transportation • Section 4.2 Volume 8B: Technical Reports	---
2.	Describe which biophysical or socio-economic elements in the study area are of ecological, economic, or human importance and require more detailed analysis taking into account the results of consultation (see Table A-1 for examples). Where circumstances require more detailed information in an ESA see: i. Table A-2 – Filing Requirements for Biophysical Elements; or ii. Table A-3 – Filing Requirements for Socio-economic Elements.	Volume 5A: ESA - Biophysical • Sections 5.0 and 6.0 Volume 5B: ESA - Socio-Economic • Sections 5.0 and 6.0 Volume 5C: ESA - Biophysical Technical Reports Volume 5D: ESA - Socio-Economic Technical Reports	Volume 8A: Marine Transportation • Section 4.2 Volume 8B: Technical Reports	---
3.	Provide supporting evidence (<i>e.g.</i> , references to scientific literature, field studies, local and traditional knowledge, previous environmental assessment and monitoring reports) for: • information and data collected; • analysis completed; • conclusions reached; and • the extent of professional judgment or experience relied upon in meeting these information requirements, and the rationale for that extent of reliance.	Volume 5A: ESA - Biophysical • Sections 5.0 and 6.0 Volume 5B: ESA - Socio-Economic • Sections 5.0 and 6.0 Volume 5C: ESA - Biophysical Technical Reports Volume 5D: ESA - Socio-Economic Technical Reports	Volume 8A: Marine Transportation • Section 4.2 Volume 8B: Technical Reports	---
4.	Describe and substantiate the methods used for any surveys, such as those pertaining to wildlife, fisheries, plants, species at risk or species of special status, soils, heritage resources or traditional land use, and for establishing the baseline setting for the atmospheric and acoustic environment.	Volume 5A: ESA - Biophysical • Sections 5.0 and 6.0 Volume 5B: ESA - Socio-Economic • Sections 5.0 and 6.0 Volume 5C: ESA - Biophysical Technical Reports Volume 5D: ESA - Socio-Economic Technical Reports	Volume 8A: Marine Transportation • Section 4.2 Volume 8B: Technical Reports	---
5.	Applicants must consult with other expert federal, provincial or territorial departments and other relevant authorities on requirements for baseline information and methods.	Volume 5A: ESA - Biophysical • Sections 3.0, 5.0 and 6.0 Volume 5B: ESA - Socio-Economic • Sections 3.0, 5.0 and 6.0 Volume 5C: ESA - Biophysical Technical Reports Volume 5D: ESA - Socio-Economic Technical Reports	Volume 8A: Marine Transportation • Sections 3.0 and 4.2 Volume 8B: Technical Reports	---

Filing #	Filing Requirement	In Application? References	Applicable Marine Transportation Elements	Not in Application? Explanation
A.2.6 Effects Assessment				
Identification and Analysis of Effects				
1.	Describe the methods used to predict the effects of the project on the biophysical and socio-economic elements, and the effects of the environment on the project (<i>i.e.</i> , changes to the Project caused by the environment).	Volume 5A: ESA - Biophysical • Section 7.0 Volume 5B: ESA - Socio-Economic • Section 7.0 Volume 7: Risk Assessment and Management of Pipeline and Facility Spills • Sections 6.0, 7.0 and 8.0 • Technical Reports	Volume 8A: Marine Transportation • Sections 4.3, 5.5 and 5.6	---
2.	Predict the effects associated with the proposed project, including those that could be caused by construction, operations, decommissioning or abandonment, as well as accidents and malfunctions. Also include effects the environment could have on the project. For those biophysical and socio-economic elements or their valued components that require further analysis (see Table A-1), provide the detailed information outlined in Tables A-2 and A-3.	Volume 5A: ESA - Biophysical • Section 7.0 Volume 5B: ESA - Socio-Economic • Section 7.0 Volume 5C: ESA - Biophysical Technical Reports Volume 5D: ESA - Socio-Economic Technical Reports Volume 7: Risk Assessment and Management of Pipeline and Facility Spills • Sections 6.0, 7.0 and 8.0 • Technical Reports	Volume 8A: Marine Transportation • Sections 4.3, 5.6 and 5.7 Volume 8B: Technical Reports	---
Mitigation Measures for Effects				
1.	Describe the standard and project specific mitigation measures and their adequacy for addressing the project effects, or clearly reference specific sections of company manuals that provide mitigation measures. Ensure that referenced manuals are current and filed with the NEB.	Volume 5A: ESA - Biophysical • Section 7.0 Volume 5B: ESA - Socio-Economic • Section 7.0 Volume 5C: ESA - Biophysical Technical Reports Volume 5D: ESA - Socio-Economic Technical Reports Volume 6B: Pipeline Environmental Protection Plan (EPP) Volume 6C: Facilities EPP Volume 6D: Westridge Marine Terminal EPP Volume 6E: Environmental Alignment Sheets Volume 7: Risk Assessment and Management of Pipeline and Facility Spills • Sections 2.0, 3.0, 4.0, 6.0, 7.0, and 8.0 • Technical Reports	Volume 8A: Marine Transportation • Sections 4.3, 5.1, 5.3, 5.6 and 5.7 Volume 8B: Technical Reports	---
2.	Ensure that commitments about mitigative measures will be communicated to field staff for implementation through an Environmental Protection Plan.	Volume 5A: ESA - Biophysical • Section 7.0 Volume 5B: ESA - Socio-Economic • Section 7.0 Volume 6A: Environmental Compliance Volume 6B: Pipeline EPP Volume 6C: Facilities EPP Volume 6D: Westridge Marine Terminal EPP Volume 6E: Environmental Alignment Sheets Volume 7: Risk Assessment and Management of Pipeline and Facility Spills • Sections 2.0, 3.0, 4.0, 6.0, 7.0 and 8.0	Volume 8A: Marine Transportation • Sections 4.3, 5.1, 5.3, 5.6 and 5.7	---

Filing #	Filing Requirement	In Application? References	Applicable Marine Transportation Elements	Not in Application? Explanation
3.	Describe plans and measures to address potential effects of accidents and malfunctions during construction and operation of the project.	Volume 5A: ESA - Biophysical • Section 7.0 Volume 5B: ESA - Socio-Economic • Section 7.0 Volume 6B: Pipeline EPP Volume 6C: Facilities EPP Volume 6D: Westridge Marine Terminal EPP Volume 7: Risk Assessment and Management of Pipeline and Facility Spills • Sections 2.0, 4.0, 6.0, 7.0 and 8.0	Volume 8A: Marine Transportation • Sections 4.3, 5.1, 5.3, 5.6 and 5.7	---
Evaluation of Significance				
1.	After taking into account any appropriate mitigation measures, identify any remaining residual effects from the project.	Volume 5A: ESA - Biophysical • Section 7.0 Volume 5B: ESA - Socio-Economic • Section 7.0	Volume 8A: Marine Transportation • Section 4.3	---
2.	Describe the methods and criteria used to determine the significance of remaining adverse effects, including defining the point at which any particular effect on a valued component is considered "significant".	Volume 5A: ESA - Biophysical • Section 7.0 Volume 5B: ESA - Socio-Economic • Section 7.0	Volume 8A: Marine Transportation • Section 4.3	---
3.	Evaluate significance of residual adverse environmental and socio-economic effects against the defined criteria.	Volume 5A: ESA - Biophysical • Section 7.0 Volume 5B: ESA - Socio-Economic • Section 7.0	Volume 8A: Marine Transportation • Section 4.3	---
4.	Evaluate the likelihood of significant, residual adverse environmental and socio-economic effects occurring and substantiate the conclusions made.	Volume 5A: ESA - Biophysical • Section 7.0 Volume 5B: ESA - Socio-Economic • Section 7.0	Volume 8A: Marine Transportation • Section 4.3	---
A.2.7 Cumulative Effects Assessment				
Scoping and Analysis of Cumulative Effects				
1.	Identify the valued components for which residual effects are predicted, and describe and justify the methods used to predict any residual results.	Volume 5A: ESA - Biophysical • Section 8.0 Volume 5B: ESA - Socio-Economic • Section 8.0	Volume 8A: Marine Transportation • Section 4.4	---
2.	For each valued component where residual effects have been identified, describe and justify the spatial and temporal boundaries used to assess the potential cumulative effects.	Volume 5A: ESA - Biophysical • Section 8.0 Volume 5B: ESA - Socio-Economic • Section 8.0	Volume 8A: Marine Transportation • Section 4.4	---
3.	Identify other physical works or activities that have been or will be carried out within the identified spatial and temporal boundaries for the cumulative effects assessment.	Volume 5A: ESA - Biophysical • Section 8.0 Volume 5B: ESA - Socio-Economic • Section 8.0	Volume 8A: Marine Transportation • Section 4.4	---
4.	Identify whether the effects of those physical works or activities that have been or will be carried out would be likely to produce effects on the valued components within the identified spatial and temporal boundaries.	Volume 5A: ESA - Biophysical • Section 8.0 Volume 5B: ESA - Socio-Economic • Section 8.0	Volume 8A: Marine Transportation • Section 4.4	---

Filing #	Filing Requirement	In Application? References	Applicable Marine Transportation Elements	Not in Application? Explanation
5.	Where other physical works or activities may affect the valued components for which residual effects from the applicant's proposed project are predicted, continue the cumulative effects assessment, as follows: <ul style="list-style-type: none"> consider the various components, phases and activities associated with the applicant's project that could interact with other physical work or activities; provide a description of the extent of the cumulative effects on valued components; and where professional knowledge or experience is cited, explain the extent to which professional knowledge or experience was relied upon and justify how the resulting conclusions or decisions were reached. 	Volume 5A: ESA - Biophysical <ul style="list-style-type: none"> Section 8.0 Volume 5B: ESA - Socio-Economic <ul style="list-style-type: none"> Section 8.0 	Volume 8A: Marine Transportation <ul style="list-style-type: none"> Section 4.4 	---
Mitigation Measures for Cumulative Effects				
1.	Describe the general and specific mitigation measures, beyond project-specific mitigation already considered, that are technically and economically feasible to address any cumulative effects.	Volume 5A: ESA - Biophysical <ul style="list-style-type: none"> Section 8.0 Volume 5B: ESA - Socio-Economic <ul style="list-style-type: none"> Section 8.0 	Volume 8A: Marine Transportation <ul style="list-style-type: none"> Section 4.4 	---
Applicant's Evaluation of Significance of Cumulative Effects				
1.	After taking into account any appropriate mitigation measures for cumulative effects, identify any remaining residual cumulative effects.	Volume 5A: ESA - Biophysical <ul style="list-style-type: none"> Section 8.0 Volume 5B: ESA - Socio-Economic <ul style="list-style-type: none"> Section 8.0 	Volume 8A: Marine Transportation <ul style="list-style-type: none"> Section 4.4 	---
2.	Describe the methods and criteria used to determine the significance of remaining adverse cumulative effects, including defining the point at which each identified cumulative effect on a valued component is considered "significant".	Volume 5A: ESA - Biophysical <ul style="list-style-type: none"> Section 8.0 Volume 5B: ESA - Socio-Economic <ul style="list-style-type: none"> Section 8.0 	Volume 8A: Marine Transportation <ul style="list-style-type: none"> Section 4.4 	---
3.	Evaluate the significance of adverse residual cumulative effects against the defined criteria.	Volume 5A: ESA - Biophysical <ul style="list-style-type: none"> Section 8.0 Volume 5B: ESA - Socio-Economic <ul style="list-style-type: none"> Section 8.0 	Volume 8A: Marine Transportation <ul style="list-style-type: none"> Section 4.4 	---
4.	Evaluate the likelihood of significant, residual adverse cumulative environmental and socio-economic effects occurring and substantiate the conclusions made.	Volume 5A: ESA - Biophysical <ul style="list-style-type: none"> Section 8.0 Volume 5B: ESA - Socio-Economic <ul style="list-style-type: none"> Section 8.0 	Volume 8A: Marine Transportation <ul style="list-style-type: none"> Section 4.4 	---
A.2.8 Inspection, Monitoring and Follow-up				
1.	Describe inspection plans to ensure compliance with biophysical and socio-economic commitments, consistent with Sections 48, 53 and 54 of the <i>NEB Onshore Pipeline Regulations (OPR)</i> .	Volume 5A: ESA - Biophysical <ul style="list-style-type: none"> Section 7.0 Volume 5B: ESA - Socio-Economic <ul style="list-style-type: none"> Section 7.0 Volume 6A: Environmental Compliance Volume 6B: Pipeline EPP Volume 6C: Facilities EPP Volume 6D: Westridge Marine Terminal EPP	Volume 8A: Marine Transportation <ul style="list-style-type: none"> Section 4.3 	---

Filing #	Filing Requirement	In Application? References	Applicable Marine Transportation Elements	Not in Application? Explanation
2.	Describe the surveillance and monitoring program for the protection of the pipeline, the public and the environment, as required by Section 39 of the <i>NEB OPR</i> .	Volume 5A: ESA - Biophysical • Section 7.0 Volume 5B: ESA - Socio-Economic • Section 7.0 Volume 6A: Environmental Compliance Volume 6B: Pipeline EPP Volume 6C: Facilities EPP Volume 6D: Westridge Marine Terminal EPP	Volume 8A: Marine Transportation • Section 4.3	---
3.	Consider any particular elements in the Application that are of greater concern and evaluate the need for a more in-depth monitoring program for those elements.	Volume 5A: ESA - Biophysical • Sections 9.0 and 10.0 Volume 5B: ESA - Socio-Economic • Sections 9.0 and 10.0 Volume 6A: Environmental Compliance Volume 6B: Pipeline EPP (Socio-Economic Management Plan of Appendix C)	Volume 8A: Marine Transportation • Section 4.5	---
4.	For <i>Canadian Environmental Assessment (CEA) Act, 2012</i> designated projects, identify which elements and monitoring procedures would constitute follow-up under the <i>CEA Act, 2012</i> .	Volume 5A: ESA - Biophysical • Section 10.0 Volume 5B: ESA - Socio-economic • Section 10.0	N/A	---

Filing #	Filing Requirement	In Application? References	Applicable Marine Transportation Elements	Not in Application? Explanation
Table A-1 Circumstances and Interactions Requiring Detailed Biophysical and Socio-Economic Information				
	Physical and meteorological environment	Volume 5A: ESA - Biophysical <ul style="list-style-type: none"> Sections 5.0, 6.0 and 7.0 	N/A	---
	Soil and soil productivity	Volume 5A: ESA - Biophysical <ul style="list-style-type: none"> Sections 5.0, 6.0, 7.0 and 8.0 Volume 5C: ESA - Biophysical Technical Reports <ul style="list-style-type: none"> Soil Assessment Technical Report Volume 7: Risk Assessment and Management of Pipeline and Facility Spills <ul style="list-style-type: none"> Section 5.3, 6.0 and 7.0 	N/A	---
	Water quality and quantity (onshore and marine)	Volume 5A: ESA - Biophysical <ul style="list-style-type: none"> Sections 5.0, 6.0, 7.0 and 8.0 Volume 5C: ESA - Biophysical Technical Reports <ul style="list-style-type: none"> Groundwater Technical Report Fisheries (Alberta) Technical Report Fisheries (British Columbia) Technical Report Wetland Evaluation Technical Report Marine Sediment and Water Quality – Westridge Marine Terminal Technical Report Volume 7: Risk Assessment and Management of Pipeline and Facility Spills <ul style="list-style-type: none"> Sections 7.0 Quality Ecological Risk Assessment of Pipeline Spills Technical Report 	Volume 8A: Marine Transportation <ul style="list-style-type: none"> Sections 4.2, 4.3, 4.4, 5.6 and 5.7 Volume 8B: Technical Reports <ul style="list-style-type: none"> Ecological Risk Assessment of Marine Transportation Spills Technical Report 	---
	Air emissions (onshore and marine)	Volume 5A: ESA - Biophysical <ul style="list-style-type: none"> Sections 5.0, 6.0, 7.0 and 8.0 Volume 5C: ESA - Biophysical Technical Reports <ul style="list-style-type: none"> Marine Air Quality and Greenhouse Gas – Marine Transportation Technical Report Air Quality and Greenhouse Gas Emissions Technical Report Volume 7: Risk Assessment and Management of Pipeline and Facility Spills <ul style="list-style-type: none"> Section 7.0 	Volume 8A: Marine Transportation <ul style="list-style-type: none"> Sections 4.2, 4.3, 4.4, 5.6 and 5.7 Volume 8B: Technical Reports <ul style="list-style-type: none"> Marine Air Quality and Greenhouse Gas Emissions 	---
	Greenhouse gas emissions (onshore and marine)	Volume 5A: ESA - Biophysical <ul style="list-style-type: none"> Sections 5.0, 6.0 and 7.0 Volume 5C: ESA - Biophysical Technical Reports <ul style="list-style-type: none"> Air Quality and Greenhouse Gas Emissions Technical Report 	Volume 8A: Marine Transportation <ul style="list-style-type: none"> Sections 4.2 and 4.3 Volume 8B: Technical Reports <ul style="list-style-type: none"> Marine Air Quality and Greenhouse Gas Emissions 	---
	Acoustic environment (onshore and marine)	Volume 5A: ESA - Biophysical <ul style="list-style-type: none"> Sections 5.0, 6.0, 7.0, and 8.0 Volume 5C: ESA - Biophysical Technical Reports <ul style="list-style-type: none"> Acoustic Environment Technical Report 	Volume 8A: Marine Transportation <ul style="list-style-type: none"> Sections 4.2, 4.3 and 4.4 Volume 8B: Technical Reports <ul style="list-style-type: none"> Marine Noise (Atmospheric) 	---

Filing #	Filing Requirement	In Application? References	Applicable Marine Transportation Elements	Not in Application? Explanation
	Fish and fish habitat (onshore and marine), including any fish habitat compensation required	Volume 5A: ESA - Biophysical <ul style="list-style-type: none"> • Sections 5.0, 6.0, 7.0 and 8.0 Volume 5C: ESA - Biophysical Technical Reports <ul style="list-style-type: none"> • Fisheries (Alberta) Technical Report • Fisheries (British Columbia) Technical Report • Marine Resources - Westridge Marine Terminal Technical Report Volume 7: Risk Assessment and Management of Pipeline and Facility Spills <ul style="list-style-type: none"> • Sections 7.0, 8.0 and 9.0 • Qualitative Ecological Risk Assessment of Pipeline Spills Technical Report 	Volume 8A: Marine Transportation <ul style="list-style-type: none"> • Sections 4.2, 4.3, 4.4, 5.6 and 5.7 Volume 8B: Technical Reports <ul style="list-style-type: none"> • Marine Resources – Marine Transportation Technical Report • Ecological Risk Assessment of Westridge Marine Terminal Spills 	---
Wetlands		Volume 5A: ESA - Biophysical <ul style="list-style-type: none"> • Sections 5.0, 6.0, 7.0 and 8.0 Volume 5C: ESA - Biophysical Technical Reports <ul style="list-style-type: none"> • Wetland Evaluation Technical Report Volume 7: Risk Assessment and Management of Pipeline and Facility Spills <ul style="list-style-type: none"> • Sections 7.0 and 8.0 • Qualitative Ecological Risk Assessment of Pipeline Spills Technical Report 	N/A	---
Vegetation		Volume 5A: ESA - Biophysical <ul style="list-style-type: none"> • Sections 5.0, 6.0, 7.0 and 8.0 Volume 5C: ESA - Biophysical Technical Reports <ul style="list-style-type: none"> • Vegetation Technical Report Volume 7: Risk Assessment and Management of Pipeline and Facility Spills <ul style="list-style-type: none"> • Sections 7.0 and 8.0 • Qualitative Ecological Risk Assessment of Pipeline Spills Technical Report 	N/A	---
Wildlife and wildlife habitat (onshore and marine)		Volume 5A: ESA - Biophysical <ul style="list-style-type: none"> • Sections 5.0, 6.0, 7.0 and 8.0 Volume 5C: ESA - Biophysical Technical Reports <ul style="list-style-type: none"> • Wildlife and Wildlife Habitat Technical Report • Wildlife Modeling and Species Accounts Report • Marine Resources –Westridge Marine Terminal Technical Report • Marine Birds – Westridge Marine Terminal Technical Report Volume 7: Risk Assessment and Management of Pipeline and Facility Spills <ul style="list-style-type: none"> • Sections 7.0, 8.0 and 9.0 • Qualitative Ecological Risk Assessment of Pipeline Spills Technical Report 	Volume 8A: Marine Transportation <ul style="list-style-type: none"> • Sections 4.2, 4.3, 4.4, 5.6 and 5.7 Volume 8B: Technical Reports <ul style="list-style-type: none"> • Marine Resources – Marine Transportation Technical Report • Marine Birds – Marine Transportation Technical Report • Ecological Risk Assessment of Westridge Marine Terminal Spills 	---

Filing #	Filing Requirement	In Application? References	Applicable Marine Transportation Elements	Not in Application? Explanation
	Species at Risk or Species of Special Status and related habitat (onshore and marine)	<p>Volume 5A: ESA - Biophysical</p> <ul style="list-style-type: none"> • Sections 5.0, 6.0, 7.0 and 8.0 <p>Volume 5C: ESA - Biophysical Technical Reports</p> <ul style="list-style-type: none"> • Fisheries (Alberta) Technical Report • Fisheries (British Columbia) Technical Report • Vegetation Technical Report • Wildlife and Wildlife Habitat Technical Report • Wildlife Modeling and Species Accounts Report • Marine Resources – Westridge Marine Terminal Technical Report • Marine Birds – Westridge Marine Terminal Technical Report <p>Volume 7: Risk Assessment and Management of Pipeline and Facility Spills</p> <ul style="list-style-type: none"> • Sections 7.0, 8.0 and 9.0 <p>Volume 7: Technical Reports</p> <ul style="list-style-type: none"> • Qualitative Ecological Risk Assessment of Pipeline Spills Technical Report 	<p>Volume 8A: Marine Transportation</p> <ul style="list-style-type: none"> • Sections 4.2, 4.3, 4.4, 5.6 and 5.7 <p>Volume 8B: Technical Reports</p> <ul style="list-style-type: none"> • Marine Resources – Marine Transportation Technical Report • Marine Birds – Marine Transportation Technical Report • Marine Transportation Spills Ecological Risk Assessment Technical Report 	---
	Human occupancy and resource use (onshore and marine)	<p>Volume 5B: ESA - Socio-Economic</p> <ul style="list-style-type: none"> • Sections 5.0, 6.0, 7.0 and 8.0 <p>Volume 5D: ESA - Socio-Economic Technical Reports</p> <ul style="list-style-type: none"> • Socio-Economic Technical Report • Managed Forest Areas Technical Report • Agricultural Assessment Technical Report <p>Volume 7: Risk Assessment and Management of Pipeline and Facility Spills</p> <ul style="list-style-type: none"> • Sections 6.0, 7.0 and 8.0 	<p>Volume 8A: Marine Transportation</p> <ul style="list-style-type: none"> • Sections 4.2, 4.3, 4.4, 5.6 and 5.7 <p>Volume 8B: Technical Reports</p> <ul style="list-style-type: none"> • Marine Commercial, Recreational and Tourism Use – Marine Transportation Technical Report 	---
	Heritage resources	<p>Volume 5B: ESA - Socio-Economic</p> <ul style="list-style-type: none"> • Sections 5.0, 6.0 and 7.0 <p>Volume 7: Risk Assessment and Management of Pipeline and Facility Spills</p> <ul style="list-style-type: none"> • Section 6.3.3 	N/A	---
	Navigation and navigation safety	<p>Volume 5B: ESA - Socio-Economic</p> <ul style="list-style-type: none"> • Sections 5.0, 6.0 and 7.0 <p>Volume 5D: ESA - Socio-Economic Technical Reports</p> <ul style="list-style-type: none"> • Socio-Economic Technical Report 	<p>Volume 8A: Marine Transportation</p> <ul style="list-style-type: none"> • Section 5.2 	---
	Traditional land and resource use	<p>Volume 5B: ESA - Socio-Economic</p> <ul style="list-style-type: none"> • Sections 5.0, 6.0, 7.0 and 8.0 <p>Volume 5D: ESA - Socio-Economic Technical Reports</p> <ul style="list-style-type: none"> • Traditional Land and Resource Use Report • Pipeline and Facilities Human Health Risk Assessment Technical Report <p>Volume 7: Risk Assessment and Management of Pipeline and Facility Spills</p> <ul style="list-style-type: none"> • Sections 7.0, 8.0 and 9.0 • Qualitative Ecological Risk Assessment of Pipeline Spills Technical Report 	<p>Volume 8A: Marine Transportation</p> <ul style="list-style-type: none"> • Sections 4.2, 4.3, 4.4, 5.6 and 5.7 <p>Volume 8B: Technical Reports</p> <ul style="list-style-type: none"> • Traditional Marine Use Report for Marine Transportation • Marine Transportation Human Health Risk Assessment Technical Report 	---
	Social and cultural well-being	<p>Volume 5B: ESA - Socio-Economic</p> <ul style="list-style-type: none"> • Sections 5.0, 6.0, 7.0 and 8.0 <p>Volume 5D: ESA - Socio-Economic Technical Reports</p> <ul style="list-style-type: none"> • Socio-Economic Technical Report <p>Volume 7: Risk Assessment and Management of Pipeline and Facility Spills</p> <ul style="list-style-type: none"> • Sections 6.0, 7.0 and 8.0 	N/A	---

Filing #	Filing Requirement	In Application? References	Applicable Marine Transportation Elements	Not in Application? Explanation
	Human health and aesthetics	Volume 5B: ESA - Socio-Economic <ul style="list-style-type: none"> • Sections 5.0, 6.0, 7.0 and 8.0 Volume 5D: ESA - Socio-Economic Technical Reports <ul style="list-style-type: none"> • Socio-Economic Technical Report • Community Health Technical Report • Viewshed Modelling Analysis Technical Report • Pipeline and Facilities Human Health Risk Assessment Technical Report Volume 7 Risk Assessment and Management of Pipeline and Facility Spills <ul style="list-style-type: none"> • Sections 6.0, 7.0 and 8.0 • Qualitative Ecological Risk Assessment of Pipeline Spills Technical Report 	Volume 7: Risk Assessment and Management of Pipeline and Facility Spills <ul style="list-style-type: none"> • Qualitative Human Health Risk Assessment of Westridge Marine Terminal Technical Report Volume 8A: Marine Transportation <ul style="list-style-type: none"> • Sections 4.2, 4.3, 4.4, 5.6 and 5.7 Volume 8B: Technical Reports <ul style="list-style-type: none"> • Marine Transportation Human Health Risk Assessment Technical Report • Marine Transportation Spills Human Health Risk Assessment Technical Report 	---
	Infrastructure and services	Volume 5B: ESA - Socio-Economic <ul style="list-style-type: none"> • Sections 5.0, 6.0, 7.0 and 8.0 Volume 5D: ESA - Socio-Economic Technical Reports <ul style="list-style-type: none"> • Socio-Economic Technical Report • Community Health Technical Report Volume 7: Risk Assessment and Management of Pipeline and Facility Spills <ul style="list-style-type: none"> • Sections 6.0, 7.0 and 8.0 	Volume 8A: Marine Transportation <ul style="list-style-type: none"> • Sections 4.2, 4.3, 4.4, 5.6 and 5.7 Volume 8B: Technical Reports <ul style="list-style-type: none"> • Marine Commercial, Recreational and Tourism Use – Marine Transportation Technical Report 	---
	Employment and economy	Volume 5B: ESA - Socio-Economic <ul style="list-style-type: none"> • Sections 5.0, 6.0, 7.0 and 8.0 Volume 5D: ESA - Socio-Economic Technical Reports <ul style="list-style-type: none"> • Socio-Economic Technical Report • Worker Expenditures Analysis Technical Report 	N/A	---

GUIDE A – A.3 ECONOMICS

Filing #	Filing Requirement	In Application? References	Not in Application? Explanation
A.3.1 Supply			
1.	A description of each commodity.	Volume 2 Section 3.1.1	--
2.	A discussion of all potential supply sources.	Volume 2 Section 3.3.2	--
3.	Forecast of productive capacity over the economic life of the facility.	Volume 2 Sections 3.3.1, 3.4.1	
4.	For pipelines with contracted capacity, a discussion of the contractual arrangements underpinning supply.	Volume 2 Section 3.3.2	--
A.3.2 Transportation Matters			
Pipeline Capacity			
1.	In the case of expansion provide: <ul style="list-style-type: none"> • Pipeline capacity before and after and size of increment • Justification that size of expansion is appropriate 	Volume 2 Sections 1.1, 2.1, 3.5	--
2.	In case of new pipeline, justification that size of expansion is appropriate given available supply.	N/A – expansion	N/A
Throughput			
1.	For pipelines with contracted capacity, information on contractual arrangements.	Volume 2 Section 3.2.1	--
2.	For non-contract carrier pipelines, forecast of annual throughput volumes by commodity type, receipt location and delivery destination over facility life.	N/A	N/A
3.	If project results in an increase in throughput: <ul style="list-style-type: none"> • theoretical and sustainable capabilities of the existing and proposed facilities versus the forecasted requirements • flow formulae and flow calculations used to determine the capabilities of the proposed facilities and the underlying assumptions and parameters 	Volume 2 Section 3.1	--
4.	If more than one type of commodity transported, a discussion pertaining to segregation of commodities including potential contamination issues or cost impacts.	N/A	N/A
A.3.3 Markets			
1.	Provide an analysis of the market in which each commodity is expected to be used or consumed.	Volume 2 Section 3.4.2	--
2.	Provide a discussion of the physical capability of upstream and downstream facilities to accept the incremental volumes that would be received and delivered.	Volume 2 Section 3.4.2	--
A.3.4 Financing			
1.	Evidence that the applicant has the ability to finance the proposed facilities.	Volume 2 Section 3.2.2	--
2.	Estimated toll impact for the first full year that facilities are expected to be in service.	Volume 2 Section 3.2.1	--
3.	Confirmation that shippers have been apprised of the project and toll impact, their concerns and plans to address them.	Volume 2 Section 3.2.1	--
4.	Additional toll details for applications with significant toll impacts.	Volume 2 Section 3.2.1	
A.3.5 Non-NEB Regulatory Approvals			
1.	Confirm that all non-NEB regulatory approvals required to allow the applicant to meet its construction schedule, planned in-service date and to allow the facilities to be used and useful are or will be in place.	Volume 2 Section 1.5	--
2.	If any of the approvals referred to in #1 may be delayed, describe the status of those approval(s) and provide an estimation of when the approval is anticipated.	Volume 2 Section 1.5	--

GUIDE A – A.4 LANDS INFORMATION

Filing #	Filing Requirement	In Application? References	Not in Application? Explanation
A.4.1 Land Areas			
1.	<ul style="list-style-type: none"> • Width of right-of-way and locations of any changes to width • Locations and dimensions of known temporary work space and drawings of typical dimensions • Locations and dimensions of any new lands for facilities 	Volume 2 Section 5.2	--
A.4.2 Land Rights			
1.	The type of lands rights proposed to be acquired for the project.	Volume 2 Section 5.3	--
2.	The relative proportions of land ownership along the route of the project.	Volume 2 Section 5.3.2	--
3.	Any existing land rights that will be required for the project.	Volume 2 Section 5.4	--
A.4.3 Lands Acquisition Process			
1.	The process for acquiring lands.	Volume 2 Section 5.4.1, 5.4.2	--
2.	The timing of acquisition and current status.	Volume 2 Section 5.4.3	--
3.	The status of service of section 87(1) notices.	Volume 2 Section 5.4.4	--
A.4.4 Land Acquisition Agreements			
1.	A sample copy of each form of agreement proposed to be used pursuant to section 86(2) of the NEB Act.	Volume 2 Section 5.4.2	--
2.	A sample copy of any proposed fee simple, work space, access or other land agreement.	Volume 2 Section 5.5.2	--
A.4.5 Section 87 Notices			
1.	A sample copy of the notice proposed to be served on all landowners pursuant to section 87(1) of the NEB Act.	Volume 2 Section 5.4.4, Appendix D	--
2.	Confirmation that all notices include a copy of Pipeline Regulation in Canada: A Guide for Landowners and the Public.	Volume 2 Section 5.4.4	--
A.4.6 Section 58 Application to Address a Complaint			
1.	The details of the complaint and describe how the proposed work will address the complaint.	N/A	N/A

CONCORDANCE TABLE WITH THE CEA ACT, 2012

CEA Act, 2012 Requirement	Section in CEA Act, 2012	Application Volume and Section
The environmental effects of the designated project, including:		
the environmental effects of malfunctions or accidents that may occur in connection with the designated project;	s.19.1(a)	Volume 5A ESA - Biophysical: <ul style="list-style-type: none"> • Section 7.0 Volume 5B ESA - Socio-economic: <ul style="list-style-type: none"> • Section 7.0 Volume 7 Risk Assessment and Management of Pipeline and Facility Spills Volume 8A Marine Transportation: <ul style="list-style-type: none"> • Sections 4.3 and 5.0
any cumulative environmental effects that are likely to result from the designated project in combination with other physical activities that have been or will be carried out;	s.19.1(a)	Volume 5A ESA - Biophysical: <ul style="list-style-type: none"> • Section 8.0 Volume 5B ESA - Socio-economic: <ul style="list-style-type: none"> • Section 8.0 Volume 8A Marine Transportation: <ul style="list-style-type: none"> • Section 4.4
the significance of the effects referred to in paragraph (a);	s.19.1(b)	Volume 5A ESA - Biophysical: <ul style="list-style-type: none"> • Sections 7.0 and 8.0 Volume 5B ESA - Socio-economic: <ul style="list-style-type: none"> • Sections 7.0 and 8.0 Volume 8A Marine Transportation: <ul style="list-style-type: none"> • Sections 4.3 and 4.4
comments from the public – or, with respect to a designated project that requires that a certificate be issued in accordance with an order made under section 54 of the <i>National Energy Board Act</i> , any interested party – that are received in accordance with this <i>act</i> ;	s.19.1(c)	Volume 3A Public Consultation Volume 3B Aboriginal Engagement Volume 3C Landowner Relations Volume 5A ESA - Biophysical: <ul style="list-style-type: none"> • Section 3.0 Volume 5B ESA - Socio-economic: <ul style="list-style-type: none"> • Section 3.0 Volume 8A Marine Transportation: <ul style="list-style-type: none"> • Section 3.0
mitigation measures that are technically and economically feasible and that would mitigate any significant adverse environmental effects of the designated project;	s.19.1(d)	Volume 5A ESA - Biophysical: <ul style="list-style-type: none"> • Sections 7.0 and 8.0 Volume 5B ESA - Socio-economic: <ul style="list-style-type: none"> • Sections 7.0 and 8.0 Volume 5C ESA – Biophysical Technical Reports Volume 5D ESA - Socio-economic Technical Reports Volume 6B Pipeline Environmental Protection Plan Volume 6C Facilities Environmental Protection Plan Volume 6D Westridge Marine Terminal Environmental Protection Plan Volume 6E Environmental Alignment Sheets Volume 8A Marine Transportation: <ul style="list-style-type: none"> • Sections 4.3, 4.4 and 5.0 Volume 8B Technical Reports
the requirements of the follow-up program in respect of the designated project;	s.19.1(e)	Volume 5A ESA - Biophysical: <ul style="list-style-type: none"> • Section 10.0 Volume 5B ESA - Socio-economic: <ul style="list-style-type: none"> • Section 10.0
the purpose of the designated project;	s.19.1(f)	Volume 5A ESA - Biophysical: <ul style="list-style-type: none"> • Section 2.0 Volume 5B ESA - Socio-economic: <ul style="list-style-type: none"> • Section 2.0 Volume 8A Marine Transportation: <ul style="list-style-type: none"> • Section 1.1

CONCORDANCE TABLE WITH THE CEA ACT, 2012

<i>CEA Act, 2012</i> Requirement	Section in <i>CEA Act, 2012</i>	Application Volume and Section
alternative means of carrying out the designated project that are technically and economically feasible and the environmental effects of any such alternative means;	s.19.1(g)	Volume 5A ESA - Biophysical: • Sections 2.0 and 4.0 Volume 5B ESA - Socio-economic: • Sections 2.0 and 4.0 Volume 8A Marine Transportation: • Section 2.2
any change to the designated project that may be caused by the environment;	s.19.1(h)	Volume 5A ESA - Biophysical: • Section 7.10 Volume 8A Marine Transportation: • Section 4.3
the results of any relevant study conducted by a committee established under section 73 or 74; and	s.19.1(i)	N/A
any other matter relevant to the environmental assessment that the responsible authority, or, – if the environmental assessment is referred to a review panel – the Minister, requires to be taken into account.	s.19.1(j)	Volume 8A Marine Transportation Volume 8B Technical Reports Volume 8C TERMPOL Reports These volumes take into consideration the <i>Filing Requirements Related to the Potential Environmental and Socio-Economic Effects of Increased Marine Shipping Activities, Trans Mountain Expansion Project</i> (September 10, 2013) (NEB 2013)
The environmental assessment of a designated project may take into account community knowledge and Aboriginal traditional knowledge.	s 19.3	Volume 5A ESA - Biophysical: • Sections 5.0, 6.0, 7.0 and 8.0 Volume 5B ESA - Socio-economic: • Sections 5.0, 6.0, 7.0 and 8.0 Volume 5C ESA - Biophysical Technical Reports Volume 5D ESA - Socio-economic Technical Reports Volume 8A Marine Transportation: • Sections 4.2, 4.3 and 4.4 Volume 8B Technical Reports
Subsection 5(1) of <i>CEA Act, 2012</i> defines environmental effects as a change that may be caused to the following components of the environment that are within the legislative authority of Parliament:		
fish as defined in section 2 of the <i>Fisheries Act</i> and fish habitat as defined in subsection 34(1) of that <i>Act</i> ;	s.5(1)(a)(i)	Volume 5A ESA - Biophysical: • Sections 5.0, 6.0, 7.0 and 8.0 Volume 5C ESA - Biophysical Technical Reports Volume 8A Marine Transportation: • Sections 4.2, 4.3, 4.4 and 5.0 Volume 8B Technical Reports
aquatic species as defined in subsection 2(1) of the <i>Species at Risk Act</i> ;	s.5(1)(a)(ii)	Volume 5A ESA - Biophysical: • Sections 5.0, 6.0, 7.0 and 8.0 Volume 5C ESA - Biophysical Technical Reports Volume 8A Marine Transportation: • Sections 4.2, 4.3, 4.4 and 5.0 Volume 8B Technical Reports
migratory birds as defined in subsection 2(1) of the <i>Migratory Birds Convention Act, 1994</i> , and	s.5(1)(a)(iii)	Volume 5A ESA - Biophysical: • Sections 5.0, 6.0, 7.0 and 8.0 Volume 5C ESA - Biophysical Technical Reports Volume 8A Marine Transportation: • Sections 4.2, 4.3, 4.4 and 5.0 Volume 8B Technical Reports
any other component of the environment that is set out in Schedule 2.	s.5(1)(a)(iv)	N/A
Subsection 5(1) of the <i>CEA Act, 2012</i> defines environmental effects as (b) a change that may be caused to the environment that would occur		

CONCORDANCE TABLE WITH THE *CEA ACT, 2012*

<i>CEA Act, 2012</i> Requirement	Section in <i>CEA Act, 2012</i>	Application Volume and Section
on federal lands,	s.5(1)(b)(i)	Volume 5A ESA - Biophysical: • Section 7.0 Volume 5B ESA - Socio-economic: • Section 7.0
in a province other than the one in which the <i>act</i> or thing is done or where the physical activity, the designated project or the project is being carried out, or	s.5(1)(b)(ii)	N/A No changes are anticipated in provinces other than Alberta and BC in relation to the ESA.
outside Canada.	s.5(1)(b)(iii)	Volume 8A Marine Transportation: • Sections 4.3, 4.4 and 5.0
Subsection 5(1) of the <i>CEA Act, 2012</i> defines environmental effects as (c) with respect to aboriginal peoples, an effect occurring in Canada of any change that may be caused to the environment on:		
health and socio-economic conditions;	s.5(1)(c)(i)	Volume 5B ESA - Socio-economic: • Sections 5.0, 6.0, 7.0 and 8.0 Volume 5D ESA - Socio-economic Technical Reports Volume 8A Marine Transportation: • Sections 4.3 and 4.4 Volume 8B Technical Reports
physical and cultural heritage;	s.5(1)(c)(ii)	Volume 5B ESA - Socio-economic: • Sections 5.0, 6.0 and 7.0
the current use of lands and resources for traditional purposes; or	s.5(1)(c)(iii)	Volume 5B ESA - Socio-economic: • Sections 5.0, 6.0, 7.0 and 8.0 Volume 5D ESA - Socio-economic Technical Reports Volume 8A Marine Transportation: • Sections 4.3 and 4.4 Volume 8B Technical Reports
any structure, site or thing that is of historical, archaeological, paleontological or architectural significance.	s.5(1)(c)(iv)	Volume 5B ESA - Socio-economic: • Sections 5.0, 6.0 and 7.0

1.0 INTRODUCTION

1.1 Project Overview

Trans Mountain Pipeline ULC (Trans Mountain) is a Canadian corporation with its head office located in Calgary, Alberta (AB). Trans Mountain is a general partner of Trans Mountain Pipeline L.P., which is operated by Kinder Morgan Canada Inc. (KMC), and is fully owned by Kinder Morgan Energy Partners, L.P. Trans Mountain is the holder of the National Energy Board (NEB) certificates for the Trans Mountain pipeline system (TMPL system).

The TMPL system commenced operations 60 years ago and now transports a range of crude oil and petroleum products from Western Canada to locations in central and southwestern British Columbia (BC), Washington State and offshore. The TMPL system currently supplies much of the crude oil and refined products used in BC. The TMPL system is operated and maintained by staff located at Trans Mountain's regional and local offices in Alberta (Edmonton, Edson, and Jasper) and BC (Clearwater, Kamloops, Hope, Abbotsford, and Burnaby).

The TMPL system has an operating capacity of approximately 47,690 m³/d (300,000 bbl/d) using 23 active pump stations and 40 petroleum storage tanks. The expansion will increase the capacity to 141,500 m³/d (890,000 bbl/d).

The proposed expansion will comprise the following:

- Pipeline segments that complete a twinning (or “looping”) of the pipeline in Alberta and BC with about 987 km of new buried pipeline.
- New and modified facilities, including pump stations and tanks.
- Three new berths at the Westridge Marine Terminal in Burnaby, BC, each capable of handling Aframax class vessels.

The expansion has been developed in response to requests for service from Western Canadian oil producers and West Coast refiners for increased pipeline capacity in support of growing oil production and access to growing West Coast and offshore markets. NEB decision RH-001-2012 reinforces market support for the expansion and provides Trans Mountain the necessary economic conditions to proceed with design, consultation, and regulatory applications.

Application is being made pursuant to Section 52 of the *National Energy Board Act (NEB Act)* for the proposed Trans Mountain Expansion Project (referred to as “TMEP” or “the Project”). The NEB will undertake a detailed review and hold a Public Hearing to determine if it is in the public interest to recommend a Certificate of Public Convenience and Necessity (CPCN) for construction and operation of the Project. Subject to the outcome of the NEB Hearing process, Trans Mountain plans to begin construction in 2015/2016 and go into service in 2017.

Trans Mountain has embarked on an extensive program to engage Aboriginal communities and to consult with landowners, government agencies (e.g., regulators and municipalities), stakeholders, and the general public. Information on the Project is also available at www.transmountain.com.

1.2 The Trans Mountain Pipeline

1.2.1 About the Applicant

1.2.1.1 The Trans Mountain Pipeline System

The TMPL system began transporting crude oil in 1953, ushering in a new era of economic growth in western Canada. Originally designed to transport just crude oil, the pipeline was later modified to allow customers to also ship refined products and production from Alberta's oil sands. Today, Trans Mountain remains the only pipeline that transports liquid petroleum from the Western Canadian Sedimentary Basin to the west coast of Canada. The pipeline celebrated 60 years of service in 2013.

1.2.1.2 Kinder Morgan

Kinder Morgan is the largest midstream and the fourth largest energy company (based on combined enterprise value) in North America. Kinder Morgan owns an interest in or operates approximately 130,000 km of pipelines transporting natural gas, refined petroleum products, crude oil, and carbon dioxide (CO₂). The Kinder Morgan family of companies has four publicly traded entities: Kinder Morgan, Inc., Kinder Morgan Energy Partners, L.P. (KMP), Kinder Morgan Management, LLC and El Paso Pipeline Partners. Combined, the Kinder Morgan companies have an enterprise value of approximately \$105 billion.

Kinder Morgan, through its operating company KMC, has owned and operated the Trans Mountain pipeline (TMPL) since 2005. Trans Mountain is the holder of the operating certificate from the NEB for the TMPL and is the applicant for the expansion.

1.2.1.3 Operations Management

Safety, compliance and protection are the key components of Kinder Morgan's Operations Management System (OMS), a single management system capturing the company's important operational expectations in areas such as physical operations, engineering, environmental compliance, asset integrity, efficiency, quality, and project management.

The OMS plays a critical role in setting the objectives and expectations for all these activities. Individual business unit operations including those of KMC, its maintenance procedures, and site-specific procedures are designed to meet these objectives and expectations.

Across all its operations, Kinder Morgan strives to provide for the safety of the public, its employees and contractors; protect the environment; comply with applicable laws, rules, regulations, and permit requirements; and operate and expand efficiently and effectively to serve our shareholders and customers. The OMS plays a critical role in setting the objectives and expectations for all these activities. Individual business unit operations including those of KMC, its maintenance procedures, and site-specific procedures are designed to meet these objectives and expectations.

Kinder Morgan is governed by its operational goals, which include risk reduction, efficiency and productivity, effective expansion and integration, quality assurance, and a culture of excellence. These goals are embedded into the company and its operations. The operations of each business unit are as unique as the regulatory and commercial environments in which they operate.

1.2.1.4 *Focused on Safety*

Pipeline safety is Kinder Morgan's top priority. With 60 years of operating experience, KMC employs rigorous safety standards.

The control centre for the pipeline is located at the Edmonton terminal, the start of the TMPL system. Control Centre Operators (CCOs) remotely monitor all aspects of pipeline operations. Operating conditions are monitored 24 hours a day, 7 days a week by staff using a Supervisory Control and Data Acquisition (SCADA) computer system. This electronic surveillance system gathers and displays such data as pipeline pressures, volume and flow rates and the status of pumping equipment and valves. Alarms notify CCOs if parameters deviate from prescribed operating limits. Both automated and manual valves are strategically located along the pipeline system to enable the pipeline to be shut down immediately and sections to be isolated quickly, if necessary. In the event of a precautionary shutdown of the pipeline there is a formal protocol, which must be followed prior to restarting the pipeline. This protocol includes analysis of SCADA and leak detection system data, aerial or foot patrols of the pipeline as appropriate, completion of any inspections or repairs, notifications to regulators, and development of a restart plan. The approval of two operations directors is required prior to the restart of the pipeline.

Operations staff trained to maintain the pipeline and respond in the event of a spill or other safety related incidents are located in communities along the pipeline route. Currently, in Alberta 100 staff are employed in Edmonton, Stony Plain, Edson, and Jasper. Through central BC in the towns of Blue River, Clearwater, and Kamloops, an additional 40 operations personnel maintain the pipeline while in southern BC, 60 staff are located in Hope, Sumas (near Abbotsford) and Burnaby.

The pipeline right-of-way is regularly patrolled by both land and air. Any unauthorized activity or encroachment is reported and investigated. KMC has a public awareness program designed to create awareness about pipelines, provide important safety information, increase knowledge of the regulations for working around pipelines, and educate first responders and the public on our emergency preparedness response activities.

The integrity of the pipeline is regularly monitored using electronic equipment called "smart pigs". These devices inspect the pipeline from the inside and can identify potential anomalies or changes to the condition of the pipe. The collected data is analyzed to pinpoint locations where further investigation is required. If necessary, a section of the pipe is exposed and assessed by qualified technicians so that it can be repaired or replaced.

As a federally regulated company, KMC is regularly audited by the NEB. Any concerns identified in these audits are addressed through a comprehensive Corrective Action Plan approved by the NEB that remains in place until all items are completed.

Kinder Morgan is committed to continually improving pipeline and facility integrity to protect the safety of the public, the environment, and company employees. The company is committed to being a good corporate citizen by incorporating responsible business practices and conducting its operations in an ethical manner.

1.2.1.5 *Westridge Marine Terminal*

Trans Mountain has been safely loading tankers and barges since 1956 from the Westridge Marine Terminal in Burnaby, BC. Trans Mountain is responsible for and has internal standards and procedures relating to marine safety at the Westridge Marine Terminal including rigorous

inspections and monitoring for each vessel. In addition, Trans Mountain works closely with Port Metro Vancouver (PMV), Transport Canada, the Canadian Coast Guard, and other agencies to ensure the safety and efficiency of this traffic. Trans Mountain has consistently worked to bring parties to the table to advance opportunities to improve the safety and efficiency of tanker traffic.

Stringent regulations and requirements provide oversight and ensure that oil tankers navigate local waters safely. For example, on the west coast of Canada all oil tankers must be double-hulled, guided by two BC coast pilots, and escorted by tethered tugs.

Trans Mountain is a shareholder and member of the Western Canada Marine Response Corporation (WCMRC), Canada's West Coast-certified response organization responsible for emergency response preparedness — on call 24 hours a day, 7 days per week to manage oil spill response on the BC coast.

1.2.1.6 *Engaging Communities*

At KMC, we believe our neighbours, governments, and Aboriginal communities play an important role in how we conduct our business. Our success depends on earning the trust, respect and cooperation of community members.

In anticipation of TMEP, Trans Mountain has established relationships with landowners, neighbours, and communities along the pipeline corridor developed over the last six decades. The TMPL crosses private properties, as well as public lands. Agreements are in place with landowners that have allowed Trans Mountain to build and operate the existing pipeline. Trans Mountain values its ongoing and positive relationships with landowners and neighbours in all communities along the route.

Trans Mountain is committed to respectful, transparent and collaborative interactions with communities to develop long-term effective relationships. To honour this commitment, we participate in communities by hosting facility open houses, providing newsletters and project updates, making safety and public awareness presentations and participating in community events.

With operations in Aboriginal traditional territories and on reserve lands, Trans Mountain recognizes and appreciates the many unique and diverse interests of Aboriginal groups, and is committed to open, transparent dialogue and creating mutually beneficial working relationships. Trans Mountain views the Crown's obligation for Aboriginal consultation as an opportunity to demonstrate recognition and respect for the constitutionally protected rights held by Aboriginal Peoples.

1.2.1.7 *Environmental Stewardship*

As a long-time industry and community member, Trans Mountain is committed to working with residents, regulatory authorities, and other stakeholders on environmental initiatives. Recent examples of Trans Mountain's commitment to preserving and protecting the environment include:

- **Raft River Stabilization (Clearwater, BC)** - Trans Mountain helped stabilize the Raft River near Clearwater, BC. This erosion protection project has helped enhance the river's fish habitat, an important historical fishing ground for local Aboriginal communities. This enhancement project involved stabilizing more than 700 m of riverbank to prevent erosion, improving the local fish habitat, as well as planting native trees and shrubs.

- **Improving wildlife habitat and conservation education along Stoney Creek (Burnaby, BC)** - 20 years ago there were no salmon in Stoney Creek. Thanks to the Stoney Creek Environment Committee, this habitat has been restored. Trans Mountain and its employees have been involved with many of these projects, including participating annually in the Stoney Creek Environmental Committee's "Great Salmon Send-Off."
- **Tree Canada Partnership** - Since 1998, Trans Mountain has contributed to the planting of 13,000 trees. Over the next 80 years, this will offset 2,300 tonnes of CO₂, a main contributor to greenhouse gases.

1.2.1.8 *Award-winning Projects: The Anchor Loop Expansion*

Kinder Morgan Canada recently expanded a portion of the TMPL, a 158 km section of the existing Trans Mountain system between Hinton, Alberta and Hargreaves, BC. Completed in 2008, the Anchor Loop expansion project involved installing a second pipeline adjacent to the existing pipeline, which included construction through Jasper National Park and Mount Robson Provincial Park, both designated part of the Canadian Rocky Mountains Parks, a United Nations Educational, Scientific, and Cultural Organization World Heritage Site.

Successful completion of Anchor Loop was the result of years of planning and execution of a very complex and highly scrutinized pipeline project. Rugged terrain, stringent environmental requirements and intense regulatory scrutiny were all challenges that were met with excellence.

For this work, KMC received a prestigious Emerald Award in 2010 from the Alberta Emerald Foundation; it has been recognizing, celebrating and inspiring environmental excellence in Alberta for more than 20 years. Each year, the Emerald Awards recognize and reward the excellent environmental initiatives undertaken each year by large and small corporations, individuals, not-for-profit associations, community groups, and governments. Of six finalists in the business category, KMC was one of three companies to receive this prestigious award that year.

The success of the Anchor Loop project has been attributed to a strong collaborative effort and teamwork involving KMC's project team, consultants, contractors, the regulatory community, Aboriginal Peoples, and stakeholders.

Today, as plans progress for the proposed expansion of the TMPL between Edmonton and Burnaby, should the NEB approve the company's bid to further expand the TMPL, KMC would aim to replicate the best practices and many successes of the Anchor Loop project.

1.3 **Regulatory Framework**

This section describes and identifies the regulatory framework applicable to the Project, including the approvals and requirements of relevant federal, provincial, and other regulatory bodies.

In May 2013, pursuant to NEB Reasons for Decision RH-001-2012, the Project received approval pursuant to Part IV of the *NEB Act* for the toll methodology, terms and conditions that would apply to the Project. This approval reinforces market support for the Project and provides Trans Mountain with the necessary economic incentive to proceed with design, consultation, and regulatory applications.

1.3.1 Federal Regulatory Framework

The Project will require a CPCN pursuant to Section 52 of the *NEB Act* to permit construction and operation of the expanded pipeline system. A comprehensive Environmental and Socio-Economic Assessment (ESA) and a public hearing is required as part of the NEB regulatory process for the Project. The recent NEB Reasons for Decision RH-001-2012 concerning Trans Mountain's tolls and tariff application provides the financial grounding that Trans Mountain requires to proceed with this application under Section 52 of the *NEB Act*. The NEB Section 52 application constitutes Trans Mountain's formal application to the NEB seeking approval for the Project. The Section 52 application forms the basis for the regulatory process and public hearing for the Project.

Trans Mountain is required to prepare an application package for the Project in accordance with guidance provided in the NEB Filing Manual (NEB 2013a). To satisfy the specifications set out for large proposals such as the Project, this application includes a facilities application that describes the Project; its economic feasibility and justification; its engineering design and operating and maintenance activities, including the quality assurance program; the public consultation program undertaken for the Project including engagement with Aboriginal communities, landowners, government agencies (e.g., regulators, municipalities), stakeholders (e.g., environmental non-governmental organizations, recreation associations), and the general public; lands information, including accurate documentation on land areas, land rights, the service of notice and the land acquisition process; and an assessment of the environmental and socio-economic implications of the Project.

For a proposed project that involves constructing or modifying facilities that require an application under the *NEB Act*, the NEB must satisfy itself, or make recommendations to the Governor in Council, that the facilities are and will be required for the present and future public convenience and necessity.

Under the *Canadian Environmental Assessment (CEA) Act, 2012*'s Designated Project Regulations, there are three possible Project-related criteria that could potentially result in the Project being a *CEA Act, 2012* designated project: length of the new pipeline, oil storage volume, and marine terminal development. Trans Mountain does not believe the criteria for oil storage volumes or creation of a new marine terminal would apply to the Project given the size of existing oil storage at any of the associated terminals is under 500,000 m³, and the Westridge Marine Terminal is an existing terminal and will continue to be located on land that has historically been used as a marine terminal. The Project will be a designated project under the *CEA Act, 2012*, based on the fact that the new pipeline will be more than 40 km in length.

In any event, based on the level of public interest in the Project, Trans Mountain believes it should be considered a designated project, and subject to a rigorous environmental review required under both the *NEB Act* and the *CEA Act, 2012*. Therefore, Trans Mountain requested that the Project be deemed a designated project under the *CEA Act, 2012*. As such, the environmental assessment prepared for the Project considers the mandatory factors listed in Section 19(1) of the *CEA Act, 2012*, as well as the factors listed in the NEB Filing Manual (NEB 2013a), and pertinent issues and concerns identified through consultation and engagement with Aboriginal communities, landowners, government agencies, stakeholders, and the general public.

Marine transportation in Canadian waters is authorized and regulated through the *Canada Shipping Act* and related legislation and regulations administered by Transport Canada and the Canadian Coast Guard. There will be additional marine traffic to offload the product from the

Project. Although regulation and authorization of marine transportation is not specifically within the jurisdiction of the NEB, the environmental and socio-economic effects of the increased marine traffic is considered by Trans Mountain in accordance with the NEB’s direction from their list of Issues for the Project, released on July 29, 2013.

Routine operation and maintenance activities will be evaluated by the NEB as part of the Section 52 application for Project construction and operation of a pipeline. For those activities listed under Section 4.1 of the Operations and Maintenance Activities on Pipelines Regulated under the *NEB Act*. Requirements and Guidance Notes (NEB 2013b), Trans Mountain will provide notification to the NEB as required.

Pursuant to the *NEB Act*, approval must be received from the NEB prior to abandonment activities taking place. Accordingly, Trans Mountain will file an application with the NEB if it seeks to abandon any portion of the TMPL system at some point in the future. Abandonment will be conducted in accordance with the legislation and requirements in place at the time of the application. The Preliminary Abandonment Plan for the Project in accordance with the NEB Filing Manual (Section 4A.2.6.1) is presented in Volume 4C, Section 12.

1.3.2 Other Federal Requirements

In addition to seeking a certificate under the *NEB Act* to construct and operate the Project, other federal permits and approvals may be required for certain construction activities to proceed. The project is federally regulated and subject to obtaining a CPCN from the NEB and complying with the conditions imposed by the NEB. Trans Mountain intends to work with provincial and municipal regulatory agencies to provide them the information they need to fulfill their permitting requirements.

1.3.2.1 Federal Undertakings

Trans Mountain will work with various federal agencies with responsibilities related to Project components and environmental impacts. Table 1.3.1 provides a preliminary list of potential federal permits and approvals required for the Project.

TABLE 1.3.1

POTENTIAL FEDERAL ENVIRONMENTAL PERMITS/APPROVALS

Regulatory Agency	Legislation	Permit, Approval, Authorization and/or Notification	Activity/Trigger
Aboriginal Affairs and Northern Development Canada	<i>Indian Act</i>	Section 28 Approval to Cross an Indian Reserve	As required, approval for the proposed pipeline corridor to cross reserve lands.
	<i>First Nations Land Management Act</i>	Section 20 Approval to Cross an Indian Reserve	As required, approval for the proposed pipeline corridor to cross reserve lands.
Canadian Transportation Agency	<i>Railway Relocation and Crossing Act</i>	Crossing Permit	Approval to cross railways with access roads and power lines.

TABLE 1.3.1

POTENTIAL FEDERAL ENVIRONMENTAL PERMITS/APPROVALS (continued)

Regulatory Agency	Legislation	Permit, Approval, Authorization and/or Notification	Activity/Trigger
Environment Canada	<i>Canadian Environmental Protection Act, 1999; Disposal at Sea Regulations; Regulations Respecting Applications for Permits for Disposal at Sea</i>	Section 127: Disposal at Sea Permit (previously called Ocean Dumping Permit)	Approval to dispose of materials at sea (e.g., dredge spoil from the Westridge Marine Terminal expansion).
	<i>Species at Risk Act (SARA)</i>	Permit pursuant to Section 73 of SARA - Species at Risk Permit	Activities that affect a listed species, its critical habitat or residence.
Fisheries and Oceans Canada (DFO) ¹	<i>Fisheries Act: Section 32(2)</i>	Case-specific request for review	Authorization required if fish will be destroyed during construction.
	<i>Fisheries Act: Section 35(2)</i>	Case-specific request for review	Authorization required if construction will cause harm to fish habitat.
	Operational Statements	Notification as per the applicable Operational Statements	As required, notifications for watercourse crossings that comply with DFO Operational Statements. Marine Communications and Traffic Services oversight of marine traffic within Canadian jurisdiction.
	<i>Section 52 of Fishery (General) Regulation</i>	Authorization of Fish Collection for Scientific, Experimental, Educational or Public Display Purposes	Approval to collect salmon, eulachon or SARA-listed species during scientific studies.
	SARA	Permit pursuant to Schedule 1 Aquatic Species of SARA - Species at Risk Permit	Activities that may affect a listed fish species, its critical habitat or residence.
Industry Canada	<i>Radiocommunication Act</i>	Radio Licence	Radio communication.
Natural Resources Canada	<i>Explosives Act</i>	Ammonium Nitrate Fuel Oil Permit	Blending of ammonium nitrate and fuel oil.
		Sections 6 and 7: Explosives Transportation Permit	Approval to transport explosives.
		Temporary Magazine Licence	Approval for any storage place of explosives in amounts that exceed the regulations. If a factory is required to make explosives near the site, additional permits may be required. Additional permits may be required, depending on the type of explosives (e.g., an Ammonium Nitrate Fuel Oil Permission) and whether they are blended.
		Temporary Blaster's License or Blaster's Permit	Approval for the use of explosives.

TABLE 1.3.1

POTENTIAL FEDERAL ENVIRONMENTAL PERMITS/APPROVALS (continued)

Regulatory Agency	Legislation	Permit, Approval, Authorization and/or Notification	Activity/Trigger
Parks Canada	<i>Canada National Parks Act</i>	Special Activity Permits	Approval to conduct activities such as valve work.
Transport Canada	<i>Canada Shipping Act</i>	An act respecting shipping and navigation	Ensures compliance of vessels with relevant marine regulations.
PMV	<i>Canada Marine Act</i>	Project Permit Building Permit Water Lease Expansion	Approval for new structures on water or land including modifications to existing structures.

Note: 1 As a result of the passage of the *Jobs, Growth and Long-term Prosperity Act* (Bill C-38), regulation requirements of some federal legislation are evolving and actual triggers and permitting requirements will be confirmed over the next year.

1.4 TERMPOL Review Process

In addition to federal authorizations, Trans Mountain requested to undertake the Technical Review Process of Marine Terminal Systems and Transshipment Sites (TERMPOL) process, which focuses on the increase in marine transportation related to the Project. The review process is chaired and led by Transport Canada and has involved other federal departments and stakeholders, as required. The review may consider safety measures above and beyond existing regulations to address site-specific circumstances.

In general and for any project, the TERMPOL process focuses on the marine transportation components of a project and examines the safety of tankers entering Canadian waters, navigating through channels, approaching berthing at a marine terminal and loading or unloading oil or gas.

With respect to the increase in existing marine traffic related to the TMEP, the TERMPOL process focuses on the effects of the incremental increase in marine traffic related to the Project. To fulfill the requirements of TERMPOL, Trans Mountain undertook a number of studies focused on the Project-related increase in tanker traffic. The relevant results of these studies have been incorporated into the ESA for marine transportation (Volume 8A, Sections 4.0 and 5.0). In particular, the results of a quantitative risk assessment informed the assessment of accidents and malfunctions, the description of spill prevention, emergency preparedness and response, and the identification of improved practices (Volume 8A, Section 5.0). The relevant TERMPOL studies referenced in Volume 8A are provided in Volume 8C.

Trans Mountain has provided all of the TERMPOL studies in Volume 8C to Transport Canada for review. In addition, Trans Mountain is seeking endorsement from Transport Canada on the proposed measures to improve navigational safety outlined in Volume 8A, Section 5.4.2, as Trans Mountain has no regulatory authority to implement the proposed measures. A summary of the TERMPOL process is provided in Volume 8C-1 (TERMPOL 3.1).

1.5 Non-NEB Regulatory Approvals

Trans Mountain is currently working with provincial and municipal agencies to understand their expectations for information and permits related to federally regulated projects.

1.5.1 Provincial Permitting Requirements

1.5.1.1 Provincial Undertakings

A list of potential provincial permits and approvals is provided in Table 1.5.1.

TABLE 1.5.1

POTENTIAL PROVINCIAL ENVIRONMENTAL PERMITS/APPROVALS

Regulatory Agency	Permit, Approval, Authorization and/or Notification
Alberta	
Alberta Culture	<ul style="list-style-type: none"> · <i>Historical Resources Act</i> clearance
Alberta Environment and Sustainable Resource Development (AESRD)	<ul style="list-style-type: none"> · Public Land Agreement (Pipeline Land Agreement) on Crown land · Fish Research License for fish rescue at isolated crossings · Temporary Field Authorization for access roads on Crown land · Wildlife damage permits for beaver, lodge and beaver dam removal · <i>Water Act</i> approval for construction within a water body · Notification under the <i>Code of Practice for Watercourse Crossings</i> · Notification under the <i>Code of Practice for Pipelines and Telecommunication Lines Crossing a Water Body</i> · Notification under the <i>Code of Practice for the Temporary Diversion of Water for Hydrostatic Testing of Pipelines</i> · Registration under the <i>Code of Practice for the Release of Hydrostatic Test Water from Hydrostatic Testing of Petroleum Liquid and Gas Pipelines</i> · Tree cutting, burning, road use and special use permits under the <i>Alberta Forests Act</i> · Master Land Withdrawal and Consent Agreement
Alberta Energy Regulator (AER)	<ul style="list-style-type: none"> · Environmental Field Report for Pipeline Licence or Approval under the <i>Alberta Public Lands Act</i>
Alberta Tourism, Parks and Recreation	<ul style="list-style-type: none"> · Research and Collection Permit
Alberta Transportation and Infrastructure	<ul style="list-style-type: none"> · Roadside Development Permit · Several other items (dangerous goods, overweight permit, etc.)
BC	
BC Oil and Gas Commission (BC OGC)	<ul style="list-style-type: none"> · NEB Pipeline Provincial Authorization Application for: <ul style="list-style-type: none"> - temporary occupation of Crown land for the pipeline right-of-way and for ancillary land uses (camps, access, workspaces, etc.); - authorizations under Section 9 of the <i>Water Act</i> (changes in and about a stream) for stream or water body crossings; - cutting permits under Section 47.4 of the <i>Forest Act</i> to harvest Crown timber; - road use permits under Section 117 of the <i>Forest Act</i>; and - Agricultural Land Reserve (ALR) authorizations for constructing a pipeline or facility, and for importing/removing soil from ALR lands. · Road permits under Section 14 of the <i>Land Act</i> · Temporary Crown land access approval under Section 14 of the <i>Land Act</i> · Section 8 <i>Water Act</i> Approval for short-term diversion or use of water · Aggregate Operations and Borrow Pit Permit

TABLE 1.5.1

POTENTIAL PROVINCIAL ENVIRONMENTAL PERMITS/APPROVALS (continued)

Regulatory Agency	Permit, Approval, Authorization and/or Notification
BC	
BC Parks	<ul style="list-style-type: none"> · Park Use Permit
BC Ministry of Forests, Lands and Natural Resource Operations	<ul style="list-style-type: none"> · Authorization under Section 40 of the BC <i>Wildlife Act</i> (temporary closure to hunting, trapping and guide outfitting if necessary during a construction activity) · General wildlife permit under the <i>Wildlife Act</i> and Approval or Notification for Changes In and About a Stream under Section 9 of the <i>Water Act</i> and Section 44 of the <i>Water Act</i> Regulations for beaver dam removal · Scientific Fish Collection Permit · <i>Heritage Conservation Act</i> permit · Road use permits · Special Use Permit · Burning Permit
BC Ministry of Transportation and Infrastructure	<ul style="list-style-type: none"> · Road Use and Highway Crossing Permit · Several other items (overweight, highway access, land closure request)
BC Ministry of Environment	<ul style="list-style-type: none"> · Section 44 Notification under the BC <i>Water Act</i> (minor work near a stream) · Section 14 Permit under the BC <i>Environmental Management Act</i> for the introduction of waste into the environment · Section 7 Waste Discharge Permit under the <i>Oil and Gas Waste Regulation</i> for testing and disposing of test water with additives

1.5.1.2 Other Non- National Energy Board Approvals

Trans Mountain will work with various municipal agencies with responsibilities related to Project components and impacts. Municipal requirements (including communities, counties [Alberta] and regional districts [BC]) may include burning permits, road crossing permits, utility crossing permits, development permits, excavation permits, refuse permits and herbicide/weed permits. Agreements with Forestry Management Area holders will be required for any Forestry Management Agreements encountered along the proposed pipeline corridor in Alberta.

2.0 PROJECT DESCRIPTION

After receiving strong commitments from its customers, KMC, in April 2012, announced a proposed expansion of the TMPL system between Edmonton and Burnaby.

In operation since 1953, the 1,150-km existing TMPL system, owned by KMC, has been responsibly providing the only West Coast access for Canadian oil products, including being the major transporter of the gasoline to the interior and south coast of BC.

The existing TMPL system began operating 60 years ago with a single pipeline constructed between Edmonton, AB (Plate 2.1) and Burnaby, BC (Plate 2.2). Shipments to the Westridge Marine Terminal on the Burrard Inlet began in 1956 (Plate 2.3). Over the years in response to changing market conditions, pumping capacity and tank storage has been added and new pipeline sections (or “loops”) have been constructed; most recently in 2008 in Jasper National Park and Mount Robson Provincial Park (Plate 2.4).

The TMPL system has a current operating capacity of approximately 47,690 m³/d (300,000 barrels per day [bbl/d]) using 23 pump stations and 40 storage tanks.

Trans Mountain is applying for approval to expand TMPL. The Project includes:

- 994 km of new, buried pipeline segments that twin (or “loop”) the existing pipeline in Alberta and BC, including two 3.6 km segments (7 km) of new buried delivery lines from the Burnaby Terminal to Trans Mountain’s Westridge Marine Terminal;
- new and modified facilities, including pump stations and terminals; and
- a new dock complex with three new berths at the Westridge Marine Terminal (the existing berth will be decommissioned).

After TMPL the capacity will be 141,500 m³/d (890,000 bbl/d), using 31 pump stations and 74 tanks.

An overview of the Project configuration is shown on Figure 2.1 and is described below. Additional details related to the pipelines and facilities are provided in the Project Design and Execution volumes (Volumes 4A, 4B, and 4C). Marine shipping activities associated with the Project are described briefly in Section 2.6 and more detail can be found in Volume 8A.



Plate 2.1 Edmonton Terminal



Plate 2.2 Burnaby Terminal



Plate 2.3 Westridge Marine Terminal



Plate 2.4 Construction of Trans Mountain Expansion Anchor Loop in Mount Robson Provincial Park

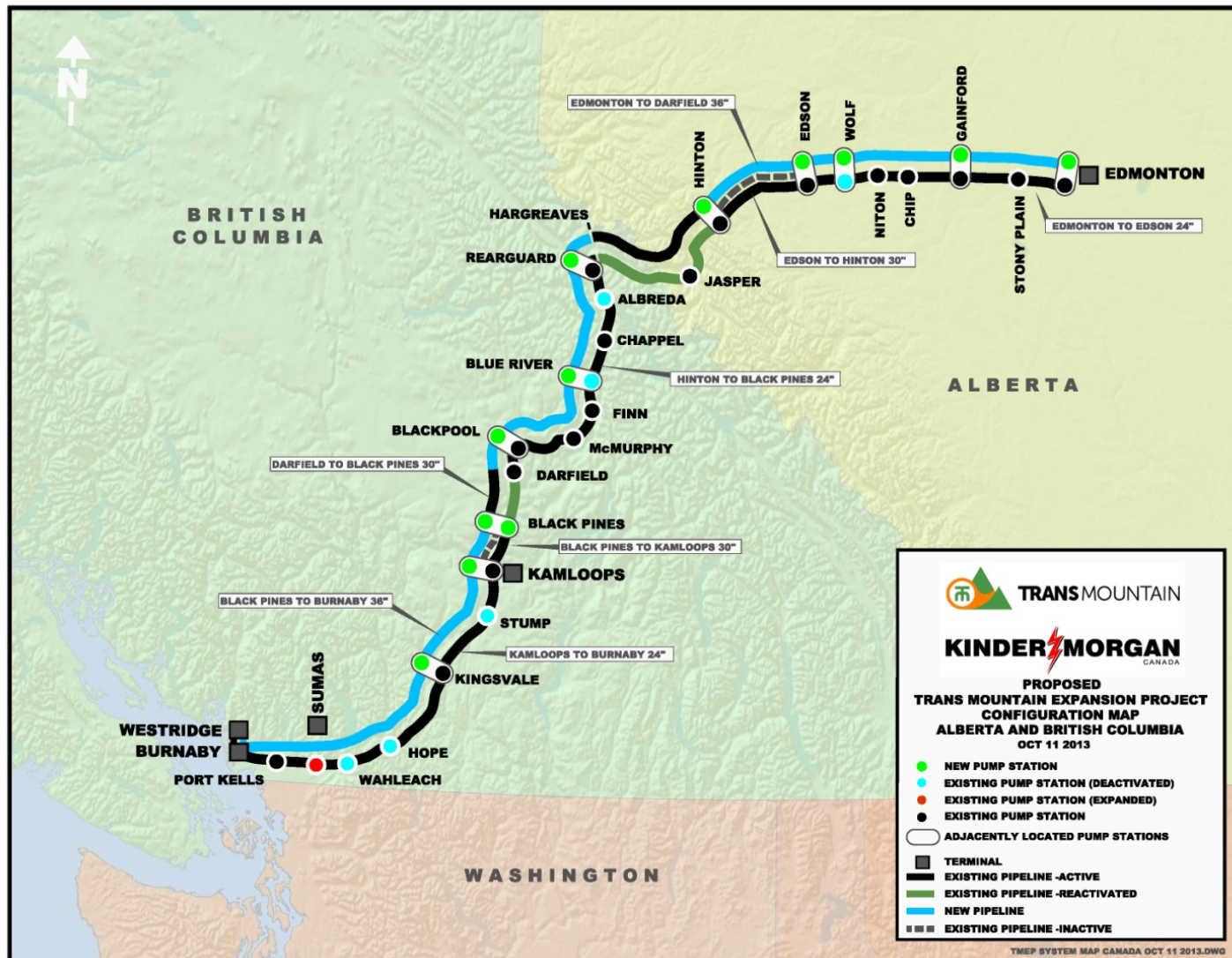


Figure 2.1 Project Configuration Map

2.1 Pipeline

The major components of the pipeline portion of the Project include:

- using existing active 610 mm (nominal pipe size [NPS] 24) and 762 mm (NPS 30) outside diameter (OD) buried pipeline segments;
- reactivating two 610 mm (NPS 24) OD buried pipeline segments that have been maintained in a deactivated state
 - Hinton to Hargreaves – 150 km;
 - Darfield to Black Pines – 43 km;
- constructing three new 914 mm (NPS 36) OD buried pipeline segments totaling approximately 987 km:
 - Edmonton to Hinton – 339.4 km;
 - Hargreaves to Darfield – 279.4 km;
 - Black Pines to Burnaby – 367.9 km; and
- constructing two parallel 3.6 km long 762 mm (NPS 30) OD buried delivery lines from the Burnaby Terminal to the Westridge Marine Terminal.

The Expansion will result in two continuous pipelines between Edmonton and Burnaby:

- Line 1 will have a sustainable capacity of 55,640 m³/d (350,000 bbl/d); and
- Line 2 will have a sustainable capacity of 85,850 m³/d (540,000 bbl/d).

Illustrations of pipeline construction are shown on Figures 2.1.1 and 2.1.2 and Plate 2.1.1. Additional details on pipeline construction methods are described in Volume 4B.

The existing TMPL has been operating safely for more than 60 years and its location is known to local TMPL operations crews, landowners, surface management agencies, and local emergency responders. To minimize environmental and socio-economic effects and facilitate efficient pipeline operations, use of the existing TMPL 18.3 m wide right-of-way has been maximized. Where it was not possible to align along the existing TMPL right-of-way, construction along other linear facilities was evaluated including other pipelines, power lines, highways and roads, railways, communication lines and other utilities. The result is that approximately 73 per cent of the of the new pipeline corridor follows the existing TMPL right-of-way, approximately 17 per cent follows other existing rights-of-way, and 10 per cent will be within a new corridor. Section 2.8 of Volume 4A details the corridor selection process. Sections 4.2 and 4.3 of Volumes 5A and 5B describe the proposed corridor and the alternatives considered.



Plate 2.1.1 Typical Pipeline Construction

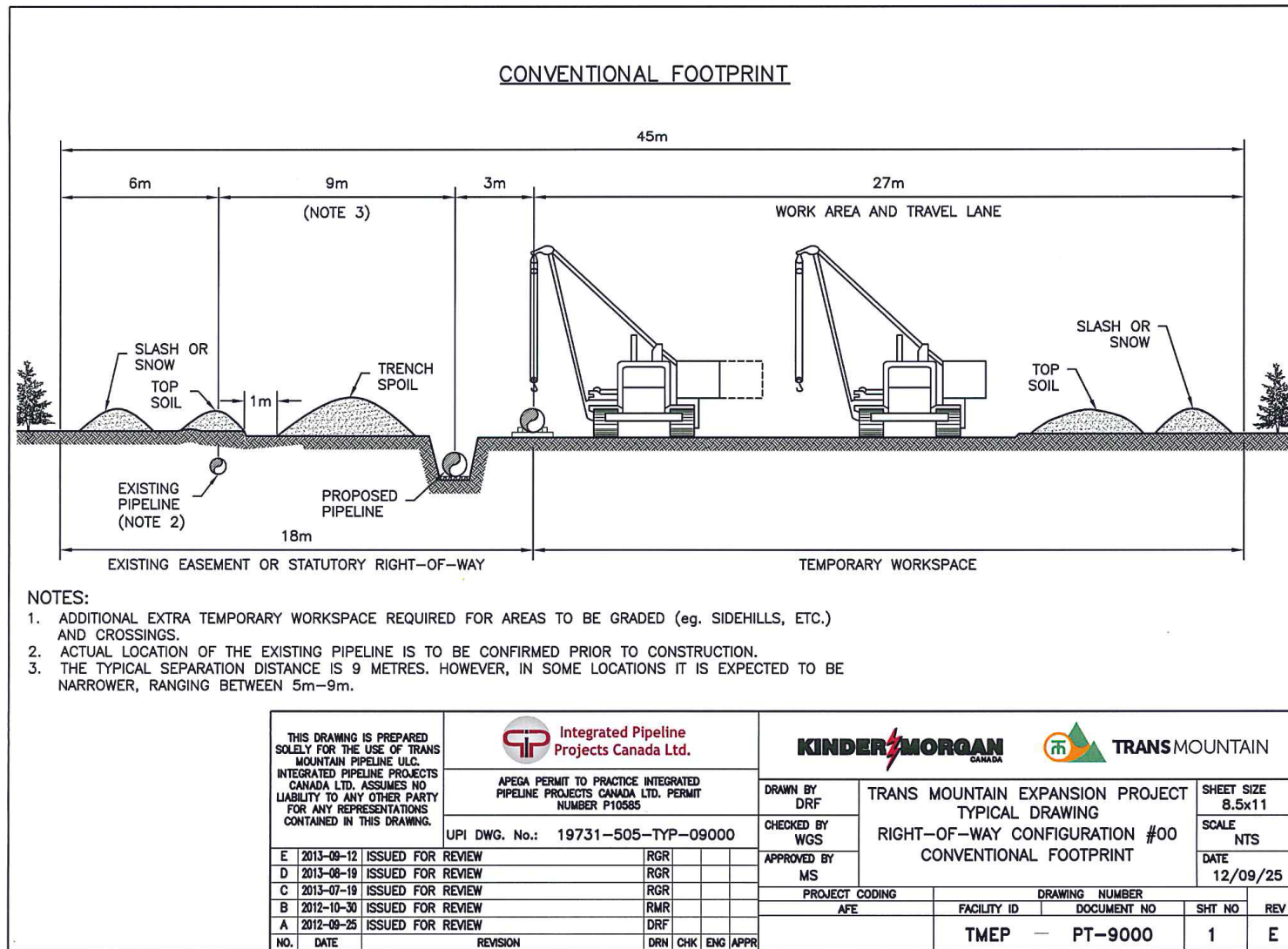


Figure 2.1.1 Conventional Footprint

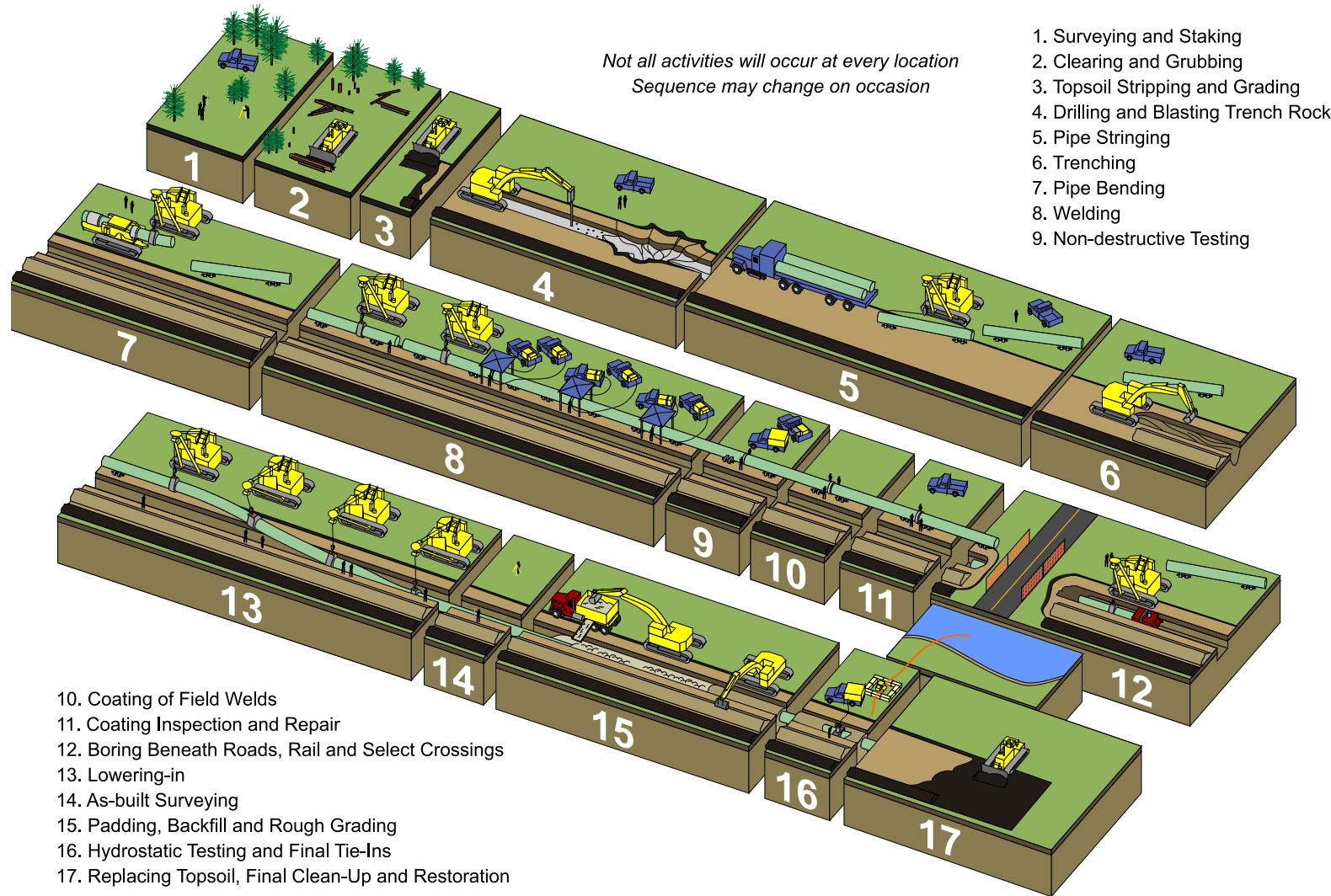


Figure 2.1.2 Typical Rural Pipeline Construction: Sequence of Activities

TABLE 2.2.1

SUMMARY OF PUMPS AND MOTORS FOR LINE 1 AND LINE 2 AFTER TMEP (continued)

Pump Station	Line 1					Line 2				
	KP	Site Status	kW	# x	HP	KP**	Site Status	kW	# x	HP
Sumas	1082.0	Existing	1,492	2 x	2,000					
Sumas Puget Sound ⁵	1082.0	Existing	1,492	2 x	2,000					
	1082.0	New	1,865	1 x	2,500					
Port Kells	1124.3	Existing	3,730	2 x	5,000					*
Burnaby	1147.1					1179.8				
Total				51					32	

- Notes:**
- * one installed spare unit retained for increased system reliability.
 - ** kilometre posts may differ from Line 1 to Line 2 because of route differences
 - KP = kilometre posts
 - HP = horsepower
 - 1 Reactivate previously deactivated pump station
 - 2 The Existing Line 1 pumps, motors and headers will be deactivated. New Line 2 pumps, motors, header and pump building will be added. The existing electrical infrastructure will be used for Line 2 operation.
 - 3 Pump station will be transferred from the 914.4 mm (NPS 36) line to the 609.6 mm line (NPS 24) line for Line 1 operation.
 - 4 This pump station may not be deactivated subject to the results of a reliability study.
 - 5 Increased flow to the United States (US) Puget Sound line will require additional horsepower at Sumas.



Plate 2.2.1 Typical Pump Station (Chappel)

2.2.1 Pump Station Operations

The TMEP pump stations, like those in the existing TMPL system will be remotely operated and continuously monitored by a CCO using the SCADA system at the Control Centre in Sherwood Park, AB. In the event of an emergency, an emergency shut-down (ESD) can shut down pump units and close the pump station suction and discharge valves.

2.3 Terminals

The major components of the associated facilities of the Project include:

- constructing 20 new tanks at the Edmonton (5), Sumas (1) and Burnaby (14) terminals, preceded by the demolition of 2 existing tanks at Edmonton (1) and Burnaby (1), for a net total of 18 tanks to be added to the system; and
- constructing a new dock complex, with a total of three Aframax-capable berths, as well as a utility dock (for tugs, boom deployment vessels, and emergency response vessels and equipment) at the Westridge Marine Terminal, followed by the deactivation and demolition of the existing berth.

2.3.1 Edmonton, Sumas, and Burnaby Terminals

A summary of numbers and capacities of the existing tanks and the tanks to be added for TMEP is provided in Table 2.3.1. The two active storage tanks at Kamloops are not included in the tank summary as there are no tank changes planned at Kamloops.

Proposed plot plans of Edmonton, Sumas and Burnaby Terminals are shown in Figures 2.3.1, 2.3.2 and 2.3.3, respectively. No additional permanent land is expected to be required at these terminals.

2.3.2 Westridge Marine Terminal

An artistic image of the expanded Westridge Marine Terminal is provided in Plate 2.3.1. A 1.4 ha expansion of the foreshore is required.

The dock complex and berth arrangement has been chosen after an extensive review with PMV, the Pacific Pilotage Authority (PPA), and the BC Coast Pilots Association, and in consideration of local input. The berths will be fitted with berthing assistance, ESD, vapour recovery, and fire-protection systems.

2.3.3 Terminal Operations

All terminals, with the exception of Sumas Terminal, which is designed for fully remote operation, will continue to have operations staff on site at all times. Tanks will be placed within secondary containment areas and be fitted with fire-protection systems. Tanks, pumps, motors, piping, and other components will be protected by sophisticated control and ESD systems.

TABLE 2.3.1

EXISTING AND NEW TANK CAPACITIES

Site	Existing ¹			New ²			Total		
	# Tanks	Capacity (m ³)	Capacity (bbl)	# Tanks ³	Capacity (m ³)	Capacity (bbl)	# Tanks	Capacity (m ³)	Capacity (bbl)
Edmonton, AB	35	1,274,310	8,015,000	5	209,070	1,315,000	39	1,470,660	9,250,000
Sumas, BC	6	113,680	715,000	1	27,820	175,000	7	141,500	890,000
Burnaby, BC	13	267,900	1,685,000	14	639,140	4,020,000	26	894,320	5,625,000
Westridge, BC	3	62,800	395,000	0	0	0	3	62,800	395,000
Total	57	1,718,690	10,810,000	20	876,040	5,510,000	75	2,569,280	16,160,000
Total Increase in Capacity			50%						

- Notes:**
- 1 Existing Capacity include Edmonton Tank 29, 30, Edmonton Terminal Expansion Project Phase I and II, original Tank 9 volume and original Burnaby Tank 74 volume
 - 2 New Capacity includes the new volumes for Edmonton Tank 9 and the new volume for Burnaby Tank 74
 - 3 New # Tanks include rebuilding Edmonton Tank 9 and Burnaby Tank 74

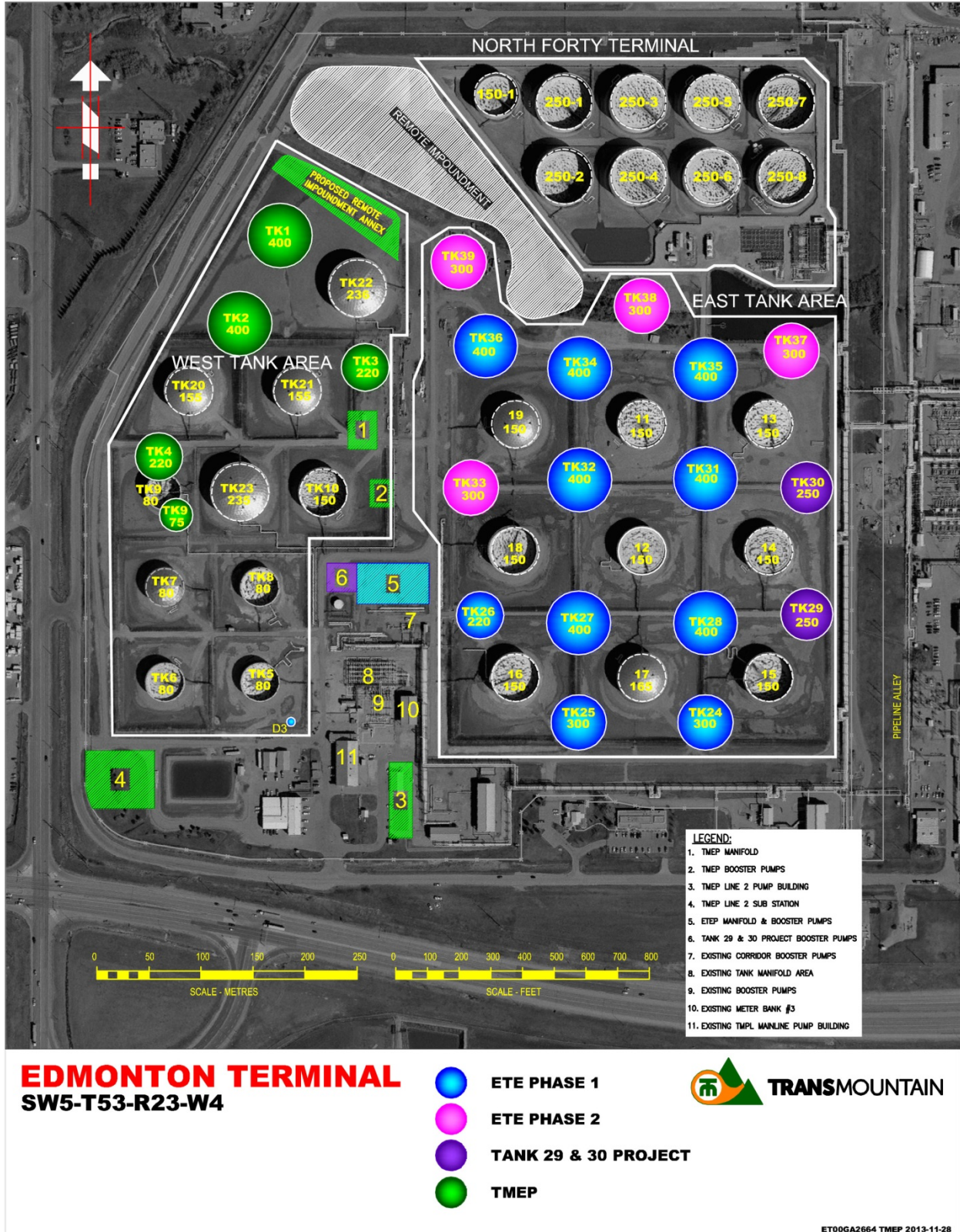


Figure 2.3.1 Edmonton Terminal Proposed Plot Plan

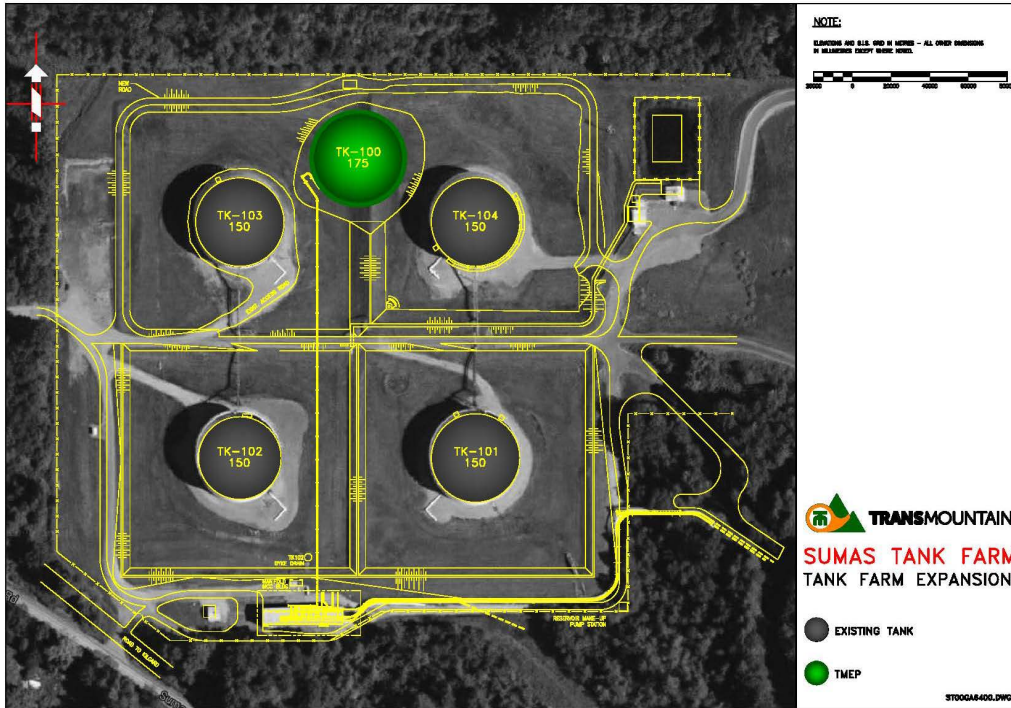


Figure 2.3.2 Sumas Terminal Proposed Plot Plan

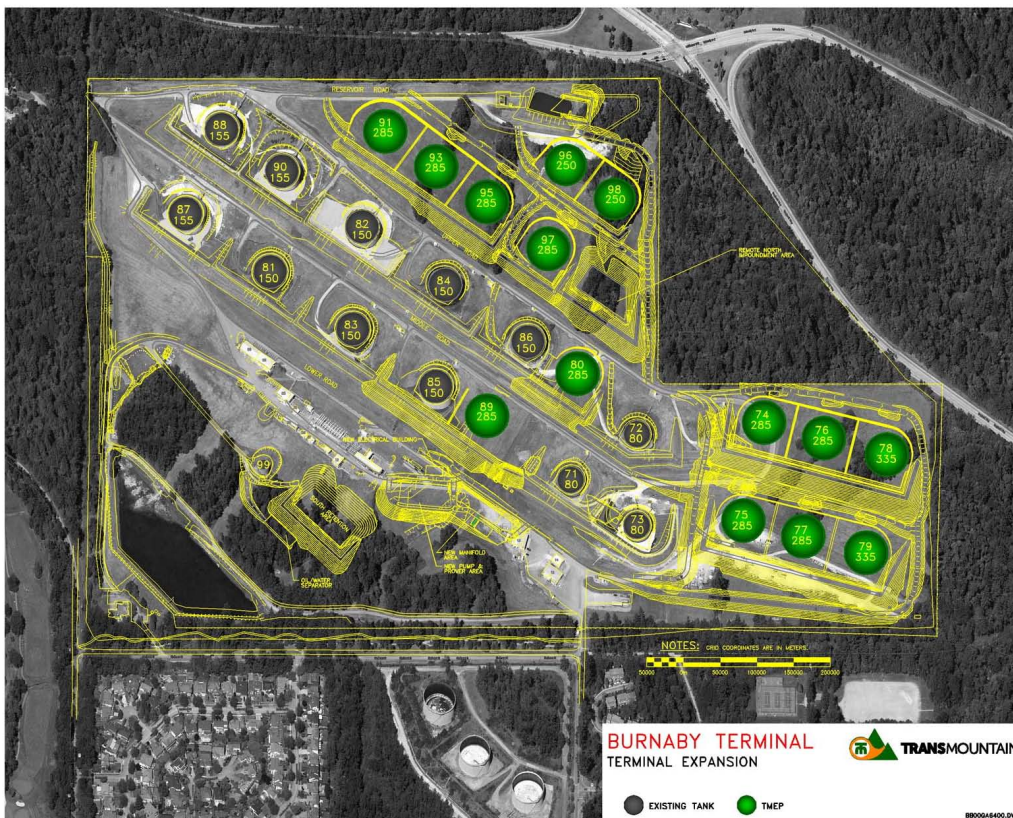


Figure 2.3.3 Burnaby Terminal Proposed Plot Plan

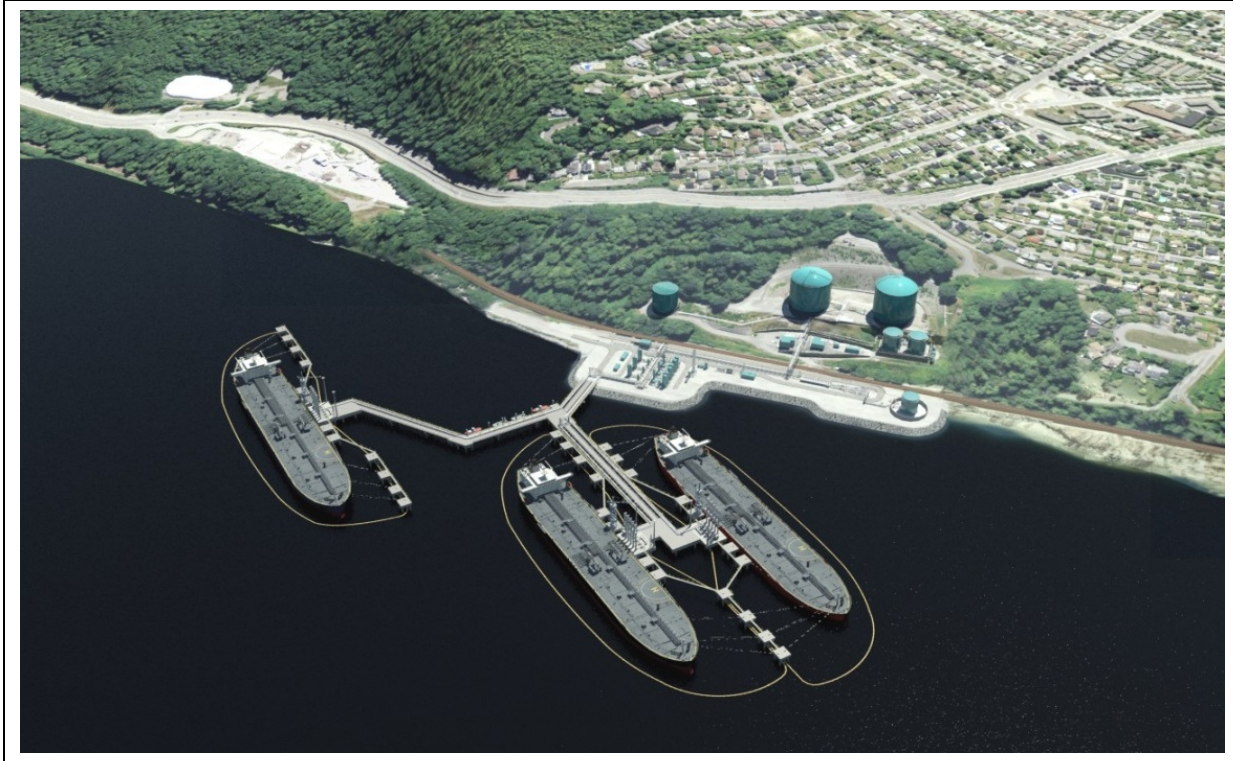


Plate 2.3.1 Westridge Marine Terminal Artistic Image

2.4 Mainline Block Valves and Sending/Receiving Traps

Remote mainline block valves (RMLBVs) and sending/receiving trap facilities are important components for the safe operation and long-term integrity of pipelines. RMLBVs will complement mainline block valves, which are located at the pump stations.

Seventy-two new buried RMLBVs will be installed on Line 2. Valve sites are typically 5 m x 12 m and will be located within the right-of-way. Preliminary valve site locations are identified in Table 5.1.12 in Appendix D of Volume 4A, with final valve site locations to be established during the detailed engineering and design phase.

To limit the volume and consequences associated with a pipeline leak or rupture, the following factors were considered in selecting the RMLBV locations:

- topography;
- the location of environmentally sensitive features and terrain, especially water crossings;
- population density;
- accessibility of electrical power;
- maintenance flexibility;
- release volume analysis;

- release volume dispersion modeling; and
- risks to high consequence areas.

A total of 23 new sending or receiving scraper traps for in-line inspection tools will be installed at facility locations along the pipeline.

2.5 Power Lines and Permanent Access Roads

The environmental and socio-economic effects of new utility power lines for the Project have been considered by Trans Mountain but authorizations for construction and operation will be sought from the appropriate provincial authorities. New 25 or 138 kV power lines will be constructed to supplement the electric power supply to three existing pump station sites (Edmonton, Edson, and Kingsvale) and to provide a new power supply to one new pump station site (Black Pines). Electrical power will also be required at each RMLBV site and at cathodic protection system rectifier locations.

The Edmonton power line will originate immediately adjacent to the terminal. The length of the power line to Edson is unknown at this time as several options are being considered by the power utility. The length of the power line to Black Pines will be approximately 4 km, while the length of power line to Kingsvale will be approximately 24 km.

A permanent access road will be required for the new Black Pines Pump Station; which will be located less than 0.5 km from the nearby road. Permanent access roads may also be required for the RMLBV or cathodic rectifier sites and a secondary emergency only access road may be considered for Westridge Marine Terminal.

2.6 Marine Shipping Activities Associated with the Project

Currently, in a typical month, five vessels are loaded with heavy crude oil (diluted bitumen) at the Westridge Marine Terminal. The expanded system will be capable of serving up to 34 Aframax class vessels per month (Plate 2.6.1) with actual demand to be influenced by market conditions. The maximum size of vessels (Aframax class) served at the terminal will not change as part of the Project. Similarly, the future cargo will continue to be crude oil, primarily diluted bitumen. Of the 141,500 m³/d (890,000 bbl/d) capacity of the expanded system, up to 100,200 m³/d (630,000 bbl/d) may be delivered to the Westridge Marine Terminal for shipment.

In addition to tanker traffic, the Westridge Marine Terminal also loads two or three barges with oil per month and receives one or two barges of jet fuel per month utilizing a separate pipeline system that serves Vancouver International Airport. Barge activity is not expected to change as a result of the Project.

While Trans Mountain does not own or operate the vessels calling at the Westridge Marine Terminal, it is responsible for ensuring the safety of the terminal operations. In addition to Trans Mountain's own screening process and terminal procedures, all vessels calling at Westridge must operate according to rules established by the International Maritime Organization, Transport Canada, the PPA, and PMV. Although Trans Mountain is not directly responsible for vessel operations, it is an active member in the maritime community and works with maritime agencies to promote best practices and facilitate improvements to ensure the safety and efficiency of tanker traffic in the Salish Sea. Trans Mountain is a member of the WCMRC, and works closely with WCMRC and other members to ensure that WCMRC remains capable to

respond to spills from vessels transferring product or transporting it within their area of jurisdiction.

To understand the potential effects of the Project-related increase on marine traffic, Trans Mountain undertook an ESA, as well as a quantitative marine risk assessment of the potential for oil spills in the marine environment. The results of these activities are incorporated in Volume 8A, Marine Transportation, and address the requirements of the NEB's List of Issues (July 29, 2013), the *CEA Act, 2012*, and the NEB's Filing Requirements Related to the Potential Environmental and Socio-Economic Effects of Increased Marine Shipping Activities, Trans Mountain Expansion Project (September 10, 2013). Trans Mountain is also participating in the TERMPOL Review Process under Transport Canada's jurisdiction. TERMPOL is a federal review process focusing on safety and marine transportation components of a project (Section 1.4).

Trans Mountain has contracted a number of studies, including the previously mentioned quantitative risk assessment, to provide recommendations to Transport Canada, the TERMPOL Review Committee, and other relevant responsible authorities to improve the safety of marine transportation related to the Project. These studies were also used as the basis for Volume 8A, Marine Transportation. All supporting studies for the ESA are provided in Volume 8B. All of the TERMPOL related technical studies are provided in Volume 8C.

Figure 2.6.1 illustrates the location of the Westridge Marine Terminal and the route inbound and outbound marine vessels would continue to travel after the Project is in operation.



Plate 2.6.1 Aframax Class Tanker Zaliv Amurskiy (Approaching Second Narrows From the East)
(<http://www.shipspotting.com/gallery/photo.php?lid=1312298>, accessed: November 2013)



Figure 2.6.1 Regional Location of Marine Shipping Lanes

2.7 Stakeholder Consultation, Aboriginal Engagement and Landowner Relations

Since the construction of the original pipeline in 1953, Trans Mountain has established and continues to maintain relationships with Aboriginal communities and Aboriginal groups, landowners and neighbours, and stakeholder communities and groups along the pipeline right-of-way.

Volume 3A provides information on the Stakeholder Engagement Program completed along the pipeline and marine corridors, and describes how stakeholder and public comments were gathered as well as how those comments have been incorporated into the application and the design of the Project. Where they have not been incorporated, Trans Mountain continues to strive for resolution while acknowledging that it is not always possible. Marine results can be found in Volume 8A of this application.

Beginning in the initial stages of the Project, Trans Mountain embarked on an extensive program to engage Aboriginal communities and to consult with landowners, government agencies (e.g., regulators and municipalities), stakeholders, and the general public. Information on the Project is also available at www.transmountain.com.

With a guiding principle of open, honest, and transparent communications, engagement activities have been designed to reflect the diverse and varied interests of the various communities and areas along the proposed pipeline route. To date these activities have included:

- toll free telephone line and project inquiry email address;
- early and ongoing notification of the Project;
- ongoing distribution of Project updates, newsletters and communication materials, including information on the NEB process;
- print and digital advertising;
- Project website, complete with online engagement forums;
- social media through Twitter;
- videos on YouTube;
- hosting of open houses, facility tours, workshops, and meetings;
- facilitating open and meaningful dialogue, both face-to-face and online;
- responding to inquiries and emerging issues; and
- resolving issues and concerns.

Trans Mountain has contacted the following as part of its engagement programs:

- over 100 Aboriginal communities and Aboriginal groups;

- private landowners, freehold and crown occupants, and public landowners and occupants;
- municipal, provincial and federal governments;
- the Major Projects Management Office;
- industry and business development agencies;
- emergency response service organizations;
- environmental non-government organizations;
- special interest groups; and
- the general public.

Volume 3B provides information on the Aboriginal Engagement Program and the engagement activities conducted to date with each Aboriginal community and Aboriginal group. Detailed information on results stemming from Traditional Land Use studies, Traditional Marine Use studies, Traditional Ecological Knowledge and socio-economic research are detailed in Volumes 5A, 5B, and 8A.

Engagement activities with Aboriginal communities and Aboriginal groups, landowners and neighbours, and stakeholder communities and groups will continue through the regulatory and construction phases of the Project. The focus will continue to be on responding to specific questions or issues and following up with previously-engaged stakeholders.

Volume 3C describes the Landowner Relations Program, where Trans Mountain introduced and discussed the Project with landowners and occupants along the proposed pipeline corridor, and provides a summary of the issues and concerns raised. Trans Mountain has met with essentially all landowners along the proposed pipeline corridor. Meetings comprised discussions about the Project in general as well as requests for consent for Project-specific surveys. The meetings also provided an opportunity for landowners to ask questions and identify concerns regarding the Project.

The questions, issues, or concerns raised by landowners were categorized most frequently related to: compensation issues, land impacts, land values, site-specific pipeline location, and issues related to the existing TMPL line (Volume 3A).

On approximately 85% of all tracts of land, the owners or occupants raised no comments or concerns at this phase of the program. Of those that did comment, the two topics that were raised most frequently were related to compensation/financial and environmental/land issues. Along the study corridor, 1,325 landowners and 295 Crown rights holders in Alberta were contacted. In BC, 4,013 landowners and 615 Crown rights holders and pending land purchasers were also contacted.

Based on feedback received, landowner issues generally include: land rights, compensation, land-specific construction and restoration activities, as well as broader Project and policy issues.

2.8 Project Execution and Schedule

Following the filing of the application to the NEB and leading up to construction, Trans Mountain will continue to undertake a number of activities, including but not limited to:

- supporting the NEB application and the applications for other federal, provincial and municipal permits and continued participation in the TERMPOL process (Section 1.3 includes a more complete list);
- ongoing Aboriginal and stakeholder engagement;
- meeting with landowners for route refinement and other details, leading to acquisition of right-of-way;
- detailed environmental and socio-economic studies;
- detailed pipeline and facilities engineering, design and construction planning; and
- procurement of materials and equipment.

Subject to receiving the necessary regulatory approvals, preliminary plans provide for the pipeline to be constructed over three construction seasons: summer 2016; winter 2016/2017; and summer 2017 (Volume 4B provides details). In this context, the summer construction seasons will extend from May through October and the winter construction season will extend from November to April. Preparatory work for pipeline construction will begin in October 2015. Work on the facilities will take place starting in the late fall of 2015 and continue through 2017. The master schedule is provided in Figure 2.8.1. The project workforce is expected to peak at approximately 4,500 workers. The schedule is predicated on receipt of a CPCN by mid-2015 to allow for the final decision by Trans Mountain to proceed with the Project, the ordering of materials, securing provincial and local permits, utilizing the upcoming construction windows, and the awarding of major contracts.

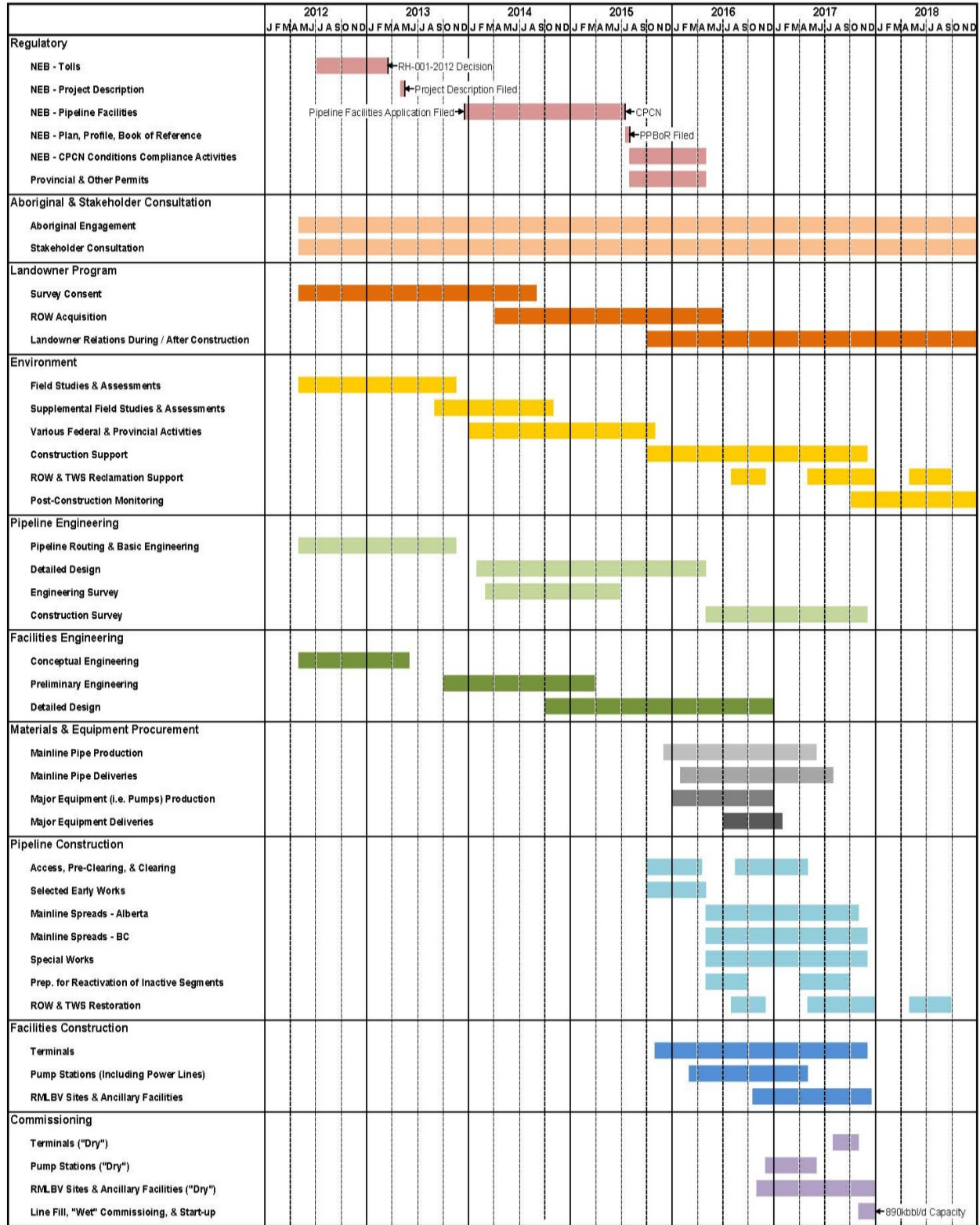


Figure 2.8.1 Master Project Schedule

2.9 Project Cost Estimate

2.9.1 Capital Cost Estimate

The \$5.5 billion capital cost estimate (exclusive of the firm service fee credit) for the TMEP was included in RH-01-2012. The cost estimate has been re-sorted in Table 2.9.1 to be generally consistent with the breakdown indicated in the NEB Filing Manual. The cost estimate will be updated for the purpose of toll calculations at the conclusion of the regulatory proceedings and prior to the start of construction, and will include an Allowance for Funds Used During Construction (AFUDC) rate then in effect.

TABLE 2.9.1

PROJECT COST ESTIMATE

Item	Estimate (M\$)*
Project Management	192.3
Engineering, Survey, and Environment	252.6
Pipeline Materials	674.7
Right-of-way and Other Land Costs	370.0
Pipeline Construction and Reactivation	2,267.6
· New Construction	2,217.7
· Reactivation	49.9
Facilities Materials and Construction	1,332.2
· Pump Stations	440.6
· Terminals	861.2
· Other Facilities	30.4
Other	94.6
Subtotal	5,184.0
AFUDC	322.3
Total	5,506.3

Note: *as spent Canadian dollars

2.9.2 Abandonment Cost Estimate

Following the end of its useful life, an application will be submitted to the NEB to decommission and abandon the pipeline and facilities, consistent with the practices of the day (Section 12 of Volume 4C). Pipeline segments and facilities constructed for the Project are not expected to be abandoned for more than 50 years.

A conceptual Abandonment Cost Estimate for the TMPL system, after the completion of TMEP, and the associated incremental cost for the abandonment of the TMEP pipelines and facilities is included in Table 2.9.2.

The conceptual Abandonment Cost Estimate was developed from the preliminary Abandonment Cost Estimate for the existing TMPL system, as approved by the NEB in MH-001-2012. Given that the TMEP pipelines and facilities are generally coincident with or adjacent to the existing TMPL system pipelines and facilities, an approach using factored quantities and unit costs was believed to be appropriate for the development of the conceptual Abandonment Cost Estimate.

TABLE 2.9.2

CONCEPTUAL ABANDONMENT COST ESTIMATE

Item	Estimate (M\$)		
	16-Apr-13 Filing	Conceptual Post-TMEP	Incremental Post-TMEP
1 Engineering & Project Management	33.3	54.3	21.0
2 Abandonment Preparation	26.6	57.9	31.3
3 Pipeline Abandonment in Place	96.8	143.9	47.1
3a Basic Abandonment in Place	35.2	56.2	21.0
3b Post-Abandonment Provision	61.6	87.7	26.1
4 Special Treatment	0.0	0.0	0.0
5 Pipeline Removal	44.8	75.4	30.6
6 Facilities	85.0	176.6	91.6
Subtotal	286.5	508.2	221.7
7 Contingency	53.6	94.6	41.0
Insurance and Taxes	17.3	27.4	10.1
Contingency	36.3	67.2	30.9
Total	340.0	602.7	262.7

3.0 PROJECT NEED AND ECONOMIC FEASIBILITY

3.1 Introduction

Section A.3 of the NEB's Filing Manual states that "The overall purpose for filing information on facility economics is to demonstrate that the applied-for facilities will be used, will be useful, and that demand charges will be paid and that sufficient funds will be available for abandonment requirements". The Filing Manual also states that "Economics information must include details on: supply; transportation; markets; and financing".

Trans Mountain has organized this section as follows. Section 3.1 provides an overview of the essential purpose and need for the Project. Section 3.2 covers the commercial arrangements, the transportation service agreements and the anticipated financing arrangements. Section 3.3 discusses the market supply and demand outlook. Section 3.4 outlines the expected benefits, including the general economic and fiscal benefits, as well as the benefits to the energy sector. Finally, Section 3.5 discusses the overall economic feasibility, in view of the evidence provided in the preceding sections.

3.1.1 Purpose

The primary purpose of the Project is to provide additional transportation capacity for crude oil from Alberta to markets in the Pacific Rim including BC, Washington State, California, and Asia. The provision of enhanced access to growing Pacific Rim markets will provide a critical alternative market to Canadian crude oil producers. The additional capacity is required to meet both the needs of Trans Mountain's long-term contractual shippers and the general growth in demand for transportation service by all shippers.

3.1.2 Need

The marketplace has clearly demonstrated the need for the Project. The demand for transportation services exceeds the current TMPL system capacity and has resulted in the need to apportion the available capacity. This has also affected the quality of common carriage, as shippers have experienced increasing uncertainty that they will have adequate access to capacity on a month-to-month basis. The degree of apportionment and the willingness of shippers to pay large bid premiums to secure access to transportation service on TMPL to the Westridge Marine Terminal are clear indicators of the value shippers place on obtaining access to West Coast and offshore markets¹. The high dock bid premiums, which totaled \$163 million in 2012, also provide a market price signal that additional capacity is required.

The need for the Project has also been strongly demonstrated by the long-term financial commitments shippers have made through entering into firm contracts for 80 per cent of the nominal capacity on the expanded system. The tolling methodology, including all aspects of the transportation service agreements, was approved by the Board in its Reasons for Decision RH-001-2012, released on May 13, 2013. It can be reasonably assumed that shippers would not have freely entered into these contracts, which obligate them to make substantial financial commitments on a take-or-pay basis over the lifetime of their contracts, if they were not convinced of the need for the Project and that they would utilize the capacity.

Beyond the needs of the contracting shippers, there is a need for the Project to meet the demands of spot shippers. There are shippers that have a requirement to move crude oil and

¹ Westridge Dock Bid Premiums are collected in accordance with Tariff Revisions – Westridge Dock Capacity Allocation Procedure, NEB Reasons for Decisions, April 11, 2006.

products to markets, but did not for their own reasons, commit to firm contract space. The expanded pipeline system will reserve 20 per cent of the total nominal capacity on a spot basis for those shippers.

More generally, the Project is required to provide needed flexibility for Western Canadian producers. Oil markets are continually subject to changing market conditions, refinery shut-downs, supply interruptions and other events that impact markets. In order for Western Canadian producers to obtain access to the highest value markets, sufficient pipeline capacity to alternative markets is required. The Project is one of a group of pipeline projects being proposed by pipeline companies to meet the needs of Western Canadian producers for additional market access². Trans Mountain responded to the requests of shippers to expand the TMPL system, which has resulted in the submission of this Application to the Board.

Finally, the Project is required from a broader public interest perspective to ensure that producers and governments obtain the highest value for their petroleum resources. Canadians are the ultimate owners of petroleum resources as represented through their provincial governments. The Canadian public is deprived of receiving the full market value for these resources when it is not possible to access the highest value end markets.

Since governments collect taxes based both on oil prices (provincial royalties) and corporate profits (provincial and federal corporate income taxes), higher revenues to producers also means that governments will also collect considerable revenues. As indicated in Section 3.4, oil producer revenues are forecasted to rise by \$45.4 billion over the first 20 years of operations, as a result of the market access provided by the Project, and this is expected to generate total federal and provincial fiscal benefits of \$14.7 billion. Therefore, the existing situation of inadequate access to markets is a matter of concern to Western Canadian oil producers and governments.

3.2 Commercial Arrangements

3.2.1 *Transportation Agreements*

The salient features of the approved transportation contracts from RH-001-2012 include:

- As a result of an open season process, 13 companies entered into binding 15- and 20-year transportation service agreements with Trans Mountain for a total of 707,500 bbl/d, equal to approximately 80 per cent of the expanded system's nominal capacity. The agreements provide for a sharing of risks between Trans Mountain and its shippers during the development stage, including the construction of the Project, and the long-term operations of the pipeline system.
- The service agreements provide each shipper with an entitlement to a certain amount of capacity each month, and the shippers are required to pay for this capacity whether or not they use it. These provisions provide a very strong incentive to shippers to maximize their use of the capacity, and help ensure that the expanded pipeline will be used at a high load factor.
- The transportation agreements also provide flexibility to the contractual shippers, which will enable them to manage their entitlements and associated

² The four projects are TMEP, Northern Gateway, Keystone XL, and Energy East.

financial obligations. Shippers can assign their shipping rights to third parties on a short or long-term basis, thereby reducing the risk of holding the contracts and helping ensure that the firm capacity is fully utilized. There are also make-up provisions in the event that shippers cannot use their full entitlements in any given month.

- The toll will be established according to a risk sharing formula and escalated during the lifetime of the contracts at a fixed rate. Therefore, the toll will not be adjusted according to actual costs incurred as would normally occur under a cost-of-service approach³. This arrangement provides toll certainty to shippers, reduces the risk of unanticipated increases in transportation costs over time, and enables producers and refiners to arrange their long-term business with confidence in their associated transportation costs.
- Approximately 180,000 bbl/d, representing 20 per cent of the expanded system's nominal capacity, will be reserved for spot month-to-month shipments. The toll for spot shipments is tied to the toll for long-term service and, as such, spot shippers benefit from all of the contractual provisions that protect long-term shippers from cost escalation.

The tolling methodology and transportation contracts, as already approved by the Board, provide strong assurances that the expanded pipeline will be used at a high load factor during the lifetime of the firm contracts and beyond. Further, the contractual arrangements incent Trans Mountain to build the Project and operate the pipeline efficiently, while maintaining the high standards for construction and operations that are outlined in this application. This will help ensure that the transportation service on the TMPL remains cost competitive during the first 20 years of operation and beyond.

3.2.2 Financial Capability of the Applicant

The expected capital cost for the Project is approximately \$5.4 billion. Financing will be arranged by Trans Mountain's parent company KMP.

Kinder Morgan Energy Partners, L.P. is one of the largest midstream energy companies in North America with an enterprise value of more than US\$48 billion⁴. Table 3.2.1 provides unaudited KMP consolidated balance sheets. KMP typically finances growth projects using a mix of 50 per cent debt and 50 per cent equity. Funding sources may include a combination of the issuance of long-term debt securities, bank financing, and the issuance of public equity at KMP.

³ The variable toll component will include and be adjusted accordingly for the recovery of uncontrollable costs, resulting from changes in operations that are not currently anticipated or cannot be reasonably included in calculating the toll. An example of such costs is the collection of pipeline abandonment costs pursuant to Board Order RH-2-2008.

⁴ Kinder Morgan 2013 Analyst Conference, Corporate Overview, Page 10. Enterprise value is a measure of a company's value, often used as an alternative to straightforward market capitalization. Enterprise value is calculated as market capitalization plus debt, minority interest and preferred shares, minus total cash and cash equivalents.

TABLE 3.2.1

**KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
 CONSOLIDATED BALANCE SHEETS**

(In Millions)
 (Unaudited)

	September 30, 2013	December 31, 2012(a)
Assets		
Current assets		
Cash and cash equivalents	\$ 534	\$ 529
Accounts receivable, net	\$ 1,236	\$ 1,114
Inventories	\$ 399	\$ 338
Assets held for sale	—	\$ 211
Other current assets	\$ 283	\$ 185
Total Current assets	\$ 2,452	\$ 2,377
Property, plant and equipment, net	\$ 26,742	\$ 22,330
Investments	\$ 2,207	\$ 1,864
Goodwill	\$ 6,532	\$ 5,417
Other intangibles, net	\$ 2,448	\$ 1,142
Deferred charges and other assets	\$ 1,604	\$ 1,846
Total Assets	\$ 41,985	\$ 34,976
Liabilities and Partners' Capital		
Current liabilities		
Current portion of debt	\$ 702	\$ 1,155
Accounts payable	\$ 1,313	\$ 1,091
Accrued interest	\$ 206	\$ 327
Accrued other current liabilities	\$ 1,218	\$ 674
Total Current liabilities	\$ 3,439	\$ 3,247
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding	\$ 18,910	\$ 15,907
Debt fair value adjustments	\$ 1,332	\$ 1,698
Total Long-term debt	\$ 20,242	\$ 17,605
Deferred income taxes	\$ 273	\$ 249
Other long-term liabilities and deferred credits	\$ 1,010	\$ 1,113
Total Long-term liabilities and deferred credits	\$ 21,525	\$ 18,967
Total Liabilities	\$ 24,964	\$ 22,214
Commitments and contingencies (Notes 3 and 9)		
Partners' Capital		
Common units	\$ 9,416	\$ 4,723
Class B units	\$ 9	\$ 14
i-units	\$ 4,054	\$ 3,564
General partner	\$ 3,073	\$ 4,026
Accumulated other comprehensive income	\$ 71	\$ 168
Total KMP's Capital	\$ 16,623	\$ 12,495
Non-controlling interests	\$ 398	\$ 267
Total Partners' Capital	\$ 17,021	\$ 12,762
Total Liabilities and Partners' Capital	\$ 41,985	\$ 34,976

Source: KMP Third Quarter 2013 filing to the US Securities and Exchange Commission.

Kinder Morgan Energy Partners, L.P.'s long-term corporate debt credit rating is BBB (stable) at Standard & Poor's Ratings Services, Baa2 (stable) at Moody's Investors Service, Inc. and BBB (stable) at Fitch, Inc.

The success of a pipeline project and its related financing depends upon the economics of linking a supply basin with a major market region and the resulting transportation agreements between the pipeline carrier and shippers. As discussed in the sections on supply and markets below, at one end the Project will have access to the large reserves and growing crude oil production from the Western Canadian Sedimentary Basin (WCSB). At the other end, it will provide access to one of the largest petroleum markets in the world in the Pacific Rim region. The financial market recognizes that Canadian oil producers need to diversify their markets.

The long term financial commitments Trans Mountain has received are from a group of shippers⁵ consisting of significant players in the energy industry that have investment grade or better credit ratings; this provides further assurance concerning the cash flow that will be generated by the Project and its ability to support the long term financing requirements.

Taking into account the financial capacity and credit quality of KMP, the value proposition that the Project brings to the market and the term, size, and quality of the long term shipper commitments, Trans Mountain does not anticipate that KMP will face any significant challenges in securing the funds required to finance the Project.

3.3 Market Supply and Demand Outlook

3.3.1 Supply and Demand

Trans Mountain commissioned independent expert evidence to provide an opinion on the outlook for oil market supply and demand, and related issues. The evidence of Mr. Steven Kelly of IHS Global Canada Limited (IHS) is provided in Appendix A. Mr. Kelly's evidence addresses: whether the Project will provide access to new markets; whether the Project will produce an economic gain for Canadian producers; and whether the Project will be highly utilized. Trans Mountain relies upon and adopts the evidence of Mr. Kelly in support of this application and his conclusions concerning market supply and demand, including:

- Total Western Canadian crude production is forecasted to grow at 3.0 per cent annually from 2013 to 2037, resulting in 3.43 million bbl/d of incremental production over the same period. Oil sands crude production is expected to grow by about 3.23 million bbl/d between 2013 and 2037, from 1.95 million bbl/d to 5.17 million bbl/d.
- Despite a lack of demand growth in US refining markets, Canadian crude exports to the US are expected to approximately double from 2013 to 2035, representing growth of more than 2.5 million bbl/d. Canadian crude exports will account for a growing share of US crude consumption, and will lead to a dramatic drop in US imports from other countries. This will occur despite an increase in US crude production. This suggests that there is a need for additional transportation capacity to provide access to both North American and offshore markets.

⁵ BP Canada Energy Trading Company, Canadian Natural Resources, Canadian Oil Sands Limited, Cenovus Energy Inc., Devon Canada Corporation, Husky Energy Marketing Inc., Imperial Oil Limited, Nexen Marketing Inc., Statoil Canada Ltd., Suncor Energy Marketing Inc., Suncor Energy Products Partnership, Tesoro Refining & Marketing Company and Total E&P Canada Ltd

- Refineries on the West Coast and in Asian markets would gain increased access to Canadian crudes if the Project is constructed. In IHS's opinion, these are potentially large and viable markets for Western Canadian crudes.
- IHS estimates that if all of the major planned pipeline expansion capacity was built as planned by 2018, all of the capacity will still be needed to meet projected crude production by about 2029 as surplus pipeline capacity will be absorbed by supply growth.
- It is likely that the Project facilities will be utilized at a high rate, considering the forecast of continued long-term growth in Western Canadian crude oil production and the markets accessible from the Project.

3.3.2 Crude Oil Supplies from Contracting Shippers

Trans Mountain has entered into long-term firm transportation contracts with 13 shippers, for a total volume of 707,500 bbl/d. The shippers represent a mix of some of the largest producing companies in the WCSB, and a number of them represent some of the largest integrated oil companies in the world. These companies have direct access to large volumes of supply, either through their own production, or through their position in the market as a large marketer and/or refiner of crude oil. It can be reasonably concluded that none of these companies would have made the financial commitments entailed in the firm transportation service agreements, if they were not confident that they would have access to adequate oil supplies over the term of the contracts.

As discussed above in Section 3.2.1, the transportation service contracts enable a shipper to assign its capacity rights on a short or long-term basis. These provisions will allow shippers to respond to changing market conditions, including possible supply disruptions, by assignment to others, thereby ensuring that supply will be available and that the pipeline capacity will be used at a high load factor.

3.4 Project Benefits

The construction and operation of the Project will provide substantial economic and fiscal benefits to Canada and its regions. There will be significant benefits to the parties directly involved, to all Western Canadian oil producers, and to all Canadians and their governments.

3.4.1 Macroeconomic and Fiscal Benefits

To estimate the economic and fiscal benefits that can be expected from the construction and operation of the Project, Trans Mountain commissioned an independent study by the Conference Board of Canada, which was conducted under the direction of Mr. Glenn Hodgson. Mr. Hodgson's evidence is provided in Appendix B. Specifically, Mr. Hodgson assesses the impacts associated with: the capital investments required to build the pipeline and related infrastructure; the operation of the pipeline; and the higher netbacks to oil producers that are expected to result from the Project. Trans Mountain relies upon and adopts the evidence of Mr. Hodgson in support of this Application and his conclusions, including:

- The development (construction) period is forecasted to boost Canadian Gross Domestic Product (GDP) by approximately \$4.9 billion⁶, with \$2.8 billion accruing to BC and \$1.4 billion to Alberta. There will be a total of

⁶ All of the figures cited from the Conference Board study are in constant \$2012.

58,000 person-years of employment generated across Canada during development, with approximately 36,000 in BC and 15,000 in Alberta.

- There will be \$646 million in federal taxes generated during the project development phase and an additional \$568 million of provincial taxes, with \$309 million received by BC and \$168 million by Alberta.
- There will be an overall boost to employment of 50,000 to 65,000 person-years during the first 20 years of operations, with 60 per cent of the jobs being created in BC and 20 per cent in Alberta.
- The operations phase will boost Canadian GDP by at least \$13.3 billion over the first 20 years. BC will see the largest impact with a boost of about \$8.5 billion, followed by Alberta at almost \$4 billion.
- The Project will generate about \$1.4 billion in additional tax revenues for the federal government during the operations phase and an additional \$1.1 billion in provincial taxes, with BC receiving about \$727 million and Alberta receiving about \$278 million.
- Oil producer revenues in the IHS study are forecasted to rise by \$45.4 billion over the first 20 years of the pipeline's operations, as a result of higher netbacks that can be attributed to Western Canadian oil producers having access to new markets through the Project. This revenue associated with higher netbacks is expected to generate total federal and provincial fiscal benefits of \$14.7 billion, with Alberta receiving \$8.2 billion and the federal government \$6.1 billion.

In addition to the tax benefits created at the federal and provincial levels, the Project will also yield benefits to communities along the right-of-way through employment and economic activity, and generating additional property taxes for the life of the pipeline. As part of the environmental and socio-economic analysis completed by TERA Environmental Consultants as presented in Volume 5B, it was estimated that the additional property taxes generated by the Project will be about \$22.1 million (a 103 per cent increase) annually in BC and \$3.2 million (a 119 per cent increase) annually in Alberta.

3.4.2 Energy Industry Benefits

The Project will help to realign Canada's pipeline system with changing supply/demand fundamentals. Trans Mountain relies on and adopts the evidence of Mr. Kelly (Appendix A) and Mr. Reed (Appendix C) concerning the benefits to the energy industry associated with the Project including:

- Delivery of a large volume of Canadian crude to new markets is expected to strengthen the price of Canadian heavy crude in Alberta. The effect of removing Canadian heavy crude from the North American market would be to ease the situation of excess supply in traditional markets, such as the US Midwest. By increasing market access for Canadian heavy crudes, infrastructure developments such as the Project should ensure that extraordinary price discounts are avoided in future.

- All Western Canadian producers would have the opportunity to realize higher netback prices through the Project, on production that is priced in the Asia/Pacific region rather than the US Gulf Coast region. Exports to California are expected to provide a \$3 to \$4 per barrel (constant US\$2012) netback premium and exports to Asia/Pacific markets are expected to provide a \$2 per barrel netback premium. These benefits would apply from 2018 through the end of the forecast period in 2037.
- Total revenues for Western Canadian oil producers attributable to market access provided by the Project are estimated to be approximately \$45 billion, including both general industry benefits and higher netback prices on deliveries to Asia. This is based on a proportionate share of the total benefits associated with all of the major planned pipeline expansion projects.
- The Project represents a path to higher netback markets, and can be expected to produce an above-average level of netbacks. In addition, if one or more of the other new pipeline projects was assumed to not go forward or to be delayed, the benefits derived from the Project would increase. Therefore, the estimated netback benefits for the Project are considered to represent a conservative estimate of its likely standalone benefits.
- The Project would provide optionality benefits and market diversity for producers in a market characterized by uncertainty. There is no certainty regarding what the highest value market will be over the forecast period, so ensuring that multiple markets are accessible offers significant value to producers.
- The Project will provide firm service capacity for contract shippers, and generally improve the quality and reliability of pipeline access and transportation service for all shippers.
- The Project will improve the quality of the price signals in, and economic efficiency of, the market for transportation services, and position transportation market participants to compete on a level playing field for existing and incremental production. This includes enhancing secondary market competition to serve uncommitted volumes.

3.5 Economic Feasibility

Trans Mountain commissioned independent expert evidence to provide an opinion on the economic and financial feasibility of the Project. The evidence of Mr. John Reed of Concentric Energy Advisors, Inc. is provided in Appendix C. Mr. Reed's evidence addresses whether the Project meets the Board's standards for economic and financial feasibility, and the energy industry and economic benefits of the Project. Trans Mountain relies upon and adopts the evidence of Mr. Reed in support of this Application, and his conclusions concerning the economic feasibility, including:

- The Project is both economically and financially feasible. There is convincing evidence of: more than adequate supplies of oil; premium netbacks expected from access to California and Asia; market support through firm contractual commitments; and, the capability of Trans Mountain to finance the Project on reasonable terms.

- The Project is one of a group of pipelines that are being proposed to meet the market's need for additional pipeline capacity. However, the financial feasibility of the Project does not depend on the success or failure of any of those other projects; the shipper commitments are not contingent on what happens with other projects, and shippers have provided clear and convincing support for the development of this expanded path to high-value markets.
- Based on the analysis completed by IHS, there is a potential for some level of under-utilization of the region's aggregate pipeline capacity during the 2017 to 2030 period, if all proposed projects proceed as planned. However, that does not indicate that the Project, or any of the other proposed projects, is not economically feasible. The Project provides a feasible and efficient means of addressing the asymmetrical risk of too much/too little capacity. Some level of optionality in capacity markets promotes economic efficiency, reflects the likelihood of future additional demand and does not detract from the economic feasibility of the Project.
- The relative attractiveness of markets can change quickly, as supply and demand fundamentals shift. Having transportation infrastructure that accommodates shifts in market preferences creates value, by providing the option and ability to redirect flows as markets change. The willingness of producers to commit to take-or-pay demand charges for pipeline capacity to multiple markets makes economic sense when viewed in this context, and providing that optionality enables Canadian producers to maximize the value they derive from their production.
- As noted in the IHS report, the netback price for crude delivered to Asian or California markets is expected to be higher than the value of supplies delivered to US Gulf Coast markets. Therefore, spot service demand on the expanded TMPL system can be expected to be higher than on other pipelines, which access lower value markets. The availability of spot service and its economic advantage over competing routes can be expected to contribute to the economic feasibility of the Project.
- The Project is highly likely to be used and useful and it should be expected to operate at a high load factor. The Project is fully consistent with the Board's criteria for assessing economic feasibility, and consistent with the new market dynamics regarding the need for pipeline transportation optionality and flexibility.

Trans Mountain submits that the evidence presented in the foregoing sections and the sponsored expert evidence demonstrates that the Project is economically feasible.

The evidence on supply indicates that the Project will have access to large and growing crude oil supplies, as production from the WCSB is expected to grow significantly over the long-term.

The evidence on markets indicates that the Project will link the WCSB supply with large and growing Pacific Rim markets.

The evidence on the underlying transportation arrangements is that long-term commitments have been made that provide strong assurances that the Project will be well-used over the lifetime of these contracts. The shippers who have signed long-term contracts are well

capitalized, sophisticated market participants with access to large oil supplies. The transportation contracts provide strong incentives for them to use their capacity entitlements at a high load factor, while the overall contract terms provide a high level of assurance that all parties will remain committed to the Project.

The toll on the expanded TMPL will enable western Canadian oil producers to deliver crude oil to tidewater at a very attractive rate, both for long-term shippers and spot shippers. The evidence provided by IHS demonstrates that the Project will provide access to markets that yield attractive netbacks, and Trans Mountain is confident that the expanded TMPL system will attract considerable spot volumes during its operating life. In short, the transportation arrangements are clearly structured to ensure the maximum use of the pipeline over the lifetime of the Project.

Finally, the evidence on financing arrangements is unequivocal. Canadian oil producers need access to US Pacific Northwest and Pacific Rim markets and the Project will provide this access. The Project makes business sense and, hence, financial markets can be expected to provide the debt financing. The evidence on financing also demonstrates that Trans Mountain's parent KMP has the financial capability to finance the Project.

4.0 PIPELINE ROUTE AND FACILITY SITING

4.1 Alternatives

Section 4.2.2 of the NEB Filing Manual (NEB 2013a) asks the applicant to describe:

- Project need: outlined in Section 3.0 of Volume 2;
- Route and site selection: outlined in Section 4.0 of Volume 2 and Section 2.8 of Volume 4A; and
- Design and construction alternatives: outlined in Volumes 4A and 4B.

The *CEA Act, 2012*, in Section 19, states:

19. (1) The environmental assessment of a designated project must take into account the following factors:

[...]

(g) alternative means of carrying out the designated project that are technically and economically feasible and the environmental effects of any such alternative means;

In developing the Project, Trans Mountain did not consider fundamentally different alternatives such as rail transportation rather than pipelines, or pipeline concepts to different destinations. The RH-001-2012 proceeding demonstrated the need and benefits of expanding the existing TMPL. For these reasons, no effort was made to consider the economic feasibility or environmental effects of these or other conceptual alternatives.

The scope of the Project is described in Section 2.0, Project Description, and more completely elsewhere in other volumes, particularly Volume 4A. That scope formed the basis of the environmental and socio-economic assessment. As described in Volumes 5A and 5B, the environmental and socio-economic assessment considers the mandatory factors listed in Section 19(1) of the *CEA Act, 2012*, the factors listed in the NEB Filing Manual (NEB 2013a), and pertinent issues and concerns identified through Aboriginal engagement and consultation with landowners, regulatory authorities, stakeholders, and the general public. As well, the “List of Issues for the Trans Mountain Expansion Project” was released by the NEB on July 29, 2013. The NEB also, on September 10, 2013, issued “Filing Requirements to Trans Mountain Pipeline ULC Related to the Potential Environmental and Socio-Economic Effects of Increased Marine Shipping Activities” specifically for the Project.

In response to Section 19(1)(g) of the *CEA Act, 2012*, Trans Mountain considered alternative pipeline corridors and pump station locations in the environmental and socio-economic assessment. These are described in Section 4.0 of Volumes 5A and 5B.

4.2 Pipeline Corridor Selection

4.2.1 Environmental Setting

The Project includes looping the remaining segments of the existing 1,147 km TMPL from Edmonton to Burnaby, built in 1953. Previously, 320 km of the system were looped including the 160 km Anchor Loop which was constructed in 2008 through Jasper National Park and Mount Robson Provincial Park. The 987 km of pipeline that will be looped as part of the Project

traverses a wide range of landforms from flat farmland to mountainous terrain. Land use varies from densely populated urban areas around Edmonton, Vancouver, and elsewhere to sparsely populated rural agricultural and forested Crown lands. The pipeline segments to be constructed as part of the Project will also potentially cross 500 rivers and streams, 8 provincial parks and 13 Indian Reserves (Figure 4.2.1).

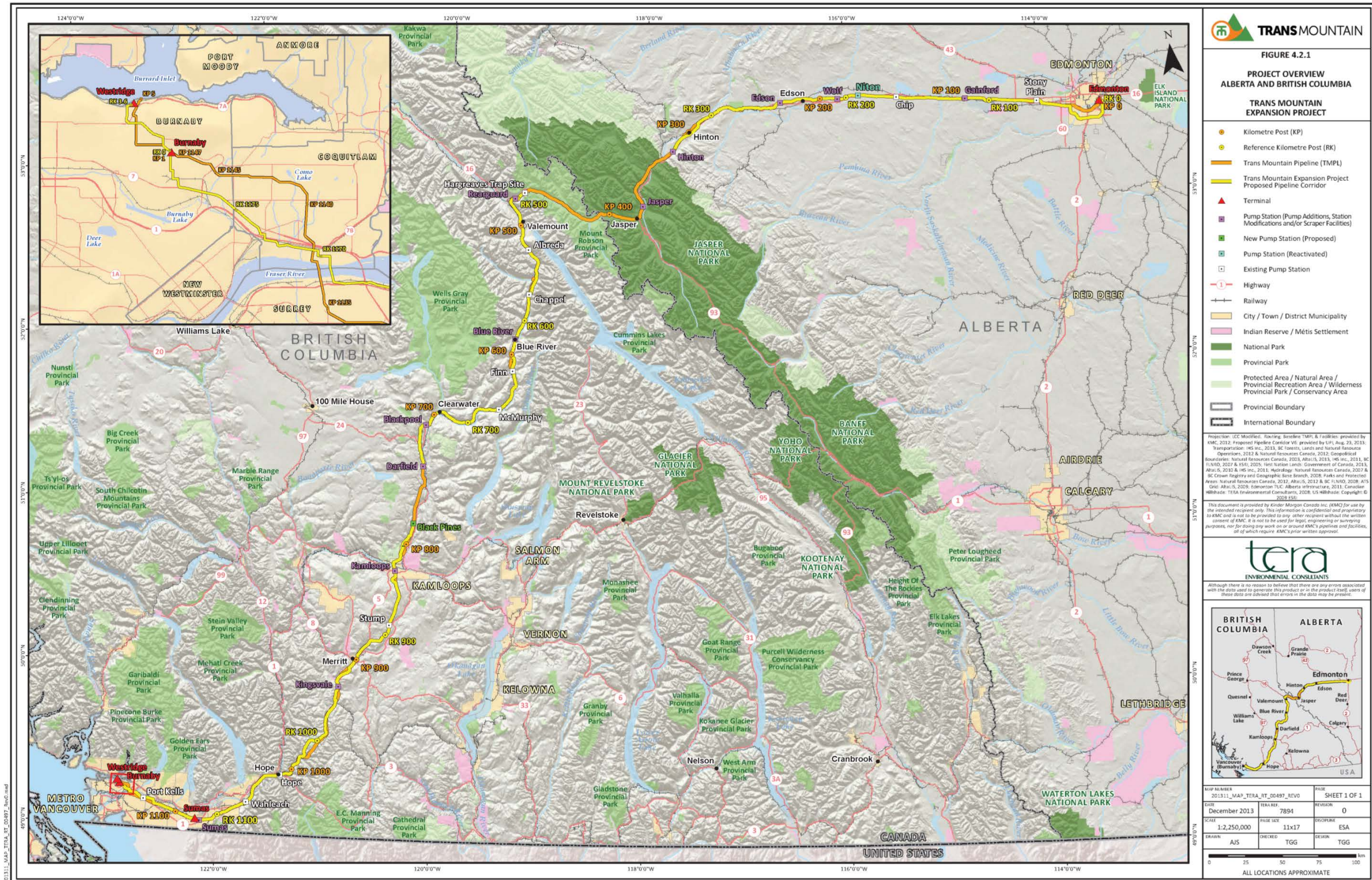


Figure 4.2.1 Project Overview – BC and Alberta

4.2.2 General Routing Objectives and Criteria

Early in the project planning process, Trans Mountain decided that the new pipeline segments should be contiguous with the existing 18 m wide TMPL easement to the greatest extent practical to minimize environmental and socio-economic effects and facilitate efficient pipeline operations. While this was determined to be possible for over 70 per cent of the distance, it was not possible in all locations. As engineering, environmental and other disciplines examined maps, completed field observations and consulted with stakeholders, landowners, and community representatives, a hierarchy of routing criteria was established. In descending order of preference, these were:

- Wherever feasible, install the Line 2 segments on or adjacent to the existing TMPL easement.
- Where that proves not feasible, install the Line 2 segments adjacent to easements or rights-of-way of other linear facilities including other pipelines, power lines, highways, roads, railways, fiber optic transmission systems (FOTS), and other utilities.
- Or if that is not feasible, install the Line 2 segments in a new easement (*i.e.*, not parallel to other easements) selected to balance a number of engineering, construction, environmental, and socio-economic factors.
- Lastly, in the event a new easement is necessary, minimize the length of the new easement before returning to the TMPL easement or other easements.

In the context of the hierarchy of routing criteria, feasibility includes consideration of a range of factors including constructability, long-term geotechnical stability, environmental and socio-economic suitability and others. Specific factors that could result in a deviation from the TMPL easement are listed on Table 4.2.1.

While the proposed Line 2 pipeline segments generally require a construction right-of-way of 45 m, Trans Mountain decided to study and apply for a wider corridor (generally 150 m). The wider corridor is intended to provide flexibility for minor alignment adjustments during the detailed engineering and design phase.

TABLE 4.2.1

FACTORS THAT COULD RESULT IN DEVIATION FROM EXISTING TMPL EASEMENT

Factor
1. Safety - minimize areas posing hazards to: <ul style="list-style-type: none"> a. construction/operations workers – workspace, overhead hazards, geotechnical hazards b. public – traffic interaction, proximity to excavations and heavy equipment
2. Pipeline integrity – minimize crossing areas with geotechnical hazards, high potential for third-party contact, and poor maintenance access.
3. Environment – minimize environmental impacts by attempting to reduce the following as much as is practical: <ul style="list-style-type: none"> a. the total number of watercourse crossings b. length in the Riparian Reserve Zone c. difficult reclamation areas and unstable terrain d. length within provincial parks and other designated protected areas e. the total number of wetland crossings g. creating new access in areas considered to be ecologically important

TABLE 4.2.1

**FACTORS THAT COULD RESULT IN DEVIATION FROM EXISTING TMPL EASEMENT
 (continued)**

Factor
4. Constructability – avoid factors negatively affecting construction efficiency.
5. Terrain – minimize crossing side slopes, geohazards, rock, water bodies, wetlands, and high water table areas.
6. Infrastructure – minimize encroachment on existing and planned infrastructure.
7. Access – avoid limited or difficult existing access roads (stability, turn radius, local interference)
8. Stakeholders and socio-economic requirements: <ul style="list-style-type: none"> a. review and be consistent with land use policy documents b. landowner – consider landowner concerns c. parks – avoid where practical d. recreational areas – avoid where practical e. infrastructure – dependant on meetings with representatives of applicable utility f. residential density - reduce length in high density areas where other options are available
9. Aboriginal Impact; <ul style="list-style-type: none"> a. reserve Lands dependant on consultations; provide alternate routing for planning b. traditional Lands – dependant on consultation
10. Cost and Schedule – reduced length is preferred; schedule reduction due to improved constructability over a longer distance should be considered.

4.2.3 Proposed Pipeline Corridor

4.2.3.1 Introduction

The following describes the proposed pipeline corridor and provides a high level overview of the key issues that influenced its selection. Additional details are provided in Section 2.8 of Volume 4A and Sections 4.1 to 4.3 of Volumes 5A and 5B, respectively.

Looping (“twinning”) of the 1,147 km existing TMPL from Edmonton to Burnaby will require construction of 987 km of new mainline pipeline and two, parallel 3.6 km delivery lines from Burnaby Terminal to Westridge Marine Terminal. The new pipe segments will be within a proposed corridor on or adjacent to the existing 18.3 m wide TMPL easement (including areas where other linear facilities have pre-empted TMEP from being directly contiguous with the original TMPL easement) for 722 km, or 73 per cent of the total length. Approximately 170 km (17 per cent) follows beside other existing rights-of-way, making for a total parallel length of 892 km (90 per cent). A total of 98 km (10 per cent) of the TMEP will be on new corridor.

4.2.3.2 Alberta

Given that the TMPL Edmonton Terminal is on the east side of the City of Edmonton, it is difficult for a pipeline heading toward the West Coast to avoid traversing the city. The original TMPL 18 m easement bypassed the then southern limits of the city, but 60 years of urban growth have caused the city boundaries to move many kilometres further south (Plate 4.2.1). Rather than run adjacent to hundreds of residential properties, Trans Mountain chose to take advantage of the Edmonton Transportation/Utility Corridor (TUC) established by the Province of Alberta in the 1970s. Accordingly, a major deviation from the existing TMPL right-of-way to the south takes place in the first 45 km of pipeline corridor. Final placement of Line 2 within the TUC will be subject to specific direction by Alberta Infrastructure, the TUC administrator.

The proposed pipeline corridor rejoins the TMPL easement west of Edmonton, passing through less developed portions of the City of Spruce Grove and the Town of Stony Plain before entering more rural landscapes and scattered country residential developments in Parkland County. The existing TMPL easement traverses Wabamun Lake Provincial Park for several kilometres. The currently proposed corridor passes north of the park but recent discussions with Alberta Tourism, Parks and Recreation indicate that it may be possible to follow TMPL within the park. Further west, the proposed pipeline corridor generally follows the TMPL easement, passing near the Town of Edson, which is immediately to the south. For the remainder of the length in Alberta, the proposed pipeline corridor generally follows the TMPL easement, with the exception of passing south of the Town of Hinton following a proposed new Highway 16 bypass.



Plate 4.2.1 Existing TMPL easement surrounded by urban development within the City of Edmonton.

4.2.3.3 *British Columbia*

In general, the factors influencing selection of the proposed pipeline corridor are more complex in BC than Alberta. Although much of the route through the Rocky Mountains was crossed by the Anchor Loop project constructed in 2008, the proposed pipeline corridor must still cross several interior mountain ranges before entering the rich farmland and urban development in the Lower Mainland. A large portion of the urban development in the Lower Mainland, Kamloops and elsewhere occurred after construction of TMPL. Likewise, the seven provincial parks potentially encountered by the Project have been established since TMPL was built.

Commencing at Hargreaves on the west side of Mount Robson Provincial Park, the proposed new TMEP pipeline corridor generally follows the TMPL easement through the Fraser River valley except for a deviation to avoid crossing Rearguard Falls Provincial Park and a second crossing of the Fraser River. The proposed pipeline corridor then crosses a height of land to enter the Rocky Mountain Trench, bypassing the Village of Valemount to the west. Further south, the proposed pipeline corridor follows the existing TMPL easement through successive narrow, mountain valleys occupied by Camp Creek and the Albreda River, respectively.

As it continues to follow the existing TMPL easement, the proposed pipeline corridor then enters the upper reaches of the North Thompson River valley, which it generally follows for several hundred kilometres as far south as the City of Kamloops. In the upper part of the valley, the TMPL easement crosses the North Thompson River five times in less than 4 km. The proposed pipeline corridor deviates from the TMPL easement to parallel a nearby power line and forestry road for approximately 15 km as far south as Chappel Pump Station. Consequently, the proposed pipeline corridor crosses the North Thompson River once instead of five times. The proposed pipeline corridor continues to generally follow the existing TMPL easement, descending the narrow, forested North Thompson River valley towards the Community of Blue River. At Blue River, the proposed pipeline corridor is immediately west of the community where it is adjacent to the existing TMPL easement and the existing Blue River Pump Station. Further south, the proposed pipeline corridor continues to generally follow the existing TMPL easement in the North Thompson River valley as far as Finn Creek Provincial Park where there are alternatives to either go through the park beside TMPL or avoid the park to the east. Further south, the proposed pipeline corridor continues following the existing TMPL easement through the widening North Thompson River valley, passing by the communities of Avola and Vavenby and the District of Clearwater before encountering two portions of the North Thompson River Provincial Park. The northern portion of the park and the Clearwater River crossing is unavoidable, whereas there is an alternative to either transect the southern portion of the park along the TMPL easement or avoid it to the west. Further south, the proposed pipeline corridor continues to follow the TMPL easement as far south as Darfield Pump Station.

From the location of the new Black Pines Pump Stations, the proposed pipeline corridor follows the TMPL easement on the west side of the lower North Thompson River valley, which now averages 2 km in width and is becoming increasingly settled and agricultural. The community of Westsyde in the City of Kamloops has been recently built up on a broad terrace of the River (Plate 4.2.2). To avoid passing through Westsyde for several kilometres, an alternative to the west is being considered. This alternative would follow a FOTS right-of-way through Lac Du Bois Grasslands Protected Area (Plate 4.2.3). The proposed pipeline corridor then rejoins the TMPL easement and crosses the Thompson River just east of the Kamloops Airport, climbing the south slope of the river valley to eventually enter the Kamloops Pump Station on the south side of Highway 5.

The proposed pipeline corridor generally follows the existing TMPL easement across a semi-forested upland plateau from Kamloops to Merritt with three possible exceptions. The first is a jog to the west on the proposed Ajax Mine property to avoid Jacko Lake and a narrow valley where there is insufficient room to install a second pipeline. Further south, the TMPL easement crosses corners of two Indian Reserves north of Merritt (Zoht 5 and Zoht 4) where minor deviations avoiding the Reserves are being considered in addition to following beside TMPL through the Reserves.



Plate 4.2.2 Existing TMPL easement encroached by urban development through the community of Westsyde.



Plate 4.2.3 Existing FOTS right-of-way within Lac Du Bois Grasslands Protected Area.

The proposed pipeline corridor follows the existing TMPL easement through the eastern limits of the City of Merritt in the Nicola Valley, cutting the northwest corner of the Joeyaska Indian Reserve No. 2. A minor deviation avoiding the Indian Reserve to the north and west is also being considered. Further south, the proposed pipeline corridor continues to follow the existing TMPL easement up the Coldwater River valley. The TMPL easement traverses the Coldwater Indian Reserve No. 1 for 7 km. Trans Mountain has identified alternative corridors east and west of the Reserve and currently proposes a corridor which avoids the Reserve to the east. Further south, the proposed pipeline corridor rejoins the existing TMPL easement ascending the narrowing Coldwater River valley to just south of Kingsvale Pump Station. From this point, the proposed pipeline corridor leaves the TMPL easement several times to parallel the Spectra gas pipeline right-of-way which generally parallels TMPL in the Coldwater River valley area. These deviations are generally undertaken to take advantage of better terrain, to reduce the number of Coldwater River crossings or to minimize the length in the riparian reserve zone.

The terrain becomes increasingly mountainous as the proposed pipeline corridor moves further south through the Hozameen Range of the Cascade Mountains. A major deviation takes place near Coldwater River Provincial Park where the proposed pipeline corridor crosses Highway 5 (Coquihalla Highway) west of the Park, continues southwards beside the Spectra and highway rights-of-way, crossing the Coldwater River and the divide into the Coquihalla River drainage and the north end of Coquihalla Summit Recreation Area (Plate 4.2.4). At this point, the proposed pipeline corridor is approximately 1 km west of TMPL. The TMPL right-of-way continues southwards into the Coquihalla Lakes area into the narrow gorge locally known as Coquihalla Canyon, crossing the Coquihalla River 13 times in less than 20 km. There is limited working room for a second pipeline easement, and constructability is a concern. Instead of following the Coquihalla Canyon route, Trans Mountain elected to follow the Coquihalla Highway into the Boston Bar drainage approximately 6 km to the west. This corridor is also used by two Spectra gas pipelines and a FOTS cable and traverses the Coquihalla Summit Recreation Area for a shorter distance than the TMPL easement. The TMPL easement and the proposed TMEP pipeline corridor rejoin where Boston Bar Creek flows into the Coquihalla River. From this point to the District of Hope, the proposed pipeline corridor follows either beside the existing TMPL easement, Coquihalla Highway, Spectra or FOTS rights-of-way in the narrow and steep Coquihalla River valley, depending upon the most constructible terrain and other factors. For example, the TMPL easement traverses the Coquihalla River Provincial Park for 3 km, whereas the proposed pipeline corridor avoids the park altogether. Once in the District of Hope, the proposed pipeline corridor generally follows the TMPL easement or the Spectra right-of-way, avoiding the Kawkawa Lake Indian Reserve No. 16 before crossing the Coquihalla River upstream of its confluence with the Fraser River and entering Hope Pump Station. West of the District of Hope, the proposed pipeline corridor generally follows the existing TMPL easement and Highway 1 (Trans-Canada Highway) in the narrow strip of land between the Fraser River and the Skagit Range of the Cascade Mountains.

The remainder of the proposed pipeline corridor traverses the rich agricultural lands of the Lower Mainland of BC, which becomes increasingly urbanized from the Fraser Valley Regional District west to Metro Vancouver. Most of the agricultural lands are part of the provincial ALR. The proposed pipeline corridor generally follows the existing TMPL easement unless otherwise specifically mentioned.



Plate 4.2.4 Existing TMPL easement within Coquihalla Canyon in foreground and proposed corridor beside Coquihalla Highway and FOTS in midground.

The proposed pipeline corridor continues further west into the Lower Mainland, although minor deviations are being considered to avoid Ohamil Indian Reserve No. 1, Peters Indian Reserve No. 1A and Popkum Indian Reserve No. 1. East of the City of Chilliwack, the proposed pipeline corridor crosses to the north side of the Trans-Canada Highway to parallel a BC Hydro power line in order to avoid a crossing of Bridal Veil Falls Provincial Park and Popkum Indian Reserve No. 2. A small portion of Cheam Lake Wetland Regional Park would be crossed although minor deviations are being considered in this area to avoid the park.

Further west, the proposed pipeline corridor passes through the City of Chilliwack, with minor deviations to the TMPL easement considered to avoid crossing Grass Indian Reserve No. 15 and Tzeachten Indian Reserve No. 13. The Vedder River is the major watercourse crossed in the Chilliwack area. Further west, the proposed pipeline corridor enters the City of Abbotsford, crossing the Sumas River and surrounding agricultural Sumas Prairie before ascending the forested south flank of Sumas Mountain. The existing TMPL easement provides for a branchline to access TMPL's Sumas Terminal. On the west side of Sumas Mountain, the proposed pipeline corridor crosses increasingly urbanized areas and a golf course in the vicinity of Clayburn. Towards the western end of the City of Abbotsford, the proposed pipeline corridor crosses the Matsqui Main Indian Reserve No. 2, although a minor deviation is also being considered to the south. The proposed pipeline corridor then enters the Township of Langley and continues along the existing TMPL easement until the vicinity of the Salmon River valley south of Fort Langley. From this point onwards to the Fraser River crossing, urbanization in Langley and the City of Surrey has sufficiently encroached on the existing TMPL right-of-way in the past 60 years to make contiguous looping not feasible (see 4.2.2). For this reason an alternative pipeline corridor was sought. Trans Mountain chose to take advantage of the existing Canadian National (CN)

railway right-of-way and new South Fraser Perimeter Road corridor on the south side of the Fraser River. Accordingly, the proposed pipeline corridor leaves the TMPL right-of-way near a golf course and heads north on new corridor a short distance across farmland before reaching the CN railway right-of-way. Other minor deviations are being examined to follow property lines and cross a second golf course further north before joining the CN railway right-of-way. From this point it parallels the CN railway right-of-way and later the South Fraser Perimeter Road in a westerly direction through Langley and Surrey before finding a location to cross the Fraser River near the Port Mann Bridge. The proposed pipeline corridor traverses the edge of the Surrey Bend Regional Park for about 3 km, although a minor deviation is being considered to reduce this length by taking advantage of surplus land released from the recent South Fraser Perimeter Road project.

Two primary locations are being considered to cross the main stem of the Fraser River between the cities of Surrey and Coquitlam using the horizontal directional drill (HDD) method (see Plate 4.2.5). Currently, the proposed pipeline corridor is located about 500 m east of the existing TMPL pipeline, but a second location is being considered on the east side of the Port Mann Bridge. On the north side of the Fraser River, urbanization in the cities of Coquitlam and Burnaby have sufficiently encroached on the existing TMPL easement in the past 60 years to make contiguous looping not feasible (Plate 4.2.6). The proposed pipeline corridor follows the Lougheed Highway although a deviation is being considered to traverse existing industrial lands and railway easements within the Brunette River Conservation Area. Both corridors eventually link up with TMPL's Burnaby Terminal via other city streets.

From the Burnaby Terminal to the Westridge Marine Terminal on Burrard Inlet, urbanization in the City of Burnaby has sufficiently encroached on the existing TMPL right-of-way in the past 60 years to make contiguous looping with twin 30-inch pipelines not feasible. Accordingly, an alternative corridor is being considered alongside Burnaby Mountain Parkway, Hastings Street, and Cliff Avenue before turning east into TMPL's Westridge Marine Terminal. Other more direct alternatives involving partial or total trenchless (HDD or tunnel) methods of construction are also under consideration.

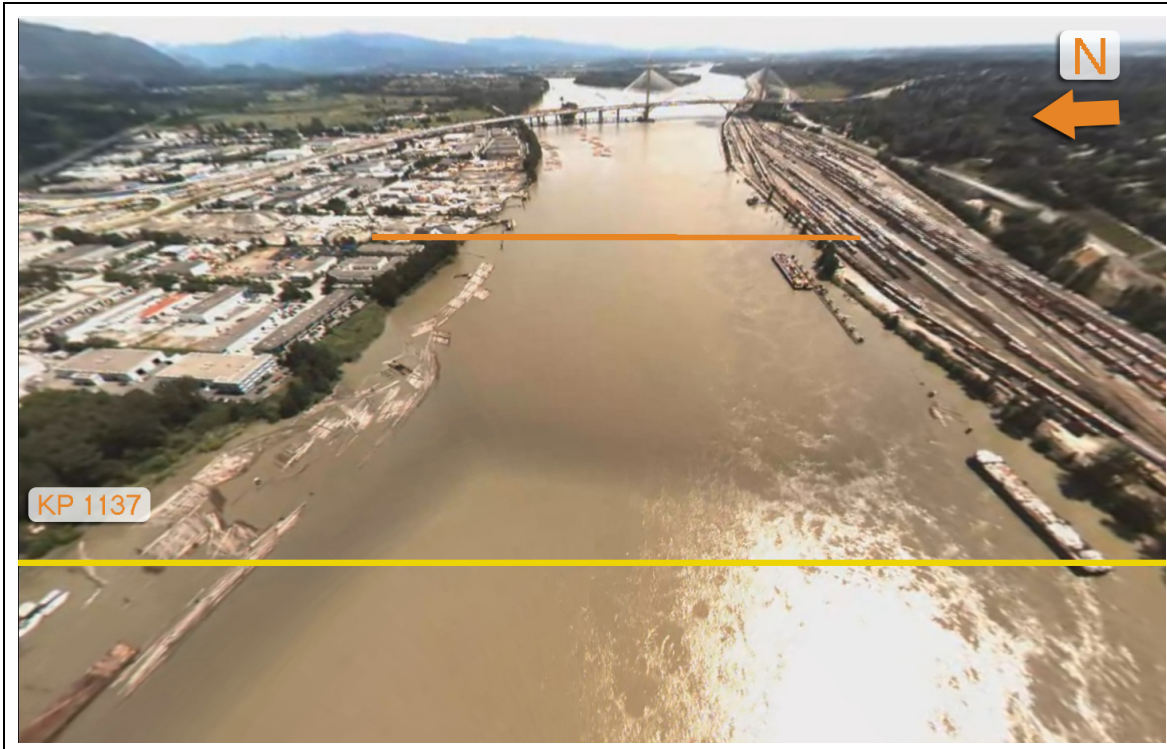


Plate 4.2.5 Overlooking the existing crossing of the Fraser River looking east with existing TMPL easement (shown in yellow) in foreground, proposed pipeline corridor (shown in orange) in midground and Port Mann Bridge in background.



Plate 4.2.6 Looking south along the existing TMPL easement encroached by urban development in the City of Coquitlam.

4.3 Facility Siting

In general, the existing TMPL terminals and pump station sites are sufficiently large to accommodate TMEP facilities. The two pump stations at Black Pines, approximately 38 km north of Kamloops, will require a new site approximately 150 m x 150 m (2.25 ha) in size. Factors considered in site selection include:

- optimization of pipeline hydraulics;
- terrain suitability;
- environmental suitability;
- availability of road access and electrical power; and
- landowner considerations.

Three candidate sites are under consideration with the preferred location to be finalized in the coming months.

In addition, a small extension to the foreshore area at the Westridge Marine Terminal will be required.

Additional detail on siting methodology is provided in Section 4.4 of Volumes 5A and 5B.

5.0 LAND RELATIONS, RIGHTS AND ACQUISITION

5.1 Introduction

Trans Mountain will acquire the necessary easement interests, permits and rights from private land owners and Crown License agreements in both Alberta and BC for the construction, operation, and maintenance of the Project.

5.1.1 Purpose of this Section

This section provides information on the land required for the Project and includes summaries of:

- land areas required for the Project;
- land rights;
- service of notice; and
- land acquisition process.

This section has been prepared to meet the requirements of the NEB Filing Manual, Chapter 4, Section A.4, Lands Information.

5.1.2 Project Overview

The Project is fully described in Section 2.0, above, and elsewhere.

5.2 Land Requirements

To construct, operate, and maintain the pipeline, facilities and associated infrastructure for the Project, surface rights must be acquired from the Crown and private landowners in BC and Alberta.

The summary in Table 5.2.1 provides estimates at this time. The actual quantities will be determined at completion of engineering design and construction planning.

TABLE 5.2.1

LAND AREA SUMMARY

Requirements	Alberta		BC	
	Area (ha)	Comment	Area (ha)	Comment
Right-of-way	621.2	18.3 m wide combination of existing TMPL and new right-of-way. Proportion to be determined following engineering design.	1,178.9	18.3 m wide, combination of existing TMPL and new right-of-way. Proportion to be determined following engineering design.
Temporary Workspace	906.2	Average 26.7 m wide.	1,726.8	Average 26.7 m wide.
Temporary Construction Lands	26.0 (min)	Total is undetermined at this time.	50.0 (min)	Total is undetermined at this time.
Pump Stations	0.3 (min)	Total is undetermined at this time.	3.02 (min)	Total is undetermined at this time.

TABLE 5.2.1

LAND AREA SUMMARY (continued)

Requirements	Alberta		BC	
	Area (ha)	Comment	Area (ha)	Comment
Pump Stations TWS		Undetermined at this time.		Undetermined at this time.
Power Lines	0.3 (min)	Total is undetermined at this time.	129.5	Total is undetermined at this time.
Subtotal	1,554		3,088	
Total	4,642 ha			

5.2.1 Right-of-Way

The proposed pipeline route follows the existing TMPL (Line 1) alignment except where other developments, restrictions, impediments or environmental features require deviations. The route selection processes and routing options are described in Section 2.8 of Volume 4A.

Distance measurements along the Project (TMEP, Line 2) study corridor are described as reference kilometres (RKs). These RKs are measured along the centre line of the study corridor that is typically 150 m wide. Comparatively, distances measured along the centre line of the existing TMPL are referred as KPs. Alignment deviations between the TMPL and the Project's study corridor create differences in length; therefore, only the Project's RKs are used for reference through the following sections.

In Alberta, the Project begins at the Trans Mountain Terminal in East Edmonton (RK 0.0). The pipeline will be located within the south TUC to the west side of Edmonton. There it will converge with the existing TMPL and continue westward to the Hinton Pump Station (RK 339.4). The segment from the Hinton Pump Station, AB, and the Hargreaves Scraper Trap Site, BC, was previously looped.

In Alberta, approximately 69 per cent, of the TMEP right-of-way will abut the TMPL. Approximately 23 per cent will abut other existing utilities and infrastructure. Along the remaining 8 per cent of the route, the right-of-way will not be contiguous with any other linear infrastructure. The width of existing TMPL easement is typically 18.3 m wide. Where practical, along those segments abutting the existing TMPL, the TMEP will be built within the existing easement when safe and practical. In some circumstances, no new easement will be required. In other cases, up to 18.3 m of additional width of new easement will be necessary. Through the TUC in Edmonton, AB, the width of easement is intended to be 18.3 m but may be restricted by Alberta Infrastructure to not more than 10 m.

The total land area required for right-of-way in Alberta will be approximately 621.2 ha based on a width of 18.3 m throughout. Until engineering design is complete, the full or partial use of existing TMPL right-of-way is undetermined. The combined width of the new and existing right-of-way will be minimized. The width of the new right-of-way will generally not exceed 18.3 m.

In BC, TMEP will begin at the Hargreaves Scraper Trap Site (RK 489.6) and continue to the Darfield Pump Station (RK 769). The segment between the Darfield Pump Station and the Kamloops Pump Station (RK 850.8) has been previously looped. This segment of Line 1 has been deactivated. Line 1 will be reactivated between the Darfield Pump Station and the new Black Pines Pump Station (RK 811.8). Acquisition of new permanent land rights is not

anticipated through this segment. The TMEP pipeline will begin again at the new Black Pines Pump Station (RK 811.8) and continue through to KMC's Burnaby Terminal (RK 1179.7). Extending beyond the Burnaby Terminal, two NPS 30 pipelines are proposed to connect to the Westridge loading facility (3.6 km).

Along the segment between Hargreaves and Darfield, approximately 73 per cent of the route will abut the existing TMPL while 15 per cent of the TMEP right-of-way will abut other utilities and infrastructure. Approximately 12 per cent of right-of-way will not be contiguous with other linear infrastructure. Between Black Pines and Burnaby Terminal, approximately 61 per cent of the route will abut TMPL while 27 per cent of the route will abut other utilities and infrastructure. About 12 per cent of the TMEP route will not be contiguous to other linear infrastructure.

Between the Burnaby Terminal and the Westridge Facility, approximately 17 per cent of the length of the route will be on or adjacent to the existing TMPL right-of-way while 19 per cent of the length will abut other existing infrastructure. Sixty-four per cent of the length will not be contiguous with other linear infrastructure.

In BC, as in Alberta, the width of new easement will vary. Where the pipeline is built on the existing easement, it may be possible that no new easement will be required. The width of the new easement will vary up to 18.3 m. Where the pipeline is to be installed within municipal streets, no easement is expected but instead, the pipeline will be operated and maintained under permit or license from the municipal authority. Due to physical limitations within municipal streets, the effective width of license areas may be approximately 3 to 5 m.

The total land area required for right-of-way or license in BC will be approximately 1,178.9 ha based on a width of 18.3 m or less as limited by licenses. Until engineering design is complete, the full or partial use of existing TMPL right-of-way is undetermined. The combined width of the new and existing right-of-way will be minimized. The width of the new right-of-way will generally not exceed 18.3 m.

5.2.2 Temporary Workspace and Construction Facilities

5.2.2.1 Temporary Workspace

During construction and installation of the Project, the average width of the construction footprint will be approximately 45 m (includes permanent right-of-way and temporary workspace [TWS]). Where TMEP is constructed on lands not contiguous with TMPL, the construction footprint may be reduced to a width of 40 m.

The width of TWS will vary depending on the nature of terrain, construction season and on the specific features encountered or crossed by the pipeline. The total area of TWS (area beyond new or existing easement of 18.3 m width) will be approximately 2,633 ha based on the preliminary length of 987 km (Edmonton to Burnaby Terminals) plus 3.6 km between the Burnaby Terminal and the Westridge Marine Terminal. The average width of TWS is estimated to be 26.7 m.

The width of TWS will be reduced to mitigate land impacts as required and also in respect of physical limitations such as within urban streets or proximity to other linear infrastructure. The width of TWS may be increased to provide additional workspace for:

- watercourse crossings;
- highway, road, and utility crossings;

- grading along sloping terrain;
- timber storage; and
- other special circumstances.

Temporary workspace lands are expected to be required for the construction and reclamation phases of the Project only and will not be required for the longer-term operational needs.

5.2.2.2 Other Construction Infrastructure

5.2.2.2.1 Construction Lands

Land will be required by the Project on a temporary basis, for staging and stockpiling of equipment and material, construction yards, work camps and borrow pits. Wherever practical, these temporary facilities will be located within previously disturbed areas. The specific requirements for such lands will be finalized during detailed engineering design and construction planning.

Temporary lease and permitting arrangements will be made with the respective Crown or Municipal authority or private landowners.

Construction access to the Project, where it is not contiguous with the existing TMPL, will be from existing public access points/roads, rights-of-way of others (e.g., CN railway, TELUS) and existing or temporary access roads (shoo-flies). Where new access is required, arrangements will be made with Crown authorities, occupants and private landowners for construction, reclamation and long-term pipeline operations.

Existing borrow pits will be utilized to the extent practical. Locations will be determined during detailed engineering design and construction planning.

The estimated requirements for construction infrastructure are listed in Table 5.2.2.

TABLE 5.2.2

ESTIMATED LAND AREA REQUIRED FOR CONSTRUCTION INFRASTRUCTURE

Construction Infrastructure	Area (ha)
Construction camps: Alberta one site	3 to 5
BC two sites	6 to 10
New Access	Undetermined at this time
Stockpile sites: Alberta four sites	23
BC eight sites	44
TOTAL	76 to 82

5.2.2.2.2 Pump Stations, Valves, Cathodic Systems, and Terminals

The Project includes the acquisition of land for the installation, construction, operation, and maintenance of one new electric drive pump station along the TMPL system. It is located in BC at Black Pines (approximately RK 811.8). The preliminary footprint for the new pump station compound is approximately 150 x 150 m (2.25 ha). The required size is to be confirmed during detailed engineering design. A typical pump station is located within a fenced area and contains:

pumps and motors housed in a building; an operator's building; and electrical substation and an electrical equipment building. The pump station will be connected to the provincial electrical power grid via new power lines, and access will be by newly constructed permanent graveled access road within a 15 to 20 m wide right-of-way. The parcel acquired for the new station will be purchased on a fee simple transfer value. Excess lands will be left as an undisturbed buffer around the station site.

The new Black Pines Pump Station will be located approximately 28 km north of the City of Kamloops, BC. Trans Mountain has investigated the availability of three possible site locations on freehold lands. Final site selection has not been completed and negotiations for land acquisition have not concluded.

Modification planned for three other existing pump stations will require additional lands for expansion. This will include permanent and temporary-use land on adjacent properties. The following land areas are preliminary estimates based on pre-design assumptions. The values are likely to change. Permanent Lands will be required at:

- Darfield Pump Station BC 0.07 ha freehold land;
- Rearguard Pump Station BC 0.7 ha crown land; and
- Hinton Pump Station Alberta 0.3 ha freehold land.

To facilitate the operations, maintenance, repair, and shutdown of the pipeline system, valves will be installed at various locations along the new pipeline loop. These valve sites will consist of a small gravel pad, a small building or cabinet to house instrumentation, and will be fenced. The typical footprint for a valve site is approximately 5 m × 12 m. Most valve sites will not require additional land acquisition since they will be located either within permanent pipeline easement or within pump station sites.

Additional cathodic systems will be required but the types and locations will not be determined until the detailed design phase. Each cathodic bed will be included in requirements for appropriate easement.

5.2.2.2.3 Terminals

No additional permanent land is expected to be required at the Edmonton, Kamloops, Sumas, and Burnaby terminals. Temporary offsite staging/parking areas may be required which will be determined during construction planning.

At the Westridge Marine Terminal, an expansion of the foreshore is expected to be needed. The size of the expansion is estimated to be about 1.4 ha. Temporary offsite staging/parking areas may also be required. This will be determined as construction plans are developed.

5.2.2.2.4 Power Lines

Power lines will be constructed to supplement electrical power to three existing pump stations and provide service to one new pump station. Electrical power will also be required at each automated valve site as well as new cathodic rectifier locations. Electrical power will be provided from existing provincial power grids. Investigations have been initiated with provincial power suppliers to determine appropriate power service and interconnection sites to existing power lines.

For pump stations in BC, power lines of 138 or 69 kV within a 40 to 50 m wide right-of-way, will be constructed from the interconnection sites to each of two pump stations.

Power requirements at valve and rectifier sites will range between 12.5 and 25 kV. These will be located on the margin of the existing or new pipeline right-of-way. Alternatively, where it is not possible to co-locate the power lines on pipeline rights-of-way, new rights-of-way will be acquired, which may be between 20 and 30 m wide.

In BC, Trans Mountain will initially acquire the land rights for power lines and later transfer those interests to the power service utility company.

Additional power to the pump stations in Alberta will be either 25 or 138 kV depending on future studies by power service utility companies. In Alberta, the utility companies will complete design, regulatory applications and acquisition of required lands. Electrical power to valve and cathodic sites will be similarly located within the pipeline right-of-way or new power line rights-of-way of 20 to 30 m wide.

Interconnection sites and routing are to be determined by power service utility companies. Detailed studies are not yet complete.

- Supplemental overhead power service will be required at existing facilities:

Alberta

Edson Pump Station RK 247.1	power line route unknown at this time	
Edmonton Terminal RK 0.0	approximately 100 m at 30 m wide right-of-way	0.3 ha

BC

Kingsvale Pump Station RK 955.5	approximately 24 km at 50 m wide	117.5 ha
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- New overhead power service will be required at new pump station:

BC

Black Pines Pump Station RK 811.8	approximately 2.4 km at 50 m wide	12.0 ha
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5.3 Land Rights

To construct, operate and maintain the pipelines, facilities and associated infrastructure for the Project, surface rights must be acquired from the Crown and private landowners in BC and Alberta.

5.3.1 Type of Land Rights

Types of land rights required by the project include:

- Easement (Statutory right-of-way): Easements provide a partial right to the land for a specific activity (*i.e.*, access, preconstruction activities pipeline construction, operation, repair and maintenance). Easements have been registered against land titles for the existing TMPL. In most cases, the existing easements provide for installation, operations and maintenance of pipelines on the right-of-way. New statutory right-of-way agreements will be registered against land titles. Agreements will identify requirements for above-ground appurtenances as required. Easements will be sought for all privately owned lands as well as Provincial, Federal and Indian Reserve Lands in BC.

- An application for right-of-way and TWS on Indian Reserves will be submitted where required.
- Pipeline Lease Agreements will be acquired for those portions of Crown lands in Alberta from AESRD. These agreements will apply to the construction, operation and maintenance of the pipeline loop and Project. This interest will be granted following the receipt of consent agreements from the disposition holders (occupants) as directed by AESRD. The form of Lease Agreement will be prescribed by AESRD.
- In BC, applications will be made to the BC OGC for tenure on Crown lands.
- For those lands within BC provincial parks, the appropriate authorities will be consulted regarding the statutory process that must be followed to acquire the necessary land tenure.
- Statutory right-of-way agreements will also be required for power lines and permanent access roads. The easements shall provide for access, construction, operations, repair, and maintenance.
- Temporary workspace: Temporary land use agreements will be entered into with Crown authorities and private landowners for construction of pipelines, power lines, valves, cathodic beds and other facilities. These agreements are to provide temporary rights for the use of lands for construction and reclamation. Agreements related to TWS will be registered onto respective land titles.
- Fee simple land ownership: Provides absolute ownership of the land (preferable for facility and facility expansions). Alternatively, if purchase of required lands is not possible, long-term lease arrangements may provide a viable alternative. Lease agreements must provide exclusive land right granted by the land title owner for use of the land. Lease agreement will be registered on respective land titles.
- Leased Lands: Lease agreements will be made with Crown authorities and private landowners for temporary land use for construction and reclamation activities. The scope includes pipe/material and equipment storage yards, construction yards, and camps.

5.3.2 Land Ownership

Land ownership along the Project corridor is a mixture of privately owned lands held in fee simple, provincial Crown lands, federal Crown lands and Indian Reserve lands.

Table 5.3.1 summarizes land ownership within the study corridor which is typically 150 m wide. The final centre line location of the pipeline will be defined in 2014. At that time, the summary of land ownership will be refined.

In Alberta there are 989 tracts of land within the study corridor, of which 673 are privately owned and 316 are owned by the Crown. In BC, there are 2,952 tracts within the study corridor, of which 2,293 are privately owned, 645 are Crown parcels, and 12 are Aboriginal communities.

TABLE 5.3.1

LAND OWNERSHIP DETAILS – TMEP

Location		Land Ownership Details
Alberta		
RK From	RK To	
0.0	2.2	Lands owned by industrial corporations.
2.2	42.0	Alberta Crown, TUC administered by Alberta Infrastructure.
42.0	134.0 Entwistle	Mostly private landowners. Crown lands administered by Alberta Transportation and AESRD.
134.0	228.8	Mostly private land ownership. Crown lands administered by AESRD.
228.8	339.4 Hinton Station	Near equal proportion of private land ownership and Crown parcels c/o AESRD.
BC		
RK From	RK To	
489.6	523 Valemount	Distribution of private land ownership and crown parcels care of BC OGC.
523	614.7 Blue River Station	Mostly Crown care of BC OGC; some private land ownership.
614.7	721 Clearwater	Distribution of private land ownership and Crown parcels care of BC Oil and Gas and BC Provincial.
721	769 Darfield Station	Mostly private land ownership, some Crown lands care of BC OGC and BC provincial parks.
769	850.6 Kamloops Station	Distribution of private land ownership and Crown parcels care of BC OGC. Ministry of Transportation and BC Protected Areas.
850.6	930 Merritt	Distribution of private land ownership and Crown parcels care of BC OGC. Also, lands to Aboriginal communities.
930	1043.7 Hope Station	Distribution of private land ownership and Crown parcels care of BC OGC, Ministry of Transportation, and BC Recreational Areas. Also, lands to Aboriginal communities.
1043.7	1097 Chilliwack	Distribution of private land ownership and Crown parcels care of BC OGC, Ministry of Transportation and BC provincial parks. Also, lands to Aboriginal communities.
1097	1179.6 Burnaby Terminal	Mostly private land ownership. One parcel to Aboriginal communities.
Burnaby Terminal	KP 3.6 Westridge	All private land ownership.

5.4 Lands Acquisition Process

5.4.1 Process

The primary program goal of the TMEP Land Program is to deliver land access on a timely basis to support survey, construction, reclamation, operations, and maintenance. More specifically, the program objectives are obtaining landowner acceptance and land rights grants for survey, construction, restoration and transition to operations by providing fair compensation and addressing non-monetary issues in a respectful, sincere, and honest manner.

Trans Mountain will implement the following land acquisition process for the new pipeline, one new pump station site, additional lands for expansion of three existing pump stations and for TWS for the pipeline, power lines, and cathodic systems.

- The pipeline right-of-way will be acquired by application to the appropriate Crown agency in Alberta and BC, and by way of an easement agreement or statutory right-of-way agreement on privately owned lands. Licenses or permits may be acquired from municipal authorities for construction within some municipal lands. Similarly, a form of TWS agreement or disposition will be used for TWS on privately owned lands and Crown lands. Trans Mountain plans to acquire a fee simple interest in the one new pump Station at Black Pines and for the expansion of three existing pump stations. Crown Disposition will be acquired for expansion of one additional pump station in BC. All land will be acquired with strict adherence to, and accordance with, the provisions and regulations of the NEB and, in particular, Section 87(1) of the *NEB Act*.
- Individual Ownership Sketches (IOSs) will be prepared for all lands required for the Project. The IOSs will define the location of the right-of-way lands (easement and TWS), new pump station, land for pump station expansion, and cathodic beds. The IOSs will define the areas required, and provide title and ownership information. Pursuant to Section 87(1) of the *NEB Act*, Trans Mountain will complete a real estate market analysis for the proposed right-of-way lands, the new pump station and expansion areas at existing stations and lands for cathodic beds. The values determined as a result of this process will be used to complete the market value of the Section 87(1) notice.
- Land agents acting on behalf of Trans Mountain will make personal contact with the landowners, occupants, and tenants of the lands required for rights-of-way, TWS, the new pump station, pump station expansions, and cathodic beds necessary for the Project. A Section 87(1) notice and a copy of the NEB's "Pipeline Regulation in Canada, a Guide for Landowners and the Public." Along with the NEB pamphlet, "A Proposed Pipeline or Powerline Project: What you Need to Know", will be provided to and reviewed with the landowners, occupants and tenants.
- The negotiation for a voluntary purchase or right-of-way agreement will continue until such time as an alternative course of action is necessary (e.g., Appropriate Dispute Resolution, Detailed Route Hearing, application to NEB, pursuant to Section 104 of the *NEB Act*, for a right of entry order).

5.4.1.1 Existing Easements

Under most existing easement agreements, Trans Mountain has the ability to place one or more pipelines within the existing 18.3 m wide easement. In certain easements, the practicability of utilizing this right is questionable because the existing line was not placed in a consistent offset location within the easement, meaning that either additional easement would be required or additional undercrossings would be required to locate the new line entirely within the existing easement. In addition, the easement agreements are silent respecting TWS or compensation for placing an additional line within the existing easement. For those reasons, Trans Mountain may be acquiring additional land rights from landowners. This includes the payment for equivalent easement rights (or rights-in-kind), in addition to payments for TWS, damages and

inconvenience as described in the *NEB Act* Section 97(1). This approach means that under certain circumstances, landowners will be compensated for the right to place a second line on their land, irrespective of any rights in the existing easement agreement.

5.4.1.2 Land Valuation

The Section 87(1) land values in Alberta and BC can be estimated by completing independent market valuation or relying on existing appraisals or market values available from government sources. For Alberta, the proposed approach is the use of independent market valuation developed for similar land types in similar areas. The approach is recognized as the Pattern of Dealing (POD). In BC, the Provincial Assessments are generally considered to be good indicators of market value and can be relied upon to provide efficient, objective land valuations. Preliminary study indicates sales values may exceed the provincial assessment values; therefore, an uplift amount will be considered.

5.4.1.3 Compensation Framework

The Compensation Framework needs to address two sets of values: the values Trans Mountain will use in the Section 87(1) Notices to satisfy the NEB requirements and the values Trans Mountain will use as the basis for calculation of the consideration offered to landowners for easement, working space, and fee-simple land purchases.

For the purposes of 87(1) notice, Trans Mountain proposes to use bare land values. Bare land market values will be determined in Alberta through POD for bare land prepared by a registered or accredited appraiser. In BC, market values will be based on BC assessment values plus uplift as may be required. A competent real estate valuator will review and comment on value to determine if adjustments are appropriate.

Typically, Trans Mountain would have to make payments for easements, working space, inconvenience, and signing consideration in advance of construction. Damage payments can be paid in advance (under a formulaic approach where included damages are defined, with any extra damages compensated for following restoration) or following restoration, based on actual damages.

Land acquisition agreements between Trans Mountain and landowners will provide Trans Mountain an interest in the required lands. Landowners will receive a payment at the time of entering into a land acquisition agreement. Once the agreement is executed, the agreement is to be registered with land titles to protect Trans Mountain's interest in the event of a sale or transfer of land title. The terms of the agreements are concluded with the full payment of the remaining amounts by a set date or within a set timeframe after the issuance of approval to construct in the area the land is located.

In calculating the full consideration offered to landowners as an inducement to agree to grant Trans Mountain the required easement and working space, the following approach is used:

- For re-entry and reuse of existing easement, where the pipeline can be constructed wholly within the existing easement, a re-entry fee will be paid for each hectare of land within the existing easement (*i.e.*, an impacted width up to 18.3 m by the length of the pipeline within the land parcel).
- For new easement, where some or all of the easement needs to be located on previously unencumbered lands, the easement value will be based upon an

examination of historic PODs for right-of-way prices in areas that the pipeline right-of-way traverses in Alberta and the assessment value plus consideration to uplift in BC. The difference in approach reflects patterns of use in both Alberta and BC. At most, the new easement area on any one parcel will be a maximum of 18.3 m wide by the length of the pipeline within the land parcel. This new easement area will be reduced to the extent practical, where portions of the existing easement can be re-used.

- Working space will be calculated as a percentage of the fee value of the affected lands used for construction and be based upon a three-year term to allow construction and restoration to be completed. For the purposes of compensation, lands required for working space will not include easement, and the payment for easement will provide full compensation for temporary construction use as well as permanent easement rights.
- Compensation for damages will be based upon actual damages, determined following construction and will be paid upon completion of restoration as part of the landowner sign-off process.
- Inconvenience payments will be paid to owners who have demonstrated an inconvenience.

5.4.2 Surface Rights Process

Acquisition of surface rights will comply with the provisions and regulations of the NEB, including Section 87 of the *NEB Act*. Disagreements over compensation payments, if not settled through negotiation, will be resolved according to the negotiation or arbitration procedures set out in the *NEB Act*. In addition, the surface rights acquisition agreements with Trans Mountain will adhere to Section 86(2) of the *NEB Act*.

5.4.3 Timing and Status

Communications with landowners and tenants began in April 2012. First efforts focussed on landowners along the existing TMPL and were later expanded to include other landowners and tenants within the 150 m wide study corridor. The communications provided notification of the Project and information of related NEB regulations. Trans Mountain collected landowner comments and concerns, and acquired landowner consent to enter their lands for subsequent engineering and environmental study.

At this time, the Land Acquisition process has not commenced. Engineering design and construction planning will be completed to determine the specific land parcels affected. The Land Acquisition Process is planned to begin in the middle of 2014.

5.4.4 Section 87 Notice

Notices will be served according to Section 87(1) of the *NEB Act*, describing the lands required, compensation offered and other details pursuant to the *NEB Act*. Along with this notice, landowners will receive a copy of the NEB's Pipeline Regulation in Canada: A Guide for Landowners and the Public.

5.4.4.1 Status

To date, no notices pursuant to Section 87(1) of the *NEB Act* have been served.

5.4.4.2 S.87 (1) Notice Sample Copy

Sample copies of the notice proposed to be served on all owners of land pursuant to Section 87(1) of the *NEB Act* are attached within Appendix D.

The form of Section 87(1) notice varies between provinces. They also vary to reflect minor differences between Crown and private lands. The notices for private lands include greater explanation of the detailed route hearing and arbitration process.

5.4.5 Section 34 Notice

Once the CPCN has been issued by the NEB, Trans Mountain will prepare and submit to the NEB a Plan, Profile and Book of Reference of the pipeline of which certified copies, when approved by the NEB, will be deposited in the appropriate land titles/registry office. In addition, all landowners will be personally served with a notice pursuant to Section 34(1) of the *NEB Act*.

5.5 Land Acquisition Agreements

5.5.1 Surface Rights Acquisition Agreements

5.5.1.1 List of Notice and Agreements

Samples of the following surface rights acquisition notices and use agreements are provided as appendices:

- Notices Pursuant to Section 87(1) of the *National Energy Board Act* for BC and Alberta (Appendix D);
- Agreement for Easement, Province of Alberta (Appendix E);
- *Land Title Act* Form C and Statutory Right of Way Agreement, Province of British Columbia (Appendix F);
- Agreement for Temporary Working Space, Province of Alberta (Appendix G);
- Agreement for Temporary Working Space, Province of British Columbia (Appendix H); and
- Option to Purchase Agreements for BC and Alberta (Appendix I).

5.5.2 Other Sample Agreements

Damage release has not been included but will be used after construction is completed.

6.0 REFERENCES

6.1 Literature Cited

National Energy Board. 2013a. Filing Manual. Release 2013-03. ISBN: 0-662-36977-7. The Publication Office, National Energy Board, Calgary, AB. 236 pp.

National Energy Board. 2013b. Operations and Maintenance Activities on Pipelines Regulated under the *National Energy Board Act*. Requirements and Guidance Notes. Calgary, AB.

7.0 APPENDICES

Appendix A Direct Written Evidence of Steven J. Kelly, IHS Global Canada Limited

**Trans Mountain Expansion Project
Direct Written Evidence of
Steven J. Kelly**

Prepared For:

Trans Mountain Pipeline (ULC)

November 30, 2013

Submitted by:

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Suite 200, 1331 Macleod Trail S.E.
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ABBREVIATIONS AND ACRONYMS

ANS	Alaskan North Slope
B/D	Barrels per Day
C5+	Pentanes Plus
CAPP	Canadian Association of Petroleum Producers
CEAA	Canadian Environmental Assessment Agency
CLB	Cold Lake Blend
DilBit	Bitumen Blend, diluted with C5+
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
ERCB	Alberta Energy Resources Conservation Board
FCC	Fluid Catalytic Cracking
GHG	Greenhouse Gas
JRP	Joint Review Panel
KXL	Keystone XL Pipeline
LLS	Light Louisiana Sweet
NEB	National Energy Board
PADD	Petroleum Administration for Defense District
PGI	Purvin & Gertz, Inc.
RFO	Residual Fuel Oil
SCO	Synthetic Crude Oil
TMEP	Trans Mountain Expansion Project
VGO	Vacuum Gas Oil
WCS	Western Canadian Select
WTI	West Texas Intermediate



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1 INTRODUCTION

2 Q.1. Please state your full name, position and business address.

3 A.1. My name is Steven J. Kelly. I am a Vice President at IHS Global Canada Limited ("IHS").
4 I direct the Downstream Energy Consulting operations at the IHS office in Calgary,
5 Alberta. Prior to IHS, I was Senior Vice President and Director at Purvin & Gertz Inc.
6 ("Purvin & Gertz" or "PGI"). IHS acquired PGI in November 2011. My business address is
7 Suite 200, 1331 Macleod Trail S.E., Calgary, Alberta, T2G 0K3.

8 Q.2. Please describe your educational and professional background.

9 A.2. I graduated with a Bachelor of Engineering degree in Chemical Engineering from
10 McMaster University in Hamilton, Ontario in 1982. I obtained a Master of Engineering
11 degree in Chemical Engineering from McMaster University, with specialization in process
12 computer control in 1985, and a Master of Business Administration degree from the
13 University of Calgary in 1998. I worked as a process engineer at the Sarnia and Scotford
14 refineries of Shell Canada, and in a variety of operations and strategic planning roles at
15 Shell Canada's Calgary head office. In 1996, I joined PGI's Calgary office as an
16 Associate Consultant. I have worked at PGI (and IHS since November 2011) for a total of
17 17 years, including a four-year posting in the Purvin & Gertz office in London, UK. Much
18 of my work at PGI/IHS has involved market studies for conventional crude oil, oil sands
19 and refined products in North America and Europe. I have prepared and provided expert
20 testimony on pipeline matters in Canada before the National Energy Board ("NEB"). I am
21 a Professional Engineer, registered in Alberta.

22 Q.3. Please describe IHS and its Energy Insight consulting operations.

23 A.3. IHS is a global information company that provides comprehensive content, insight and
24 expertise to business and government clients around the world. IHS has been providing
25 information, independent analysis and insight to its customers for more than 50 years.
26 IHS has been in business since 1959 and became a publicly traded company on the
27 New York Stock Exchange in 2005. The company is headquartered in Englewood,
28 Colorado, USA. As of September 2013 the company employs over 8,000 people
29 worldwide. IHS Energy Insights Consulting offers industry and business advisory
30 expertise across the upstream, midstream, downstream, and chemicals segments of the
31 energy value chain.

32 Q.4. What is the purpose of your evidence in this proceeding?

33 A.4. Trans Mountain Pipeline ULC ("Trans Mountain") has proposed an expansion of its
34 existing oil pipeline ("TMEP" or "the Project"). The proposed expansion would increase
35 capacity of the current pipeline from 300,000 barrels per day ("B/D") to 890,000 B/D. As



1 part of this application to the NEB (“the Application”), Trans Mountain engaged IHS to
2 address various supply and market issues related to the Project. Specifically, IHS was
3 asked to address the following questions:

- 4 1. If the TMEP is constructed as planned, is it reasonable to expect that the facilities
5 will be highly utilized?
- 6 2. If the TMEP is built as planned, is it reasonable to expect that it will produce a benefit
7 for Canadian producers in the form of higher netback prices for their crude oil
8 production? What is the expected aggregate amount of economic gain to producers
9 from the Project’s development?
- 10 3. Would the TMEP provide access to new markets, and is access to these new
11 markets a benefit to producers?

12 **SUMMARY OF CONCLUSIONS**

13 **Q.5. Please summarize your conclusions.**

14 A.5. IHS’ major conclusions from this analysis are summarized below:

- 15 · If the TMEP project is constructed as proposed, IHS believes that the facilities will be
16 utilized at a high rate. IHS forecasts continued growth in Western Canadian crude oil
17 production over the forecast period to 2037. Marketed crude supply growth in Western
18 Canada is likely to be mainly heavy crude grades. Based on our analysis of the potential
19 markets for Western Canadian crudes in the Asia/Pacific region, and the outlook for
20 crude balances, the crude shipped by TMEP may include both light and heavy grades.
- 21 · IHS concludes that as one of several major export pipeline projects, the TMEP would
22 provide benefits for Western Canadian crude producers. The annual revenue benefits
23 from new pipeline development are estimated at about \$6 billion (constant 2012 US) in
24 2018, increasing with production to about \$11 billion (constant 2012 US) by 2030 in the
25 Base Case. Total estimated benefits attributable to TMEP are \$37 billion through the
26 forecast period.¹ These benefits would be realized through higher netback prices for
27 heavy crude oil production, associated with the avoidance of discounted crude prices in
28 the future when supplies exceed takeaway pipeline capacity.
- 29 · In addition to the above general benefits, TMEP would provide structural access to new
30 markets in the Asia/Pacific region. IHS has addressed the potential for market
31 development in California and selected countries in Asia, based on existing refinery
32 capabilities, expected future crude demand and the need for imported crudes. Producers

¹ Benefits attributable to TMEP equate to 26.6 percent of the total estimated benefits for export pipeline capacity expansions.



1 with capacity on TMEP would have the opportunity to realize higher netback prices on
2 production that is priced in the Asia/Pacific region rather than the U.S. Gulf Coast region.
3 As compared to exports to the U.S. Gulf Coast, exports to California are expected to
4 provide a \$3 to \$4 per barrel (constant 2012 US) netback premium to Canadian
5 producers, and exports to Asia/Pacific markets are expected to provide a \$2 per barrel
6 netback premium. These benefits would apply from 2018 through the end of the forecast
7 period. The benefits associated with higher netbacks from markets in Asia are estimated
8 at \$8 billion over the forecast period.² Total benefits attributable to TMEP are \$45 billion,
9 including both general industry benefits and higher netback prices on deliveries to Asia.

10 · The benefits calculated for export pipeline capacity expansion are considered
11 conservative, because no allowance has been made for the possibility of extraordinary
12 discounts on Canadian crude re-emerging in the future. The calculated benefits are also
13 considered conservative because the optionality benefits provided by the TMEP were not
14 quantified and included in the analysis.

15 · The Project would provide optionality benefits and market diversity for its shippers, in a
16 market characterized by substantial uncertainty. As demonstrated by the experience in
17 Canada from 2010 to present, logistical constraints in reaching the highest-value export
18 markets can cost the industry tens of billions of dollars per year.³ Furthermore, there is
19 no certainty regarding what the highest value market will be over the forecast period, so
20 ensuring that multiple markets are accessible offers significant value to producers.

21 **SUMMARY OF SUPPORTING ANALYSIS**

22 · IHS forecasts continued growth in Western Canadian crude oil production, with total
23 crude production growing at a 3.0 percent compound annual average growth from 2013
24 to 2037. This growth trend results in 3.43 million B/D of incremental production over the
25 same period. The Base Case forecast has been compared to the most recent production
26 forecasts of the Canadian Association of Petroleum Producers (“CAPP”), the NEB and
27 the Alberta Energy Resources Conservation Board (“ERCB”), and has been found to be
28 generally consistent with them, although below the CAPP forecast for the years after
29 2020. IHS forecasts marketed heavy crude supply (which accounts for upgrading and
30 diluent addition) to increase by 4.30 million B/D between 2013 and 2037.

² These benefits would be realized on volumes shipped to Asia and priced against Middle East crude imported into the region. The benefits for TMEP shippers are based on half of the TMEP firm commitments (equal to 707,500 B/D ÷ 2 = 353,750 B/D) being priced in China rather than in the U.S. Gulf Coast for the period 2018 to 2037.

³ IHS estimates that Western Canadian producers would have received between \$15-19 billion in incremental revenue in 2012, had they been able to bring their crude oil to other markets.

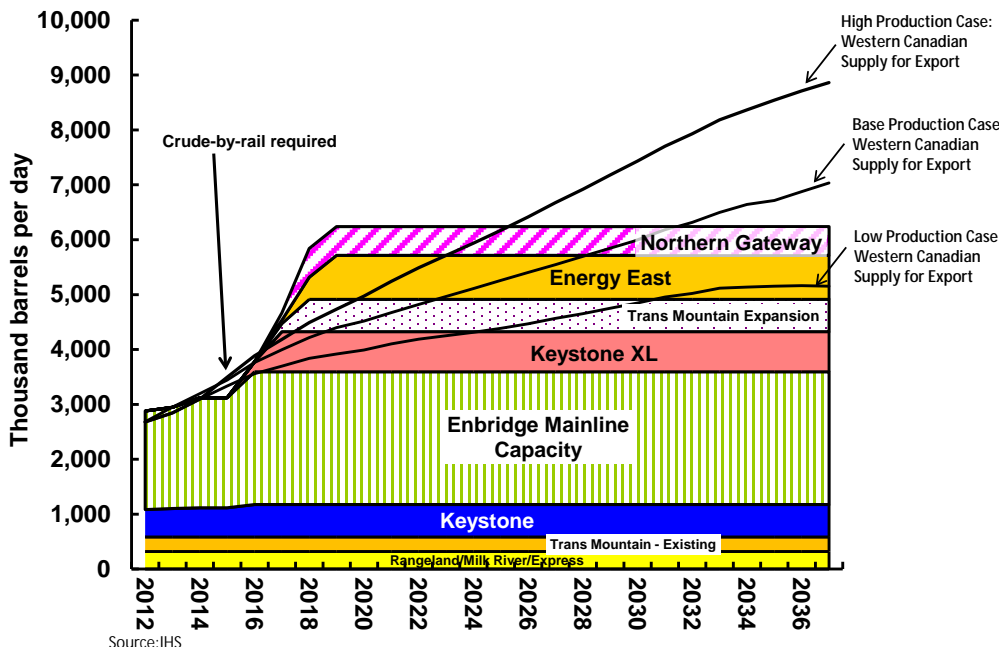


- 1 · Western Canadian crude currently serves markets in Canada, the U.S., and offshore
2 locations. IHS forecasts that total crude demand by U.S. refineries will remain relatively
3 stagnant through the end of the decade, and that their demand will decline thereafter.
4 Canadian crude will account for a growing share of U.S. crude consumption. Other
5 markets may be served via the Canadian West Coast and the Canadian East Coast.
6 Refineries in Canada, the U.S. and Asia are potential disposition outlets for Western
7 Canadian crude and U.S. northern tier crude. The increasing need for imported crude of
8 all types in Asia is the basis for interest by Asian companies in Canadian oil sands
9 crudes.
- 10 · To assess the aggregate need for and benefits of incremental pipeline capacity, IHS
11 analyzed and compared two scenarios. The “Expansion Scenario” is premised on all
12 planned pipeline projects⁴ coming on line in the time period to 2018, as proposed by the
13 project sponsors. For comparison, the “Reference Scenario” assumes that only projects
14 currently in construction and the Keystone XL Pipeline are developed.
- 15 · Figure 1 compares the Base Case forecast of crude supply for export in Western Canada
16 with the future outlook for pipeline takeaway capacity in the Expansion Scenario, over
17 the 2013 to 2037 period. For the presentation in Figure 1, all pipeline projects are
18 assumed to be available at their nameplate capacity. IHS estimates that all of the
19 expansion capacity is needed to meet projected crude production after 2026. Before this
20 expansion capacity comes on line, rail shipments will also be required to meet the
21 shortfall in pipeline capacity. Rail shipments are forecast to peak in 2015. By 2030, rail
22 shipments would again begin to be required to accommodate growth in crude production.

⁴ The projects include those currently under construction, as well as TransCanada Pipeline's Keystone XL Pipeline (“KXL”) in 2016, the Trans Mountain Expansion Project in 2017, TransCanada Pipeline's Energy East project (“Energy East”) in 2017 and Enbridge's Northern Gateway project in 2018.



Figure 1 - Western Canadian Supply for Pipeline Export vs. Pipeline Capacity



- 1 • The Expansion Scenario indicates that rail deliveries will be required until 2016, at which
- 2 time Enbridge expansions and Keystone XL absorb the growth in marketable crude
- 3 supply. TMEP, Energy East and Northern Gateway are assumed to come on in 2017 and
- 4 2018, and thereby reduce the need for rail. Term commitments on new pipeline projects
- 5 suggest that the crude available for spot deliveries to markets in the U.S. Midwest and
- 6 rail will be in short supply for several years, between about 2018 and 2022.

- 7 • Figure 1 also compares Western Canada takeaway capacity with crude supply in two
- 8 alternative production cases. In the Expansion Scenario with slower bitumen production
- 9 growth (a case we have defined as the Low Production case), IHS estimates that
- 10 pipeline capacity additions will be adequate to keep up with crude supply growth for the
- 11 forecast period. In the Expansion Scenario with increased bitumen and tight oil
- 12 production growth (defined as the High Production case), IHS estimates that pipeline
- 13 capacity additions will fall short of crude supply growth before 2025.

- 14 • Takeaway capacity in the Reference Scenario (not shown in Figure 1) includes only
- 15 pipeline projects currently under construction and development of the Keystone XL
- 16 pipeline in 2016. In this scenario, takeaway capacity would be inadequate to clear the
- 17 supply of heavy crude by pipeline throughout the forecast period.

- 18 • IHS believes that development of export pipelines would contribute to a reduction in the
- 19 use of rail transportation for Western Canadian crude oil. Pipeline capacity additions
- 20 over the next several years are expected to reduce the dependence on rail transportation
- 21 for light and heavy crude oil, until such time as crude production once again exceeds
- 22 pipeline takeaway capacity. The use of pipeline capacity instead of rail transportation is



1 conservatively estimated to provide an increase in producer netbacks of \$5-6 per barrel
2 (constant 2012 US) during the forecast period.

3 **Q.6. Please summarize the analysis you conducted in order to answer the questions**
4 **indicated above.**

5 **A.6. Supply/Infrastructure Development**

6 IHS developed the Expansion Scenario and the Reference Scenario for infrastructure
7 development, as described above. In addition to the Base Case supply outlook, IHS
8 developed alternative production and supply cases to analyze how different production
9 growth rates for bitumen and light crude might affect the results. These cases are
10 referred to as the “Low Production” and “High Production” cases. The Low Production
11 case includes a premise of lower bitumen production and supply, while the High
12 Production case includes a premise of higher bitumen production and supply, and higher
13 U.S. tight oil production. The Low Production and High Production cases have been
14 examined under the premises of the Reference Scenario and Expansion Scenario for
15 infrastructure development.

16 **Crude Prices and Producer Netbacks**

17 IHS applied its standard methodologies to the analysis of Canadian crude prices under
18 the different production and infrastructure development cases defined above. Canadian
19 crude prices are established in the markets they serve, based on refining value
20 differentials to appropriate competing crude oils. Netback prices are set by the market
21 price, less applicable transportation costs from the point of production. The clearing
22 market sets the price for the marginal barrel. In our methodology, Dated Brent is
23 indicative of world crude prices, and is used as the basis for other regional crude price
24 forecasts. For this analysis, IHS developed price forecasts for oil sands crudes (Cold
25 Lake bitumen blend and Syncrude SSP), which are based on competition with competing
26 crudes in Midwest, West Coast and Asia/Pacific markets. Refineries on the West Coast
27 and in Asian markets would gain increased access to Canadian crudes if TMEP is
28 constructed as proposed.

29 **Industry Benefits**

30 IHS estimated industry benefits associated with higher price realizations for Canadian
31 heavy crudes by comparing producer revenue (on a per barrel basis) from pipeline and
32 rail transportation. In general, the netback price for Canadian heavy crude blends would
33 be higher if the netback price is established by pipeline rather than rail transportation,
34 since the cost to move crude oil by rail is typically higher than the cost to move crude oil
35 by pipeline. IHS estimated total revenue benefits by multiplying the unit revenue increase
36 by the total volume of Western Canadian heavy crude supply. Following the startup of
37 the export pipelines in the Expansion Scenario, increased revenues should be expected
38 to continue until Canadian supply once again exceeds pipeline takeaway capacity, and
39 the netback reverts to a rail transportation basis. In the Reference Scenario, producer



1 revenue would be reduced by the amount of the difference between pipeline and rail
2 transportation for the period of time that rail is used as the market clearing mechanism.

3 **Q.7. Which sources did IHS rely on for preparation of its evidence?**

4 A.7. In preparing its evidence, IHS reviewed Application material provided by Trans Mountain.
5 Regulatory filings considered to be relevant to this proceeding were also reviewed.
6 Public information and IHS' own proprietary models and databases were utilized in
7 preparation of the IHS analysis. IHS reviewed other available publicly available
8 information and forecasts pertaining to Canadian oil production and demand, as
9 prepared by industry associations, regulators, public companies and other organizations.

10 **DEVELOPMENT OF THE IHS ANALYSIS**

11 **Q.8. Please explain the Base Case supply/demand outlook in more detail.**

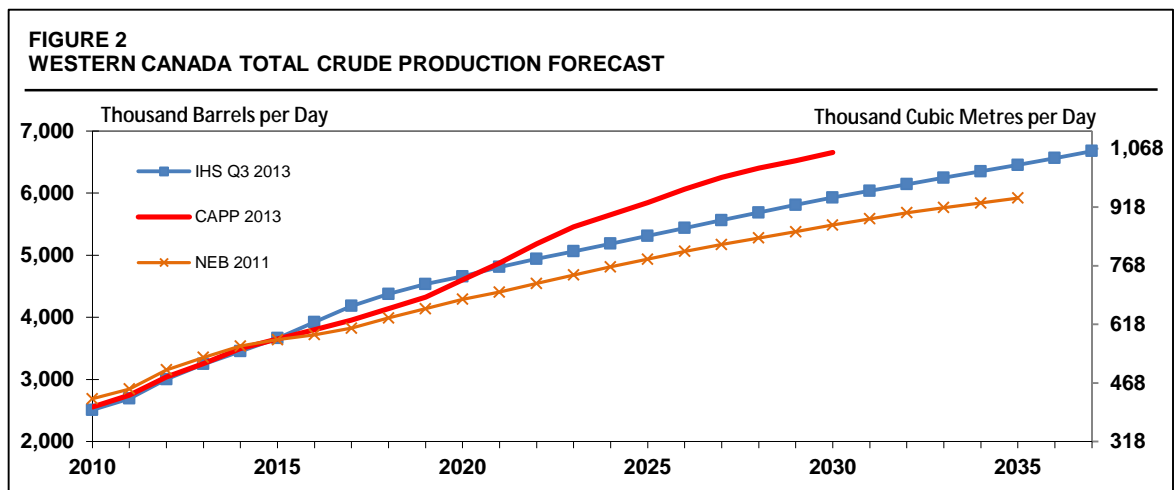
12 A.8. The Base Case supply outlook takes into account the following key premises:

- 13 . IHS crude price and light/heavy differential forecasts
14 . IHS North American regional crude production forecasts (Q3 2013)
15 . IHS outlook for crude market demand (type and volume) and interregional trade
16 . Rail infrastructure development for crude export is based on existing in-service
17 capacity and proposed expansions

18 The Base Case production outlook is summarized in Figure 2.⁵ IHS forecasts that growth
19 in oil sands crude production will offset a decline for conventional crude. Between 2013
20 and 2037, the Base Case forecast for Western Canada crude production calls for an
21 increase of 3.43 million B/D. Heavy crude production, including bitumen, accounts for the
22 majority of this increase. Bitumen production growth is forecast to average 118,000 B/D
23 per year between 2013 and 2037. Figure 2 also presents the most recent forecasts
24 developed by CAPP and the NEB, for comparison to the Base Case.

⁵ Refer to Appendix A, which supplements this presentation by including more details of the IHS analysis.





1 The Base Case disposition forecast is predicated on total crude demand by U.S.
 2 refineries remaining relatively stagnant through the end of the decade, at between 15.5
 3 and 16 million B/D. Demand by U.S. refineries is forecast to decline thereafter. Despite
 4 the lack of demand growth in U.S. refining markets, Canadian crude exports to the U.S.
 5 are expected to approximately double from 2013 to 2035, representing growth of more
 6 than 2.5 million B/D. As shown in Table 1, Canadian crude exports will account for a
 7 growing share of U.S. crude consumption, and will contribute to a dramatic drop in
 8 imports from other countries. This will occur despite an increase in U.S. crude production
 9 which is forecast to continue through the early part of the next decade, due to
 10 technological advances that have unlocked the potential of certain shale oil resources.

TABLE 1
TOTAL U.S. CRUDE OIL SUPPLY / DEMAND
 (Thousand Barrels per Day)

	2012	2013	2014	2015	2020	2025	2030	2035
Total Runs	15,020	15,264	15,548	15,715	15,860	15,338	14,956	14,574
Total Capacity	17,776	17,689	17,714	17,743	17,743	17,743	17,743	17,743
% Capacity Utilization	84	86	88	89	89	86	84	82
Production	6,521	7,336	7,549	7,768	8,359	8,079	7,593	7,513
Canadian Imports	2,279	2,522	2,690	2,909	3,571	4,270	4,550	5,092
Other Imports	6,133	5,522	5,457	5,263	4,221	3,336	3,109	2,248
Total Imports	8,412	8,043	8,147	8,172	7,793	7,606	7,658	7,340
Total Supply	14,879	15,264	15,548	15,715	15,840	15,338	14,956	14,574

11 **Q.9. Please explain the Low Production and High Production case outlooks in more**
 12 **detail.**

13 A.9. The Base Case supply of bitumen and conventional light crude is adjusted in the Low
 14 Production case and the High Production case. The Low Production case assumes lower
 15 Alberta bitumen production growth relative to the Base Case, by 55,000 B/D per year on



1 a cumulative basis between 2015 and 2037. The growth rate in bitumen production
2 incorporated into the Low Production case forecast is half of the average annual growth
3 rate incorporated into the Base Case forecast. The High Production case assumes
4 higher Alberta bitumen production growth relative to the Base Case, by the same amount
5 (55,000 B/D per year on a cumulative basis) over the forecast period. The High
6 Production case also includes a premise of higher production of U.S. light crude over the
7 forecast period. Over the forecast period from 2015 to 2037, the cumulative changes in
8 bitumen production amount to a 1.265 million B/D decrease in the Low Production case,
9 and a 1.265 million B/D increase in the High Production case. In each case, imported
10 condensate for bitumen blending is assumed to be available from local production,
11 diluent import pipelines and supplementary rail deliveries.

12 **Low Production case outlook**

- 13 · Lower bitumen production forecast versus the Base Case, which may be the
14 result of wider light/heavy price differentials, higher project costs or other factors
15 affecting bitumen production
- 16 · Base Case forecast of tight oil production
- 17 · Base Case outlook for crude market demand (type and volume) and interregional
18 trade to balance

19 **High Production case outlook**

- 20 · Higher bitumen production forecast versus the Base Case, which may be the
21 result of narrower light/heavy price differentials, lower project costs or other
22 factors affecting bitumen production
- 23 · Higher forecast of tight oil production
- 24 · Base Case outlook for crude market demand (type and volume) and interregional
25 trade to balance



**TABLE 2
POTENTIAL INDUSTRY BENEFITS OF EXPORT PIPELINE CAPACITY**

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Base Case																				
Heavy Crude Supply, MB/D	3,193	3,372	3,485	3,665	3,833	3,995	4,159	4,323	4,488	4,656	4,820	4,986	5,153	5,316	5,479	5,644	5,812	5,985	6,140	6,306
Pipeline vs. Rail Netback ⁽¹⁾																				
Per Barrel Benefit (2012 \$/B)	5.00	5.08	5.14	5.20	5.25	5.30	5.36	5.40	5.44	5.49	5.54	5.59	5.64	5.69	5.73	5.78	-	-	-	-
Total Benefit (2012 Billion \$)	5.8	6.2	6.5	7.0	7.3	7.7	8.1	8.5	8.9	9.3	9.8	10.2	10.6	11.0	11.5	11.9	-	-	-	-
TIMEP Heavy Crude to Asia, MB/D ⁽²⁾	213	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354
Asia vs. US Gulf Coast Netback																				
Per Barrel Benefit (2012 \$/B)	1.76	2.19	2.49	2.49	2.32	2.21	2.12	1.99	1.98	1.97	1.95	1.94	1.82	1.81	1.80	1.80	7.61	7.65	7.68	7.72
Total Benefit (2012 Billion \$)	0.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	1.0	1.0	1.0	1.0
Low Production Case																				
Heavy Crude Supply, MB/D	2,867	2,964	2,995	3,124	3,226	3,307	3,390	3,475	3,559	3,646	3,730	3,816	3,903	3,987	4,070	4,155	4,242	4,328	4,413	4,499
Pipeline vs. Rail Netback ⁽¹⁾																				
Per Barrel Benefit (2012 \$/B)	-	-	5.14	5.20	5.25	5.30	5.36	5.40	5.44	5.49	5.54	5.59	5.64	5.69	5.73	5.78	5.82	5.86	5.90	5.95
Total Benefit (2012 Billion \$)	-	-	5.6	5.9	6.2	6.4	6.6	6.8	7.1	7.3	7.5	7.8	8.0	8.3	8.5	8.8	9.0	9.3	9.5	9.8
TIMEP Heavy Crude to Asia, MB/D ⁽²⁾	188	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354
Asia vs. US Gulf Coast Netback																				
Per Barrel Benefit (2012 \$/B)	1.76	2.19	2.49	2.49	2.32	2.21	2.12	1.99	1.98	1.97	1.95	1.94	1.82	1.81	1.80	1.80	1.79	1.78	1.78	1.77
Total Benefit (2012 Billion \$)	0.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
High Production Case																				
Heavy Crude Supply, MB/D	3,519	3,780	3,975	4,264	4,528	4,770	5,015	5,260	5,505	5,753	5,997	6,243	6,489	6,733	6,976	7,221	7,469	7,716	7,961	8,207
Pipeline vs. Rail Netback ⁽¹⁾																				
Per Barrel Benefit (2012 \$/B)	5.00	5.08	5.14	5.20	5.25	5.30	5.36	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Benefit (2012 Billion \$)	6.4	7.0	7.5	8.1	8.7	9.2	9.8	-	-	-	-	-	-	-	-	-	-	-	-	-
TIMEP Heavy Crude to Asia, MB/D ⁽²⁾	238	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354
Asia vs. US Gulf Coast Netback																				
Per Barrel Benefit (2012 \$/B)	1.76	2.19	2.49	2.49	2.32	2.21	2.12	7.39	7.42	7.46	7.49	7.53	7.46	7.50	7.54	7.57	7.61	7.65	7.68	7.72
Total Benefit (2012 Billion \$)	0.2	0.3	0.3	0.3	0.3	0.3	0.3	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Note: (1) Rail netback price assumes DIBIT transportation from Edmonton to US Gulf Coast. Excludes rail car lease costs.

(2) Benefit accrues to shippers with capacity on West Coast pipeline projects. Benefits shown assume 50% of TIMEP firm capacity are deliveries to China.



NETBACK PRICING AND BENEFITS ANALYSIS

1 **Q.10. What impact is the expansion of pipeline capacity expected to have on heavy**
2 **crude netback prices in Western Canada, and what are the aggregate benefits?**

3 A.10. TMEP, as one of the pipeline capacity expansion projects included in the Expansion
4 Scenario, is expected to contribute to significantly higher heavy crude netback prices for
5 Canadian oil producers. As shown in Table 2, below, netback prices for heavy crude are
6 estimated to be \$5 to \$6 per barrel (constant 2012 U.S.) higher as a general
7 consequence of the development of new pipeline capacity. The netback price benefit is
8 attributed to the lower cost of pipeline transportation for heavy crude to the assumed
9 clearing market location (the U.S. Gulf Coast), compared to the cost of rail
10 transportation.⁶ This is considered a conservative estimate, in part because the rail
11 transportation cost estimate excludes rail car lease costs.

12 Table 2 summarizes the producer revenue benefits for the three supply cases developed
13 for this analysis. The annual revenue benefits from pipeline development in the
14 Expansion Scenario are about \$6 billion (constant 2012 US) in 2018, increasing with
15 production to about \$11 billion (constant 2012 US) by 2030 in the Base Case. The
16 benefits for heavy crude producers would be expected to continue until such time that
17 the balance indicates a need for additional pipeline capacity for Western Canadian
18 crude. This would occur late in the forecast period.

19 Annual benefits for the Expansion Scenario would be of a smaller magnitude in the Low
20 Production case, and would be expected to start later due to lower bitumen production
21 growth. Annual benefits would be higher in the High Production case, and would
22 commence sooner compared to the Base Case. Pipeline capacity expansions would be
23 full in the High Production case before 2025.

24 In aggregate, higher netback prices for heavy crude equate to about \$140 billion U.S. of
25 producer benefits in the Base Case (on a constant 2012 US, undiscounted basis) over
26 the 2017 to 2037 time period. In the Low Production case, the aggregate benefits are
27 estimated at about \$138 billion U.S. over the same time period. In the High Production
28 case, aggregate benefits are estimated to be less, at around \$57 billion U.S. because the
29 pipeline projects reach capacity sooner, reducing prices to a rail-equivalent netback from
30 the U.S. Gulf Coast. However, the estimated benefit in the High Production case is
31 considered very conservative, because it excludes any extraordinary discounts on
32 Canadian heavy crude which may result when pipelines and rail export facilities reach
33 capacity. As noted above, the annual revenue loss in 2012 estimated by IHS (equal to

⁶ The analysis shown is based on rail delivery of DilBit, which may or may not be the form that bitumen is shipped by rail. Other blends of bitumen are possible, including blends with lesser amounts of diluent or no diluent at all.



1 \$15-19 billion) provides an indication of the potential impact of having inadequate
2 pipeline and rail capacity.

3 **Q.11. What is the estimated benefit attributable to TMEP?**

4 A.11. As described above, IHS completed the analysis by assuming that TMEP, Energy East
5 and Northern Gateway all achieve commercial operation in the 2017-2018 timeframe,
6 consistent with announced development plans. Therefore, IHS concludes that TMEP, as
7 part of an aggregate expansion of capacity, contributes to these higher netback prices.
8 TMEP represents 26.6 percent of the assumed capacity additions,⁷ and it is assumed to
9 produce at least the same percentage of the aggregate benefits.

10 In addition, the analysis also indicates that TMEP represents a path to higher netback
11 markets, and can be expected to produce an above-average level of netback benefits.
12 Further, if one or more of the other new pipeline projects were assumed to not go
13 forward, the benefits derived from TMEP (expressed per unit of capacity) would
14 increase. This is because the initial level of underutilized capacity would decrease.
15 Therefore, the apportioned benefits for TMEP are considered to represent a conservative
16 estimate of the likely standalone benefits of the Project. Further, the calculated benefits
17 are also considered conservative because the optionality benefits provided by the TMEP
18 were not quantified and included in the analysis.

19 Benefits attributed to the TMEP are estimated as follows, based on the overall benefits
20 for pipeline capacity expansion and the TMEP share of capacity. In the Base Case,
21 TMEP would be attributed \$37.4 billion US of the total industry benefits over the 2018 to
22 2037 time period. In addition, TMEP would produce benefits of about \$8 billion U.S. due
23 to the realization of higher netback prices for crude priced in Asia rather than the U.S.
24 Gulf Coast. Total benefits attributable to TMEP are therefore about \$45 billion U.S. over
25 the forecast period.

26 **Q.12. What causes this increase in netbacks for oil sands producers?**

27 A.12. The price of Canadian heavy crude has been discounted below price parity against
28 comparable crudes (such as Mexican Maya at the U.S. Gulf Coast) for much of the last
29 decade. This has been the case, even though these crudes are similar in quality and
30 have nearly equivalent values in coking refineries. The price discount suggests that the
31 supply of Canadian heavy crudes has exceeded demand in their main markets north of
32 the U.S. Gulf Coast, which has led producers to seek access to other markets. For
33 example, the TMEP targets large markets in the Asia/Pacific region, to expand the
34 market for Canadian heavy crudes.

⁷ TMEP capacity is 590,000 B/D, Energy East capacity is 1.1 million B/D, and Northern Gateway capacity is 525,000 B/D.



1 The IHS price forecast is premised on Canadian heavy crude being priced to clear the
2 market at the U.S. Gulf Coast beginning in 2016. The increase in the netback price (after
3 elimination of extraordinary discounts) is consistent with Canadian heavy crude reaching
4 U.S. Gulf Coast parity against Maya crude. IHS expects this pricing to be realized
5 because new pipeline capacity will provide structural access to this large refining market.
6 Other pipeline projects to North American markets, such as the Enbridge Line 9 project
7 and the Enbridge Gulf Coast Access project, to the extent they ship heavy crude, should
8 allow the price of Canadian heavy crude to avoid extraordinary discounts in future.

9 TMEP is one of several projects that target delivery of a large volume of Canadian crude
10 to new markets. The expansion of pipeline capacity is expected to strengthen the price of
11 Canadian heavy crude in Alberta. By providing diversification and new market access for
12 Canadian heavy crudes, infrastructure developments such as those considered in the
13 Expansion Scenario should ensure that extraordinary discounts are avoided in future.

14 **Q.13. Please discuss the sensitivity of the estimated aggregate benefits associated with**
15 **pipeline expansions?**

16 A.13. The benefits associated with expansion of export pipeline capacity may be categorized
17 as follows:

- 18 · Improved netback for pipeline versus rail delivery
- 19 · Higher netback realized from offshore crude pricing

20 The first of these benefits arises from the avoidance of a price discount when supplies of
21 heavy crude exceed the takeaway capacity on available pipelines. We have
22 conservatively modelled this situation using a rail delivery netback for Western Canadian
23 heavy crude, which would result in a lower netback price in Alberta compared to a
24 pipeline netback. As shown in Table 2, this situation arises in the Base Case after 2033,
25 due to increased supply of heavy crude.

26 The second source of benefits would accrue to shippers on a pipeline that provides
27 capacity to markets with higher potential netbacks. For example, TMEP would provide
28 access to large and growing markets in California or Asian countries. The netback price
29 for crude valuation in California or China (based on expected Middle East refining parity
30 relationships) is estimated to be higher than the U.S. Gulf Coast price for the duration of
31 the forecast. The higher netback price would be realized by TMEP shippers, who could
32 expect to achieve the regional parity price. Similar benefits may be available to shippers
33 on other export pipelines.

34 A shift in the clearing market location from U.S. Gulf Coast to a higher valued market
35 may occur with the startup of TMEP and other pipeline projects. However, we view this
36 as an unlikely outcome. We believe that (for example) a Midwest refiner seeking supply
37 of heavy crude after startup of the major export pipeline projects may be required to bid
38 supplies away from committed shippers on such pipeline projects. The diversion of
39 heavy crude from the large U.S. Gulf Coast market - potentially the most likely source of



1 supply for the Midwest refiner - would require the Gulf Coast refiner to, in turn, secure
2 supply from other sources. TMEP and other projects, which would allow Canadian crude
3 to reach new market regions, would also create the possibility for Gulf Coast refiners to
4 attract crudes away from current suppliers to those same regions. The net result would
5 be a more efficient trade balance for heavy crude, but not a fundamental shift in the
6 pricing mechanism.

7 Higher crude prices resulting from export pipeline expansion would increase revenues
8 for Canadian heavy crude producers. Heavy crude producers would be expected to
9 realize an increase in the heavy crude price of between \$5-6 per barrel by realizing a
10 pipeline netback price rather than a rail netback price, as discussed above and shown in
11 Table 2. Although the price comparison is specifically for Cold Lake Blend versus Maya,
12 the same level of discounting is assumed to be applicable to other Canadian heavy
13 crudes including other DilBit streams, conventional heavy crudes and blends such as
14 Western Canadian Select ("WCS"), since prices for Canadian heavy crudes track each
15 other more than the Maya price.

16 The benefits calculated for export pipeline capacity expansion are considered
17 conservative for several reasons. No allowance has been made for the possibility of
18 extraordinary discounts on Canadian crude re-emerging in the future. Although rail could
19 be utilized to provide export capacity, growth in bitumen supply may outpace rail capacity
20 additions. This is analogous to the situation in much of the last decade, in which
21 Canadian bitumen was subject to extraordinary discounts due to inadequate export
22 capacity in pipelines. Further, the optionality benefits provided by the TMEP were not
23 quantified or included in the analysis.

24 Similar impacts may also apply to light synthetic crudes if supply exceeds demand in the
25 Midwest. However, no allowance has been made for these volumes in our analysis,
26 since IHS does not anticipate that supply of sweet SCO will exceed demand in
27 accessible North American markets. While they may deliver some light crude to
28 Asia/Pacific markets, the new pipeline capacity serving these markets is expected to be
29 primarily used for heavy crude volumes.

30 Certain factors could negatively affect producer revenues, and would act to offset the
31 revenue gains outlined above for Canadian producers. For example, "ship-or-pay" costs
32 could be incurred for underutilized term commitments, or temporarily higher tolls may be
33 incurred on common carrier pipelines due to offloading of these systems. However, in
34 our opinion, these costs and uncertainties would be far less than the expected revenue
35 gains, resulting in significant net benefits to the Canadian producing industry.

36



1 **Q.14. Describe in more detail the results for the alternative supply cases, including**
2 **specific discussion of the Trans Mountain Expansion Project.**

3 A.14. Following is a summary description of the cases developed for this project.

4 **Base Case**

5 In the Base Case under the Expansion Scenario premises, a tighter supply/demand
6 crude balance will be realized in 2017 and 2018, particularly for heavy crude. The
7 Expansion Scenario results suggest that for several years, availability of crude for spot
8 deliveries to markets such as the U.S. Midwest will be limited as new pipeline projects
9 divert supply to other markets. The use of rail for crude transportation is expected to be
10 largely reduced or eliminated, as the pipeline project startups are adequate to absorb
11 available supplies. This situation is forecast to persist until at least the end of the next
12 decade. Industry benefits would accrue from the realization of pipeline netback prices
13 from the U.S. Gulf Coast, rather than rail netback prices.

14 For shippers on export pipeline projects, the potential exists for higher netback prices on
15 crude sold in newly accessible markets, such as the Asia/Pacific region. IHS estimates
16 that regional netback prices based on refining parity valuation would be higher in the
17 Asia/Pacific region than the price realized from the U.S. Gulf Coast.

18 The Base Case under the Reference Scenario premises (without TMEP, Energy East
19 and Northern Gateway) suggests that lower netback prices would continue due to
20 realization of rail transportation economics. In our analysis, we estimate that the lower
21 (rail-equivalent) netback price would occur through much of the forecast period,
22 assuming that rail capacity would expand to handle the additional production. If existing
23 rail loading capacity were in fact to become fully utilized, this could lead to a re-
24 emergence of extraordinary discounts on Western Canadian crude. The recent historical
25 period demonstrates that the extent of price discounting that could result in this situation
26 cannot be predicted with any certainty.

27 **Low Production Case**

28 In the Low Production case under the Expansion Scenario premises, development of the
29 major export pipeline projects would contribute to a significantly tighter supply/demand
30 balance for heavy crude. Cumulative takeaway commitments on each of the major
31 pipelines would be substantial. As a result, we estimate that the remaining supply of
32 crude for spot deliveries to markets such as the U.S. Midwest would be limited for an
33 extended period. The major export pipeline projects may not be required by their
34 proposed in-service dates based on the supply/demand balance, so a phased approach
35 may be needed to balance takeaway capacity with available crude supply. The use of rail
36 for crude transportation is not forecast to be needed in this case. The tight balance
37 situation would persist through the end of the forecast period. As in the Base Case,
38 industry benefits would accrue from realization of spot pipeline netback prices from the
39 U.S. Gulf Coast.



1 **High Production Case**

2 In the High Production case under the Expansion Scenario premises, the major export
3 pipelines would directionally help balance Western Canadian crude markets when they
4 start up between 2016 and 2018. The remaining supply of crude for spot deliveries to
5 markets such as the U.S. Midwest are more ample than the Base Case, and are seen as
6 generally being adequate for the needs of refineries in this region, despite the diversion
7 of crude to the new pipelines. The use of rail for crude transportation may be needed in
8 this case, which suggests that additional pipeline capacity may be required to maintain
9 the market balance.

10 **Q.15. Have you prepared a report providing more details of your analysis of the need for**
11 **and expected benefits derived from the development of additional pipeline**
12 **capacity?**

13 A.15. Yes, I have. Appendix A presents the IHS analysis, which is based on the fundamental
14 supply and market analysis completed for this assignment. Appendix A addresses the
15 following topics:

- 16 I. Western Canada & U.S. Northern Tier Crude Oil Production
- 17 II. North American Crude Oil Market Overview
- 18 III. Asian Crude Oil Market Overview
- 19 IV. Canadian Crude Oil Export Pipeline Capacity & Utilization
- 20 V. Crude Oil Pricing

21 **Q.16. Does this conclude your evidence?**

22 A.16. Yes.



APPENDIX A

I. WESTERN CANADA & U.S. NORTHERN TIER CRUDE OIL PRODUCTION

Crude oil production in Western Canada includes crude produced from both conventional and oil sands resources. Conventional crude oil production includes light crude oil in Alberta, British Columbia, Saskatchewan, Manitoba and the Northwest Territories; heavy crude oil in Alberta and Saskatchewan; and, pentanes plus (“C5+”) or condensate in Alberta and British Columbia. Oil sands crude includes bitumen and synthetic crude oil (“SCO”), which is produced by any of a number of upgrading processes. In 2012, total crude oil production in Western Canada was approximately 3.0 million B/D. Of this total, conventional crude oil and condensate production is estimated at 1.23 million B/D while oil sands production is estimated at 1.77 million B/D.

Crude oil production in the U.S. northern tier includes light crude produced from conventional and shale resources in several states. The main crude producing states in the U.S. northern tier are North Dakota and Montana. In 2012, total crude oil production from these two states was 735,000 B/D.⁸ Of this total, North Dakota production was 663,000 B/D and Montana production was 72,000 B/D.⁹ Combined production from North Dakota and Montana has risen sharply, up from 131,000 B/D in 2000 and 188,000 B/D in 2005.¹⁰

I-1. WESTERN CANADIAN PRODUCTION

IHS forecasts total crude production in Western Canada to increase through 2037. The Base Case forecast for this report was prepared in the third quarter of 2013. Refer to Figure A-1, where the IHS forecast is compared with available forecasts from the Canadian Association of Petroleum Producers (“CAPP”) and the National Energy Board (“NEB”). Each of these forecasts calls for production increases for Western Canadian crude. The Base Case forecast shows an increase in Western Canada crude production of about 2.7 million B/D between 2013 and 2030, from 3.25 million B/D to 5.93 million B/D. The CAPP 2013 forecast¹¹ shows a higher absolute increase of about 3.4 million B/D between 2013 and 2030, from 3.26 million B/D to 6.65 million B/D of production. The

⁸ U.S. Energy Information Administration crude oil production data, http://www.eia.gov/dnav/pet/TblDefs/pet_crd_crpdn_tbldef2.asp, accessed on 8 September 2013.

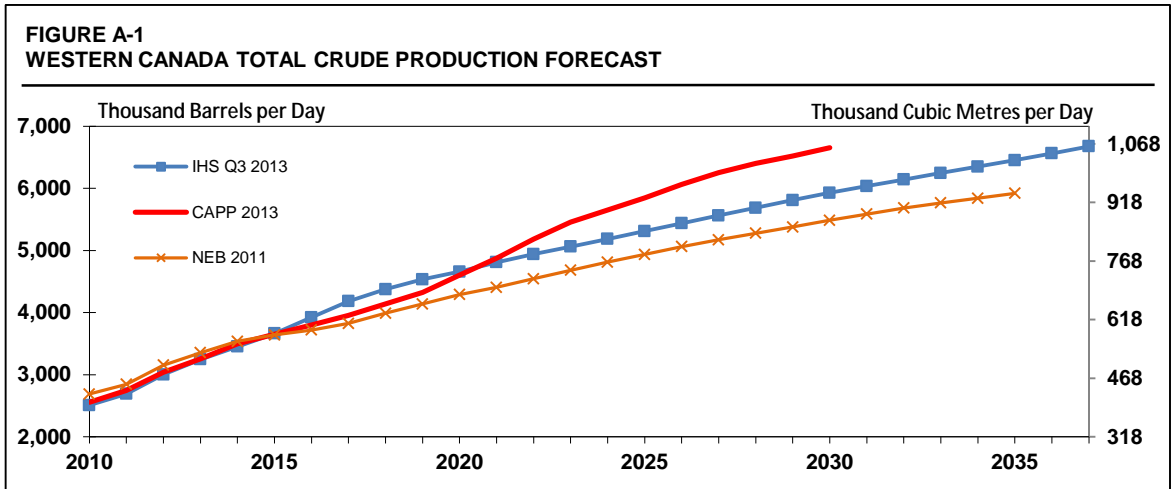
⁹ U.S. Energy Information Administration crude oil production data, http://www.eia.gov/dnav/pet/TblDefs/pet_crd_crpdn_tbldef2.asp, accessed on 8 September 2013.

¹⁰ U.S. Energy Information Administration, http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbldpd_a.htm, accessed on 10 July 2013.

¹¹ CAPP, “Crude Oil Forecast, Markets & Pipelines”, June 2013



1 NEB 2011 Reference Case forecast¹² calls for an increase of 2.57 million B/D between
 2 2013 and 2035, from 3.36 million B/D to 5.92 million B/D.



3 For this report, IHS prepared two alternative production outlooks, which incorporate
 4 changes in key aspects of the production forecast. A Low Production case is premised
 5 on lower bitumen production growth, and a High Production case is premised on higher
 6 conventional light crude and bitumen production growth. These adjustments are
 7 discussed in more detail later.

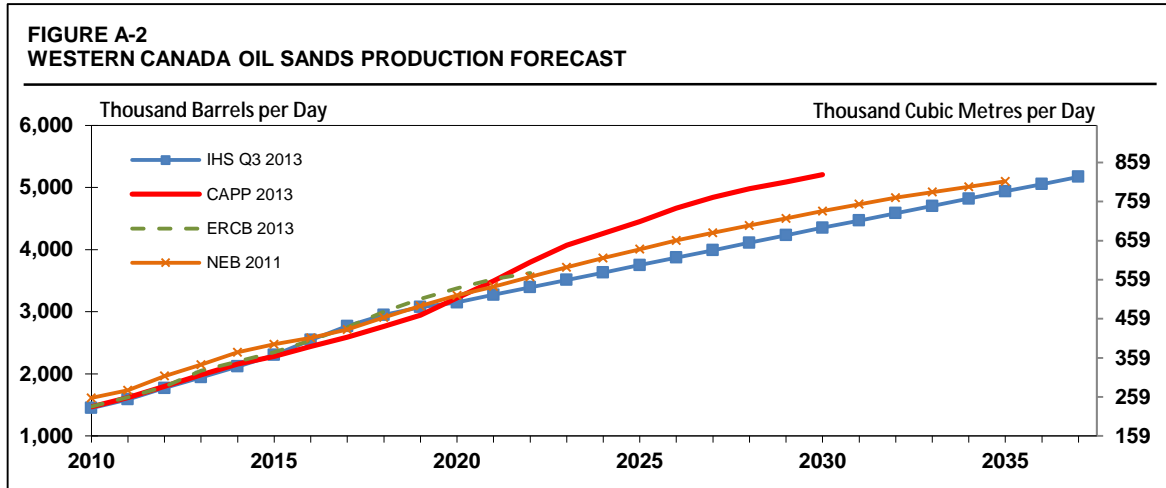
8 **Oil Sands Production**

9 Oil sands production includes mining and in-situ production of bitumen. IHS forecasts oil
 10 sands production to increase through 2037, and to account for the majority of the overall
 11 increase in Canadian crude production. Figure A-2 compares the Base Case forecast of
 12 oil sands production with the CAPP forecast. Figure A-2 also shows the oil sands
 13 production forecasts prepared by the NEB and the Alberta Energy Resources
 14 Conservation Board (“ERCB”).¹³ The current ERCB forecast extends to 2022. The IHS
 15 forecast for 2022 is 230,000 B/D below the ERCB forecast. The ERCB forecast is higher
 16 than the CAPP 2013 forecast until 2021. By 2022, the IHS forecast of oil sands
 17 production reaches 3.4 million B/D, which is about 406,000 B/D below the CAPP 2013
 18 forecast.

¹² National Energy Board, “Canada’s Energy Future: Energy Supply and Demand Projections to 2035”,
<http://www.neb-one.gc.ca/clf-nsi/nrgynfmrn/nrgyrprt/nrgyfr/2011/nrgsppldmndprjctn2035-eng.pdf>, November
 2011.

¹³ Alberta Energy Resources Conservation Board (“ERCB”) ST98-2013, “Alberta’s Energy Reserves 2012 and
 Supply/Demand Outlook 2013–2022”. The ERCB forecast includes only Alberta production. Since oil sands are
 located in Alberta, the oil sands production forecast can be included in the comparison to other forecasts, as
 shown in Figure 2.





1 The Base Case forecast has oil sands production increasing by about 2.4 million B/D
 2 from 2013 to 2030, to 4.35 million B/D. This is lower than the CAPP 2013 forecast for
 3 2030 production (5.21 million B/D).

4 The IHS forecast shows an increase in oil sands crude production of about 3.23 million
 5 B/D between 2013 and 2037, from 1.95 million B/D to 5.17 million B/D. The annual oil
 6 sand production increase over this period is about 134,500 B/D. The NEB 2011
 7 Reference Case forecast¹⁴ calls for an increase in oil sands production of 2.95 million
 8 B/D between 2013 and 2035, from 2.15 million B/D to 5.1 million B/D. The annual
 9 increase in the NEB forecast is about 134,100 B/D, which is close to the increase in the
 10 IHS forecast.

11 Other forecasts of oil sands growth are available. BP, in its 2013 Energy Outlook,
 12 forecasts growth in oil sands production of 2.7 million B/D by 2030.¹⁵ The International
 13 Energy Agency (“IEA”) forecasts that Canada’s oil sands production will grow from 1.6
 14 million B/D in 2012 to 4.3 million B/D by 2035, an increase of 2.7 million B/D.¹⁶ These
 15 forecasts are generally comparable (on an annual basis) to the increase in the current
 16 IHS forecast.

17 **Conventional Crude Production**

18 Conventional crude production in North America was in decline for many years, but this
 19 situation is changing. Figure A-3 shows close agreement on the near term outlook for
 20 Western Canada conventional crude production, between the IHS forecast and the
 21 CAPP forecast. IHS forecasts an increase of about 200,000 B/D in conventional crude

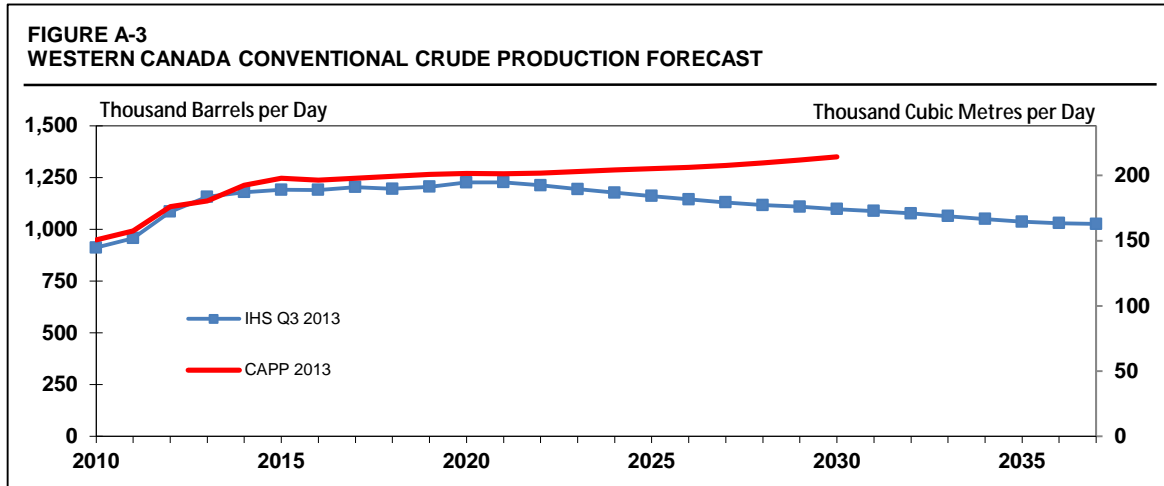
¹⁴ National Energy Board, “Canada’s Energy Future: Energy Supply and Demand Projections to 2035”, <http://www.neb-one.gc.ca/clf-nsi/nrgynfmtn/nrgyrprt/nrgyfr/2011/nrgsppldmndprjctn2035-eng.pdf>, November 2011.

¹⁵ BP Energy Outlook 2030, http://www.bp.com/content/dam/bp/pdf/statistical-review/BP_World_Energy_Outlook_booklet_2013.pdf, accessed on 18 September 2013.

¹⁶ “World needs oil sands crude, IEA economist says”, The Globe & Mail, <http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/world-needs-oil-sands-crude-iea-economist-says/article5702107/>, accessed on 18 September 2013.



1 production between 2013 and 2020. IHS is calling for a resumption of the decline in
 2 conventional crude production after 2015, although the decline rate is offset by growth in
 3 pentanes plus supply from tight gas production. CAPP is projecting conventional crude
 4 production to remain relatively flat at slightly less than 1.4 million B/D after 2015.



5 The trend shown in Figure A-3 for conventional crude production in the Base Case
 6 forecast is based on expected production from tight shale plays, which depends on the
 7 application of advanced production techniques. Such technologies have been applied
 8 with success in the Williston Basin in the northern tier of the U.S., and are expected to
 9 also be successful in Western Canada.

10 I-2. NORTH AMERICAN CRUDE SUPPLY/DEMAND BALANCE

11 The historical and forecast U.S. crude balance is summarized in Table A-1. IHS expects
 12 that U.S. refinery crude demand will increase slightly through the end of the decade, and
 13 decline thereafter. This crude demand forecast is consistent with IHS' forecast for
 14 demand growth of refined products. However, U.S. domestic crude production is forecast
 15 to grow for a number of years due to the contribution of tight oil production, before
 16 resuming an overall decline. As a result, U.S. crude imports will decline to balance
 17 market demand.

18 U.S. refining capacity in 2013 is approximately 17.7 million B/D, and crude demand is
 19 estimated at 15.3 million B/D. In addition to using approximately 7.3 million B/D of
 20 domestic crude, U.S. refineries are expected to import an estimated 8 million B/D of
 21 crude in 2013, including more than 2.5 million B/D of Canadian crude.

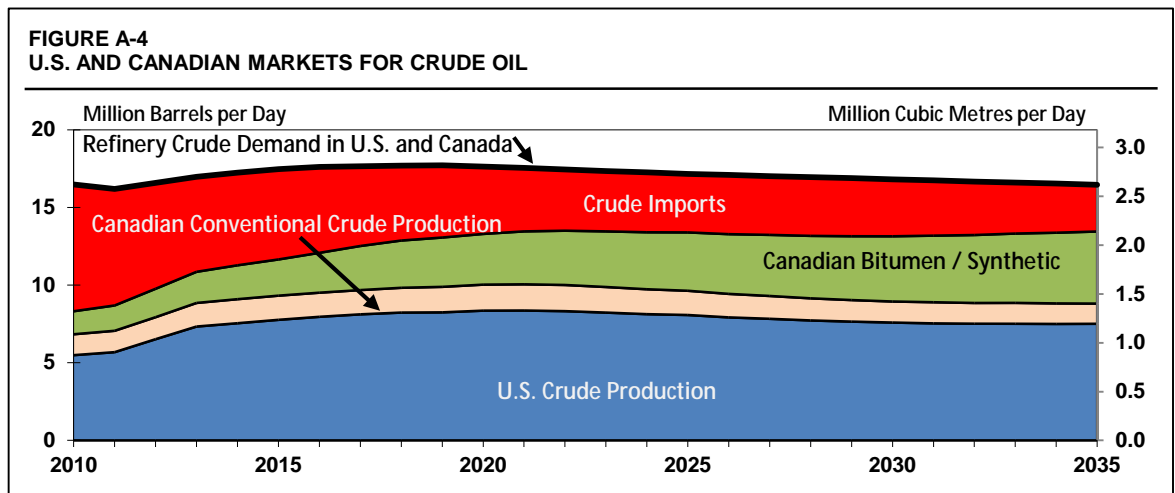


TABLE A-1
TOTAL U.S. CRUDE OIL SUPPLY / DEMAND
 (Thousand Barrels per Day)

	2012	2013	2014	2015	2020	2025	2030	2035
Total Runs	15,020	15,264	15,548	15,715	15,860	15,338	14,956	14,574
Total Capacity	17,776	17,689	17,714	17,743	17,743	17,743	17,743	17,743
% Capacity Utilization	84	86	88	89	89	86	84	82
Production	6,521	7,336	7,549	7,768	8,359	8,079	7,593	7,513
Canadian Imports	2,279	2,522	2,690	2,909	3,571	4,270	4,550	5,092
Other Imports	6,133	5,522	5,457	5,263	4,221	3,336	3,109	2,248
Total Imports	8,412	8,043	8,147	8,172	7,793	7,606	7,658	7,340
Total Supply	14,879	15,264	15,548	15,715	15,840	15,338	14,956	14,574

1 U.S. crude oil production has been declining more or less continuously for two decades.
 2 However, production gains from tight oil developments, such as the Williston Basin and
 3 Eagle Ford plays, have temporarily reversed this historical decline. As a result, U.S.
 4 imports of crude oil are forecast to decrease below 8 million B/D, as shown in Table A-1.
 5 U.S. imports of Canadian crude are forecast to increase steadily through 2035, primarily
 6 due to U.S. refineries processing growing supplies of oil sands crudes. IHS forecasts
 7 that U.S. imports of Canadian crude will reach 3.6 million B/D by 2020, and 5.1 million
 8 B/D by 2035.

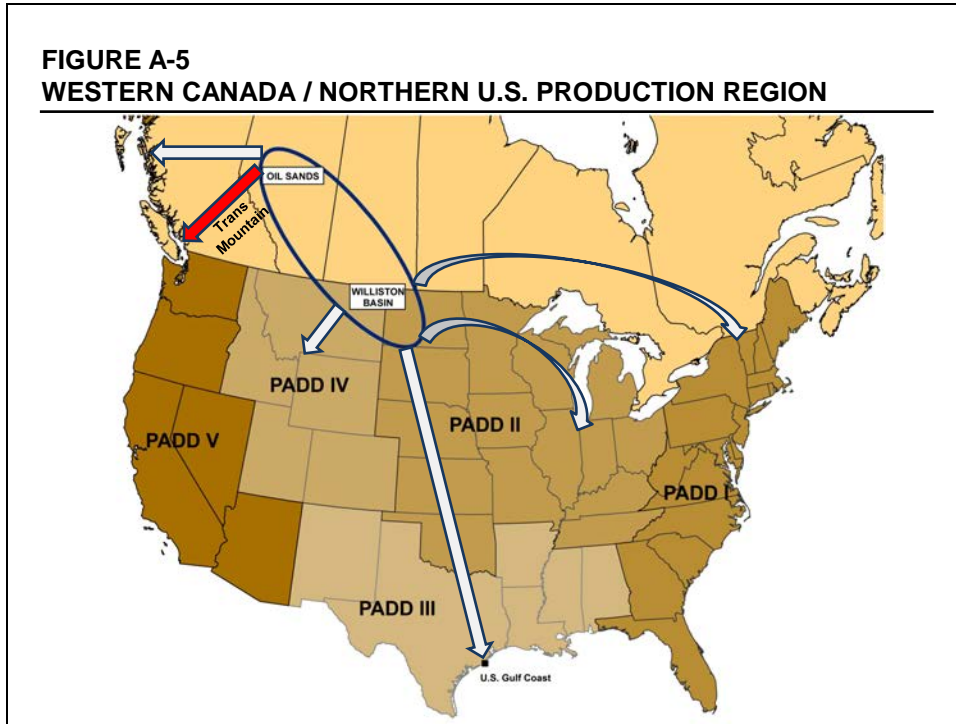
9 Figure A-4 illustrates the crude supply/demand balance for North America, based on
 10 IHS' forecast of crude supply and demand. The growth in Canadian bitumen and
 11 synthetic crude runs is expected to offset a decline in domestic U.S. crude production,
 12 which is expected to occur early in the next decade. The outlook for crude consumption
 13 is relatively flat, which results in a decreased requirement for crude imports from outside
 14 of North America over the forecast period.



15 The U.S. is divided into five Petroleum Administration for Defense Districts (“PADD”) by
 16 the U.S. Department of Energy (“DOE”), as shown in Figure A-5. PADD regions are



1 alternatively referred to in this report as follows: PADD I is the East Coast; PADD II is the
 2 Midwest; PADD III is the Gulf Coast; PADD IV is the Rocky Mountains; and PADD V is
 3 the West Coast. PADD V includes Alaska and Hawaii.



4 Canadian crude currently serves all of the U.S. PADD regions. As infrastructure
 5 development continues, and within the constraints of refining capabilities in each region,
 6 further growth in market share is expected for Western Canadian crude. The Pacific
 7 Northwest region of PADD V is currently served by Trans Mountain. California and other
 8 markets in the Pacific Rim also receive Western Canadian crude supplies via Trans
 9 Mountain.

10 For the purposes of this analysis, we have defined a supply region that includes Western
 11 Canada and the U.S. northern tier. This supply region is served by some of the same
 12 pipelines, and serves many of the same refining locations.

13 **I-3. WESTERN CANADIAN CRUDE SUPPLY**

14 IHS uses the term “marketed supply” to refer to the cumulative volume of all the various
 15 crude blends that are delivered by pipeline or rail. Marketed supply is different from
 16 production, as it allows for upgrading yield losses and heavy crude diluent blending.
 17 Some bitumen and heavy crude may be upgraded at the resource site or at standalone
 18 facilities to produce SCO. Depending on the upgrading process employed, SCO can be
 19 light or heavy crude. To date most upgrading has converted heavy crude production into
 20 light crude supply.



1 Bitumen and some conventional heavy crude oils require diluent to be shipped by
 2 pipeline. The traditional diluent for bitumen is pentanes plus (“C5+”), which is a
 3 recovered natural gas liquid. The blended product of bitumen and C5+ is commonly
 4 referred to as “DilBit”. SCO may also be used as a diluent, in which case the blended
 5 product is referred to as “SynBit”. The blending of diluent increases the supply of heavy
 6 crude and decreases the supply of light crude. The demand for diluent is forecast to
 7 increase with growth in bitumen production. The supply of C5+ from traditional sources
 8 in Western Canada is expected to grow, due to tight gas developments. Other options
 9 are available to supplement the supply of diluent, including import by rail, import or
 10 recycle of suitable streams by pipeline,¹⁷ or use of other light crudes.

11 The Base Case marketed supply forecasts for total crude, heavy crude and light crude
 12 are given in Table A-2. The IHS forecast for Western Canada crude supply is compared
 13 with the most recent CAPP forecast. Total marketed supply increases in both the Base
 14 Case forecast and the CAPP forecast.

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030	2035	2037
Total Crude Supply													
IHS Q3 2013	3,193	3,462	3,713	3,964	4,285	4,581	4,803	4,985	5,105	5,862	6,610	7,348	7,675
CAPP 2013	3,199	3,438	3,738	3,935	4,130	4,333	4,564	4,804	5,165	6,773	7,846		
Heavy Crude Supply													
IHS Q3 2013	1,791	2,004	2,230	2,453	2,746	2,991	3,193	3,372	3,485	4,323	5,153	5,985	6,306
CAPP 2013	1,747	1,872	2,100	2,267	2,498	2,722	2,965	3,205	3,561	5,120	6,093		
Light Crude Supply													
IHS Q3 2013	1,402	1,458	1,482	1,511	1,539	1,590	1,610	1,612	1,620	1,538	1,458	1,440	1,369
CAPP 2013	1,452	1,566	1,637	1,668	1,632	1,610	1,600	1,598	1,604	1,653	1,752		

15 The refining regions served by Western Canadian crude supply may also be served by
 16 U.S. northern tier crude supply. The pipelines serving markets in the Upper Midwest and
 17 Midwest region, as well as Ontario, provide access to Western Canadian and U.S.
 18 northern tier crude supply. U.S. northern tier crude supply may be considered
 19 competitive with Western Canadian crude supply, both from a logistics perspective and
 20 from a crude quality perspective. The crude oils available in the U.S. northern tier are
 21 generally light sweet grades that could be processed by a wide range of refineries.
 22 However, crude supplies in the U.S. northern tier cannot access market regions to the
 23 west of Edmonton, including the Pacific Northwest, California and Asian markets. Trans
 24 Mountain serves these markets.

¹⁷ The Enbridge Southern Lights Pipeline Project was constructed to provide access to imported or recycled sources of suitable diluent streams. It commenced operations in 2010. The Cochin Pipeline is proposed for reversal and conversion from natural gas liquids (“NGL”) export service to condensate import service. If approved, it would commence operations in 2014.



II. NORTH AMERICAN CRUDE OIL MARKET OVERVIEW

Following is an overview of selected regional refining industries in North America. The key features of the regional industries are refining capacity and configuration. Refinery capacity is normally designated by atmospheric crude distillation capacity. Configuration refers to the conversion capabilities of the refining industry, with the usual designations (from most complex to least complex) being coking (also called full conversion), cracking (medium conversion), hydroskimming and topping.

In major North American markets, IHS considers the marginal (or breakeven) refinery configuration to be the cracking configuration. This configuration includes either a fluid catalytic cracking ("FCC") or hydrocracking unit for conversion of vacuum gas oil ("VGO") to lighter fuel products.

II-1. WESTERN CANADA / ONTARIO

There are eight refineries in Western Canada with total crude distillation capacity of 655,000 B/D, as shown in Table A-3. Capacity information shown for refineries in this report is based on the 2012 Oil & Gas Journal Refining Survey¹⁸, and IHS estimates. About 40 percent of Western Canada capacity is in coking refineries, and 54 percent is in cracking refineries. Western Canadian refineries rely exclusively on regional crude supplies, as they have access to crude supplies before they enter major trunk pipelines. The Chevron Canada Limited refinery at Burnaby, BC receives crude from Trans Mountain.

The Ontario refining industry is comprised of 5 refineries with total crude distillation capacity of about 469,000 B/D. Four of the refineries are located in or near Sarnia, ON. Most of the Ontario refining capacity is in cracking configurations. The Ontario refineries process a range of Western Canadian crudes that they receive via the Enbridge system.

TABLE A-3

WESTERN CANADA/ONTARIO REFINERY CONFIGURATION: JANUARY 2013

	Western Canada			Ontario			Total		
	Number	Capacity MB/D	Percent	Number	Capacity MB/D	Percent	Number	Capacity MB/D	Percent
Coking	2	265	40	1	121	26	3	386	34
Cracking	4	353	54	3	268	57	7	622	55
Hydroskimming	1	25	4	-	-	-	1	25	2
Topping	1	12	2	1	80	17	2	92	8
Total	8	655	100	5	469	100	13	1,125	100

Source: Oil & Gas Journal (December 2012) and IHS estimates

¹⁸ Oil & Gas Journal, "2012 Worldwide Refining Survey", December 3, 2012. The Oil & Gas Journal survey has been used as a consistent source for refinery capacity information throughout this document, although it recognized that company information and other sources may be available. Where capacity information is not available from the Oil & Gas Journal survey, other sources (including IHS estimates) have been utilized.



1 II-2. U.S. MIDWEST (PADD II)

2 The U.S. Midwest (PADD II) covers the heartland of the United States. Within this large
3 region, there are a total of 26 refineries with total crude distillation capacity of 3.81
4 million B/D. Table A-4 summarizes refineries in PADD II by type. Approximately three-
5 quarters of PADD II refining capacity is accounted for in coking configurations.

	Number	CAPACITY	
		MB/D	Percent
Coking	14	2,782	73
Cracking	10	1,008	26
Hydroskimming	2	20	1
Topping	-	-	-
Total	26	3,810	100

Source: Oil & Gas Journal (December 2012) and IHS estimates

6 IHS adopts the regional divisions used by the Energy Information Administration (“EIA”)
7 for PADD II. The refining sub-districts in PADD II include the Upper Midwest (refineries in
8 Minnesota, North Dakota and Wisconsin), the Mid-continent (refineries in Kansas and
9 Oklahoma) and the Midwest (refineries in Kentucky, Illinois, Indiana, Michigan, Ohio and
10 Tennessee).

11 The Upper Midwest and northern portion of the Midwest (in the states bordering the
12 Great Lakes) have traditionally been key markets for Western Canadian crude.
13 Refineries in the southern Midwest (around Wood River, IL) and the Mid-continent have
14 been increasing their consumption of Canadian crudes. Several pipeline projects
15 (discussed later) have allowed Canadian crudes to gain access to these markets, as
16 refiners sought new supplies to replace declining domestic production.

17 II-3. U.S. ROCKY MOUNTAIN REGION (PADD IV)

18 The U.S. Rocky Mountain region (PADD IV) has a small refining industry, with 16
19 refineries and total crude distillation capacity of 622,000 B/D. Table A-5 summarizes
20 capacity and configuration data for the PADD IV refining industry. Coking (55 percent)
21 and cracking (42 percent) account for the majority of the regional refining capacity.



	Number	CAPACITY	
		MB/D	Percent
Coking	6	341	55
Cracking	7	264	42
Hydroskimming	3	17	3
Topping	-	-	-
Total	16	622	100

Source: Oil & Gas Journal (December 2012) and IHS estimates

1 Historically, crude production in PADD IV was surplus to the needs of the regional
 2 refineries. Refineries in northern PADD IV (Montana) access Canadian crude through
 3 southbound regional pipelines originating in Alberta. Refineries in the southern PADD IV
 4 markets of Salt Lake City, UT and Denver, CO process indigenous and imported
 5 Canadian crude, mainly light sweet and synthetic grades. In recent years, production of
 6 light sweet crude from shale formations such as the Bakken play has added a new
 7 source of supply for PADD IV.

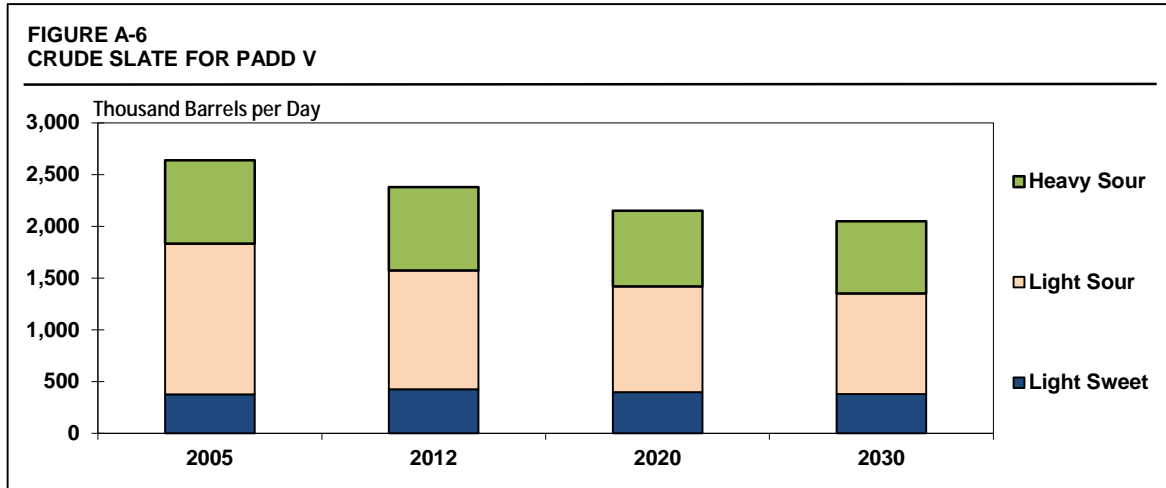
8 **II-4. U.S. WEST COAST (PADD V)**

9 The U.S. West Coast (PADD V) includes refineries in California, Washington State,
 10 Alaska and Hawaii. The major refining industries on the West Coast are centred in Los
 11 Angeles, San Francisco, and the Pacific Northwest. Smaller refining centres are located
 12 in Hawaii and in Alaska. The California refining industry includes large, complex
 13 refineries that are located in proximity to major refined product markets. California is a
 14 small but growing market for Western Canadian crude.

15 Since the late 1990s, PADD V has become increasingly dependent on crude imports and
 16 refined product transfers from other PADD regions to satisfy its product demand. This
 17 trend towards greater integration of the PADD market with other markets, both in the
 18 U.S. and internationally, is expected to continue in the future.

19 Figure A-6 summarizes the historical and future outlook for crude demand by type in
 20 PADD V. Overall demand for crude is forecast to decrease, largely due to mandated fleet
 21 efficiency improvements which will reduce gasoline demand. However, runs of light
 22 sweet and heavy sour crude are forecast to remain relatively stable in PADD V.
 23 Descriptions for the regional refining industries in the Pacific Northwest and California,
 24 including discussion of the types and sources of crude processed, and the potential for
 25 oil sands crudes, are presented below the figure.





1 **Pacific Northwest**

2 The Pacific Northwest refining industry consists of five refineries, all located in
 3 Washington State. Table A-6 summarizes capacity and configuration information for the
 4 Washington State refineries. There are four fuels refineries in Puget Sound and a smaller
 5 asphalt plant in Tacoma, with a total combined distillation capacity of 630,900 B/D. Two
 6 of the Puget Sound refineries are coking configurations (BP and Shell) and two are
 7 cracking configurations (Tesoro and Phillips 66).

**TABLE A-6
REFINERIES IN WASHINGTON STATE**

Owner	Location	Configuration	Crude Capacity (B/D)
BP	Ferndale	Coking	222,300
Phillips 66	Ferndale	Cracking	101,000
Shell Oil Products US	Anacortes	Coking	148,600
Tesoro West Coast Co.	Anacortes	Cracking	120,000
US Oil & Refining Co.	Tacoma	Hydroskimming	<u>39,000</u>
Total			630,900

Source: Oil & Gas Journal (December 2012)

8 Historically, Alaskan North Slope (“ANS”) has been the dominant crude processed in
 9 Washington State, with the balance coming from imports. Canada, Latin America, Africa
 10 and the Middle East are the main sources of imported crude for the Washington State
 11 refineries. Imports of Western Canadian crude in the Pacific Northwest region are
 12 received via the Trans Mountain system, and include a range of light and heavy crudes.
 13 In 2012, refineries in Washington State imported approximately 146,000 B/D of Canadian
 14 crude.



1 **California**

2 The California refining industry is among the most complex regional refining industries in
 3 the world, and features extensive heavy oil upgrading capability. Many refineries were
 4 originally developed to process heavy California crude oils, but as the use of fuel oil was
 5 phased out of the utility sector, refineries added coking capacity in order to eliminate fuel
 6 oil sales. As shown in Table A-7, there are 18 California refineries with approximately 2.0
 7 million B/D of crude oil distillation capacity, most of which is in coking configurations.
 8 Two refineries owned by Alon, with capacity of 83,000 B/D, are temporarily shutdown.
 9 They are included in Table A-7, because they are expected to restart.

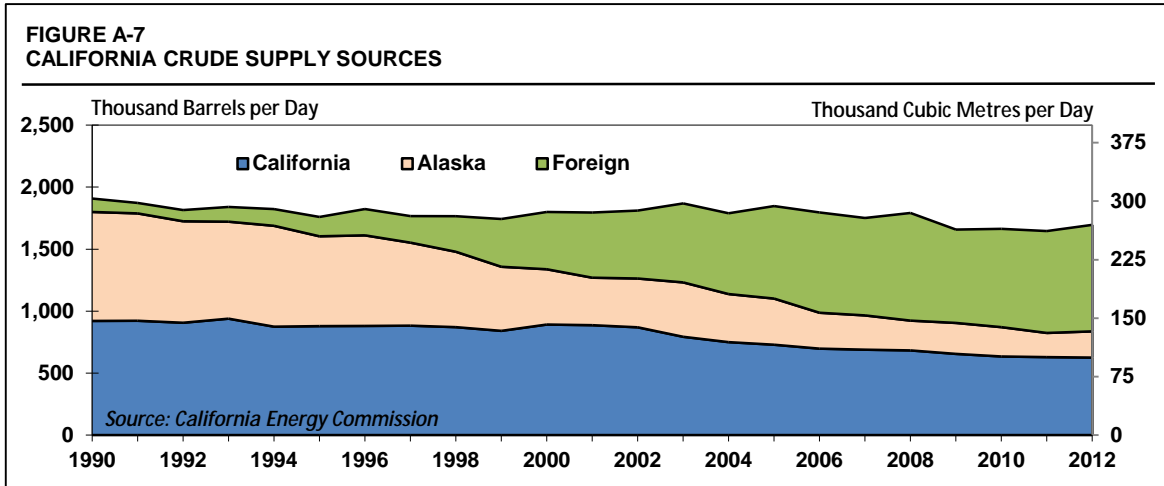
	Number	CAPACITY	
		MB/D	Percent
Coking	10	1,588	80
Cracking	1	243	12
Hydroskimming	2	76	4
Topping	5	82	4
Total	18	1,989	100

Source: Oil & Gas Journal (December 2012) and IHS estimates

10 ANS and California crude account for slightly more than half of the crude runs in
 11 California. According to the California Energy Commission,¹⁹ the proportion of domestic
 12 crude runs has steadily decreased, from about three-quarters of the state total in 2000 to
 13 less than half in 2012. In 2012, about 837,000 B/D of domestic crude was run in the
 14 state. Of this volume, about 625,000 B/D was California production, and 211,000 B/D
 15 was from Alaska. The remaining deficit, approximately 860,000 B/D, was satisfied
 16 through imports of foreign crude. Figure A-7 summarizes the historical crude supply for
 17 California, and shows the increasing dependence on imported crude.

¹⁹ California Energy Commission,
http://energyalmanac.ca.gov/petroleum/statistics/2010_foreign_crude_sources.html, accessed August 15, 2013





1 The main source of imports for California refineries has been the Middle East, which has
 2 accounted for up to 50 percent of total imports in recent years. Saudi Arabia and Iraq
 3 have been the leading suppliers of crude to California refineries. U.S. EIA import
 4 statistics indicate that Middle Eastern crudes are mainly light sour grades, which are
 5 suitable for processing in many California refineries. Light sour and heavy sour crudes
 6 are also imported from Latin America.

7 Imports of Canadian crude by California refineries have been a relatively small fraction of
 8 the total imports to the state, but the trend has been increasing. California Energy
 9 Commission statistics²⁰ indicate that Canadian crude imports in 2012 were 39,000 B/D
 10 (about 2.3 percent of total California crude runs). This is up from 15,000 B/D in 2007,
 11 which was about 0.8 percent of California crude runs in that year.

12 **Potential for Oil Sands Crudes**

13 There are several factors that favour growth in oil sands crude in the PADD V market.
 14 Western Canadian crude has a logistical advantage compared to other supply sources
 15 for the PADD V refineries, and in particular for the Pacific Northwest refineries. The
 16 Pacific Northwest refineries have capabilities to process a range of oil sands light and
 17 heavy crudes, in addition to conventional crudes.

18 The size and complexity of the refining industry in California, and the trend of growing
 19 dependence on imports in the state, suggests that interest in access to Western
 20 Canadian supply should continue to increase. IHS expects bitumen and conventional
 21 heavy blends from Western Canada to be of the most interest to California refineries.
 22 The existing capabilities of the California refining industry to process heavy crude oil
 23 should allow Western Canadian heavy crudes to gain market share, particularly as
 24 domestic supplies of heavy crude continue to decline. Constraints for Western Canadian
 25 heavy crude processing would need to be addressed on a refinery-specific basis, given

²⁰ California Energy Commission, *ibid.*

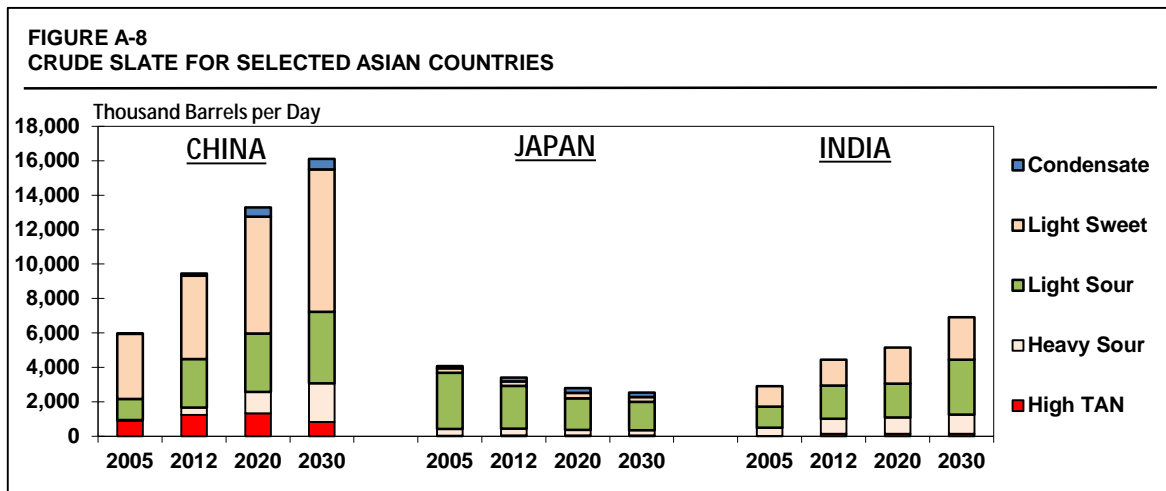


1 that bitumen blends have different characteristics than the indigenous heavy crudes
 2 historically processed in California. Such an analysis is beyond the scope of this report.

3 **III. ASIAN CRUDE OIL MARKET OVERVIEW**

4 There are large refining markets in Asia that can process Western Canadian crude. For
 5 this report, IHS has provided a brief description of selected Asian countries that are
 6 markets of growing interest for Western Canadian producers. The focus is on refining
 7 industries in China, Japan and India. Several other Asian countries are also discussed,
 8 but in less detail.

9 Figure A-8 summarizes the historical and future outlook for crude demand by type in the
 10 aforementioned Asian countries. Demand for most types of crude is forecast to increase
 11 in China and India, as refining industries in these countries expand and evolve to meet
 12 domestic product requirements. Descriptions for the refining industry in each of these
 13 countries, the types and sources of crude processed, and the potential for oil sands
 14 crudes, are presented below the figure.



15 **III-1. CHINA**

16 Crude distillation capacity in China is the largest among all countries in Asia. Capacity
 17 has been growing rapidly. Strong product demand growth has prompted increases in
 18 refining capacity, and has also increased the operating rate of existing refineries.
 19 Increasing product imports to China have also been reported. Capacity expansions will
 20 continue into the foreseeable future.

21 Table A-8 summarizes the distillation capacity and configuration for the Chinese refining
 22 industry.²¹ More than three-quarters of the 9.8 million B/D of distillation capacity is in

²¹ Oil & Gas Journal, "2012 Worldwide Refining Survey", December 3, 2012, and IHS estimates.



1 coking refining configurations, although these refineries are oriented to processing
 2 indigenous crudes. Simple refining capacity accounts for a small fraction of total
 3 capacity, excluding small regional refineries. Much of this capacity is located in inland
 4 regions, or in small state-owned refineries that produce feedstocks for petrochemical
 5 plants.

	Crude Distillation Capacity		
	Number	MB/D	Percent
Coking	42	7,405	76
Cracking	22	2,082	21
Hydroskimming	1	82	1
Topping	3	205	2
Total	68	9,774	100

Note: Excludes distillation capacity of local refineries.
 Source: Oil & Gas Journal (December 2012) and IHS estimates

6 IHS expects that domestic refining will continue to supply the majority of Chinese fuel
 7 requirements over the forecast period. Several new refineries are currently under
 8 construction, and these, along with further expansions and upgrades at existing
 9 refineries, are expected to keep pace with projected demands at least through the end of
 10 this decade.

11 Most of the refineries in China were originally designed to process indigenous Chinese
 12 crudes, but now that runs far exceed domestic production most of the coastal refineries
 13 are equipped to process Middle East and other imported crude. China now imports about
 14 half of its crude slate. The Middle East and Africa together account for most of China's
 15 crude imports.

16 **Potential for Oil Sands Crudes**

17 IHS expects diversification of China's crude sources and crude slate, to include more
 18 sour and heavy crudes. An increasing need for imported crude of all types suggests that
 19 interest in Canadian oil sands crudes should continue. China is generally expected to
 20 move towards more complex refining configurations as capacity is added, with the
 21 addition of cracking, coking and hydroprocessing capacity.

22 Light sweet SCO could be processed in coastal refineries in China that have sweet crude
 23 cracking capacity, given its characteristic low sulphur and high distillate yield. China is
 24 expected to increase its imports of light sweet crude by 2020, to help supply the growth
 25 in refinery runs. IHS believes that SCO demand potential could grow with this
 26 requirement.



1 The amount of Canadian bitumen blends that may be processed in existing refineries in
 2 China depends on their ability to handle high sulphur residue in coking units, and on the
 3 availability of hydrotreating capacity to handle hydrogen deficient bitumen-derived
 4 crudes. However, the potential for lower quality crude production from Western Canada
 5 to be integrated with new build refinery capacity in dedicated projects is significant.
 6 Interest by Chinese firms in Canadian oil sands is indicated by the recent CNOOC
 7 acquisition of Nexen²² and by the positions taken in other oil sands companies. These
 8 ventures are expected to support the expansion of domestic refining capacity in China.

9 III-2. JAPAN

10 The Japanese refining industry (summarized in Table A-9) consists of 31 refineries, with
 11 total distillation capacity of 4.18 million B/D.²³ Japan continues to downsize and
 12 consolidate its refining industry.

	Crude Distillation Capacity		
	Number	MB/D	Percent
Coking	4	357	9
Cracking	22	3,593	86
Hydroskimming	2	155	4
Topping	3	73	2
Total	31	4,178	100

Source: Oil & Gas Journal (December 2012) and IHS estimates

13 The Japanese refining industry is well balanced, and has historically been oriented
 14 toward meeting domestic refined product demand. However, Japan's petroleum
 15 consumption is forecast to decline slowly, as shown in Figure A-8. With the decline of
 16 domestic markets, Japanese refiners may seek opportunities to export products,
 17 potentially allowing them to serve other Asian markets.

18 Japanese crude imports are heavily dominated by Middle East sour grades, which
 19 accounted for almost all imports in 2012. Sweet crude imports are low, currently less
 20 than 10 percent of total crude imports. African crudes comprise a small fraction of total
 21 Japanese crude runs.

²² The Globe & Mail, "CNOOC completes \$15.1-billion takeover of Nexen", <http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/cnooc-completes-151-billion-takeover-of-nexen/article9043968/>, February 25, 2013, accessed on October 3, 2013.

²³ Oil & Gas Journal, "2012 Worldwide Refining Survey", December 3, 2012, and IHS estimates.



1 **Potential for Oil Sands Crudes**

2 Our analysis of oil sands market potential in Japan suggests that light sweet SCO could
 3 be used at many Japanese refineries in place of imported sweet or light sour crude. IHS
 4 believes that SCO substitution could be limited by operating constraints for Japanese
 5 refineries. However, alternative grades of SCO may be developed, which would conform
 6 to the constraints of the Japanese refining industry. Alternatively, bitumen blends with
 7 SCO (normally referred to as SynBit) or other blends of oil sands and conventional
 8 crudes may be of interest to Japanese refineries. Cracking refineries that process light
 9 sour crude oil could also directly substitute light sweet SCO, if justified by substitution
 10 economics.

11 **III-3. INDIA**

12 The capacity and configuration of the Indian refining industry is summarized in
 13 Table A-10. As of January 2013, India has total installed distillation capacity of 4.43
 14 million B/D in 21 refineries, and a high concentration of conversion capacity.²⁴ A number
 15 of refinery expansions and grassroots projects are at various stages of development.

	Crude Distillation Capacity		
	Number	MB/D	Percent
Coking	12	2,749	52
Cracking	8	1,656	47
Hydroskimming	0	-	0
Topping	1	20	0
Total	21	4,425	100

Source: Oil & Gas Journal (December 2012) and IHS estimates

16 The crude oil processed by India's refining industry is a mixture of indigenous production
 17 and imports from the Middle East, Southeast Asia and Africa. Crude oil imports have
 18 increased over the last few years, a reflection of stagnant crude oil production and strong
 19 demand growth. The crude oil slate is increasingly composed of light to medium gravity
 20 sour crudes, in contrast to the domestic production, which is mainly light sweet. Most
 21 recently installed capacity and current projects are designed for sour Middle East crude
 22 or heavy Atlantic Basin crude.

²⁴ Oil & Gas Journal, "2012 Worldwide Refining Survey", December 3, 2012, and IHS estimates.



1 **Potential for Oil Sands Crudes**

2 As noted above, Indian refineries currently process a mainly light crude slate. Light
3 sweet SCO may be a substitute for African sweet imports currently processed in India.
4 IHS believes these opportunities are likely to be limited due to logistical disadvantages.

5 Although limited volumes of heavy crude have historically been processed in Indian
6 refineries, this trend is changing. Several Indian refineries require heavy feedstock, in
7 particular the Reliance refinery complex at Jamnagar. The Reliance refinery consists of
8 two facilities with total distillation capacity of 1.24 million B/D.²⁵ The second Reliance
9 refinery, with capacity of 580,000 B/D, was started up in 2009. Due to its proximity to the
10 Middle East, Reliance would see a logistical advantage to process Middle East heavy
11 crude rather than Western Canadian crude. Nevertheless, interest by Indian refineries in
12 Western Canadian heavy crude is growing. IHS attributes this to competing demand for
13 heavy crude in the Middle East from new or modified refineries, and to an interest by
14 Indian refiners in securing alternative sources of supply.

15 **III-4. OTHER ASIAN COUNTRIES**

16 South Korea has a large domestic refining industry, with combined distillation capacity of
17 about 3 million B/D. There is no crude production in South Korea, so all crude runs are
18 based on imported supplies. Imported crudes are sourced from a variety of suppliers,
19 and the Middle East is the largest supply region. The crude slate is relatively light. IHS
20 estimates that South Korean refineries could substitute light sweet SCO from Western
21 Canada for other light crude imports. Alternative formulations of SCO, which are closer
22 in quality to Middle East sour crudes, would likely be of interest in South Korea.

23 There are three large fuels refineries and one condensate splitter in Singapore, with
24 combined distillation capacity of 1.35 million B/D. There is no crude production in
25 Singapore, so all crude runs are imported. Singapore refineries rely mainly on Middle
26 East sour crude, and to a lesser extent on Asian sweet crude. Markets for Canadian oil
27 sands crudes in Singapore could include substitution of sweet SCO for other light
28 crudes.

29 There are three large refining centres in Taiwan, with combined distillation capacity of
30 about 1.3 million B/D. Because Taiwan has almost no crude production, runs are
31 dominated by imports. Middle East sour crude is the dominant crude type processed in
32 Taiwan. IHS sees oil sands crude potential in Taiwan as somewhat limited, but sweet
33 SCO could certainly be substituted for other imported light sweet crudes.

²⁵ Oil & Gas Journal, "2012 Worldwide Refining Survey", December 3, 2012.



1 **IV. CANADIAN CRUDE OIL EXPORT PIPELINE CAPACITY & UTILIZATION**

2 Canadian crude oil export pipeline systems are described in this section. Current
3 capabilities and expansion plans for the major export pipeline systems are presented.
4 The utilization of pipeline systems is discussed, with reference to the crude supply
5 forecast provided in the previous section of this report. Table A-11 summarizes the major
6 pipeline projects that would increase markets for Western Canadian crude oil.

7 **IV-1. TRANS MOUNTAIN**

8 Trans Mountain transports crude oil, as well as various feedstocks and blendstocks from
9 Edmonton and Kamloops, BC to its Burnaby terminal (for the Chevron Burnaby refinery),
10 to its Westridge Marine Terminal dock (for marine exports), and also to its U.S. affiliate,
11 Trans Mountain Pipeline (Puget Sound) LLC ("Puget Sound Pipeline") (for export from
12 Sumas, BC to four Washington State refineries). Trans Mountain delivers various grades
13 of light and heavy crudes. Trans Mountain also transports refined products from
14 Edmonton to both Kamloops and Burnaby.

15 Trans Mountain capacity is dependent upon the amount of heavy crude being shipped.
16 The convention has been to define capacity based on 20 percent of the crude oil shipped
17 as heavy oil. On this basis, the current operational capacity is 300,000 B/D.

18 Trans Mountain has completed a number of expansion projects. The system reached its
19 current capacity in 2008 with the completion of its Anchor Loop project, which added
20 40,000 B/D of capacity. Application is being made for the proposed Trans Mountain
21 Expansion Project ("TMEP"). Subject to the outcome of the NEB hearing process, Trans
22 Mountain plans to begin construction in 2016. The project would go into service in late
23 2017.



**TABLE A-11
MAJOR PIPELINE PROJECTS CONNECTING OIL SANDS TO FUTURE MARKETS**

<u>Destination</u>	<u>Pipeline project (proponent)</u>	<u>Route</u>	<u>Distance (km)</u>	<u>Capacity (B/D)</u>	<u>Status</u>	<u>Proposed in-service date</u>
US Gulf Coast	Flanagan South (Enbridge)	Flanagan, IL to Cushing, OK	960	585,000	Announced	2014
	Keystone XL (TransCanada Pipelines)	Hardisty, AB to Port Arthur, TX	2,750 ¹	830,000	Regulatory review	2015
	Seaway reversal—Phase 1 (Enbridge/Enterprise Products) Seaway—Phase 2 (Enbridge/Enterprise Products) Seaway—Phase 3 (Enbridge/Enterprise Products)	Cushing, OK to Freeport, TX	800	150,000 250,000 450,000	Operating Operating Application	2012 2013 2014
East Coast	Energy East (TransCanada Pipelines)	Alberta to Montreal and/or Quebec City, QC and/or Saint John, NB	3,500	1,100,000	Announced	2017
	Line 9 Re-reversal (Line 9B) (Enbridge)	Sarnia, ON to Montreal, QC ²	640	300,000	Regulatory review	2014
	Portland to Montreal Pipeline Reversal (Montreal Pipe Line)	Montreal, QC to South Portland, ME	380	140,000	Conceptual	n/a
West Coast	Northern Gateway Pipelines (Enbridge)	Bruderheim, AB to Kitimat, BC	1,180	525,000	Regulatory review	2018
	Trans Mountain Expansion Project (Kinder Morgan)	Edmonton, AB to Westridge Marine Terminal in Burnaby, BC	1,150	590,000	Regulatory review	2017

Source: Various sources and IHS analysis

Notes: (1) Keystone XL consists of two parts: A 1,897-km (1,179-mi) leg from Hardisty, Alberta to Steele City, Nebraska, and a 780-km (485-mi) leg from Cushing, Oklahoma to Nederland, Texas combined with a 76-km (47-mi) lateral to the Houston, Texas area (called the Gulf Coast Pipeline Project).

(2) In July 2012 the National Energy Board of Canada approved the reversal of the 192-km section of Line 9 from Sarnia, ON to North Westover, ON ("Line 9A").

The reversal of the line from Montreal, QC to North Westover ("Line 9B") and an increase in capacity of the system are proposed.

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IV-2. ENBRIDGE MAINLINE

1 The majority of Canadian crude produced in Alberta currently flows east through the
2 Enbridge Pipeline System (the portion in Canada) and the Enbridge Energy Partners,
3 L.P. System (the connecting Lakehead system portion in the U.S.). Together these two
4 systems have the ability to supply crude directly and indirectly to numerous refineries in
5 Canada and the U.S. The system receives other crudes along the route in both Canada
6 and the U.S.

7 Enbridge has continued to expand the mainline system with approval of the NEB and
8 with agreement from crude oil producers, as represented by CAPP. Recently completed
9 and potential Enbridge export expansion projects are summarized below:

- 10 · **Alberta Clipper (Line 67) Expansion:** Enbridge is expanding the capacity of its
11 Line 67 (initially the Alberta Clipper Pipeline) in phases, from 450,000 B/D to
12 800,000 B/D.
- 13 · **Flanagan South Pipeline:** Enbridge is proposing the Flanagan South Pipeline
14 Project, a 36-inch diameter pipeline that would originate in Flanagan, IL and
15 terminate in Cushing, OK. The majority of the pipeline would parallel the existing
16 Enbridge Spearhead pipeline right-of-way. Initial capacity of the Flanagan South
17 Pipeline would be 585,000 B/D. Construction would proceed from mid-2013 to
18 mid-2014, and the line would be in-service by mid-2014.
- 19 · **Line 9 Reversal:** Line 9 is an existing Enbridge pipeline with capacity of 240,000
20 B/D that extends from Montreal, QC to Sarnia, ON and currently transports
21 offshore crude oil in a westbound direction. Enbridge has NEB approval to
22 reverse a section of Line 9 between Sarnia and North Westover, ON, and is also
23 proposing the Line 9B Reversal and Line 9 Capacity Expansion Project, which
24 would reverse the pipeline between North Westover and Montreal to allow
25 Western Canadian crude to supply refineries in Quebec.

26 IV-3. ENBRIDGE NORTHERN GATEWAY

27 The proposed Enbridge Northern Gateway Project would consist of twin pipelines from
28 Edmonton to a new marine terminal at Kitimat on the West Coast of British Columbia. An
29 export pipeline would have capacity of 525,000 B/D, and an optional diluent import
30 pipeline would have capacity of 193,000 B/D. Wharfage and terminal facilities at Kitimat
31 would be designed to handle Very Large Crude Carrier ("VLCC") tankers for Canadian
32 crude exports, and up to Suezmax class tankers for condensate imports.

33 A regulatory application was filed by Enbridge in mid-2010. An independent review
34 process is being led by the NEB and the Canadian Environmental Assessment Agency
35 ("CEAA"). The Northern Gateway hearing process has been completed. The Joint
36 Review Panel ("JRP") assigned to review the project is scheduled to submit its report to



1 the federal government by December 31, 2013. The pipeline is proposed to start up in
2 2018.²⁶

3 **IV-4. KEYSTONE**

4 The Keystone pipeline project was developed by TransCanada, and put into service in
5 2010. The project allows Canadian crude to reach Wood River, IL and Patoka, IL. In July
6 2008, the NEB approved Keystone's application for an expansion of the Phase 1
7 Keystone system to reach Cushing, OK. The extension of the Keystone system south to
8 Cushing, OK from Steele City, NE and expansion to 590,000 B/D of capacity was started
9 up in 2011.

10 **Keystone XL**

11 TransCanada proposed the Keystone XL Pipeline ("KXL") in 2008, with a route that
12 would transport crude from Hardisty, AB to Texas via Cushing to potentially serve
13 refineries on the Gulf of Mexico. The project requires a Presidential Permit, which would
14 be issued by the U.S. Department of State. A decision on the KXL project has been
15 deferred until late 2013 or early 2014. KXL would have a capacity of 700,000 B/D from
16 Hardisty, AB to Cushing, and 500,000 B/D from Cushing to the Gulf Coast. It would carry
17 heavy and light Canadian crudes. The proposed in-service date for KXL is 2015,
18 although given the delay in the state department decision the project has been delayed
19 until 2016 in our balances.

20 **IV-5. ENERGY EAST**

21 The TransCanada Energy East Pipeline is a proposed 4,500-kilometer pipeline that
22 would have capacity to transport 1.1 million B/D from Alberta, Saskatchewan and the
23 U.S. northern tier to refineries in Eastern Canada and beyond. The project involves:
24 conversion of an existing natural gas pipeline to an oil transportation pipeline;
25 construction of new pipeline connections in Alberta, Saskatchewan, Manitoba, Eastern
26 Ontario, Quebec and New Brunswick to link up with the converted pipe, and construction
27 of the associated facilities required to ship crude oil from Alberta to Quebec and New
28 Brunswick, including marine facilities that enable access to other markets by ship. The
29 planned starting point for Energy East would be a new tank terminal in Hardisty, AB.
30 New terminals would be built in Saskatchewan, in the Quebec City area and in the Saint
31 John, NB area. The pipeline would deliver oil to existing refineries in Montreal, Quebec
32 City and Saint John. Crude oil could then be exported to Atlantic Basin markets from
33 either Quebec or Saint John. The project is currently estimated to cost \$12 billion.

²⁶ "Northern Gateway pipeline to be running by 2018, says Enbridge", <http://www.cbc.ca/news/canada/british-columbia/northern-gateway-pipeline-to-be-running-by-2018-says-enbridge-1.1875899>, October 2, 2013, accessed on October 3, 2013.



1 Submission of regulatory applications to the NEB for approval to build and operate the
2 Energy East Pipeline is planned for early 2014. Assuming approval by late 2015, the
3 project is expected to be in service to Montreal and Quebec City in late 2017 and to
4 Saint John in late 2018.

5 **IV-6. OTHER EXPORT PIPELINES**

6 The Express Pipeline system (“Express”) is owned by Spectra Energy, who acquired it in
7 2013. Express was expanded in 2005 to its current capacity of about 280,000 B/D.
8 Express is comprised of the Express Pipeline (from Hardisty, AB to Casper, WY) and the
9 Platte Pipe Line Company (“Platte”) (from Casper, WY to Wood River, IL).

10 The Enbridge North Dakota Pipeline gathers North Dakota and Montana crudes for
11 shipment east to Clearbrook, MN where it joins the main line of the Lakehead system.
12 Due to increased crude production in Montana and North Dakota and oversupply in the
13 U.S. Rocky Mountain region, movements on the Enbridge North Dakota Pipeline have
14 increased and exports of Canadian crudes, especially Midale, on this system have fallen.
15 The Enbridge Bakken Program is a coordinated set of projects in Canada and the U.S.,
16 which would accommodate growth in regional crude production.

17 The Wascana Pipeline (owned by Plains Midstream) runs from Regina to the Montana
18 border, where it connects to the Bridger Pipeline. Bridger moves crude south to the U.S.
19 Rocky Mountain market. The Wascana Pipeline has a nominal capacity of around 50,000
20 B/D. Although it has not operated in recent years, Plains plans to reverse the Wascana
21 pipeline to Regina and tie-in Bakken production.

22 Other crude oil pipelines that export crude from Alberta to pipelines in the U.S. include
23 the Rangeland Pipeline (capacity of about 65,000 B/D) and the Milk River Pipeline
24 (118,000 B/D).

25 **IV-7. RAIL CAPACITY**

26 Extraordinary discounts for Western Canadian crudes have encouraged the use of rail
27 loading operations to ship crude to market. Rail movements of crude oil from Western
28 Canada have increased from negligible levels in 2011 to an estimated 145,000 B/D in
29 the second quarter of 2013. IHS expects rail movements to be sensitive to crude price
30 discounts.

31 Rapid growth is projected in Western Canadian and U.S. northern tier crude on-loading
32 capacity, as summarized in Table A-12. More project announcements are expected. New
33 rail loading capacity is expected to incorporate efficiency improvements, which will



1 involve the use of unit trains or other efficiency improvements in many cases.²⁷ This will
 2 contribute to improved economics, particularly for facilities that are connected by
 3 pipeline.

Company	Location	Rail Company	Capacity, MB/D		
			Current	Additions ⁽¹⁾	Total
<u>Western Canada</u>					
TORQ	Kerrobert, SK	CP	-	168	168
USD/Gibson	Hardisty, AB	CP	-	140	140
TORQ	Unity, SK	CN/CP	11	59	70
Canexus	Bruderheim, AB	CN/CP	30	40	70
Gibson Energy	Edmonton, AB	CN/CP	-	60	60
Altex Energy	Lashburn, SK	CN	30	30	60
Kinder Morgan	Edmonton, AB	CN/CP	-	40	40
Enbridge/Keyera	Cheecham, AB	CN	32	-	32
TORQ/Altex	Lloydminster, SK	CP	27	-	27
TORQ	Whitecourt, AB	CN	12	12	24
Other	Various		55	58	113
Total Western Canada Capacity			197	607	804
<u>North Dakota</u>					
Inergy	Epping	BNSF	120	-	120
Bakken Oil Express	Dickenson	BNSF	100	-	100
Savage Services	Trenton	BNSF	90	-	90
Enbridge	Berthold	BNSF	80	-	80
Dakota Plains	New Town	CP	30	50	80
Plains	Ross/Manitou	BNSF	65	-	65
EOG	Stanley	BNSF	65	-	65
Plains	New Town	CP	65	-	65
Hess	Tioga	BNSF	60	-	60
Musket	Dore	BNSF	60	-	60
Great Northern	Fryburg	BNSF	60	-	60
Other	Various	BNSF	70	-	70
Total North Dakota Capacity			935	50	985
Note: (1) Additions up to the end of 2016					

4 In IHS' opinion, proposed pipelines will add sufficient takeaway capacity for crude oil
 5 from Western Canada and the U.S northern tier to reduce the need for rail loading. As
 6 such, rail loading capacity for crude oil would become underutilized by 2015 or 2016.

²⁷ Shipment of different bitumen blends by rail may contribute to more efficient operation. Rather than ship traditional blends of bitumen and condensate which meet pipeline specifications, blends with lesser volumes of added condensate or no added condensate may be prepared. The costs of rail transportation include loading and unloading charges, transportation charges and tank car lease costs.

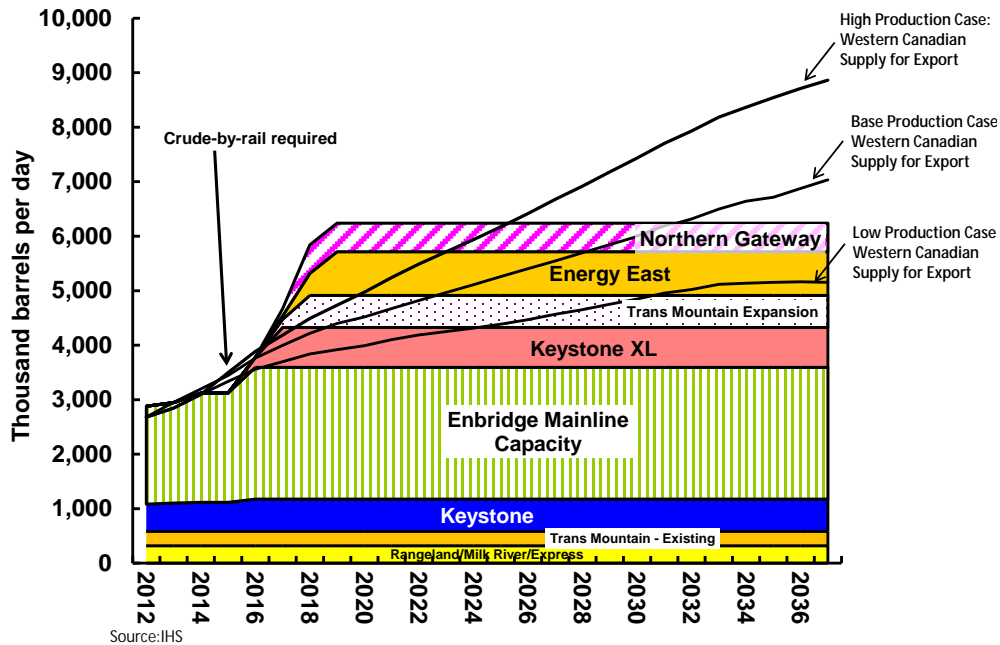


1 However, if new pipelines lag oil sands growth, we expect that rail will be available to fill
 2 the gap. This is consistent with the response observed over the last two years.

3 **IV-8. WESTERN CANADA TAKEAWAY CAPACITY VS. PRODUCTION**

4 The forecast of crude oil supply for export from Western Canada is compared with
 5 pipeline takeaway capacity in Figure A-9, for the Expansion Scenario. The IHS supply
 6 forecast was presented in Section I. The capacity shown in Figure A-9 is at the end of
 7 each year. Western Canada crude deliveries in the Base Case supply forecast increase
 8 from 3.3 million B/D in 2013 to 5.1 million B/D in 2020 and to 6.6 million B/D in 2030.

Figure A-9 - Western Canadian Supply for Pipeline Export vs. Pipeline Capacity



9 Takeaway capacity in 2013 is estimated at 3 million B/D. IHS estimates that there will be
 10 insufficient takeaway capacity until 2016. The use of rail is assumed to supplement
 11 pipeline takeaway capacity to meet this requirement. Rail loading of crude in Western
 12 Canada is estimated to reach its maximum in 2015. From 2016 through 2020, pipeline
 13 capacity expansions and new build projects will result in surplus pipeline capacity,
 14 which will exist until supply growth catches up. The addition of KXL capacity (2016),
 15 the TMEP and the Energy East project (2017) and the Northern Gateway project (2018)
 16 in the Expansion Scenario would result in surplus takeaway capacity. Surplus capacity
 17 is estimated to reach a maximum value of 1.8 million B/D in 2019. By 2030, surplus
 18 pipeline capacity is projected to be absorbed.

19 Table A-13 presents the IHS analysis of available Western Canadian and U.S. northern
 20 tier crude supply for the Expansion Scenario, as well as designated dispositions and



1 remaining supply. The U.S. northern tier has been included in the analysis because
 2 capacity on some export pipelines is allocated to “on-ramps” for Williston Basin crude
 3 production. Included in the designated dispositions are crude deliveries to markets in
 4 Western Canada and Ontario, PADD I, PADD II (Upper Midwest only) and PADD IV.
 5 These are markets with either advantageous access to Canadian crude supply or limited
 6 practical alternatives for supply. Committed volumes of 728,000 B/D are estimated by
 7 2013 in the Enbridge Spearhead and TransCanada Keystone pipelines.

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030	2035	2037
Supply ⁽¹⁾	3,860	4,344	4,686	4,982	5,382	5,765	6,063	6,309	6,480	7,328	7,825	8,483	8,673
Disposition													
Subtotal Advantaged Markets	1,728	1,697	1,687	1,725	1,720	1,719	1,722	1,724	1,726	1,714	1,677	1,610	1,690
Subtotal Term Committed Volumes	728	728	728	728	728	728	728	728	728	728	728	728	728
Potential Term Committed Volumes ⁽²⁾													
Enbridge Gulf Coast Access	-	-	219	439	439	439	439	439	439	439	439	439	439
TCPL Keystone XL (KXL)	-	-	-	-	187	498	747	747	747	747	747	747	747
Enbridge Line 9	-	-	113	225	225	225	225	225	225	225	225	225	225
Trans Mountain Expansion Project	-	-	-	-	-	177	420	640	707	707	707	707	707
TCPL Energy East	-	-	-	-	-	62	400	600	800	900	900	900	900
Enbridge Northern Gateway	-	-	-	-	-	-	223	446	446	446	446	446	446
Subtotal Potential Term Committed Volumes	-	-	332	664	851	1,400	2,454	3,097	3,364	3,464	3,464	3,464	3,464
Total Designated Dispositions	2,456	2,425	2,747	3,117	3,298	3,847	4,904	5,549	5,818	5,906	5,869	5,802	5,882
Remaining Supply ⁽³⁾	1,403	1,919	1,939	1,866	2,084	1,917	1,159	760	662	1,422	1,957	2,681	2,790

Notes: (1) Includes Western Canada and U.S. Bakken production, from IHS Base Case forecasts, August 2013.
 (2) IHS estimates.
 (3) Supply potentially available for Trans Mountain (for PADD V PNW), Enbridge (mainline) or Express (for Platte), spot deliveries to other pipelines or rail.

8 Term volume commitments on proposed projects would reduce available supply for spot
 9 shipments. Line 9 would deliver approximately 225,000 B/D to the Quebec refineries
 10 starting in 2014. KXL (shown with deliveries commencing in 2016) has estimated total
 11 volume commitments of 657,000 B/D. Starting up in 2017, TMEP would increase
 12 capacity to the West Coast with 707,000 B/D of commitments. Energy East would start
 13 up in 2017 to inland markets, and to 2018 to the East Coast. Northern Gateway has been
 14 included with potential term commitments starting in 2018.

15 Remaining supply in Western Canada and the U.S. northern tier, shown in Table A-13 is
 16 the volume of crude available for delivery on Trans Mountain to the Pacific Northwest
 17 region, the Enbridge mainline or Express (for delivery on the Platte system), as well as
 18 spot deliveries on pipelines with set-aside capacity for this purpose, and rail. For
 19 comparison, crude demand in these markets is forecast to be relatively stable at about
 20 1.6 million B/D. The remaining supply is an indicator of the pressure on the crude
 21 supply/demand balance, and is used to inform the IHS crude price forecasts, which are
 22 described later.

23 The future outlook for remaining supply is a function of input assumptions for the
 24 potential term commitments identified above. In 2013, the remaining supply in Western
 25 Canada is estimated at about 1.9 million B/D. Increased crude supply through the end of
 26 the decade is estimated to be offset by term commitments on new pipeline projects. As a
 27 result, with the proposed expansions and new projects proceeding before 2020, the

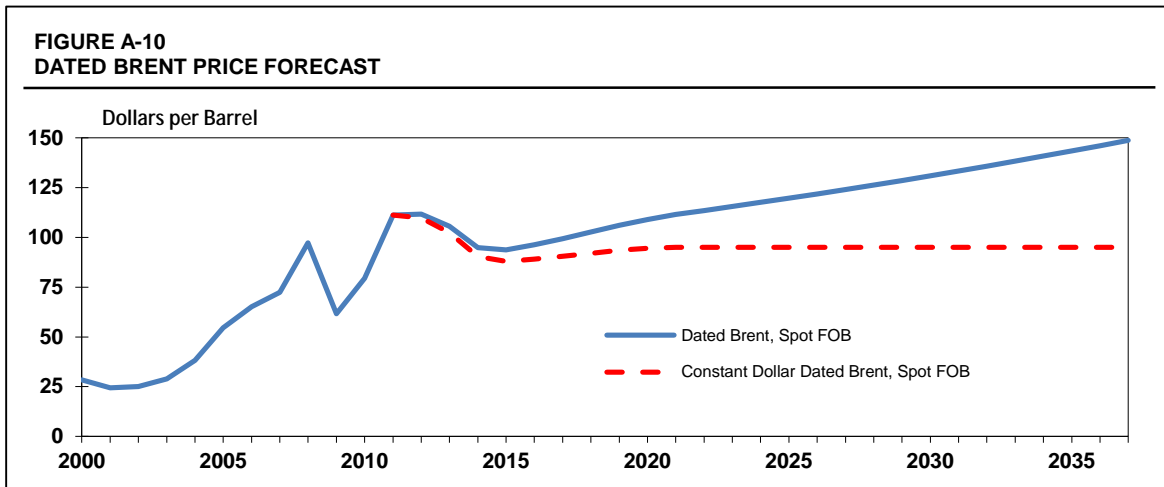


1 estimated remaining supply is estimated to be reduced to about 662,000 B/D in 2020.
 2 Remaining supply grows thereafter, mainly due to bitumen production growth.

3 **V. CRUDE OIL PRICING**

4 The IHS crude pricing forecast methodology begins with the price of Dated Brent crude
 5 oil. This is the starting point in our methodology of projecting crude price differentials.
 6 Brent is a light sweet crude oil which can be processed by most refineries, and which
 7 competes with Middle Eastern and African crudes serving all major markets.

8 Figure A-10 presents the Brent price history and forecast, in current and constant 2012
 9 dollars. Over the past two years the average annual price for Brent has been about \$111
 10 per barrel. This is the highest average price level for crude oil in recorded history, either
 11 in nominal (current) dollars or on an inflation-adjusted constant dollar basis. Our current
 12 long-term oil price outlook has Brent crude oil declining from these record levels to an
 13 annual average of about \$94 by 2015 (\$88 in real 2012 dollars) before rebounding.



14 In 2013 - 2015, we expect the “call on OPEC” to grow just slightly.²⁸ Although world
 15 demand growth is expected to be strong, the increase in non-OPEC crude production
 16 and other liquids growth is robust enough to meet most of it. OPEC productive capacity
 17 will also increase over the next few years, with much of the growth in Iraq. During this
 18 period, we expect downward pressure on prices.

19 As prices moderate, we expect less upstream investment compared with an environment
 20 of continuously rising prices. The lower level of capital expenditures will reduce the pace
 21 of non-OPEC supply growth later this decade, something the markets will anticipate and
 22 reflect with rising prices. Therefore we expect prices to rebound to about \$95 per barrel

²⁸ The “call on OPEC” is the difference between global crude oil demand and non-OPEC crude oil supply.

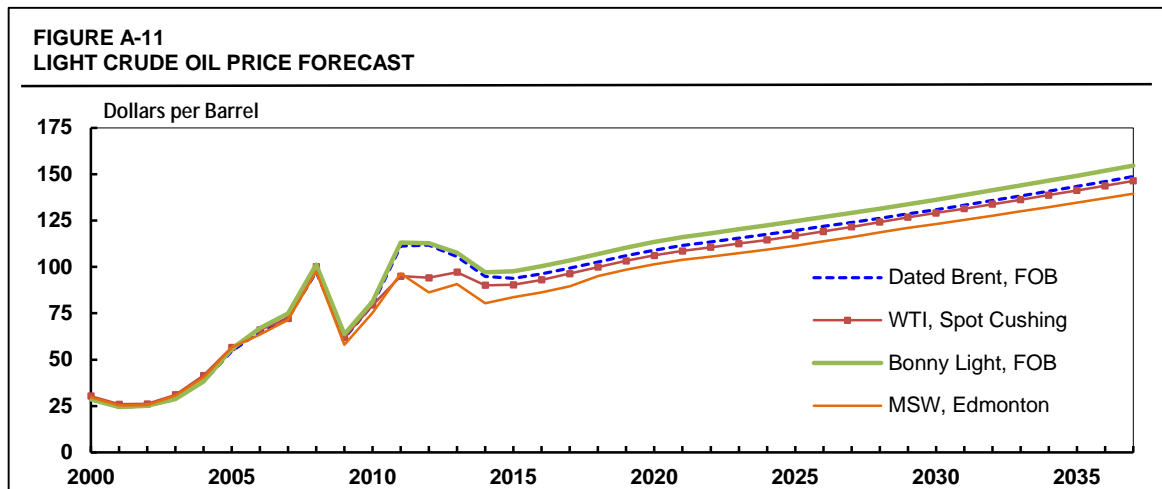


1 in real terms by 2020, remaining flat for the rest of the outlook horizon. In nominal terms,
2 this results in a price of \$142 per barrel by 2035.

3 Once the Brent price level is established, other crude prices can be determined through
4 a combination of location and quality differentials. Price adjustments are also applied as
5 needed based on specific market conditions or structural constraints. Crude quality
6 differentials are based on refining economics and the connection between crude oil price
7 spreads and refined product prices. The marginal refining configuration in a given region
8 is used to estimate the value difference between two crude oils. Product pricing
9 relationships, in particular light/heavy product pricing relationships, largely determine the
10 value difference between crude oils. At the same time, refined product price relationships
11 and differentials are based in part on crude prices and crude balances.

12 V-1. WTI-BRENT DIFFERENTIAL

13 Figure A-11 presents the outlook for selected light sweet crude oils, including Brent,
14 West Texas Intermediate (“WTI”), Bonny Light and Alberta Mixed Sweet Blend (“MSW”).
15 The crudes shown in the figure are discussed later.



16 Since 2010, surging tight oil production in North America has changed historical
17 benchmark crude oil pricing relationships. The most conspicuous change has been the
18 relationship between WTI and Brent, with WTI trading well over \$20 per barrel below the
19 Brent North Sea price during much of 2011, 2012, and early 2013. Prior to 2010, the WTI
20 price at Cushing, OK maintained its connection to international oil prices because of the
21 need for inland U.S. refining markets to supplement their crude supply with offshore
22 imports (which were delivered to the region from the Gulf Coast via northbound
23 pipelines). However, since 2010, growth in U.S. and Canadian supply has overwhelmed
24 local refinery demand in markets in and around Cushing, depressing WTI prices and
25 disconnecting WTI from international prices (represented by Brent).

1 The solution to this situation has been the revitalization of the link between Cushing and
2 the international market via southbound pipelines, so surplus crude oil in and around
3 Cushing can access the large refining market on the Gulf Coast. Several projects have
4 been completed or are in progress, as summarized in Table A-11. These projects should
5 provide ample capacity for crude supply around Cushing to transit to the Gulf Coast. We
6 forecast that by the end of 2013, the WTI Cushing price will be around \$5.50 per barrel
7 below Louisiana Light Sweet (“LLS”).²⁹ This represents the pipeline tariff cost (plus small
8 differences in crude quality) to move crude from Cushing to the Gulf Coast.

9 **V-2. LIGHT-HEAVY CRUDE PRICE DIFFERENTIAL**

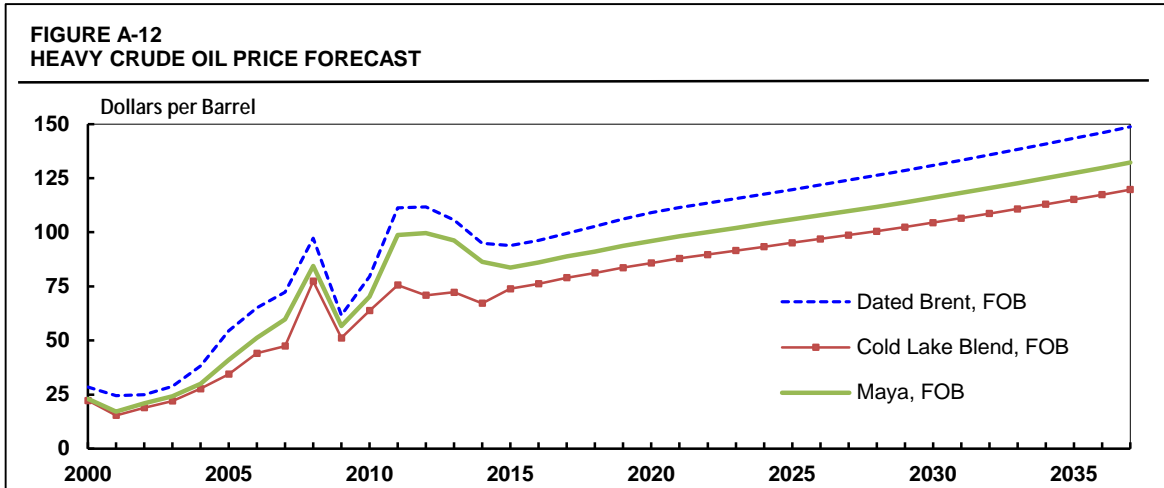
10 The price differential between light and heavy crude oil grades primarily reflects the price
11 relationship between light refined products (such as gasoline and diesel) and heavy
12 products (heavy fuel oil). In our methodology, the Brent and Maya differential is used as
13 an indicator of the general trend in light-heavy crude oil price differentials. Light-heavy
14 differentials are a key element in heavy crude production economics, refining margins,
15 and refining investment.

16 The light-heavy product and light-heavy crude spreads are driven by refinery conversion
17 economics. For example, when there is a need for the global refining system to keep
18 pace with light product demand growth and add conversion capacity (through investment
19 or increased utilization), light product prices strengthen relative to heavy fuel oil, which
20 increases margins for conversion refineries able to upgrade heavy fuel oil into light
21 products.

22 Maya is the basis for analysis of Western Canadian heavy crude prices in North
23 America. The long term forecast for Maya, FOB is presented in Figure A-12. Cold Lake
24 Blend is priced in North American markets. While its price can be related to Maya there
25 are a number of factors, including logistical constraints, which can contribute to wide
26 discounts. This situation has existed since 2010.

²⁹ Light Louisiana Sweet (“LLS”) is the key domestic light sweet crude grade in the U.S. Gulf Coast.





1 **V-3. PRICE RELATIONSHIPS FOR WESTERN CANADIAN CRUDE OILS**
 2 **ON THE U.S. WEST COAST**

3 The relationship of crude oil prices on the U.S. West Coast to other regional and
 4 international markets has reflected the regional supply/demand balance. ANS is a light
 5 sour crude produced in PADD V. Given that PADD V will increasingly depend on
 6 imported crude supplies, the IHS outlook for ANS price reflects parity values that are
 7 consistent with delivered Middle East crude.

8 U.S. West Coast refineries could import more Canadian crudes if they were priced
 9 competitively and sufficient transportation infrastructure was available. Opportunities
 10 exist for oil sands crudes, as described in Section II-4. Price relationships for oil sands
 11 crudes on the West Coast are described below. The potential impact of West Coast
 12 pricing on Alberta netback prices is discussed later in this section.

13 **Light Sweet SCO**

14 Light sweet SCO, such as Syncrude SSP, has no vacuum residue so it has a higher
 15 refining value than ANS and other light sour crudes based on cracking refinery yields.
 16 IHS does not expect that sweet bottomless SCO will have a significant market in
 17 California coking refineries. On the other hand, cracking refineries in Washington State
 18 can use SCO, and do so if it is priced competitively. IHS values SSP in Washington State
 19 against a Middle East light sour import barrel. Price discounts since 2010, due to pipeline
 20 constraints in inland markets, have affected SCO as well as conventional light crude,
 21 making it more attractive to refiners in the region. IHS forecasts prices of SCO based on
 22 clearing the market in the Midwest, so it is normally priced attractively for Washington
 23 State. Any future price discounts due to growing SCO availability would make the crude
 24 more attractive in Washington State, compared with its refining value.



1 **Heavy Blends**

2 California is expected to require a growing amount of imported heavy crude. IHS
3 forecasts prices there for Canadian heavy blends including Cold Lake Blend (“CLB” or
4 “DilBit”), using the valuation principles described above. IHS forecasts the prices of
5 Canadian bitumen blends in California based on the price of a Middle East light sour
6 import barrel, which values imports appropriately against the incremental supply for the
7 region. DilBit has a higher content of vacuum residue than light sour crudes, so its
8 refining value is lower. Trans Mountain delivers heavy crude through its Westridge
9 Marine Terminal which may be shipped to the California market. As noted in Section II-4,
10 California refineries have been increasing imports of Western Canadian crude. This
11 trend is expected to continue.

12 **V-4. PRICE RELATIONSHIPS FOR WESTERN CANADIAN CRUDE IN ASIA**

13 Canadian crudes are currently available to the Asian market via Trans Mountain's
14 Westridge Marine Terminal. If additional pipeline capacity is built to the Canadian West
15 Coast, more Canadian crudes could be shipped to Asia. The TMEP would provide
16 additional capacity for the Asian market.

17 In its global analysis, IHS prepares estimates for the balance of crude oil flows in the
18 world, on an overall basis and by major quality grade. Many Asian countries have
19 indigenous crude oil production. However, Asia imports most of the crude required to
20 meet refined product demand. The majority of Asian imports are from the Middle East,
21 although imports from West Africa are rising. Arab Light and Bonny Light are used as the
22 light sour and light sweet marker crudes in the Asia-Pacific region, respectively.

23 Western Canadian crudes that could be available for the Asian market include light
24 conventional crudes, sweet SCO, conventional heavy and bitumen blends. In addition,
25 other grades of crude that could be tailored to the needs of the Asian refineries may be
26 produced. Light grades could be of interest in Japan, China and other countries, whereas
27 a heavy blend would most likely be used in China and India. This was described in
28 Section III.

29 **Light Sweet SCO**

30 Sweet SCO such as Syncrude SSP may be expected to compete with conventional light
31 sweet crude in North Asian markets. The price for the benchmark light crude, Bonny
32 Light, is likely to serve as the basis for establishing sweet SCO prices in the region.

33 Sweet SCO has a high proportion of VGO, which would become low sulphur residual fuel
34 oil (“RFO”) in a relatively simple (hydroskimming) refinery. There are large RFO markets
35 in Asia. As a result, we estimate the refining value of SCO to be near that of Bonny Light.
36 IHS believes there would also be opportunities to enhance market potential through
37 alternative formulations of light sweet SCO with less VGO. Such a crude would have



1 more value in a hydroskimming refinery, and might also prove attractive to refineries in
2 Asia with cracking configurations.

3 **Heavy Blends**

4 Refineries in Northeast Asia currently use relatively small volumes of heavy crude, and
5 any heavy crude being processed is not likely to be as heavy as oil sands blends such
6 as DilBit. Most of the current heavy crude use in Asia is in China. Trans Mountain is
7 understood to have delivered heavy crude for Asian markets on a spot basis.

8 IHS believes that significant future potential exists to place growing volumes of Western
9 Canadian heavy crude in Asia. Heavy crude processed by Asian refineries would likely
10 be marketed under long-term supply agreements or through structural arrangements
11 between companies with common ownership. Refining capacity may be constructed or
12 modified to use more heavy crude, particularly in China. The growth potential for heavy
13 blends in Asia, particularly in China and India, was discussed in Section III.

14 **V-5. CRUDE NETBACK PRICES IN ALBERTA**

15 Netback values are forecast from markets in the Asia/Pacific region, including the U.S.
16 West Coast and Northeast Asia. The refining valuation principles for Canadian oil sands
17 crudes in California, Washington State and Asian markets were discussed in Section V-3
18 and Section V-4. Netback values depend on refinery gate prices and transportation costs
19 from Alberta. The forecast netback values at Edmonton are presented in Table A-14, in
20 current and constant 2012 dollars. The analysis summarized here is based on the IHS
21 supply/demand balance, and our current estimate of pipeline tolls and tanker costs. The
22 outlook is based on the pipeline infrastructure developments described in Section IV,
23 which are included in the Expansion Scenario.



	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2037
Inflation Factor (2012 = 1.00)	1.10	1.11	1.13	1.15	1.17	1.20	1.22	1.24	1.35	1.48	1.54
<u>Current U.S. Dollars per Barrel</u>											
Sweet SCO											
From Midwest / USGC ⁽²⁾	103.05	106.60	109.71	112.23	114.26	116.32	118.42	120.72	133.56	146.32	151.70
From Washington	110.48	114.20	117.38	120.21	122.43	124.75	127.09	129.38	141.76	156.29	162.44
From Japan	104.68	108.27	111.42	114.04	116.18	118.38	120.61	122.87	134.77	147.94	153.50
Cold Lake DilBit											
From Midwest / USGC ⁽²⁾	81.21	83.65	85.76	87.90	89.70	91.53	93.34	95.16	104.45	106.48	110.56
From California	84.89	87.85	90.45	92.70	94.38	96.19	97.98	99.70	109.23	120.39	125.11
From China	86.12	89.12	91.66	93.89	95.60	97.41	99.21	100.97	110.56	121.80	126.56
<u>Forecast in Constant 2012 U.S. Dollars per Barrel</u>											
Sweet SCO											
From Midwest / USGC ⁽²⁾	93.95	95.63	96.77	97.31	97.32	97.32	97.34	97.48	98.64	98.62	98.59
From Washington	100.73	102.44	103.54	104.23	104.28	104.38	104.46	104.47	104.70	105.34	105.57
From Japan	95.44	97.12	98.28	98.88	98.96	99.04	99.13	99.21	99.53	99.72	99.75
Cold Lake DilBit											
From Midwest / USGC ⁽²⁾	74.04	75.04	75.65	76.21	76.40	76.58	76.72	76.83	77.14	71.77	71.85
From California	77.39	78.81	79.78	80.38	80.39	80.48	80.53	80.50	80.67	81.15	81.30
From China	78.52	79.94	80.85	81.40	81.43	81.50	81.54	81.53	81.65	82.10	82.24
Notes: (1) Netback values assuming price parity at each market location; not a forecast price unless noted. (2) Indicates IHS forecast price.											

1 Table A-15 provides estimated transportation costs for crude delivery from Edmonton to
2 identified Pacific markets in 2017. Costs include estimated TMEP tolls and waterborne
3 tanker transportation charges. For this analysis, and to be conservative, the use of
4 Panamax tankers is assumed. If Aframax tankers are utilized, then per barrel costs for
5 waterborne transportation would be reduced.

Crude/Market	Trans Mountain Toll ^{(1) (2)}	Tanker		Total
		Size	Rate	
Light Crude				
Japan (Yokohama)	4.36	Panamax	3.12	7.48
Singapore	4.36	Panamax	4.65	9.01
Heavy Crude				
California	4.42	Panamax	1.54	5.96
China (Shanghai)	4.42	Panamax	3.52	7.95
India (Jamnagar)	4.42	Panamax	6.36	10.78
Notes: (1) Based on Trans Mountain Expansion Project TSA, for annual term deliveries < 75,000 barrels (2) Converted from \$CDN at assumed exchange rate of 0.92 \$US/\$CDN				

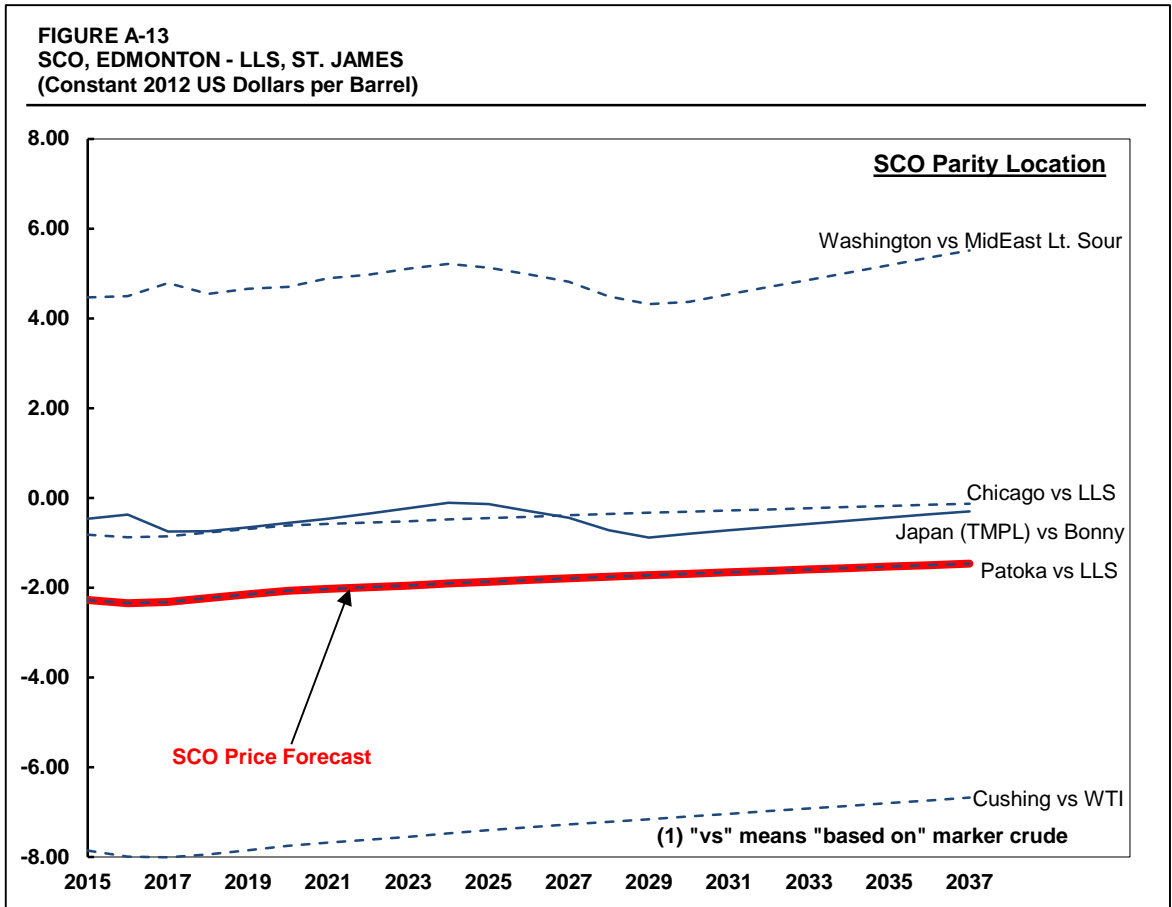


1 **LIGHT SWEET SCO NETBACK PRICES**

2 Light sweet SCO production is expected to grow at a relatively slow pace through 2020,
 3 due to the cancellation or postponement of upgrader projects in Alberta. Despite this,
 4 new SCO projects in 2009 and 2010 have increased supply, so the availability of
 5 segregated SCO is forecast to increase through 2020. As a result, the price of SCO is
 6 forecast to weaken toward Patoka parity versus LLS by 2015, and remain at that level
 7 through the forecast period.

8 To assess the potential impact of netback prices from other market locations, IHS
 9 evaluates Syncrude SSP prices in the U.S. Midwest, Washington State as well as Japan.
 10 The Edmonton netback values from different market locations are compared with the IHS
 11 price forecast in Figure A-13. Chicago and Patoka netback prices assume parity with
 12 LLS rather than WTI, as this would likely be the crude processed in these locations.

13 Based on our price forecast (denoted by the red line in Figure A-13), SCO should be
 14 attractive to refineries in Washington State and northern PADD II (around Chicago). SCO
 15 should also be attractively priced for refineries in Japan using Trans Mountain (based on
 16 estimated future TMEP tolls) through Vancouver.

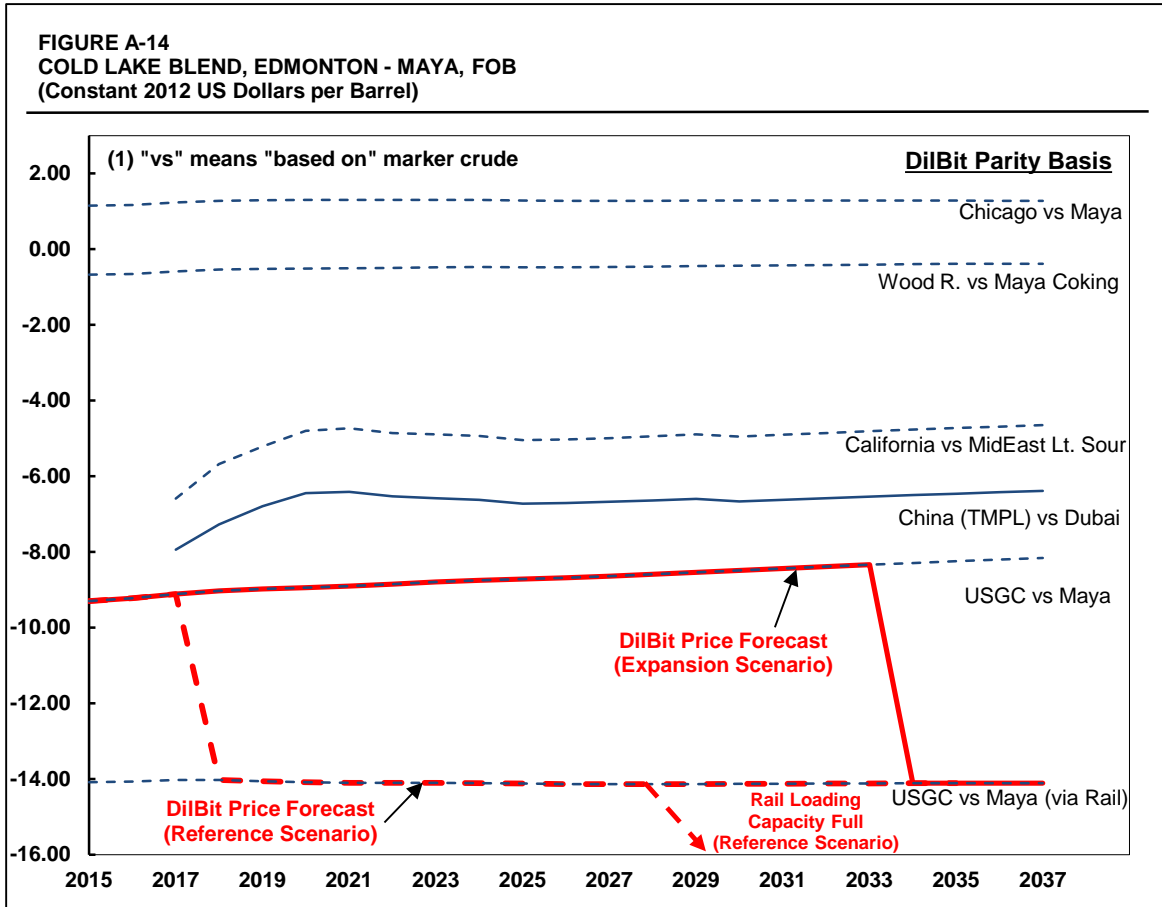


1 COLD LAKE DILBIT NETBACK PRICES

2 The historical growth in supplies of Canadian heavy crude blends, combined with recent
3 infrastructure developments, means that some of this crude now reaches the U.S. Gulf
4 Coast. IHS expects Canadian prices to strengthen from 2013 to 2016, due to more
5 refinery coking capacity and additional crude pipeline capacity such as the Enbridge
6 Flanagan South / Seaway projects. The CLB (DilBit) price is forecast to strengthen to
7 U.S. Gulf Coast parity with Maya by 2016. The basis for the calculated netback is the
8 Enbridge-Pegasus pipeline routing. The CLB price is expected to remain at U.S. Gulf
9 Coast parity in the Expansion Scenario, based on pipeline transportation costs.
10 However, starting in 2033, we estimate that there will be excess supply of crude for
11 pipeline disposition; the Edmonton price is forecast to weaken to the equivalent of a rail
12 transportation netback from the U.S. Gulf Coast as a result. Prior to 2033, a tight balance
13 for heavy crude suggests that prices would be set by Gulf Coast parity on a spot pipeline
14 delivery basis. The uncommitted tolls on Keystone XL are not known at present, but may
15 become the price-setting basis for Canadian heavy crude during this period if the tolls
16 are lower.

17 DilBit netback prices versus benchmarks in the U.S. Midwest, California, China and the
18 U.S. Gulf Coast are compared in Figure A-14. At the U.S. Gulf Coast netback price,
19 DilBit would be attractive to heavy crude refineries in the U.S. Midwest. IHS assessed
20 the value of DilBit in California, as this is considered to be a potential growth market for
21 heavy bitumen blends. Based on the U.S. Gulf Coast parity price, refineries in California
22 should find DilBit to be priced attractively. This should support further growth in
23 deliveries to this market. DilBit is also estimated to be priced competitively in China
24 throughout the forecast period, based on the TMEP term toll.





1 Our forecast of the CLB netback price in the Reference Scenario, without the major
 2 export pipelines (TMEP, Energy East and Northern Gateway) is shown in Figure A-14.
 3 IHS estimates that the available supply of heavy crude in this case is in excess of the
 4 pipeline capacity to connected markets. As a result, the netback price is shown
 5 weakening to the equivalent of the rail netback price from the U.S. Gulf Coast, for an
 6 extended period, beginning as early as 2018.

7 Furthermore, the IHS analysis of the balance for this scenario suggests that the current
 8 rail loading capacity would be inadequate to handle the volume of surplus crude well
 9 before 2030. This indicates that prices may weaken below the U.S. Gulf Coast rail parity
 10 price, which is directionally shown in Figure A-14. In our opinion, this could again give
 11 rise to the type of extraordinary discounts observed in recent years for Canadian heavy
 12 crude.

13 **V-6. IMPLICATIONS OF NETBACK PRICING RESULTS**

14 The availability of bitumen blends is forecast to increase through 2037. The marketed
 15 supply of crude oil will depend on the production of raw bitumen, upgrading project
 16 developments, and the availability of suitable diluent streams. Comparative netback
 17 pricing in Alberta for the major oil sands marketed streams has been broadened to



1 include potential markets in the Asia/Pacific region, which may become accessible via
2 TMEP. The opportunity to deliver oil sands crudes to refineries in California and several
3 Asian countries would be facilitated by such developments. As noted previously, an
4 increasing need for imported crude oil supplies is expected in these regions. TMEP
5 provides access to these growth markets.

6 As noted in Section V-5, DilBit should be attractive in California and China for the
7 forecast period. Trans Mountain is already delivering heavy crude for markets in the
8 Pacific Rim. The results presented above suggest that crude deliveries to these markets
9 should increase due to favourable pricing. IHS notes that the volume of Canadian oil
10 sands crude that eventually reaches these markets over the forecast period will depend
11 on refining economics and on other factors. These include the pace and extent of other
12 infrastructure developments, product market and quality considerations, the availability
13 of suitable refinery capacity, tanker and pipeline transportation costs, environmental
14 legislation across jurisdictions and in some cases, the ability of industry participants to
15 conclude commercial arrangements for strategic long-term supply.



APPENDIX B: RESUME OF PROFESSIONAL QUALIFICATIONS STEVEN J. KELLY

1 EDUCATION

2 B.Eng. Chemical Engineering from McMaster University (Hamilton, Ontario) in 1982.

3 M.Eng. Chemical Engineering from McMaster University (Hamilton, Ontario) in 1985.

4 M.B.A. from University of Calgary (Calgary, Alberta) in 1998.

5 PROFESSIONAL ASSOCIATIONS

6 Association of Professional Engineers and Geoscientists of Alberta (APEGA)

7 Canadian Heavy Oil Association

8 CURRENT POSITION

9 Vice President, Downstream Energy Consulting, IHS Calgary

10 WORK EXPERIENCE

11 Mr. Kelly joined Purvin & Gertz (acquired by IHS in 2011) in 1996, and has applied his
12 experience in the analysis of crude oil and petroleum markets as a consultant for more than 17
13 years. His focus has been on markets in Canada, the U.S. Midwest and the Pacific Rim. Mr.
14 Kelly has assisted numerous crude oil producers in the development of marketing strategies. His
15 experience includes projects for a variety of conventional light, heavy and synthetic crude oils.
16 Through these assignments, Mr. Kelly has developed significant expertise in heavy crude
17 upgrading. Mr. Kelly has significant experience with logistical issues, and has assisted clients in
18 a range of petroleum transportation studies. In addition, he has worked with Purvin & Gertz study
19 teams in the simulation and modeling of refineries and has assisted clients in a number of
20 competitive analysis studies.

21 Mr. Kelly managed the firm's European market analysis activities while on a foreign
22 assignment (August 2001 through July 2005). He returned to Calgary in July 2005 and assumed
23 the role of Calgary office manager in January 2006.

24 Mr. Kelly joined Purvin & Gertz from Shell Canada Limited, where he was involved in
25 manufacturing and supply optimization activities at their corporate headquarters. In that capacity,
26 he identified short-term profitability opportunities for Shell's Canadian refining operations. He
27 participated in several strategic planning and re-engineering studies, and has extensive



1 experience with the use and construction of optimization models. Mr. Kelly worked as a refinery
2 operations engineer at Shell's Scotford Refinery. Mr. Kelly has a graduate degree in process
3 control, and has developed applications for a wide range of refinery units. Prior to joining Shell
4 Canada, Mr. Kelly was employed by Polysar Limited for two years at its Sarnia manufacturing
5 facility, as a process engineer.

6 REPRESENTATIVE MAJOR PROJECT EXPERIENCE

7 MARKET ANALYSIS

- 8 · **CRUDE OIL & OIL SANDS MARKET OUTLOOK** – Mr. Kelly was a co-developer of
9 this service, which presented long range outlooks for North American crude oil
10 supply, disposition and pricing, with a focus on the Canadian oil sands. The service
11 included detailed crude balances and refining industry analysis, as well as regional
12 crude and refined products pricing and refining margins.
- 13 · **GLOBAL MARKETS FOR CANADIAN OIL SANDS CRUDES** – Mr. Kelly directed this
14 major multiclient study, which investigated supply, disposition and pricing issues for
15 a range of crudes available from the Canadian oil sands. The study considered
16 markets in North America and selected Northeast Asian countries, economics of
17 various upgrading configurations, production and trade scenarios, and analysis of
18 infrastructure requirements for Canadian crude exports.
- 19 · **GLOBAL PETROLEUM MARKET OUTLOOK** – Mr. Kelly has prepared many
20 contributions to this major multi-client service. The service covered refined product
21 demand projections for each country, trade balances, and refining industry analysis.
22 Mr. Kelly completed detailed analysis of petroleum demand projections for Europe
23 (while on an overseas posting), and contributed to the analysis of the North
24 American petroleum outlooks.
- 25 · **INTRODUCTION TO UPGRADING, REFINING & ECONOMICS COURSE** – Mr. Kelly
26 developed the content and manages this two-day course, and participates as an
27 instructor. The course provides attendees with a unique introduction to the
28 downstream petroleum sector, with particular focus on issues of interest to
29 Canadian oil sands industry players. The course has been offered twice annually
30 since 2008.
- 31 · **EUROPEAN MARKET ANALYSIS** – Mr. Kelly had responsibility for the European
32 edition of Purvin & Gertz' monthly Crude Oil & Refining Outlook service while on an
33 overseas posting. This multi-client service provides ongoing analysis of European
34 products supply/demand trends and refining operations, and develops projections of
35 refining margins and crude oil and refined product prices.
- 36 · **OUTLOOK FOR RUSSIAN PETROLEUM TRADE TO EUROPE** – Mr. Kelly directed
37 this multi-client study that investigated regional demand and trade issues for Europe



- 1 and adjacent Commonwealth of Independent States. Crude oil production and
2 logistics in Russia were evaluated, as a driver of refining activity and product
3 surpluses. The study included regional balances for Russia and the interface
4 countries, as well as pricing dynamics for crude oil and products at selected points
5 within Russia.
- 6 • **CRUDE OIL & REFINING OUTLOOK** – For five years, Mr. Kelly prepared the U.S.
7 Midwest/Canadian edition of this monthly multi-client service, which provided
8 in-depth analysis of the supply/demand balance for Canadian crudes, and
9 equilibrium pricing relationships between benchmark crudes. Mr. Kelly was
10 responsible for ongoing monitoring of U.S. Midwest petroleum product markets,
11 including supply/demand balances, pricing and refining margins.
- 12 • **INTERNATIONAL CONDENSATE SUPPLY/DEMAND** – As part of a wide-ranging
13 study of LPG and condensate markets, carried out in support of a proposed
14 investment in North African exploration and production, Mr. Kelly analyzed
15 international condensate production projects, splitting/refining projects, and
16 condensate demand trends. Analysis included development of inter-regional trade
17 matrices, which were used in conjunction with other information to assess the price
18 setting mechanisms for various condensates.
- 19 • **HEAVY CRUDE MARKET STUDY** – Mr. Kelly was the director of a large multiclient
20 study, which investigated supply, disposition and pricing issues for heavy crude. The
21 scope of the study covered Western Hemisphere production regions, and
22 considered the key market regions in Canada and the U.S. Strategic issues facing
23 market participants were investigated.
- 24 • **NATURAL GAS/NGL MARKET ANALYSIS** – Mr. Kelly has been involved in a number
25 of studies related to natural gas and NGL markets. Studies have included an
26 evaluation of supply/demand fundamentals and forecasts of North American regional
27 natural gas prices. Mr. Kelly has also prepared long-range natural gas and NGL price
28 forecasts.

29 **CRUDE OIL/REFINED PRODUCTS MARKETS AND LOGISTICS**

- 30 • **WILLISTON BASIN CRUDE MARKET STUDY** – The market and logistical forces
31 behind severe discounting of crude produced in the Williston Basin area of Montana
32 and North Dakota were studied for an industry group by a Purvin & Gertz team led by
33 Mr. Kelly. The study estimated the impact of proposed pipeline solutions and the
34 potential for restrictions on pipeline crude qualities.
- 35 • **NORTH DAKOTA REFINING CAPACITY ANALYSIS** – Steven led PGI's activities
36 for this study. Purvin & Gertz was part of a study team that evaluated the implications
37 of additional refining capacity potentially being developed in North Dakota. PGI's
38 analysis included crude oil and refined products price impacts, and was based on
39 logistical optimization models developed for the assignment.



- 1 · **CRUDE EXPORT PIPELINE QUALITY BANK DESIGN** – PGI advised a consortium on
2 the design of a quality bank for a major crude export pipeline. Mr. Kelly managed Purvin
3 & Gertz activities on this assignment, which included identification of potential crude oils
4 that may be served by the pipeline, and analysis of different options for the mechanism
5 of the quality bank and formulation of proposals to the consortium.
- 6 · **CRUDE OIL MARKETS AND PRICING FOR CASPIAN CRUDE** – On behalf of a
7 consortium of crude oil producers in the Caspian region, Steven directed a study of the
8 likely markets for the potential export stream. Markets analyzed included Europe, the
9 Far East, the U.S. and Latin America. Pricing projections were based on full refining
10 value analysis from available crude assay data. Netback values to the assumed load
11 port were calculated.
- 12 · **CRUDE OIL VALUATION AND MARKETING** – Steven has undertaken several
13 assignments to value new crude oil production streams relative to internationally traded
14 crudes. In many cases the value of the new crude has been developed both as a stand-
15 alone production stream and as a component of a commingled stream in a common
16 carrier pipeline system. This work has also involved assisting in developing marketing
17 strategies, identifying potential buyers with favorable logistics and appropriate refining
18 capacity.
- 19 · **CRUDE EVALUATION MODELLING** – Mr. Kelly participated on a Purvin & Gertz study
20 team that prepared models of refining valuations for a major Middle Eastern crude
21 producer. His objective in this study was to define refinery configurations for the
22 European markets that could potentially process crude oil from the client, and develop
23 real-time models for refining value differentials against defined benchmark crude oils.
- 24 · **CRUDE OIL MARKET ANALYSIS** – Mr. Kelly has developed refining values and
25 comparative economics for many North American, North Sea and various other
26 international crude oils. This work has been completed in numerous single client
27 projects. Through this work Mr. Kelly has developed specific expertise in the valuation of
28 synthetic crude oils.

29 **REGULATORY ASSISTANCE**

- 30 · **PIPELINE TOLL HEARING** – Mr. Kelly acted as an independent expert in a toll
31 hearing before the National Energy Board, relating to the proposed tolling
32 methodology for a major capacity expansion to an existing pipeline system in
33 Western Canada. He prepared direct evidence, provided advice and input for
34 information requests, and provided oral testimony at the hearing.
- 35 · **THROUGHPUT ANALYSIS** – Mr. Kelly led the firm's activities in support of a National
36 Energy Board application being prepared by a pipeline company with operations in
37 Western Canada. PGI developed throughput forecasts for the pipeline under a range
38 of input premises.



- 1 · **PIPELINE TOLL HEARINGS** – Mr. Kelly provided consulting assistance to an
2 intervenor in two separate regulatory applications relating to a crude oil pipeline in
3 Eastern Canada. He prepared direct evidence relating to alternative uses of the
4 pipeline facilities, and participated in the information request process. In each case,
5 the matter was resolved prior to proceeding to an NEB oral hearing.
- 6 · **PIPELINE TOLL HEARING** – Mr. Kelly provided consulting assistance to an
7 intervenor in a regulatory application relating to a crude oil pipeline in British
8 Columbia. He prepared direct evidence relating to future utilization of the pipeline,
9 and participated in the information request process. The matter was resolved prior to
10 proceeding to an oral hearing.
- 11 · **PIPELINE FACILITIES HEARING** – As part of a study team engaged by a
12 group of producers, Mr. Kelly participated as an independent expert in a facilities
13 hearing before the National Energy Board, relating to the proposed reversal of an oil
14 pipeline in Eastern Canada. He prepared direct evidence, provided advice and input
15 for information requests, and provided oral testimony.
- 16 · **LEADED GASOLINE ADDITIVES** – Steven led the company’s activities in providing
17 consulting support to a legal firm, engaged in a dispute relating to a supply contract
18 for the leaded gasoline additive, tetraethyllead (TEL). This involved analysis of the
19 technical and commercial aspects of TEL production, and review of global markets
20 for leaded gasoline.

21 **STRATEGIC BUSINESS ADVICE**

- 22 · **PORT STRATEGIC PLAN** – A North European port commissioned Purvin & Gertz to
23 conduct a strategic planning study. Mr. Kelly led the study. In light of potential
24 changes in the port’s business environment, the assignment focused on
25 identification and ranking of alternative businesses that could be developed at the
26 facility. Purvin & Gertz provided an analysis and ranking of a wide range of options,
27 after evaluating the business environment.
- 28 · **FUELS REFINERY INVESTMENT ANALYSIS** – A European refiner facing significant
29 refinery investments to produce ultra-low sulphur fuels commissioned Purvin &
30 Gertz to evaluate several alternatives. Mr. Kelly led the company’s efforts to
31 simulate current refinery capabilities, using a proprietary optimization model. A
32 detailed analysis was completed, to assess the impact of each alternative on the
33 forecast refining margin.
- 34 · **CRITICAL REVIEW OF BUSINESS PLAN** – As part of an independent review of a
35 proposed privatization, Steven was required to review the future earning projections
36 relating to petroleum retailing outlets in India. Opinions were developed to realistic
37 target penetrations that could be achieved and issues were raised concerning the
38 impact of delays in foreseen regulatory changes.



- 1 · **EUROPEAN LIGHT PRODUCTS MARKETS STUDY** – In support of a client's analysis
2 of condensate disposition options, Mr. Kelly was closely involved in an analysis that
3 studied a range of alternatives to process or to sell a new condensate stream. In
4 addition to analyzing refining investments and economics, the study examined the
5 outlook for markets for light products, and particularly for gasoline and naphtha
6 markets.
- 7 · **REFINING STRATEGIC STUDY** – A refiner with multiple operations engaged Purvin
8 & Gertz to analyze its competitive position among its peer group. Detailed LP
9 analyses were used to assess crude slate and product yield profitability of refineries
10 in the study group. Study recommendations allowed the client to improve its
11 competitive position.
- 12 · **MIDWEST/CANADIAN REFINING STRATEGIC STUDY** – As part of a study team, Mr.
13 Kelly was involved in an evaluation of U.S. Midwest and Ontario refiners in the
14 current and future business environment. Refineries were modeled using Purvin &
15 Gertz' proprietary LP and operating cost models. Comparative margins were
16 developed for each refinery. Regional profitability rankings were compiled, and a
17 number of recommendations were tabled.
- 18 · **HEAVY OIL DILUENT STRATEGIC STUDY** – Mr. Kelly was part of a Purvin & Gertz
19 study team engaged to evaluate strategic options for a heavy crude oil producer,
20 relative to the availability and pricing of diluent. The results of the study included
21 recommendations for strategic management of diluent supply.
- 22 · **CANADIAN REFINING INDUSTRY COMPETITIVENESS STUDY** – Mr. Kelly worked as
23 part of a Purvin & Gertz study team, engaged to evaluate the competitiveness of the
24 Canadian refining industry, in the current business climate and with varying degrees
25 of fuel reformulation. Detailed LP models and operating cost models were prepared
26 for the refineries in the study group. Cash flow models were developed to assess
27 the impact of fuel sulphur reduction on these refineries. The strategic implications of
28 fuel reformulation were assessed, for individual refineries and regional segments of
29 the Canadian industry.
- 30 · **HEAVY CRUDE MARKET EVALUATION** – A group of heavy crude producers
31 retained PGI to investigate potential market growth opportunities for heavy crude.
32 Mr. Kelly was responsible for evaluating comparative refining values for key grades.
33 He also estimated capital expenditures and processing economics for a number of
34 refineries that were identified as candidates to run heavy crude.
- 35 · **BITUMEN UPGRADING STUDY** – Mr. Kelly developed a series of heavy oil
36 upgrading schemes that were analyzed for a study evaluating opportunities to
37 expand bitumen markets. The case studies were prepared for an industry group
38 interested in a variety of options ranging from no field upgrading to full upgrading to
39 synthetic crude. A key part of this assignment was the development of partial
40 upgrading options, integration with petroleum refiners, and identification of the
41 technical and economic issues associated with these types of projects.



- 1 · **SYNTHETIC CRUDE MARKET STUDY** – Mr. Kelly has directed and participated in
2 numerous studies for current and potential Western Canadian synthetic crude
3 producers. The studies have investigated strategic options for the expansion of
4 existing refining markets for oil sands production. Through this work he has
5 considered markets across North America, and modeled all potential synthetic crude
6 refiners.
- 7 · **CLIMATE CHANGE OPTIONS PAPER** – Mr. Kelly directed a study that analyzed the
8 cost and competitiveness impacts on the Canadian refining industry, of selected
9 technical options for greenhouse gas emission reductions. The analysis included
10 development of project capital and operating costs for all Canadian fuels refineries.
11 GHG reduction potential and regional economic impacts on the industry were
12 assessed, and an analysis of refinery viability under different policy options was
13 developed.



Appendix B The Trans Mountain Expansion Project: Understanding the Economic Benefits for Canada and its Regions, The Conference Board of Canada



The Conference Board
of Canada

Le Conference Board
du Canada

CUSTOM REPORT

The Trans Mountain Expansion Project: Understanding the Economic Benefits for Canada and its Regions

Presented: November 30, 2013

Presented by: The Conference Board of Canada

Presented to: Trans Mountain Pipeline (ULC)

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Executive Summary

Oil is a global commodity, with a well established transportation infrastructure. As a result, global benchmark prices are usually nearly identical to one another once adjustments for quality and transportation costs are taken into account. However, this has not been the case in recent years, with Canadian benchmark prices lagging considerably behind their global peers. The combination of stagnant North American demand, rising North American production, and an oil transportation infrastructure that is largely confined to exporting Canadian production to the U.S. Midwest all contributed to this outcome. The result is that Canada has not been getting the full fiscal and economic benefits associated with exploiting its non-renewable oil resources.

In response, there has been growing interest in developing new oil pipeline infrastructure in North America. There are currently four major pipeline projects under consideration that would carry oil away from Western Canada if completed. One of these is the Trans Mountain Expansion Project (TMEP or the Project), which would nearly triple the capacity of the existing pipeline that runs from Edmonton, Alberta to Burnaby, British Columbia. The objective of this report is to assess the economic and fiscal impacts associated with the proposed expansion of the Trans Mountain pipeline. We do this in three ways:

- Assessing the impacts associated with the initial required investments to build the pipeline and related infrastructure.
- Assessing the impacts associated with operating the pipeline once it is up and running.
- Assessing the impacts associated with higher netbacks to oil producers that are expected to result from smaller price differentials between Canadian and international oil price benchmarks.

Impacts of TMEP's Development Phase

If approved, the TMEP is expected to cost approximately \$5.5 billion¹, with the expenditures taking place over a seven-year period, from 2012 to 2018. If we adjust for price increases, that is equivalent to \$4.9 billion in 2012 dollars. Parts of the Project, such as planning and regulatory filings have already begun; however, the bulk of the spending is expected to take place in 2016 and 2017, when construction activity peaks. For the purposes of our analysis, we exclude the financing costs from the analysis; thus we assess the economic impacts of \$4.6 billion of expenditures in 2012 dollars.²

This spending generates direct impacts in the construction sector, supply chain impacts associated with the inputs needed to complete the Project, and induced effects, which occur when the wages that employees earn from the direct and supply chain effects are spent. Combined, these three effects are expected to support 58,037 person-years of employment, with nearly half of those effects being direct,

¹ The Trans Mountain Expansion Application to the NEB provides an estimated capital cost for the Project of \$5.4 billion; this reflects a reduction in the required investment associated with the expected contribution from Westridge Dock bid premiums, which do not reduce the total expenditures on of the Project for the purposes of this Report.

² All subsequent dollar figures are in 2012 dollars unless otherwise noted.

and the rest being indirect and induced. Most of the employment effects will occur in British Columbia (61.8 per cent) and Alberta (25.2 per cent), reflecting that this is where the pipeline will be built. However, Ontario (8 per cent), Quebec (2.4 per cent), and the other Prairie provinces (1.9 per cent) will also experience job gains.

The additional economic activity also generates fiscal effects at both the federal and provincial level. The development of the TMEP is expected to generate a total of \$1.2 billion in federal (\$646 million) and provincial (\$568 million) government revenues. This is equivalent to \$27 for every \$100 of investment. The largest fiscal impacts are found in personal income taxes (\$559 million), indirect taxes such as sales taxes (\$335 million), and corporate income taxes (\$184 million). Assuming that the federal tax revenues will be distributed across the provinces on a per capita basis, British Columbia (\$394 million) and Ontario (\$307 million) will experience the largest combined federal and provincial fiscal effects. Other regions of the country, such as Alberta (\$239 million), Quebec (\$166 million), and the Prairies (\$58 million) will also experience fiscal benefits.

Impacts of TMEP's Operational Phase

Once operational, the TMEP will also generate positive economic and fiscal impacts on an ongoing basis. We assess the operational impacts of the pipeline over its first 20 years of service under two scenarios. The first considers the impact of only the long-term contracts that have been signed and can be considered the minimum impact associated with firm commitments. The second scenario assesses the economic impacts when the spot or non-firm capacity in the pipeline is fully utilized, and can be considered the maximum impact.

At a minimum, including the direct, supply chain, and induced effects we expect pipeline operations will support 50,273 person-years of employment, and this figure rises to 65,184 if the non-firm capacity is fully utilized. British Columbia (60.2 per cent) and Alberta (20.5 per cent) still experience the largest portion of the employment impacts. However, other regions of the country, such as Ontario (12.6 per cent), Quebec (3.9 per cent), and the Prairies (2 per cent) benefit from the employment impacts during the operational phase of the Project.

In terms of fiscal effects, pipeline operations are expected to generate between \$2.5 and \$3.3 billion in combined federal and provincial revenues over the first 20 years of operations. A key reason for this is that the oil pipeline industry generates large corporate income tax effects. Corporate profits account for the largest share of the revenues (60.1 per cent), followed by personal income taxes (19.7 per cent) and indirect taxes (12.5 per cent). Regionally, assuming a per capita distribution of federal revenues, British Columbia experiences the largest combined federal and provincial impact (34.8 per cent), followed by Ontario (24.3 per cent), Alberta (18.4 per cent), and Quebec (13.8 per cent).

Impacts of Higher Netbacks for Producers

In addition to the economic and fiscal impacts associated with building and operating the pipeline the TMEP has the potential to improve the price Canadian oil producers receive for their product. At a minimum, shippers on the TMEP will have access to tidewater, allowing them the ability to attract world prices for their product, rather than North America prices. However, the market study completed by IHS

Global Canada Limited (the IHS study) found that the TMEP and other planned pipeline expansion projects will alleviate the glut of oil flowing to the hub at Cushing, Oklahoma, which is expected to raise prices for all heavy oil producers in Western Canada.

As indicated in the IHS study, producers of conventional heavy oil and bitumen from the oil sands will benefit from higher prices, leading to higher revenues and profits. In turn, these businesses may choose to pay higher dividends or reinvest these profits. As well, there will be fiscal implications in terms of higher royalties and corporate profits paid to federal and provincial governments. We estimate these fiscal impacts under the three different production cases developed by IHS, a base case outlook, a high production outlook, and a low production outlook.

In the IHS base case oil company revenues rise by \$45.4 billion over the first 20 years of the pipeline's operations as a result of higher netbacks that can be attributed to the market access provided by the TMEP. This generates total fiscal benefits of \$14.7 billion. The federal corporate income tax effects account for \$6.1 billion of these effects. The combined royalty and corporate income tax effect for Alberta is \$8.2 billion, and for Saskatchewan it is \$454 million. The cumulative fiscal effect ranges between \$9.2 billion in the high production case and \$13.8 billion in the low production case.

Summary

Table 1 summarizes the economic and fiscal impacts associated with the TMEP using the minimum operating impacts and the base case for assessing the impact of higher netbacks. Between 2012 and 2037, the Project is expected to generate 108,310 person-years of employment. As well, the Project will produce \$18.5 billion of fiscal benefits over the same period.

Table 1. Summary of the Economic and Fiscal Impacts of the TMEP (cumulative effects, 2012-2037)

	Atlantic Canada	Quebec	Ontario	Other Prairies	Alberta	British Columbia	Territories	Canada
	Using Minimum Operational Effects and the Base Case for Higher Netbacks							
Employment effects (person-years)	617	3,372	11,004	2,124	24,926	66,132	135	108,310
Project development	289	1,402	4,659	1,099	14,632	35,864	92	58,037
Project operations	327	1,970	6,345	1,025	10,293	30,269	43	50,273
GDP effects (millions of 2012\$)	46.0	285.8	951.5	185.5	5,360.5	11,329.2	15.7	18,174.2
Project development	21.7	120.1	408.6	98.5	1,402.4	2,789.1	11.2	4,851.7
Project operations	24.3	165.6	542.9	87.0	3,958.1	8,540.2	4.5	13,322.5
Fiscal Impact (millions of 2012\$)	564.0	1,920.1	3,277.7	1,030.5	9,577.3	2,086.5	26.6	18,482.7
Project development	48.2	166.2	306.6	57.5	239.1	394.3	2.2	1,214.1
Project operations	104.0	352.1	620.1	111.1	469.3	887.3	4.7	2,548.6
Higher netbacks	411.8	1401.8	2,351.0	861.9	8,868.9	804.9	19.7	14,720.0

Source: The Conference Board of Canada.

Beyond these economic and fiscal benefits, the TMEP will also provide important strategic benefits. In particular, by allowing significant volumes of Canadian oil to reach tidewater Canadian production will no longer be landlocked inside the stagnant North American market. Many producers would now have access to growing markets in Asia. Ultimately, the TMEP is a means for Canada to maximize the value it receives for its non-renewable oil resources.

Chapter 1: Introduction

Oil is a global commodity, with a well established transportation infrastructure. As a result, global benchmark prices are usually nearly identical to one another once adjustments for quality and transportation costs are taken into account. However, this has not been the case in recent years, with North American benchmark prices lagging considerably behind their global peers.³ This situation has had significant negative economic and fiscal consequences for Canada, particularly in its oil producing regions.

In response, there has been growing interest in developing new oil pipeline infrastructure in North America. There are currently four major pipeline projects under consideration that would carry oil away from Western Canada if completed. One of these is the Trans Mountain Expansion Project (TMEP or the Project), which would nearly triple the capacity of the existing pipeline that runs from Edmonton, Alberta to Burnaby, British Columbia.

The objective of this report is to assess the economic and fiscal impacts associated with the proposed TMEP. (See text box “Trans Mountain Expansion Project Description.”) As part of this process, we examine the potential impacts in multiple ways, including the following:

- The impacts associated with the initial required investments to build the pipeline and related infrastructure.
- The impacts associated with operating the pipeline once it is up and running.
- The impacts associated with higher netbacks to oil producers that are expected to result from smaller price differentials between Canadian and international oil price benchmarks.

The results of this analysis allow for a clearer understanding of the economic and fiscal impacts of the pipeline itself, as well as the potential implications for Canada’s governments and the oil extraction industry. We discuss the results at both the national and the provincial level, with a particular focus on British Columbia and Alberta, since this is where most of the benefits would occur. We also examine how other provinces and the country overall will benefit, with a focus on supply chain and fiscal effects.

³ Kelly, Steve. *Trans Mountain Expansion Direct Evidence*.

Trans Mountain Expansion Project Description

The Trans Mountain pipeline system commenced operations 60 years ago and now transports a range of crude oil and petroleum products from western Canada to locations in central and southwestern British Columbia (BC), Washington state and offshore. Trans Mountain currently supplies much of the crude oil and refined products used in BC. Trans Mountain pipeline is operated and maintained by staff located at Trans Mountain's regional and local offices in Alberta (Edmonton, Edson, and Jasper) and BC (Clearwater, Kamloops, Hope, Abbotsford and Burnaby).

The Trans Mountain pipeline system has an operating capacity of approximately 47,690 m³/d (300,000 b/d) using 24 active pump stations and 40 tanks. The expansion will increase the capacity to 141,500 m³/d (890,000 b/d).

The proposed expansion will comprise the following:

- Pipeline facilities that complete a twinning (or "looping") of the pipeline in Alberta and BC with about 987 km of new buried pipeline.
- New and modified facilities, including pump stations and tanks.
- A total of three new berths at the Westridge Marine Terminal in Burnaby, BC each capable of handling Aframax tanker size.

Source: Trans Mountain.

Chapter 2: Economic Impacts Associated With the Development of the Trans Mountain Expansion Project

In terms of economic effects, all projects go through two distinct phases. The first is the development phase, when a project is planned, construction activity takes place, and equipment is purchased and installed. The second phase consists of the period over which a project is operational. This includes the annual expenditures on things like labour, facilities maintenance, and other inputs over the lifetime of a project. This chapter considers the economic impacts of developing the TMEP, while the next chapter considers the economic impacts of TMEP operations once the Project is finished.

In this report we quantify four economic effects associated with the development and operations of the TMEP, including the following:

- 1) **Direct Effects.** These are the economic effects directly associated with the development and operation of the TMEP. During the development phase, most of the direct effects occur in the construction industry, and during the operational phase all of the effects occur in the oil pipeline industry.
- 2) **Indirect Effects.** The indirect or supply chain effects measure the economic effects associated with the use of intermediate inputs or other support services that will be used to either build the pipeline or maintain it once it is operational.
- 3) **Induced Effects.** The induced effects occur when the wages that employees earn from the direct and supply chain effects are spent. As such, the economic impacts associated with induced effects generally occur in consumer oriented industries, such as retail.
- 4) **Fiscal Effects.** Finally, we measure the fiscal impact associated with the other three economic effects, at both the federal and the provincial level.

In order to conduct this analysis, we use both Statistics Canada's interprovincial Input-Output (I/O) model and the Conference Board of Canada's proprietary forecasting models. The direct, indirect, and induced gross domestic product (GDP) and employment impacts associated with the construction and operation of the TMEP were generated using Statistics Canada's I/O model, which allows for detailed supply chain analysis for nearly 300 different industries by province. For a more detailed explanation of I/O models see Appendix C. The fiscal effects were estimated by the Conference Board of Canada. The revenue and cost estimates associated with the construction and operation of the TMEP used to conduct the analysis were prepared by Trans Mountain Pipeline.

2.1 Direct Effects

If approved, the TMEP is expected to cost approximately \$5.5 billion, with the expenditures taking place over a seven-year period. Adjusted for price increases, that is equivalent to \$4.9 billion in 2012 dollars. Some of these expenditures have already occurred. Parts of the Project, such as planning and regulatory application filings have already begun, and thus Project Development is expected to cover the 2012 and 2018 period. However, the bulk of the spending activity is expected to take place in 2016 and 2017, when construction activity peaks. (See Table 2.)

Table 2. Expenditure Assumptions Associated With the Development of the TMEP (millions of \$)

Year	Nominal \$	2012 \$	2012 \$ Excluding financing costs
2012	34.2	34.2	33.4
2013	55.7	55.0	52.0
2014	93.7	90.3	83.8
2015	273.0	251.7	239.2
2016	2,547.2	2,269.9	2,194.4
2017	2,451.8	2,121.0	1,930.4
2018	49.8	41.7	41.7
Total	5,505.3	4,863.6	4,575.0

Source: Trans Mountain Pipeline.

For the purposes of the analysis, we use the price adjusted figure to conduct the analysis. This is because price inflation does not add to the economic value or jobs that would be supported by the Project. As well, we exclude the estimated financing costs associated with the Project. This is because the economic impacts of the financing costs could be quite small depending on how and where the money is raised. For example, if the project is financed through internal cash flows, or through money raised in foreign markets the impacts on the Canadian financial services sector would be minimal. The end result is that we assess the economic impacts of \$4.6 billion of expenditures in 2012 dollars.⁴

Although only 63.6 per cent of the pipeline's length will be in British Columbia, 69.5 per cent of the expenditures would take place there (\$3.2 billion), with the remainder occurring in Alberta (\$1.4 billion). To put that into perspective, this is equivalent to 8.7 per cent and 1.9 per cent respectively of total construction expenditures in British Columbia and Alberta in 2011.⁵ Factors affecting the regional mix of spending include the terrain that the pipeline covers, the fact that portions of the new pipeline will consist of reactivated existing pipe, and the need to build new port facilities at the Westridge Marine Terminal in British Columbia.

These expenditures will have a direct impact in both provinces. In terms of employment, the development of the pipeline is expected to support 28,202 person-years of employment, with 20,675 of these jobs occurring in British Columbia and the rest occurring in Alberta.⁶ The timing of these employment impacts will coincide with changes in annual expenditures on the Project. For example, in 2012, the direct employment impacts were estimated to be 206 people. But at the peak of construction in 2016, the employment supported by the Project will rise to 13,527 people. (See Chart 1.) At their

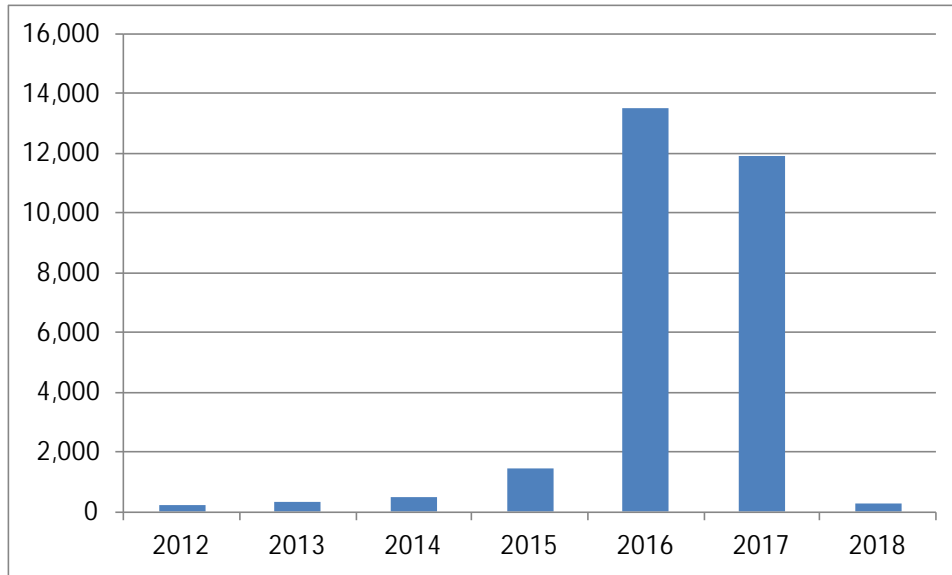
⁴ Unless otherwise noted, all subsequent dollar figures in the report are stated in 2012 dollars.

⁵ Based on data from Statistics Canada CANSIM table 029-0024.

⁶ A person-year of employment is the amount of work that one person would normally conduct in a year. It is an average figure for each industry and takes into account the fact that some workers are part time.

peak, the provincial employment effects will be equivalent to 4.3 per cent and 1.4 per cent of British Columbia's and Alberta's respective 2016 construction employment.⁷

Chart 1. Employment Impacts Associated With the Construction of the TMEP (number of employees)



Source: The Conference Board of Canada.

In terms of GDP, we expect that the TMEP will directly generate cumulative GDP effects of \$2.2 billion over the development period of the Project. Thus for every \$100 dollars spent on the Project, \$47 dollars in GDP will be generated. This means that 47 cents of every dollar spent goes to wages and profits, primarily in the construction industry, while the other 53 cents is spent on material inputs. The regional and temporal GDP impacts are similar to those noted for employment, with British Columbia accounting for 70 per cent of the total and the rest occurring in Alberta. The GDP effects peak in 2016 and 2017, when construction activity is at its peak.

2.2 Indirect Effects

In addition to the direct effects discussed above, the TMEP will also generate indirect or supply chain effects, and the I/O model captures these effects. Development of the Project will support another 14,055 person-years of employment indirectly. Thus, the combined direct and indirect employment effects of the TMEP are 42,257 person-years of employment. This is equivalent to 9,236 person-years of employment being supported for every \$1 billion dollars of investment.

Another way to look at the indirect effects is in terms of multipliers; i.e. how many jobs or dollars of GDP are indirectly generated relative to the direct effects. For example, for every two jobs directly associated with the TMEP, it supports another job indirectly among its suppliers. The GDP multiplier is somewhat larger, with \$0.58 of indirect GDP being supported by each direct dollar. The key reason for the higher

⁷ The Conference Board of Canada. *Provincial Economic Outlook: Spring 2013*.

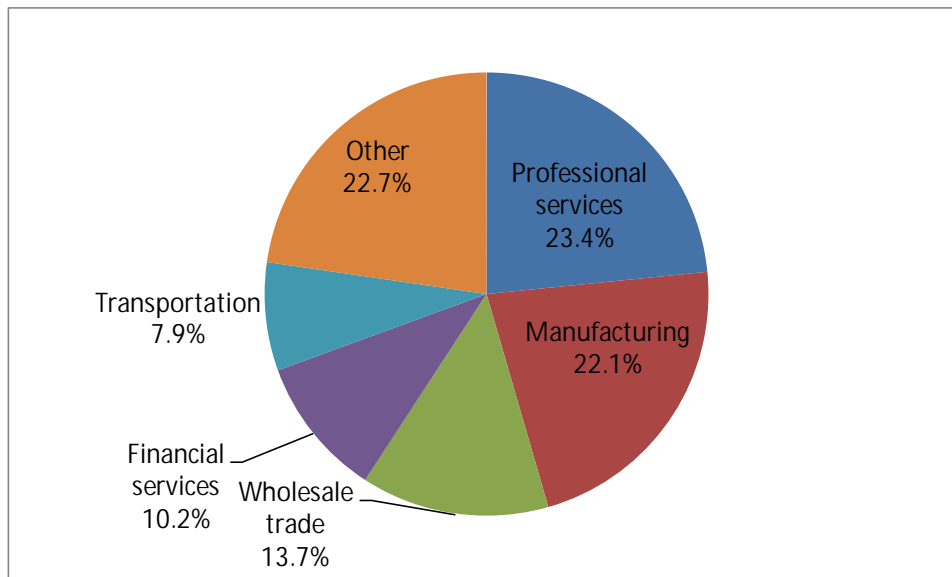
GDP multiplier is that most of the sectors where the largest indirect effects occur have a high level of GDP per employee.

The indirect effects are felt across a wide range of industries that are part of the supply chain that would be linked to the TMEP. The supply chain effects include both those that would directly supply the Project, as well as second and third order effects on suppliers who are farther down the supply chain. Although the majority of the indirect effects occur in British Columbia and Alberta, all of the other provinces experience some benefits. More than one quarter of the indirect employment effects occur in other provinces, with Ontario experiencing the largest benefit. The rest of this section describes how different industries and different regions of the country benefit from the supply chain effects that result from the construction of the TMEP.

2.2.1 Indirect Effects by Sector

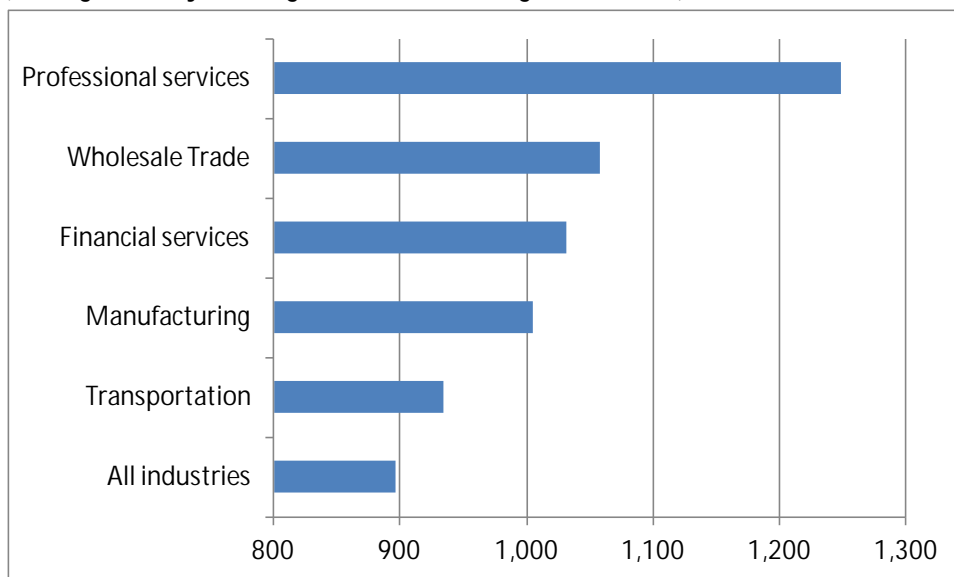
Beyond the number of jobs that would be indirectly supported by the construction of the TMEP, it is also important to examine the types of jobs. The indirect effects are largely confined to five broad sectors. In order of size, they include professional services, manufacturing, wholesale trade, financial services, and transportation. (See Chart 2.) It is worth noting that all of these sectors pay above-average wages. Even the lowest-paying sector, transportation and warehousing, has average weekly earnings that are 5 per cent above the average for all industries. (See Chart 3.) As such, the direct and indirect effects of the TMEP support a substantial number of high paying jobs.

Chart 2. Key Sectors That Experience Supply Chain Effects
(share of supply chain employment effects)



Source: The Conference Board of Canada.

Chart 3. All of the Sectors Most Affected by the TMEP's Development Pay Above Average Wages (average weekly earnings in 2012, including overtime, \$)



Source: Statistics Canada CANSIM table 281-0027.

2.2.1.1 Professional Services

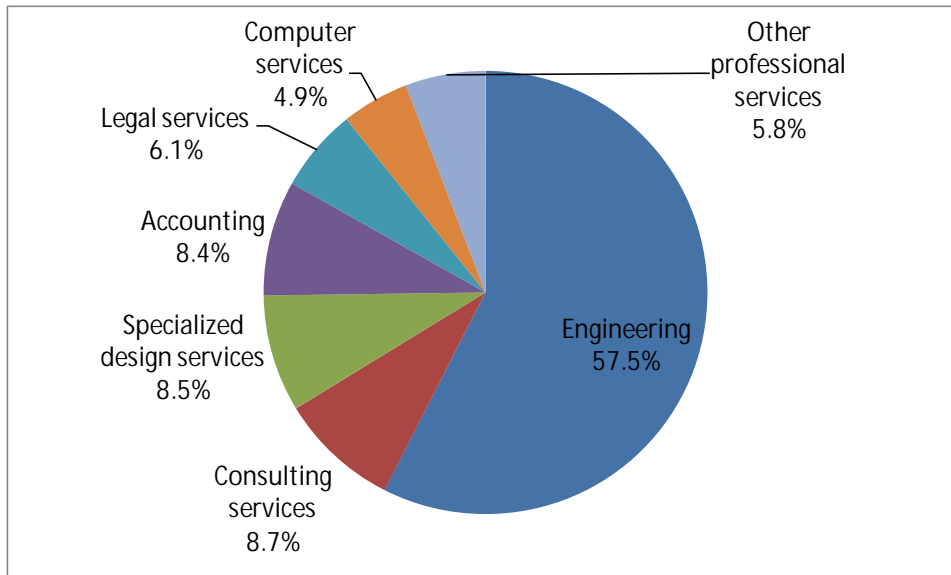
The professional services sector encompasses a wide area of activities in which human capital is the major input. These businesses essentially sell the knowledge and skills of their employees. With 3,287 person-years of employment in the sector being supported by the TMEP, or 719 for every \$1 billion of inflation-adjusted investment, the largest supply-chain effects accrue to this sector.

The single largest effects within this sector occur in the engineering services industry, with 1,890 person years of employment, or 413 for every \$1 billion in investment, being supported by the TMEP. (See Chart 4.) Engineering is the largest activity within this industry, but activities like geophysical surveying and mapping would also likely be an important component of the supply-chain benefits. The benefits for the engineering industry are so large that they account for 13.4 per cent of the total supply chain effects associated with development of the TMEP.

Other industries within the professional services sector would also realize employment benefits. For example, every billion dollars in investment generates 63 person-years of employment in consulting services. Specialized design services (61 person-years) and accounting services (60 person-years) also benefit. A variety of other professional service industries – everything from computer services, to legal services, to advertising and public relations – are also positively affected.

Regionally, the largest impact is in British Columbia, where nearly two-thirds of the employment benefits will occur, while another 25 per cent would be associated with Alberta. Still, substantial benefits do accrue to other Canadian provinces. For every \$1 billion in investment spending connected to the TMEP, 83 person-years of professional services employment will be supported outside of the two provinces through which the pipeline would traverse.

Chart 4. Engineering Accounts for Most of the Supply Chain Effects in the Professional Service Sector (share of supply chain employment effects in professional services)



Source: The Conference Board of Canada.

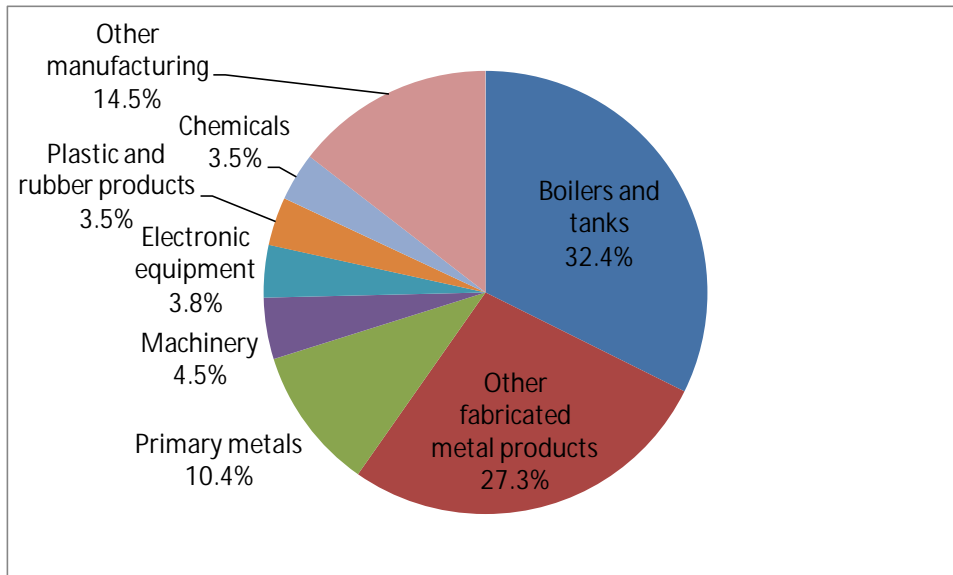
Most of the professional service jobs supported outside of Alberta and British Columbia (65 per cent) will be in Ontario; the province will experience a disproportionate benefit in several industries. For example, even though Ontario accounts for only 8 per cent of the total employment effects in professional services, it accounts for 35 per cent of the effects in the computer services industry—a higher share than either British Columbia or Alberta. It will also receive a relatively high share of the effects in the advertising and public relations (29 per cent), and scientific research and development services (27 per cent) industries. In aggregate, 96 per cent of the expected gains in professional services will accrue to British Columbia, Alberta, or Ontario.

2.2.1.2 Manufacturing

Manufacturing is another sector that experiences indirect effects associated with the development of the TMEP, accounting for 22.1 per cent of the employment benefits. This is equivalent to 3,108 person-years of employment, or 679 for every \$1 billion of investment.

Key industries within the manufacturing sector that realize the greatest benefits include makers of boilers and tanks, where 32 per cent of the manufacturing related employment effects will be apparent. (See Chart 5.) Other types of fabricated metal products, such as architectural metal products, and machine shops, as well as primary metals (in particular steel producers) are where the largest effects are apparent. For example, the economic activity associated with the producers of steel pipe (a major input into the Project), is captured in the steel products industry. However, a wide variety of other manufacturing industries, such as machinery, electronic equipment, plastic and rubber products, and chemicals also benefit.

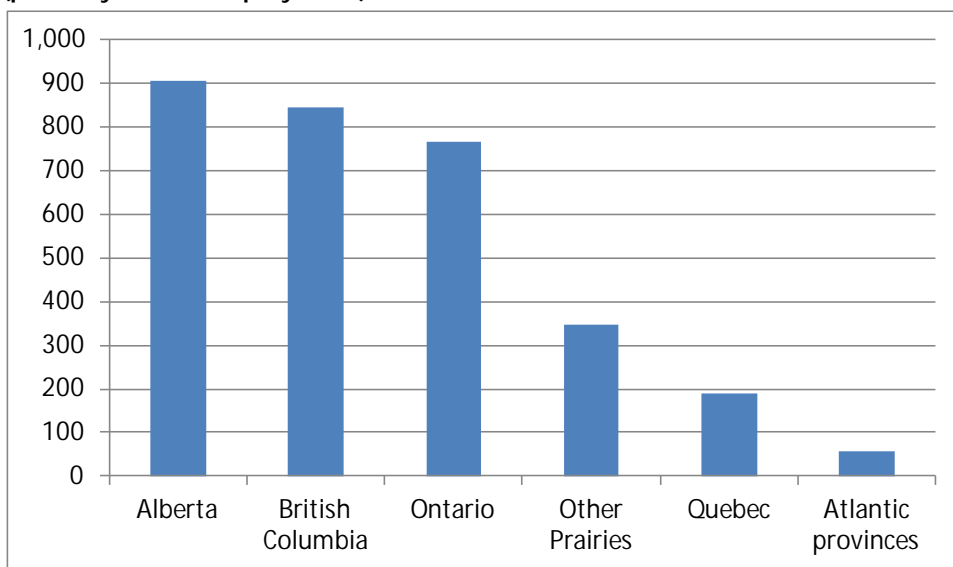
Chart 5. Most of the Manufacturing Impacts Occur Among Producers of Fabricated Metal Products (share of supply chain employment effects in manufacturing)



Source: The Conference Board of Canada.

Compared to the professional services industries, the regional impacts within the manufacturing sector are more diverse. Just 56 per cent of the associated jobs in the sector accrue to Alberta or British Columbia, compared to 88 per cent in professional services. Among the sectors most affected by the TMEP, manufacturing is where the largest benefits occur outside of Alberta and British Columbia. For every \$1 billion in inflation-adjusted investment in the TMEP, 297 new person-years of employment are supported outside of Alberta or British Columbia. (See Chart 6.)

Chart 6. The Manufacturing Employment Effects Are Widely Dispersed Across Regions (person years of employment)



Source: The Conference Board of Canada.

One-quarter of all manufacturing-related jobs supported by the TMEP would originate in Ontario, not at all surprising given that the majority of Canada's manufacturing sector is located in that province. In some industries like iron and steel mills, more benefits accrue to Ontario (60 per cent) than to Alberta and British Columbia combined. The province also does well in architectural and structural metals, steel products, and plastics. Nearly 20 percent of manufacturing jobs will be found outside of Alberta, British Columbia and Ontario. Of these, nearly half will occur in Manitoba and Saskatchewan. The remaining manufacturing employment effects are concentrated in Quebec, where 190 person-years of employment can be expected.

2.2.1.3 Wholesale Trade

The wholesaling process is an intermediate step in the distribution of goods. Firms operating in this sector are organized to sell goods in large quantities to other firms, without transformation, and to render services incidental to the sale of merchandise in general. A total of 1,919 person-years of employment would be supported in this sector as a result of the development of the TMEP, which equates to 419 person-years of employment for every \$1 billion invested.

Most of the jobs in the wholesale trade sector would be concentrated in two industries; building materials suppliers, and machinery and equipment suppliers. Combined, these two industries account for 73 per cent of the indirect benefits that are expected to accrue to the wholesale trade sector. This essentially reflects the role of wholesalers as middlemen, supplying the equipment and materiel needed to undertake the Project. The only other specific activity worth noting are wholesalers of electronic products, which account for another 10 per cent of the estimated employment effects.

Wholesaling activities are concentrated in the two provinces through which the pipeline would pass. Specifically, British Columbia would realize 1,016 (53 per cent) person-years of employment and Alberta would see 461 person-years of employment (24 per cent). However, for every \$1 billion spent on the proposed pipeline, 97 person-years of employment in wholesaling are supported outside those two provinces, and as with all other industries, the majority of them should be expected in Ontario, but about 7 per cent of them could be expected elsewhere.

2.2.1.4 Financial Services

The financial services sector covers a diverse array of activities, including banking, insurance, and investment-related services. As well, activities like the rental and leasing of machinery, equipment, and real estate are included. In total, the indirect benefits associated with this sector include 1,439 person-years of employment. This is equivalent to 315 person-years of employment per \$1 billion invested in the TMEP, and 10.2 per cent of the total indirect employment effects.

The aggregate benefits are concentrated in three main industries, including rental and leasing activities, banking, and investment services. In the case of rental and leasing activity, more than 95 per cent of the employment effects occur in either Alberta or British Columbia – a logical outcome given that rental and leasing of machinery and equipment is normally a local activity. However, both the banking and financial investment services industries experience above-average effects outside of Alberta or British Columbia.

For example, 47 per cent of all the indirect benefits in the banking industry occur elsewhere in Canada—as these services are easily tradable they tend to be less location specific.

In aggregate, for every \$1 billion invested in the TMEP, 91 person-years of employment in the financial services sector would be supported elsewhere in Canada and more than two-thirds of this would be created in Ontario. Given that most of Canada's largest banks and insurance companies are headquartered in Ontario, it is not surprising that 30 per cent of the employment effects in banking, holding companies, financial investment services, and insurance carriers would be generated there.

2.2.1.5 Transportation

The other sector to derive substantial indirect benefits as a result of the development of the TMEP is transportation. Establishments in the sector use transportation equipment as a productive asset to provide transportation of passengers or cargo, as well as the warehousing and storage of goods. The major modes of transportation include trucking, ground passenger, rail, water, air, and pipelines. Couriers and postal service are also included.

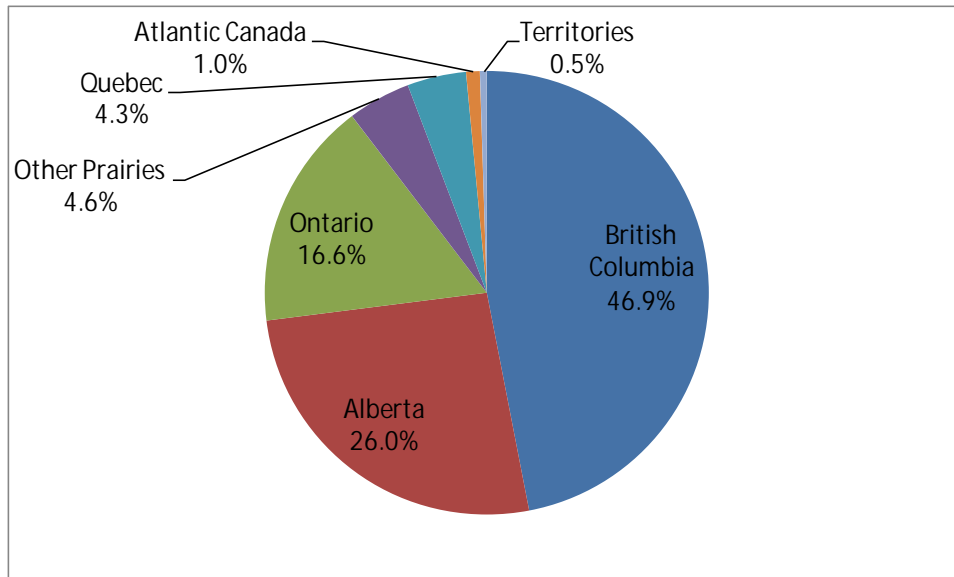
The proposed TMEP, in aggregate, would support 1,116 person-years of employment in the transportation sector, equivalent to 244 for every \$1 billion of investment. More than 60 per cent of these will be either in the trucking industry, or activities that support the trucking industry. This reflects the fact that there are logistical challenges involved with getting sufficient materials to the construction sites, given that the actual pipeline will span more than 1,000 km. Rail transportation will also garner 12 per cent of the estimated employment effects, reflecting the need to move some of the material inputs long distances across the country.

Again, British Columbia derives the largest benefits associated with the transportation sector, as 36 per cent of the employment effects will be found there, the wide majority of them in trucking. The story is similar for Alberta, which will garner 29 per cent of the benefits, most of them in trucking. Still, 394 person-years of employment will be supported in other Canadian provinces – or 86 per \$1 billion invested. Truck transportation is the dominant industry within the sector across the country, accounting for 63 per cent of the transportation jobs in Ontario, 70 per cent in Quebec, and 62 per cent of the jobs in the Prairie Provinces.

2.2.2 Indirect Effects by Region

Although the majority of indirect impacts will occur in British Columbia and Alberta, every region in the country will derive some economic benefit from the development of the TMEP. We estimate that 27.1 per cent of the indirect employment impacts, or 3,796 person years of employment will occur in other regions of the country. (See Chart 7.) As well, the mix of industries affected in each region can be very different. For example, manufacturing accounts for more than half of the employment effects in the Prairie Provinces, but only 12.8 per cent of the effects in British Columbia.

Chart 7. Indirect Employment Effects Supported by the Construction of the TMEP by Region (share of construction related indirect employment effects)



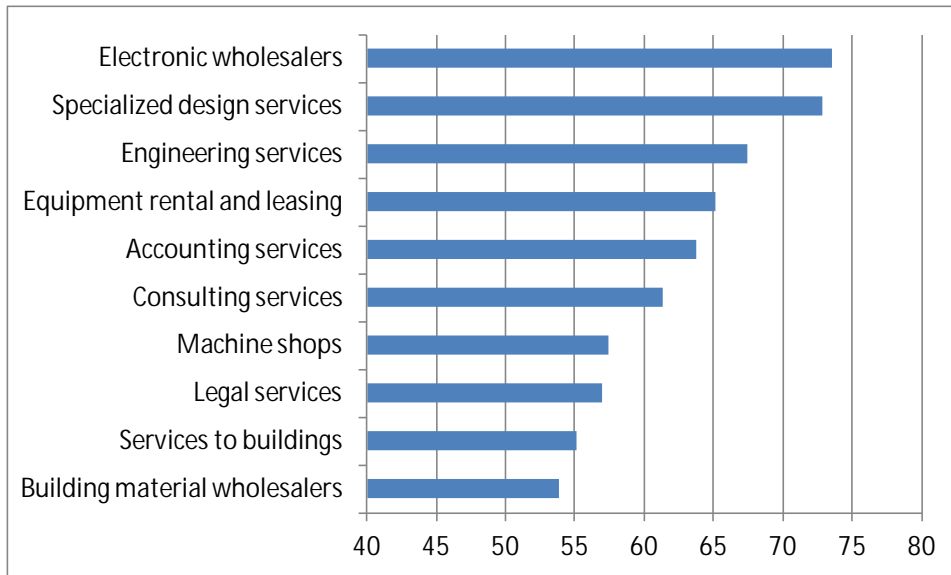
Source: The Conference Board of Canada.

2.2.2.1 British Columbia

British Columbia experiences the largest supply chain effects associated with the development of the TMEP. In total, 6,599 person-years of employment will be supported by the Project, equivalent to 46.9 per cent of the total supply chain effects. Despite the fact that nearly half of the supply chain effects will occur in British Columbia, the mix of sectors affected in the province is somewhat different than in other provinces. Professional services experience the largest benefits by far, accounting for nearly one-third of the total, followed by wholesale trade, and then manufacturing.

It is interesting to note the industries that stand out in British Columbia, in terms of those that experience effects that are both substantial in size and account for an outsized share of the national impacts. For example, 67 per cent of the national impacts in the engineering industry occur in British Columbia, accounting for a total of 1,275 person-years of employment. (See Chart 8.) Engineering accounts for the largest impact by far in British Columbia. However other industries with noticeable effects include wholesalers of building materials, specialized design services, and equipment rentals and leasing.

Chart 8. Key Industries that Experience Outsized Effects in British Columbia
(share of national supply chain employment effects for select industries, per cent)



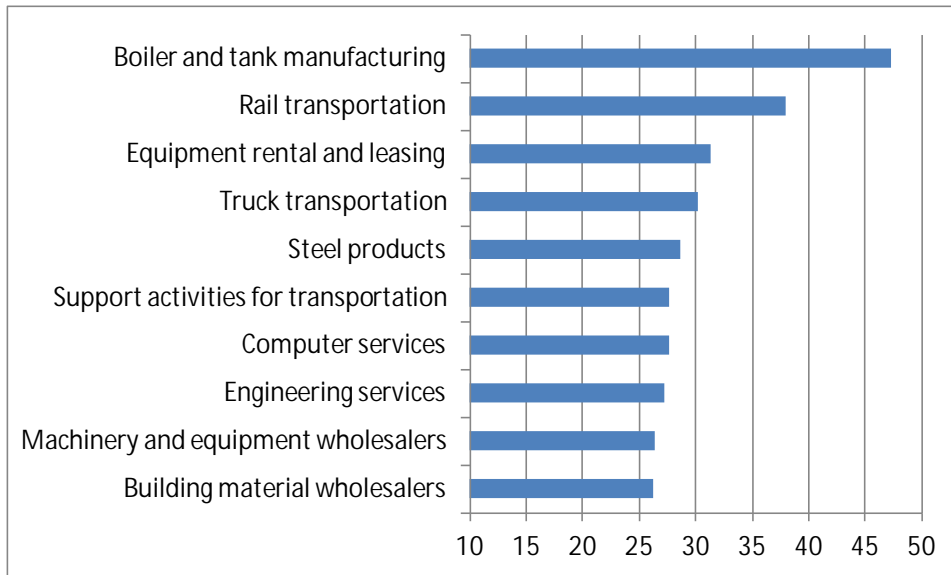
Source: The Conference Board of Canada.

2.2.2.2 Alberta

Much of the remaining indirect employment impacts accrue to Alberta. In total, the development of the TMEP is expected to support 3,660 person-years of employment in Alberta, which is equivalent to 26 per cent of the total national effects. The sector that will experience the single biggest impact in Alberta is manufacturing. This is followed by professional services, and then wholesale trade. Alberta stands out by accounting for an outsized share of the effects in the manufacturing and transportation sectors.

As is the case in British Columbia, engineering services are where the largest employment impacts occur in Alberta. (See Chart 9.) However, where Alberta stands out is in the manufacture of boilers and tanks. Nearly half of the employment effects in this industry occur in Alberta. Other industries where Alberta stands out include truck transportation, wholesalers, and rental and leasing of equipment.

Chart 9. Key Industries that Experience Outsized Effects in Alberta
(share of national supply chain employment effects for select industries, per cent)

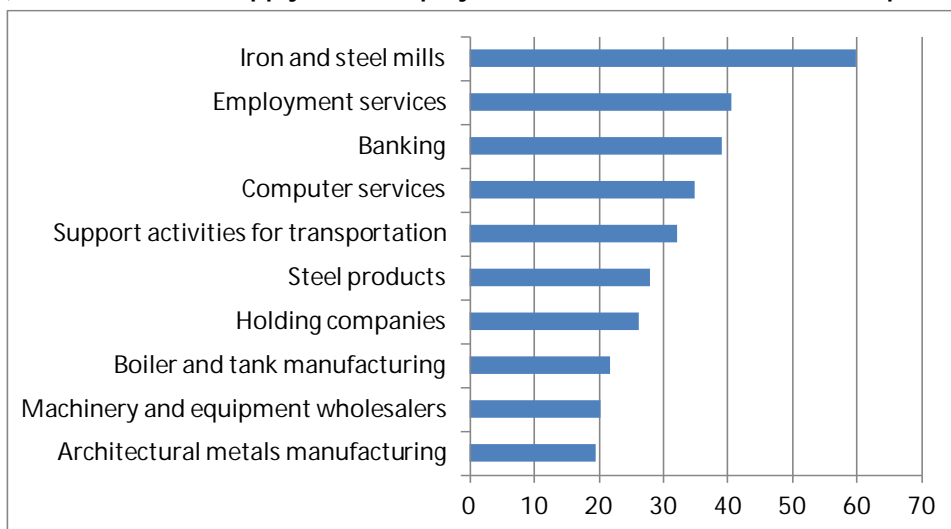


Source: The Conference Board of Canada.

2.2.2.3 Ontario

Outside of Alberta and British Columbia, Ontario experiences the largest supply chain impacts associated with the development of the TMEP. A total of 2,340 person-years of employment will be supported in Ontario, equivalent to 16.6 per cent of the total. Manufacturing and financial services are the two key areas where Ontario stands out. More specifically, industries where Ontario experiences an outsized share of the employment effects include boiler and tank manufacturing, machinery and equipment wholesalers, banking and support activities for transportation. (See Chart 10.)

Chart 10. Key Industries that Experience Outsized Effects in Ontario
(share of national supply chain employment effects for select industries, per cent)

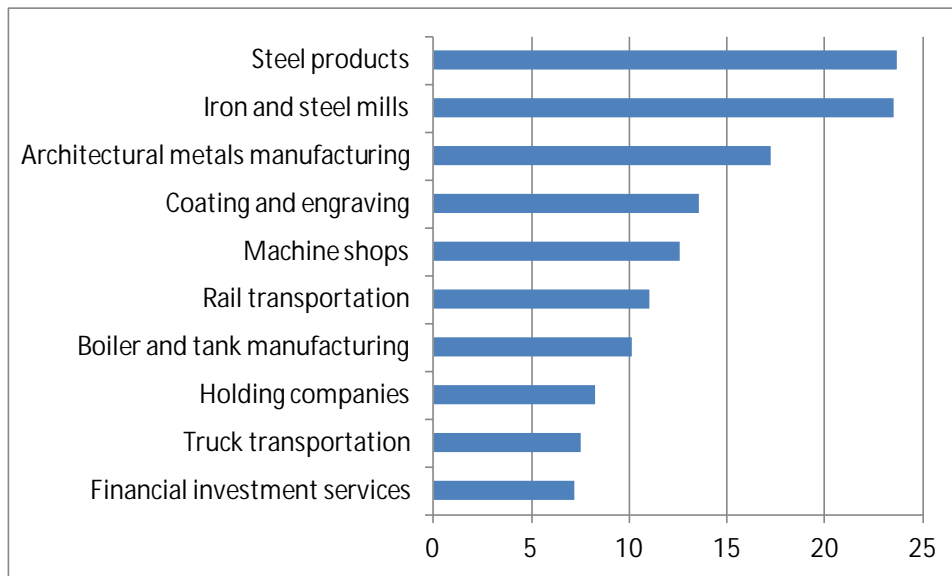


Source: The Conference Board of Canada.

2.2.2.4 Other Prairies

Beyond British Columbia, Alberta, and Ontario, the employment effects associated with the development of the TMEP become smaller. Manitoba and Saskatchewan combined will see 645 person-years of employment being supported by the Project, with the effects split evenly between the two provinces. As a result, the other Prairies region will account for 4.6 per cent of the supply chain effects. The key areas where the region stands out include manufacturing and transportation. We estimate that 53.9 per cent of the employment effects in Manitoba and Saskatchewan are found in the manufacturing sector. Key types of manufactured products include boilers and tanks, architectural metals and steel products. (See Chart 11.) In the I/O model results, a good portion of the pipe used to build the pipeline will be sourced from Saskatchewan.

Chart 11. Key Industries that Experience Outsized Effects in the Other Prairies Region (share of national supply chain employment effects for select industries, per cent)

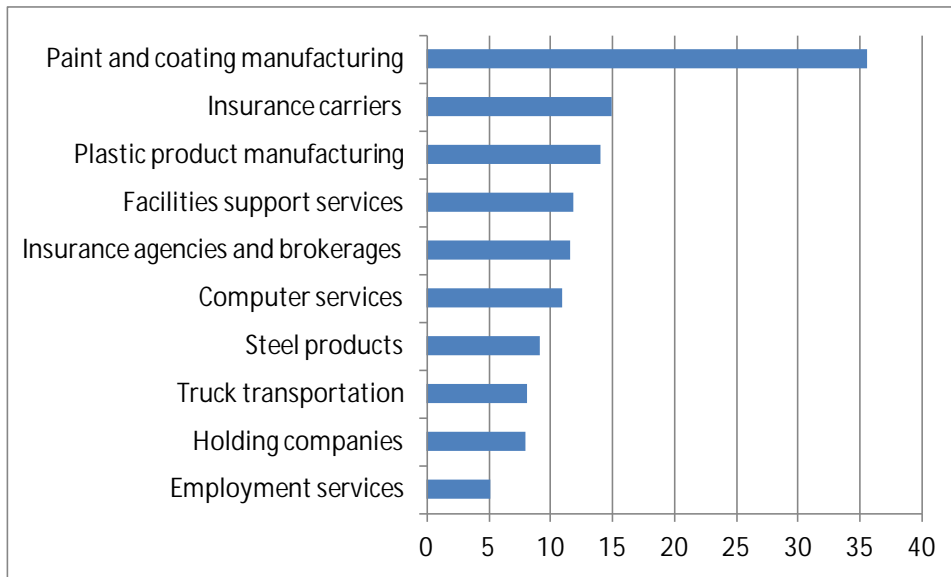


Source: The Conference Board of Canada.

2.2.2.5 Quebec

The employment impacts in Quebec are modestly smaller than those experienced in the other Prairies region. A total of 601 person-years of employment will be supported in Quebec as a result of the development of the TMEP, equivalent to 4.3 per cent of the total. Areas where the effects in Quebec stand out include manufacturing and transportation. In particular, truck transportation, manufacturing of paints and coatings, and computer services will all experience outsized effects. (See Chart 12.)

Chart 12. Key Industries that Experience Outsized Effects in Quebec
(share of national supply chain employment effects for select industries, per cent)

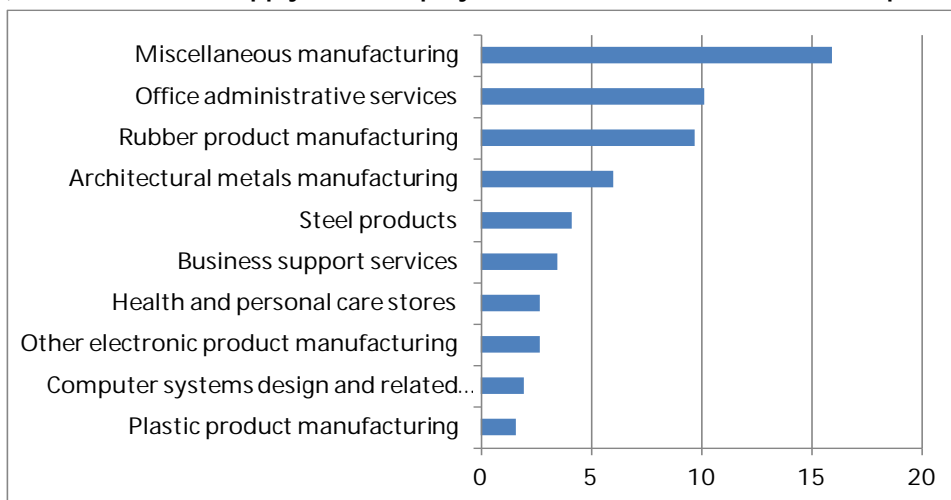


Source: The Conference Board of Canada.

2.2.2.6 Atlantic Canada

The Atlantic Provinces experience the smallest employment effects as a result of the development of the TMEP. Their smaller size and physical distance from where the TMEP will be built are both factors limiting the benefits they will experience. Only 142 person-years of employment will be supported in the region, equivalent to 1 per cent of the total impact. Most of those effects will occur in Nova Scotia and New Brunswick. The effects in any particular industry are generally quite small, but there are outsized effects in a few industries, such as architectural metals, office administrative services, and miscellaneous manufacturing. (See Chart 13.)

Chart 13. Key Industries that Experience Outsized Effects in Atlantic Canada
(share of national supply chain employment effects for select industries, per cent)



Source: The Conference Board of Canada.

2.3 Induced Effects

Additional benefits beyond those described above will arise as a result of the development of the TMEP. For example, the person-years of employment supported both directly and indirectly by development of the pipeline generates wages that, when spent, sustain additional employment across the country. This income effect is commonly referred to as “induced effects” in the economic literature.

Induced effects lead to additional impacts on GDP, employment, income, and tax revenues and they are felt across a wider range of industries relative to the supply-chain effects described above. And because the direct and indirect jobs created tend to be in high-wage industries, the spin-off effects are substantial. Indeed, the induced impacts associated with developing the TMEP are estimated to be slightly larger, in terms of both GDP and employment, than the indirect benefits.

In total, 15,780 person-years of induced employment would be supported by development of the pipeline – equivalent to 3,450 jobs for every \$1 billion in inflation-adjusted investment. These employment impacts are widespread, with 10 different sectors experiencing an impact of at least 500 person-years of employment. When the induced employment impacts are added to the previously discussed direct and indirect employment effects, the development of the TMEP is expected to support 58,037 person-years of employment.

The induced GDP effects are also considerable. For every \$1 in GDP directly created as a result of the Project, another \$0.66 is supported by the income effects, in addition to \$0.58 in supply-chain benefits. Thus, in aggregate, the GDP effects associated with the development of the Project are \$4.9 billion (\$2.2 billion directly, \$1.3 billion indirectly, and \$1.4 billion induced). This is equivalent to \$1.06 of GDP for each dollar spent on the development of the TMEP.

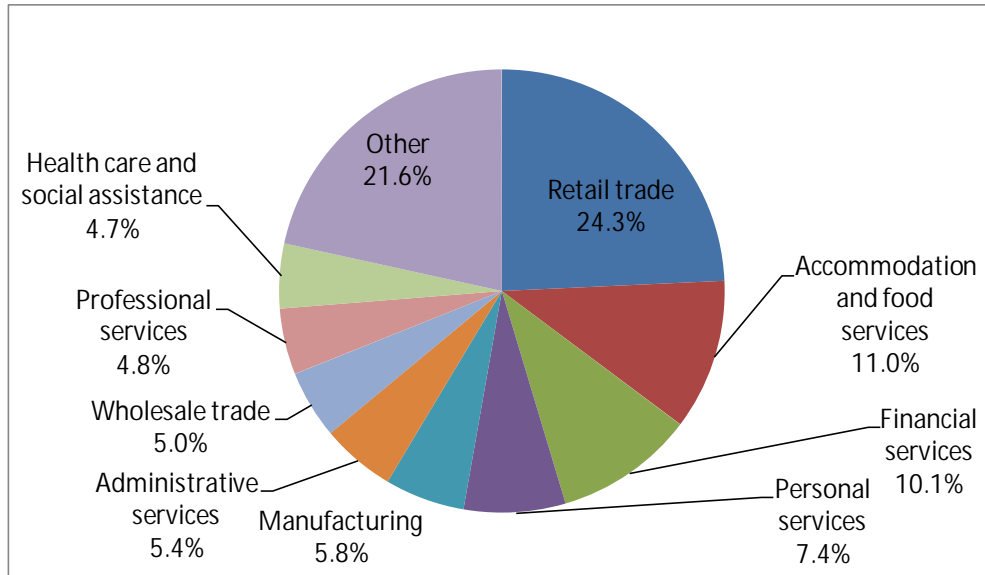
2.3.1 Induced Effects by Sector

The distribution of the induced employment effects across sectors is largely a reflection of how Canadian consumers spend their money. (See Chart 14.) For example, the largest impact is found in the retail sector, which accounts for 3,831 person-years of employment, or 24.3 per cent of the total. Specifically, the induced effects accruing to the retail sector would support 1,220 person-years of employment in food and beverage establishments, another 445 in clothing and accessories, and 328 in motor vehicles and parts sales. The benefits are extremely varied, with impacts apparent in everything from furniture and home furnishings, to home electronics and appliances, to sporting goods and hobbies.

Accommodations and food services is another consumer oriented sector that experiences sizeable benefits. A total of 1,729 person-years of employment, or 11 per cent of the total employment effects occur in this sector. Other major sectors where sizeable employment impacts will occur include financial services (1,589 person-years of employment), personal services (1,168 person-years of employment), and manufacturing (918 person-years of employment). The impacts in the financial services sector reflect people’s need for things like chequing accounts and consumer financing. Personal services includes things like household services (such as maids, nannies, and gardeners), as well as activities like

motor vehicle repair, laundry services, and hair salons. Finally the impacts in manufacturing generally occur among makers of consumer goods, such as food and furniture.

Chart 14. The Induced Impacts Affect a Range of Consumer Oriented Sectors (share of induced employment effects by sector, per cent)



Source: The Conference Board of Canada.

2.3.2 Induced Effects by Region

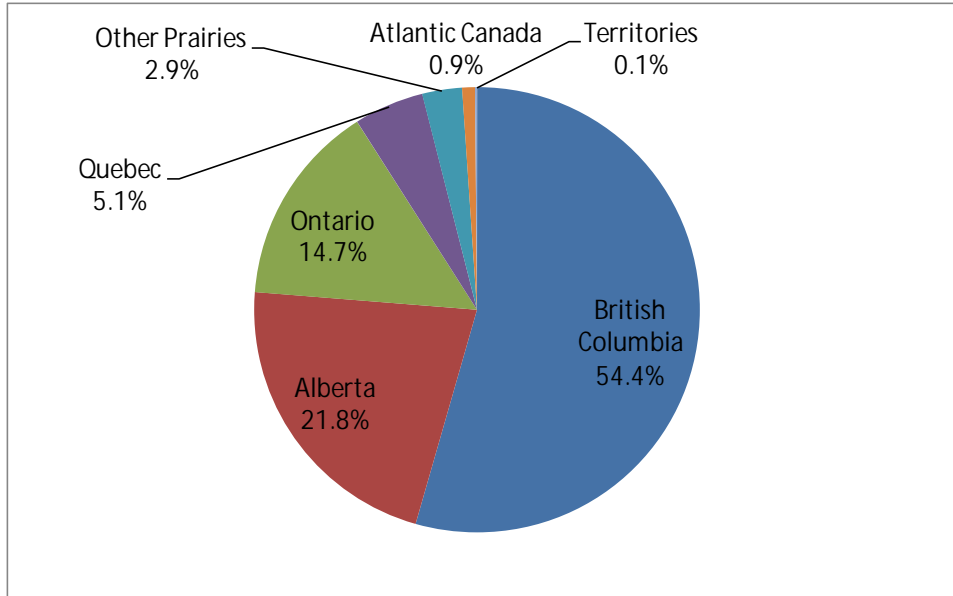
The regional distribution of the induced effects is fairly concentrated. Some 76 per cent of the total benefits accrue to either British Columbia (8,590 person-years) or Alberta (3,445 person-years). (See Chart 15.) This is not surprising. The majority of the direct and indirect jobs and labour income supported by the Project occur in those provinces, and the residents of those provinces who benefit from the Project will spend most of their income there. The induced impacts across the rest of the provinces largely reflects their shares of the direct and indirect effects.

The sectoral mix of the induced effects is similar across the different regions, since people tend to buy the same sorts of goods and services regardless of where they live. However, because the different regions of the country specialize in making different types of consumer products, there are some variations across the provinces. For example, although Ontario receives 14.7 per cent of the total induced employment effects on an aggregate basis, 24.2 per cent of the benefits in the financial services sector accrue there. Ontario also experiences an outsized share of the effects in the manufacturing sector.

Similarly, Manitoba and Saskatchewan combined can expect just 2.9 per cent of the total induced employment effects, but would garner 16.6 per cent of the agricultural impacts. Essentially the food that people buy as a result of the induced impacts needs to be grown somewhere, and the Prairies will supply some of that food. Quebec stands out in terms of its manufacturing sector. Quebec experiences

induced effects of 801 person-years of employment, 5 per cent of the total, but it experiences 15.3 per cent of the employment effects in the manufacturing sector.

Chart 15. The Induced Impacts Primarily Occur in British Columbia and Alberta (share of induced employment effects by sector, per cent)



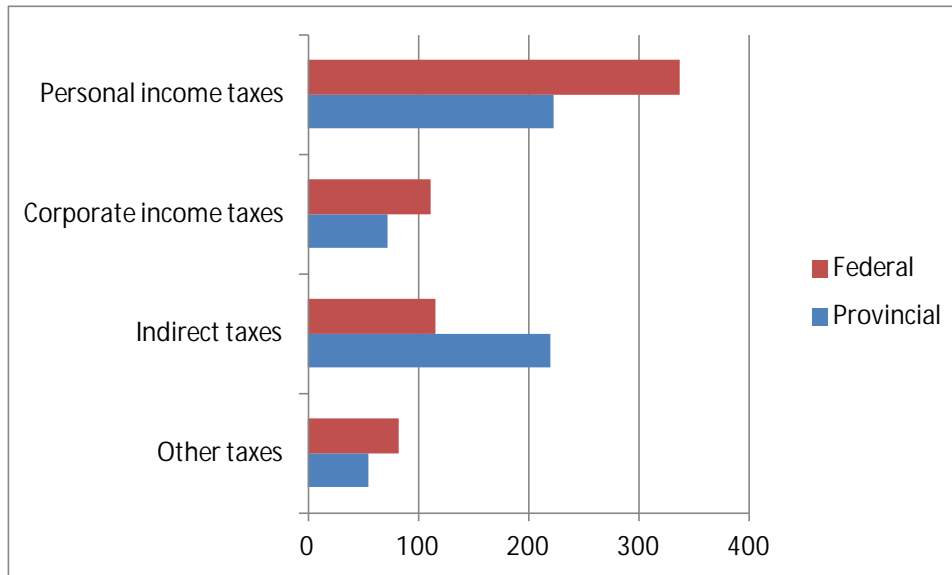
Source: The Conference Board of Canada.

2.4 Fiscal Effects

The direct, supply chain, and induced effects associated with the development of the TMEP also have positive fiscal implications at both the provincial and federal level. The three main types of government revenues that will be affected by the Project include personal income taxes, corporate income taxes, and indirect taxes (such as sales taxes and taxes on fuel). The analysis of the fiscal effects of the project was completed using The Conference Board of Canada's national and provincial forecasting models.

The \$4.6 billion in spending associated with the development of the TMEP is expected to generate \$1.2 billion in federal and provincial government revenues between 2012 and 2018. This is equivalent to \$27 for every \$100 of investment. With \$3.3 billion in wages and salaries and \$1.4 billion in corporate profits being generated by the development of the TMEP, the largest fiscal impacts are found in personal and corporate income taxes. (See Chart 16.)

Chart 16. Personal and Corporate Income Taxes Account for Most of the Fiscal Effects (tax revenues, millions of 2012\$)



Source: The Conference Board of Canada.

2.4.1 Federal Impacts

The federal government will experience the largest impact, even larger than that of Alberta and British Columbia combined. In aggregate, the development of the TMEP is expected to generate \$645.8 million in federal government revenues, or \$14 for every \$100 spent on the Project. This is equivalent to 0.3 per cent of total federal government revenues in 2012. Slightly more than half of this will come from higher personal income tax revenues. Other major sources include corporate income taxes (17.2 per cent) and goods and services tax (GST) inflows (14.4 per cent).

Another source of revenues is the \$56.4 million generated from higher employment insurance premium receipts. With a total of 58,037 person-years of employment (including the combined direct, supply chain, and induced effects) supported by the development of the TMEP, additional employment insurance premiums will be generated. Since fewer people would be unemployed, government payments of employment insurance would also be reduced, providing an additional benefit not included here.

2.4.2 Provincial Impacts

In aggregate, the TMEP is expected to generate \$568.6 million in provincial government revenues, or 12 cents for every dollar spent. This is equivalent to 0.2 per cent of total provincial revenues in 2012. At \$222 million, personal income taxes will account for nearly half of the provincial fiscal effects. Indirect taxes (which include sales taxes) and corporate income taxes account for most of the rest of the effects, at \$220 million and \$73 million, respectively.

In terms of the breakdown by province the largest benefits would accrue to British Columbia, which would receive 54.4 per cent of the total, or \$309 million. Alberta would receive most of the rest of the

provincial fiscal effects, at \$168 million. Ontario (\$57 million), Quebec (\$17 million), Saskatchewan (\$9 million), and Manitoba (\$5 million) will experience much more modest fiscal effects. For the Atlantic provinces, the fiscal effects are very small.

If we assume that the federal government revenues would be spent rather than be used to reduce the deficit, the benefits would filter down to all of the provinces through transfers and other program expenditures. Since many of these expenditures are at least partially dependent on the population distribution across provinces, the impact of higher federal revenues will be higher for most provinces than the direct province-specific fiscal effects. For example, assuming a straight per capita distribution of federal revenues, Ontario would garner 39 per cent, or \$250 million of the federal fiscal benefits, compared with a direct provincial fiscal impact of \$57 million. The exceptions are British Columbia and Alberta, where the direct provincial impact is bigger than the estimated federal transfers.

2.5 Summary

The development of the TMEP is expected to result in \$4.6 billion in investment spending, which will have positive economic and fiscal effects. For example, the combined direct, indirect, and induced employment effects will support 58,037 person-years of employment. (See Table 3.) As well, the combined GDP effects of the Project are \$4.9 billion, equivalent to \$1.06 dollars for every dollar of investment. Finally, this economic activity is expected to support \$1.2 billion in federal and provincial government revenues. British Columbia is the largest beneficiary for all of these effects, but considerable effects are apparent in Alberta and Ontario as well. In the rest of the provinces the effects are smaller, but individual industries do experience notable effects in most regions.

Table 3. Summary of the Regional Impacts of Developing the TMEP (cumulative effects, 2012-2018)

	Atlantic Canada	Quebec	Ontario	Other Prairies	Alberta	British Columbia	Territories	Canada
Employment effects (person-years)	289	1,402	4,659	1,099	14,632	35,864	92	58,037
Direct	0	0	0	0	7,527	20,675	0	28,202
Indirect	142	601	2,340	645	3,660	6,599	69	14,055
Induced	147	801	2,319	454	3,445	8,590	23	15,780
GDP effects (millions of 2012\$)	21.7	120.1	408.6	98.5	1,402.4	2,789.1	11.2	4,851.7
Direct	0.0	0.0	0.0	0.0	650.1	1,518.0	0.0	2,168.1
Indirect	10.8	52.7	207.7	61.4	394.0	514.8	9.0	1,250.5
Induced	10.9	67.4	200.9	37.1	358.3	756.3	2.2	1,433.0
Fiscal Impact (millions of 2012\$)	48.2	166.2	306.6	57.5	239.1	394.3	2.2	1,214.1
Direct Provincial Revenues	4.4	17.1	56.5	14.1	167.5	308.7	0	568.3
Per Capita Share of Federal Revenues	43.8	149.1	250.1	43.4	71.6	85.6	2.2	645.8

Source: The Conference Board of Canada.

Chapter 3: Economic Impacts Associated With the Operation of the Trans Mountain Expansion

The nature of the oil pipeline industry dictates that the scale of the effects associated with the operational phase of the Project is very different than the construction phase. The pipeline industry is heavily capital intensive; the amount of capital stock per employee in the industry is 50 times the average for all sectors in Canada.⁸ This means that a pipeline project involves large upfront costs during its development stage. Meanwhile, the subsequent operational stage generates much smaller employment effects in any given year. For example, the entire oil pipeline industry in Canada employed only 2,700 people in 2012 according to Statistics Canada's Labour Force Survey.

Although the direct employment effects for the oil pipeline industry are generally very small, it still generates considerable GDP effects. There are several factors that determine an industry's GDP, including the wages and salaries that it pays, the amount of depreciation it records on its assets, and the profits that it earns. In all three respects the oil pipeline industry is above average. As a result, the oil pipeline industry has a very high ratio of GDP per employee; at \$783,703 per employee it is nearly nine times the average for all industries.⁹

As well, since pipelines are expected to have extended lives, the cumulative impact over the course of their lives can be significant. This chapter assesses the economic and fiscal impacts of the TMEP's operations over a 20-year time horizon. Although the expected life of the Project is much longer—the existing pipeline has been in operation for nearly 60 years—20 years covers the initial period for which Trans Mountain has firm contracts in place.

3.1 Direct Effects

The assessment of the employment and GDP effects of TMEP operations is based on the incremental revenues that the Project is expected to generate. There are 13 shippers that have entered into binding 15 and 20-year contracts to ship a total of about 708,000 b/d of oil through the pipeline once it is completed. This is equal to about 80 per cent of the pipeline's planned nominal capacity of 890,000 b/d.

Because the terms of these contracts are known, the associated revenues can be reasonably estimated. Annual revenues associated with these contracts were estimated by the Conference Board to be \$944 million based on the projected capital costs of the Project and the toll structure that would be applied. This revenue estimate only includes the fixed component of the toll. The variable component is primarily based on the electricity costs associated with shipping through the pipeline and is passed directly through to shippers. As such, the variable component would not have an impact on the labour or material inputs that the pipeline would use, or on the profits that it generates, and is not included when estimating the economic effects.

⁸ Based on data from Statistics Canada CANSIM table 031-0002 and the Labour Force Survey.

⁹ Based on data from Statistics Canada CANSIM table 379-0031 and the Labour Force Survey.

The 20 per cent of the pipeline's expected capacity that is not committed to firm long-term contracts will be available on a spot or non-firm basis once the Project is operational. We consider the additional economic and fiscal effects of non-firm sales under a different scenario later in this chapter. First, we present an analysis of the effects for the capacity that is committed to long-term contracts. Since the terms of the contracts require shippers to pay for their capacity whether or not they use it, they have a strong incentive to make use of it. As such, the operational economic and fiscal impacts associated with the long-term contracts can be considered the minimum effects associated with operating the pipeline.

For the purposes of this analysis we assume that the full 708,000 b/d of capacity will be covered by long-term contracts over the 20-year period. A portion of the capacity committed to long term contracts has the potential to become available for non-firm sales after 15 years. However, we assume that the relevant contracts will be renewed for an additional five year period; this is an option available in the contracts. Otherwise, we expect that Trans Mountain would attempt to find other firm contract customers for that capacity, which would have the same effect.

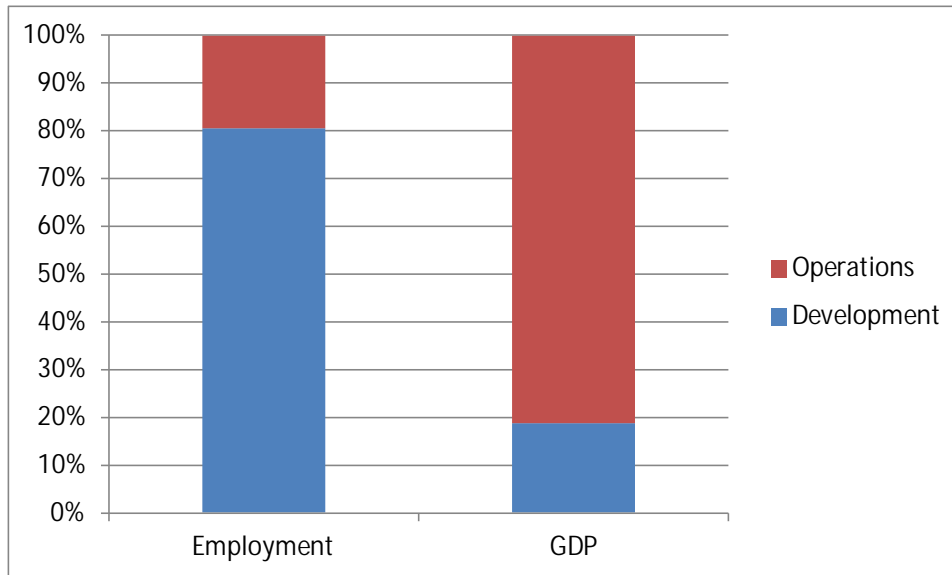
The other consideration when estimating the economic impacts of the pipeline's operations is that 300,000 b/d of capacity is already in place. The TMEP would expand this capacity to 890,000 b/d. However, even if the TMEP were not to proceed, the existing capacity would continue to operate. As such, we only consider the impact associated with the expanded operations rather than the existing pipeline. Information provided by Trans Mountain indicates that the revenues associated with the existing pipeline are approximately \$300 million per year. Once this is removed from the revenues associated with the long-term contracts for the TMEP, the Project will generate a \$644 million increase in annual revenues.

Based on annual revenue of \$644 million, the TMEP will directly support 342 jobs per year, for a total of 6,841 person years of employment over the first 20 years of the pipelines operations. The majority of these positions will be found in British Columbia, which will account for 242 jobs per year or 71 per cent of the total, with the rest being located in Alberta. This reflects the location of pipeline related facilities, such as pumping stations and terminals, which will require employees to operate them.

In terms of GDP, the TMEP is expected to generate \$469 million of GDP annually, or \$9.4 billion over the first 20 years of its operations. The GDP results stand out from the employment results in a couple of ways. First, Alberta's share of the direct GDP effects associated with pipeline operations is larger at 31.4 per cent, versus 29.3 per cent for employment. This reflects the fact that the average wages and salaries per employee in the oil pipeline industry in Alberta are higher than in British Columbia.

Secondly, the comparison of the GDP effects between the development and operational stages of the Project is very different than the employment effects. Operations will account for one-fifth of the employment effects, but 81 per cent of the total GDP effects associated with the development and operation of the project. (See Chart 17.) The reason why the GDP effects are so much larger is because the GDP per employee in the oil pipeline industry is so high. GDP per employee in the industry is very high because of the high levels of capital invested per employee, which results in high labour productivity.

Chart 17. The Direct Effects of Operations on GDP are Much Larger than for Employment (share of employment and GDP effects by project stage)



Source: The Conference Board of Canada.

3.2 Indirect Effects

As with the development phase, the TMEP will also generate indirect or supply chain effects once it is operational. An estimated 1,492 jobs will be supported by the pipeline in every year of operations. This is equivalent to 29,845 person-years of employment over the first 20 years of the Project’s life. Thus, for every job created directly by the TMEP another 4.4 are supported indirectly. This is a high employment multiplier and it is largely a reflection of the small direct employment effects in the oil pipeline industry.

The opposite situation is apparent with the indirect GDP effects. The operation of the TMEP will support \$136 million of indirect GDP annually, which is equivalent to only \$0.29 for every dollar of direct GDP. This is a very low GDP multiplier and it reflects the high level of direct GDP that the oil pipeline industry generates.

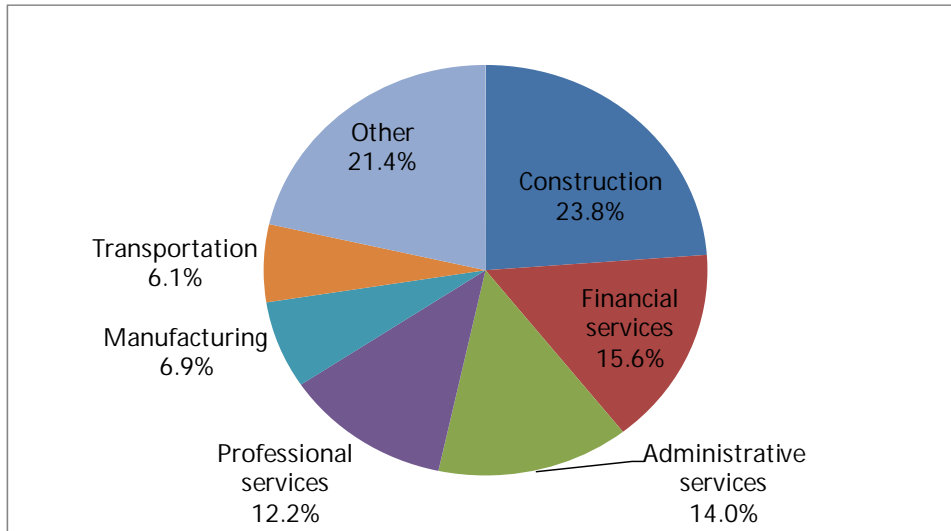
Although the number of indirect jobs supported by the operation of the TMEP is not particularly large in any given year, over the first 20 years of the pipeline’s operations they actually exceed those supported by the development of the pipeline—29,845 person-years of employment versus 14,055. What is more, the indirect effects have a somewhat different industrial and regional mix. Regionally, the operational impacts are even more heavily focused in British Columbia., Sectors like construction and administrative services, which include activities like services to buildings and employment services, grow in importance.

3.2.1 Indirect Effects by Sector

The indirect employment effects that arise from pipeline operations are largely confined to six broad sectors. In order of size, they include construction, financial services, administrative services, professional services, manufacturing and transportation. Combined, these six sectors account for 79 per cent of the indirect employment effects. (See Chart 18.) The effects within some of these sectors are

similar to what was discussed as part of the development phase in Chapter 2, but in general the impacts on specific industries can be quite different for operations than for the development phase.

Chart 18. Key Sectors that Experience Supply Chain Effects from Operations
(share of indirect employment effects from operations)



Source: The Conference Board of Canada.

Also notable is the importance of electricity as an input into the oil pipeline industry. Although it accounts for only 3.2 per cent of the supply chain employment effects, it accounts for 12.4 per cent of the indirect GDP effects. Like the pipeline industry, electricity generation is heavily capital intensive, which leads to it generating very large GDP effects, but limited employment effects. As such, although electricity is a major input into the oil pipeline industry, the employment impacts associated with this spending are small.

3.2.1.1 Construction

The TMEP is expected to support 355 indirect jobs annually in the construction sector once it is operational. The key reason for this will be ongoing maintenance and repairs. All of these jobs will be found in either British Columbia or Alberta, along the route of the proposed pipeline. The jobs will be heavily weighted towards British Columbia, which will account for 94 per cent of the total. The fact that more of the pipeline is located in British Columbia, there are more pump stations located there, and the more difficult terrain that the pipeline traverses in the province all contribute to this difference.

3.2.1.2 Financial Services

Since the financial services sector provides inputs into essentially every industry, it is a key component of the supply chains for many of them. However, with 232 jobs being indirectly supported in the financial services sector annually, it accounts for 15.6 per cent of the total employment effects associated with the operation of the TMEP. These impacts are concentrated among holding companies, investment services, banking, and insurance.

Regionally, the impacts in the financial services sector are more widely dispersed, with 29 per cent of the employment effects occurring outside of British Columbia and Alberta. Most of these effects occur in Ontario, particularly in the investment services and banking industries. These services tend to be more tradable and Ontario's well developed financial services sector means that businesses are more likely to make use of financial institutions that are located in that province.

3.2.1.3 Administrative Services

Administrative services businesses are primarily engaged in activities that support the day-to-day operations of other organizations. A total of 209 indirect jobs in the administrative services sector will be supported by TMEP operations each year. Key administrative industries that provide inputs into the oil pipeline industry include services to buildings (such as janitorial and pest control services), employment services, waste remediation, and security services.

Once again, the employment effects in the administrative services sector are concentrated in British Columbia (54.9 per cent), Alberta (21.8 per cent), and Ontario (17.3 per cent). The limited tradability of some services is a factor that restrains the impacts outside of British Columbia and Alberta. Most of the impacts in Ontario occur in the employment services industry, which has a higher degree of tradability.

3.2.1.4 Professional Services

A total of 182 professional service jobs are supported annually as a result of the supply chain effects associated with the operation of the TMEPs. However, the operating effects on the sector are very different than those associated with the development of the Project. Instead of the main effects occurring in the engineering industry, it is the computer services industry where the largest impacts occur, with 5.8 per cent of the total indirect employment effects occur in the computer services industry. Other industries within professional services that experience notable employment effects include engineering, accounting, and consulting.

Regionally, we see a similar pattern of the largest impacts occurring in British Columbia (41.2 per cent), Alberta (29.6 per cent), and Ontario (20.5 per cent). The impacts in the other provinces are very small, with Quebec accounting for nearly all of the remaining impact. Most of the professional services jobs that are supported outside of British Columbia and Alberta are computer services positions.

3.2.1.5 Manufacturing

The indirect impacts among the particular industries within the manufacturing sector associated with operations are similar to those for the development phase of the Project. Key manufactured inputs include architectural metals, boilers and tanks, and cement products. This reflects the need for ongoing maintenance and repairs on the pipeline's infrastructure over its useful life. However, the scale is smaller. Only 103 manufacturing jobs are expected to be supported annually by TMEP operations, equivalent to 2,020 person-years of employment over the first 20 years of operations. This is only about two-thirds of the manufacturing employment impacts that will occur during the development phase.

The diversity of the regional impacts within the manufacturing sector are also much less during the operating phase of the Project versus the development phase. British Columbia experiences the largest

impact (52 per cent), followed by Ontario (18.3 per cent), and then Alberta (14.8 per cent). The key reason for British Columbia accounting for a much higher share of the manufacturing effects during the operational phase is the change in the mix of manufactured inputs. For example, cement products, wood products and printing are all industries that experience a relative increase in their importance. Wood products produced in British Columbia are readily available, while the cement products and printing industries tend to be much more regionally focused than many other segments of the manufacturing sector.

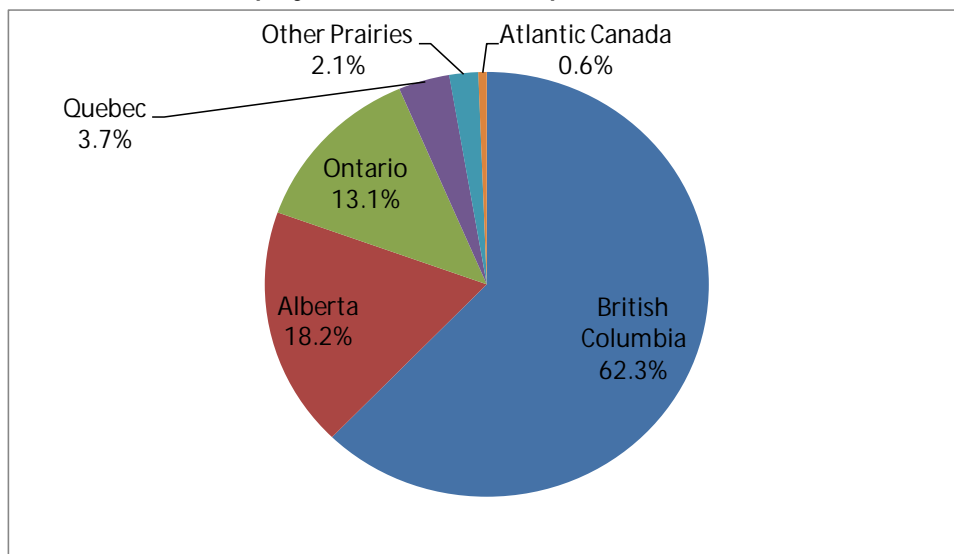
3.2.1.6 Transportation

The last major sector where considerable indirect employment effects occur as a result of TMEP operations is transportation, with 81 jobs being supported annually. Most of these jobs occur in the couriers and messengers, transportation support services, and trucking industries. The impact in the couriers and messengers industry reflects the standard day-to-day need for businesses to interact with other organizations. The impacts in the other transportation industries reflect the need to supply the TMEP with materials and supplies on an ongoing basis. The geographically dispersed nature of the pipeline also contributes to the need for transportation services. As well, the majority of the employment impacts occur in British Columbia, which accounts for 56 per cent of the total. Most of the remaining effects occur in Alberta (18.6 per cent) and Ontario (17.4 per cent).

3.2.2 Indirect Effects by Region

Nearly all of the indirect effects associated with operations of the TMEP occur in British Columbia, Alberta, or Ontario; only 6.5 per cent of the employment effects occur in other provinces. (See Chart 19.) The main reason for this is the importance of construction activity as an input into the oil pipeline industry, which by necessity is almost entirely conducted locally. Many of the other key inputs provided by sectors like administrative services and professional services require a local presence as well.

Chart 19. Supply Chain Employment Effects from Operations by Region
(share of indirect employment effects from operations)



Source: The Conference Board of Canada.

3.2.2.1 British Columbia

British Columbia experiences the majority of the supply chain effects associated with the operation of the TMEP. A total of 932 jobs are expected to be supported annually in the province, equivalent to 18,641 person-years or 62 per cent of employment over the first 20 years of operations. This is more than double the supply chain impacts in British Columbia associated with developing the Project. Industries that experience notable supply chain effects in British Columbia include repair construction, services to buildings, holding companies, and electric power generation.

3.2.2.2 Alberta

Nearly 20 per cent of the employment supported by the supply chain effects associated with the operation of the TMEP occurs in Alberta. In total, 273 jobs will be supported in Alberta annually, equivalent to 5,460 person-years of employment over the first 20 years of operations. In comparison, the development of the TMEP will support 3,660 person-years of employment in Alberta. Industries that experience significant indirect effect in Alberta include computer services, holding companies, electric power generation, construction, and employment services.

3.2.2.3 Ontario

Ontario is the only other province to experience substantial supply chain effects as a result of TMEP operations, with 195 jobs being supported annually, or 3,895 person-years of employment over the first 20 years of operations. Again the indirect operational impacts in Ontario are actually larger than the development impacts. The largest impacts in Ontario include the computer and employment services industries. As well, several different types of financial services industries benefit including banking, investment services, and holding companies.

3.2.2.4 Other Regions

The indirect employment impacts associated with the operation of the TMEP are much more modest in the rest of the country. Across all of the other provinces the employment impacts total only 99 jobs annually, or 1,970 person-years of employment over 20 years. In some cases, such as Saskatchewan, the impacts of operations are actually less than those from the Project's development. This reflects the fact that a good portion of the pipe used to initially build the pipeline would be sourced in Saskatchewan according to the modelling results. The impacts are generally spread across a variety of industries, but the largest impacts in other regions occur in industries like computer services, investment services, and holding companies.

3.3 Induced Effects

As with the development phase of the Project, the wages earned in the direct and indirect jobs supported by TMEP operations will generate additional economic effects when they are spent. These induced effects add considerably to the total economic effects associated with TMEP operations. However, in the case of operations, the induced effects are smaller than the indirect effects. The opposite was true for the induced effects from the development phase.

The key reason for the difference is that the direct employment effects of operations are much smaller than for development. Even though the direct jobs in the oil pipeline industry are very high paying, there

are fewer of them. The end result is the labour income that results from direct and indirect employment during the operational phase is only \$2.45 billion over 20 years of operations, versus \$2.62 billion for the Project’s development. Less labour income to spend results in smaller induced effects.

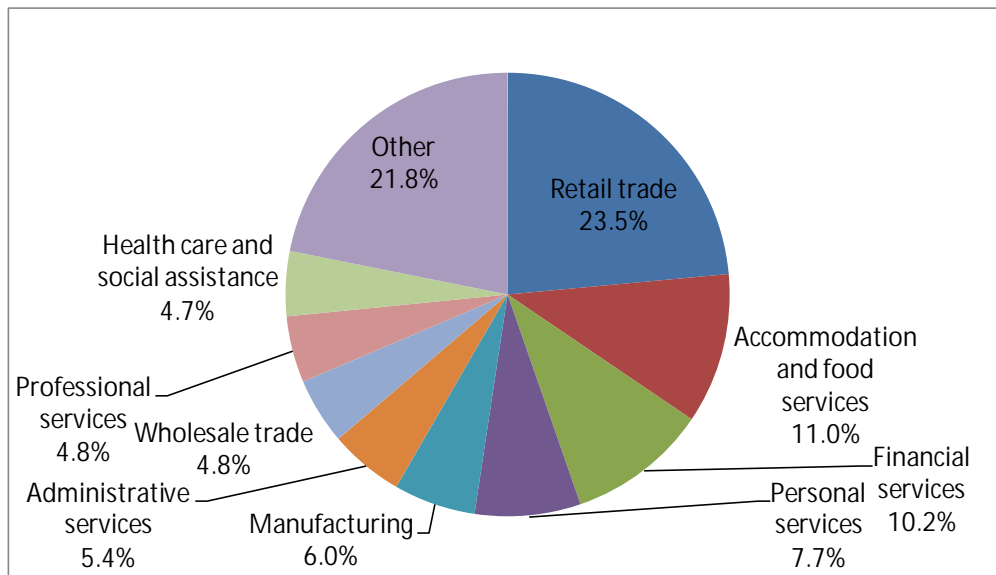
In total, 13,588 person-years of induced employment would be supported by pipeline operations over the first 20 years of operations, equivalent to 679 jobs per year. Thus, the combined direct, indirect, and induced employment impacts associated with pipeline operations will be 50,274 person-years over 20 years, or 2,514 jobs per year.

The induced GDP effects are also considerable. For every \$1 in GDP directly created as a result of the pipeline’s operations, another \$0.13 is supported by the induced effects, compared to \$0.29 in supply-chain benefits. This represents a total GDP effect of \$13.3 billion over the first 20 years of operations. Thus the combined development and operational GDP effects associated with the TMEP are \$18.2 billion.

3.3.1 Induced Effects by Sector

In terms of the industries where the induced impacts occur, the mix is very similar to those discussed in Chapter 2. The same group of consumer oriented sectors, including retail trade, accommodation and food services, financial services, and personal services account for most of the effects. (See Chart 20.) The pattern of induced effects reflects how people spend their money, and that generally is not dependent on how they earn that money. The modest differences in the sectoral induced effects between the operational and development phases of the Project are caused by the different regional mix for the direct and indirect effects. Essentially, people’s consumption patterns vary only modestly across regions.

Chart 20. Induced Employment Effects from Operations by Sector
(share of induced employment effects from operations)

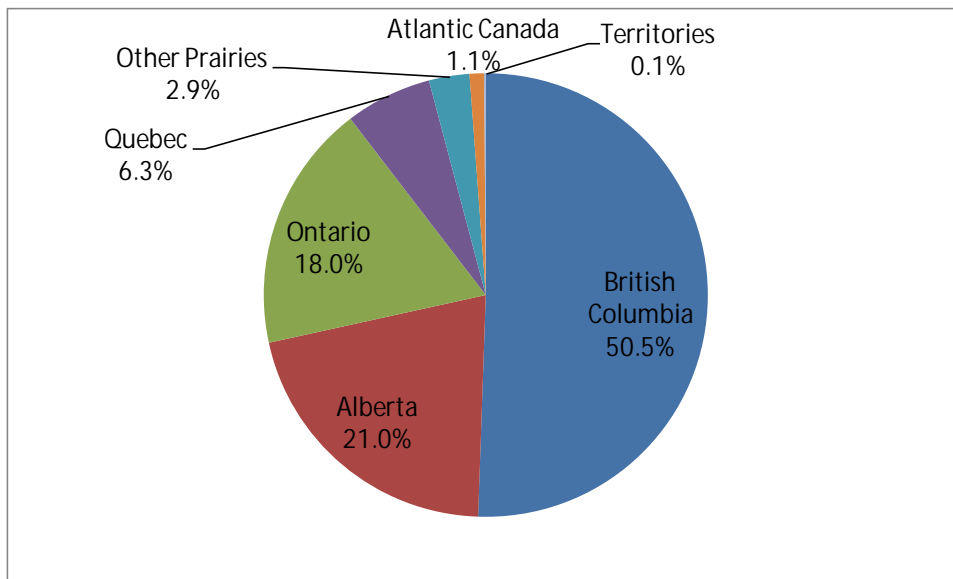


Source: The Conference Board of Canada.

3.3.2 Induced Effects by Region

The regional distribution of the induced effects is again similar to what occurs during the development phase of the Project. British Columbia (6,868 person-years) and Alberta (2,853 person-years) account for 72 per cent of the total effects. (See Chart 21.) However, since 87 per cent of the labour income generated by the direct and indirect effects is in those two provinces, this result is not surprising. The reason why the induced effects are more spread out geographically is because some of the things people buy in British Columbia and Alberta are sourced from other parts of the country.

Chart 21. Induced Employment Effects from Operations by Region
(share of induced employment effects from operations)



Source: The Conference Board of Canada.

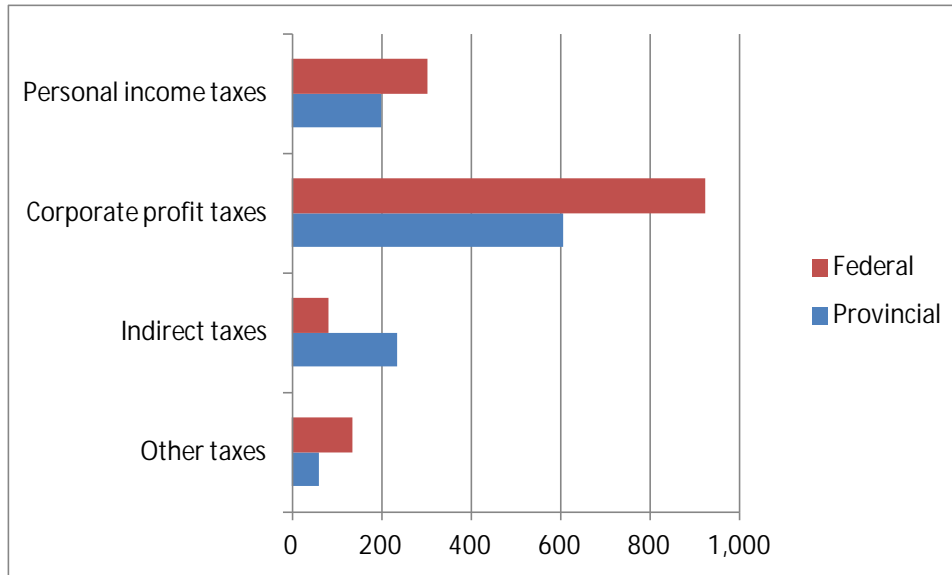
3.4 Fiscal Effects

The direct, supply chain, and induced effects associated with the operation of the TMEP also have fiscal implications at both the provincial and federal level. Over the first 20 years of its life, the TMEP is expected to generate \$2.5 billion in federal and provincial government revenues. This is more than double the \$1.2 billion in fiscal impacts associated with the development phase of the Project. The operational fiscal impacts are heavily weighted towards corporate income taxes, which account for 60 per cent of the combined provincial and federal fiscal impacts. (See Chart 22.) Personal income taxes and indirect taxes, such as sales taxes account for most of the remaining fiscal impacts.

The key reason for the large role of corporate taxes in the fiscal effects is the breakdown of the GDP effects for TMEP operations. As indicated previously, the oil pipeline industry generates a high level of GDP. Because of this, the direct GDP effects account for 70 per cent of the total operational GDP effects. At the same time, the oil pipeline industry is highly capital intensive, so most of the GDP generated by the industry comes in the form of depreciation of its assets and corporate profits. Since it is the income components of GDP, including corporate profits and labour income, that determine most of the fiscal

effects, the end result is that corporate profits in the oil pipeline industry are the key factor driving the results.

Chart 22. Corporate Income Taxes Account for Most of the Operations Related Fiscal Effects (tax revenues over 20 years of operations, millions of 2012\$)



Source: The Conference Board of Canada.

3.4.1 Federal Impacts

The federal government will be the major beneficiary of the fiscal impact from TMEP operations, at \$1.4 billion. This is equivalent to 0.6 per cent of federal government revenues in 2012. Corporate income taxes are the largest portion of this, at \$925 million. This is followed by personal income taxes (\$303 million) and indirect taxes (\$83 million). Increased contributions to social security programs, such as employment insurance, are also significant, at \$66 million.

Federal government revenues are equivalent to \$11 for every \$100 of GDP generated by the Project's operations. This is somewhat lower than the \$13 of federal tax revenues for every \$100 of GDP generated by the development phase of the Project. The key reason for this is the shift towards corporate profits as the main source of government revenue. The marginal tax rate on corporate profits is generally lower than the rate for personal income. As well, consumers pay sales taxes on the goods and services they buy, while businesses often get the sales taxes they pay refunded through input tax credits.

3.4.2 Provincial Impacts

In aggregate, the TMEP is expected to support \$1.1 billion in provincial government revenues over the first 20 years of its life. This is equivalent to 0.3 per cent of total provincial revenues in 2012. At \$607 million, corporate income taxes will account for the majority of the provincial fiscal effects. Indirect taxes (which include sales taxes) and personal income taxes account for most of the rest of the effects, at \$237 million and \$200 million, respectively.

In terms of the breakdown by province the largest benefits would accrue to British Columbia, which would receive 66 per cent of the total, or \$727 million, which is equivalent to 1.7 per cent of British Columbia's 2012-13 revenues.¹⁰ Alberta would receive most of the rest of the provincial fiscal effects, at \$278 million, equivalent to 0.7 per cent of the province's 2012-13 revenues. Ontario (\$60 million), Quebec (\$18 million), Saskatchewan (\$8 million), and Manitoba (\$5 million) will experience much more modest fiscal effects. For the Atlantic provinces, the fiscal effects are very small. However, if we redistribute the federal fiscal effects across the provinces on a per capita basis, then all of the provinces will experience a larger effect. (See Table 4.)

Table 4. Summary of Fiscal Effects from TMEP Operations
(tax revenues over 20 years of operations, millions of 2012\$)

	Direct Provincial Revenues	Per Capita Share of Federal Revenues	Total
British Columbia	277.5	160.3	437.8
Alberta	727.0	191.8	918.8
Ontario	59.9	560.2	620.1
Quebec	18.1	334.0	352.1
Other Prairies	13.8	97.3	111.0
Atlantic Canada	5.9	98.1	104.0
Territories	0.0	4.7	4.7
Total	1,102.1	1,446.4	2,548.6

Source: The Conference Board of Canada.

3.5 The Economic Effects of Non-Firm Transactions

All of the impacts discussed thus far in this chapter are based only on the transportation of volumes that are linked to long-term contracts. These can be considered the minimum economic and fiscal effects associated with the TMEP. There will be about 180,000 b/d of nominal capacity available for non-firm or spot transactions, and the degree to which this capacity is used will determine the amount of additional economic impacts. There are two key considerations concerning the effects of the non-firm capacity. The first is the toll that will be applied to any non-firm transactions. The second is the volumes that will be transported.

The tolls for non-firm capacity will be higher than for product shipped under the terms of long-term contracts. The non-firm toll will be based on a 10 per cent premium to the 15-year firm toll. However, those shippers who signed 20-year contracts receive a 10 per cent discount from the 15-year rate, and large volume shippers (those who contracted for 75,000 b/d or more) receive an additional 7.5 per cent discount.¹¹

¹⁰ Government of British Columbia. *June Update: Budget and Fiscal Plan 2013/14-2015/16*.

¹¹ Transmountain Pipeline. *TMEP Toll Application*.

Based on information provided by Trans Mountain,¹² the average fixed toll that will be applied under long-term contracts was estimated by the Conference Board of Canada to be \$3.66, assuming no change in the capital costs associated with the Project. For non-firm shippers, the estimated toll is \$4.59. The higher toll on non-firm capacity results in higher revenues on a per barrel basis up to 85 per cent capacity utilization of the TMEP. However, once capacity utilization exceeds 85 per cent, under the revenue sharing provisions of the contracts any additional revenues will be split on a 50/50 basis between shippers and Trans Mountain through reductions in the variable toll.¹³ As such, the additional revenues to Trans Mountain from non-firm shipments depend on capacity utilization rates.

If we assume that the available non-firm capacity on the TMEP system is fully utilized over its first 20 years of operations, the calculated economic and fiscal effects based on that assumption represent the maximum potential impact associated with the Project. The reality is likely to fall somewhere in between the minimum and the maximum.

We can use the previously discussed modelling results for TMEP operations to determine the expected economic and fiscal impacts associated with the non-firm transactions. One of the benefits of using an I/O model is that its results are scalable. Since the model is based on a snapshot in time, the relative effects are fixed. Thus, higher revenues from non-firm volumes will result in a proportionate increase in the supply chain and induced effects, while the mix of regions and industries will be unaffected.

Based on an average toll rate of \$4.59 per barrel, a non-firm capacity of approximately 180,000 b/d, and revenue sharing on capacity used above 85 per cent, we estimate the maximum annual revenues associated with non-firm capacity to be \$191 million. This increases the total annual incremental revenues associated with TMEP operations to \$835 million, a 30 per cent increase over the revenue estimated for the fixed contracts alone. Thus, the economic and fiscal impacts in the “maximum” scenario can be expected to be 30 per cent higher than in the “minimum” scenario.

Table 5 provides a summary of the minimum and maximum effects of TMEP pipeline operations over its first 20 years. In the maximum scenario, the combined direct, indirect, and induced employment effects increase from 50,723 to 65,184 person-years. As well, the GDP impacts rise from a cumulative total of \$13.3 billion to \$17.3 billion. Finally, the combined federal and provincial fiscal impact rises from \$2.5 billion to \$3.3 billion.

¹² The weighted average 2018 contract toll was determined by dividing initial year contract revenue by total contract volume.

¹³ Transmountain Pipeline. *TMEP Toll Application*.

**Table 5. Summary of the Regional Impacts of TMEP Operations
(cumulative effects, 2018-2037)**

	Atlantic Canada	Quebec	Ontario	Other Prairies	Alberta	British Columbia	Territories	Canada
	MINIMUM EFFECTS (LONG-TERM CONTRACTS)							
Employment effects (person-years)	327	1,970	6,345	1,025	10,293	30,269	43	50,273
Direct	0	0	0	0	2,005	4,836	0	6,841
Indirect	184	1,113	3,895	625	5,435	18,565	28	29,845
Induced	143	857	2,450	400	2,853	6,868	15	13,588
GDP effects (millions of 2012\$)	24.3	165.6	542.9	87.0	3,958.1	8,540.2	4.5	13,322.5
Direct	0.0	0.0	0.0	0.0	2,947.9	6,427.8	0.0	9,375.7
Indirect	13.7	94.8	330.4	54.3	711.7	1,505.6	3.0	2,713.4
Induced	10.6	70.9	212.5	32.7	298.5	606.8	1.5	1,233.4
Fiscal Impact (millions of 2012\$)	104	352.1	620.1	111.1	469.3	887.3	4.7	2,548.6
Direct Provincial Revenues	5.9	18.1	59.9	13.8	277.5	727.0	0	1,102.2
Per Capita Share of Federal Revenues	98.1	334.0	560.2	97.3	191.8	160.3	4.7	1,446.4
	MAXIMUM EFFECTS (INCLUDING SPOT VOLUMES)							
Employment effects (person-years)	425	2,555	8,226	1,330	13,346	39,246	56	65,184
Direct	0	0	0	0	2,600	6,270	0	8,870
Indirect	239	1,443	5,050	810	7,047	24,071	36	38,696
Induced	186	1,112	3,177	519	3,699	8,905	20	17,618
GDP effects (millions of 2012\$)	31.5	214.8	703.9	112.8	5,131.9	11,073.0	6.4	17,274.3
Direct	0.0	0.0	0.0	0.0	3,822.2	8,334.2	0.0	12,156.4
Indirect	17.8	122.9	428.4	70.4	922.7	1,952.1	4.3	3,518.5
Induced	13.7	91.9	275.5	42.4	387.0	786.8	2.1	1,599.4
Fiscal Impact (millions of 2012\$)	134.8	456.5	804.0	144.1	608.5	1150.5	6.7	3,305.1
Direct Provincial Revenues	7.6	23.5	77.7	17.9	359.8	942.6	0.0	1,429.1
Per Capita Share of Federal Revenues	127.2	433.1	726.3	126.2	248.7	207.8	6.7	1,876.0

Source: The Conference Board of Canada.

3.6 Summary

Both the development and operational phases of the TMEP will generate economic and fiscal benefits. In general, the economic and fiscal effects associated with operating the pipeline will exceed those experienced during the construction phase of the Project, although the operational effects will be spread over a longer period of time. At a minimum, both phases of the Project are expected to support 108,310 person-years of employment and \$3.8 billion in fiscal effects between 2012 and 2037. (See Table 6.) If the available non-firm capacity on the TMEP is fully utilized these effects increase to 123,221 person-years of employment and fiscal effects of \$4.5 billion.

This chapter and the previous one discussed the economic and fiscal impacts associated with building and operating the TMEP. However, the pipeline is also expected to reduce the discounts on Canadian heavy oil that have been experienced in recent years. The higher received prices for producers, or “netbacks,” will have additional fiscal implications for Canada. The next chapter discusses those impacts.

**Table 6. Summary of the Regional Impacts of TMEP Development and Operations
(cumulative effects, 2012-2037)**

	Atlantic Canada	Quebec	Ontario	Other Prairies	Alberta	British Columbia	Territories	Canada
	MINIMUM EFFECTS (LONG-TERM CONTRACTS)							
Employment effects (person-years)	617	3,372	11,004	2,124	24,926	66,132	135	108,310
Direct	0	0	0	0	9,532	25,511	0	35,043
Indirect	326	1,714	6,235	1,270	9,095	25,164	97	43,900
Induced	291	1,659	4,769	855	6,298	15,458	38	29,368
GDP effects (millions of 2012\$)	46.0	285.8	951.5	185.5	5,360.5	11,329.2	15.7	18,174.2
Direct	0.0	0.0	0.0	0.0	3,598.0	7,945.8	0.0	11,543.8
Indirect	24.5	147.5	538.1	115.7	1,105.7	2,020.3	12.0	3,963.9
Induced	21.5	138.2	413.4	69.8	656.8	1,363.1	3.7	2,666.4
Fiscal Impact (millions of 2012\$)	152.2	518.3	926.7	168.6	708.4	1281.6	6.9	3,762.7
Direct Provincial Revenues	10.3	35.2	116.4	27.9	445	1035.7	0	1,670.5
Per Capita Share of Federal Revenues	141.9	483.1	810.3	140.7	263.4	245.9	6.9	2,092.2
	MAXIMUM EFFECTS (INCLUDING SPOT VOLUMES)							
Employment effects (person-years)	714	3,957	12,886	2,429	27,978	75,110	148	123,221
Direct	0	0	0	0	10,127	26,945	0	37,072
Indirect	381	2,044	7,390	1,455	10,707	30,670	105	52,751
Induced	333	1,913	5,496	973	7,144	17,495	43	33,398
GDP effects (millions of 2012\$)	53.2	334.9	1,112.5	211.3	6,534.4	13,862.1	17.6	22,126.0
Direct	0.0	0.0	0.0	0.0	4,472.3	9,852.2	0.0	14,324.5
Indirect	28.6	175.6	636.1	131.8	1,316.7	2,466.8	13.3	4,769.1
Induced	24.6	159.3	476.4	79.5	745.3	1,543.1	4.3	3,032.4
Fiscal Impact (millions of 2012\$)	183.0	622.7	1110.6	201.6	847.6	1544.8	8.9	4,519.2
Direct Provincial Revenues	12.0	40.6	134.2	32.0	527.3	1,251.3	0.0	1,997.4
Per Capita Share of Federal Revenues	171.0	582.2	976.4	169.6	320.3	293.4	8.9	2,521.8

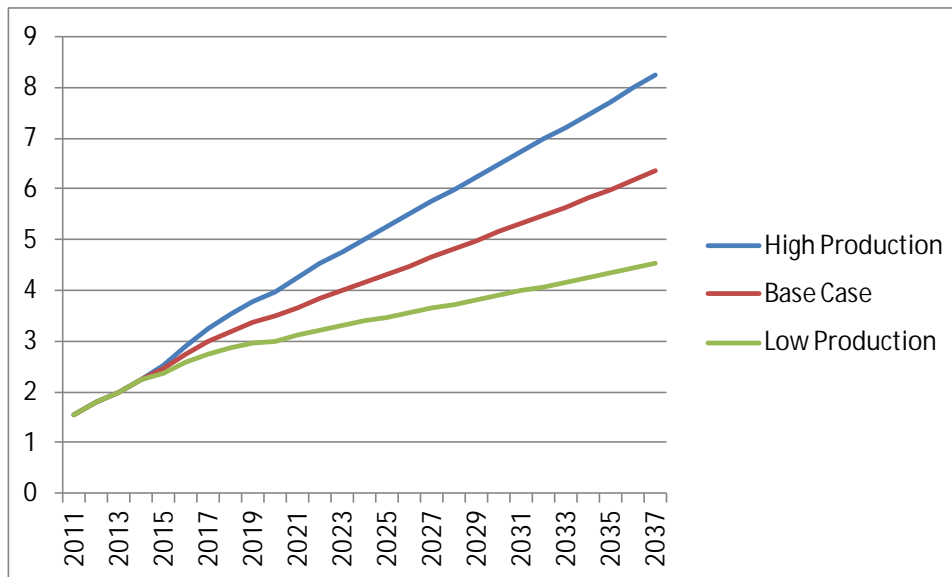
Source: The Conference Board of Canada.

Chapter 4: The Fiscal Impacts of Higher Netbacks for Canadian Oil Producers

In addition to the economic and fiscal impacts outlined in the previous two chapters, there are other implications associated with the development of the TMEP. One of these is the potential for Canadian oil producers to obtain a higher price for their product. The IHS Global Canada Ltd. (IHS) study concludes that the TMEP will help to alleviate the discounting of Canadian crude experienced in recent years and will contribute to higher prices received or “netbacks” for Canadian producers.¹⁴

IHS developed three different production cases for Western Canadian oil production.¹⁵ (See Chart 23.) In all three cases, it is assumed that the Keystone XL pipeline will be built in 2015. In addition, IHS models the price impact of TMEP, Energy East, and Northern Gateway all being completed in 2017/2018 versus a world where they are not built. In every case, the construction of these pipelines results in higher netbacks for all producers of heavy oil (both conventional and diluted bitumen) in Western Canada.

Chart 23. Western Canadian Oil Production Could Take Different Paths
(Western Canadian heavy oil supply, millions of barrels per day)



Source: IHS.

These higher netbacks would lead to higher revenues, and in turn higher profits, which would have real economic consequences, such as increased dividend payments or business investment. As well, there will be fiscal implications in terms of higher royalties and corporate income taxes paid to federal and provincial governments. It is important to note that these benefits will arise regardless of whether or not oil production or investment increases beyond what is currently expected – higher prices alone are

¹⁴ Kelly, Steve. *Trans Mountain Expansion Direct Evidence*.

¹⁵ Kelly, Steve. *Trans Mountain Expansion Direct Evidence*.

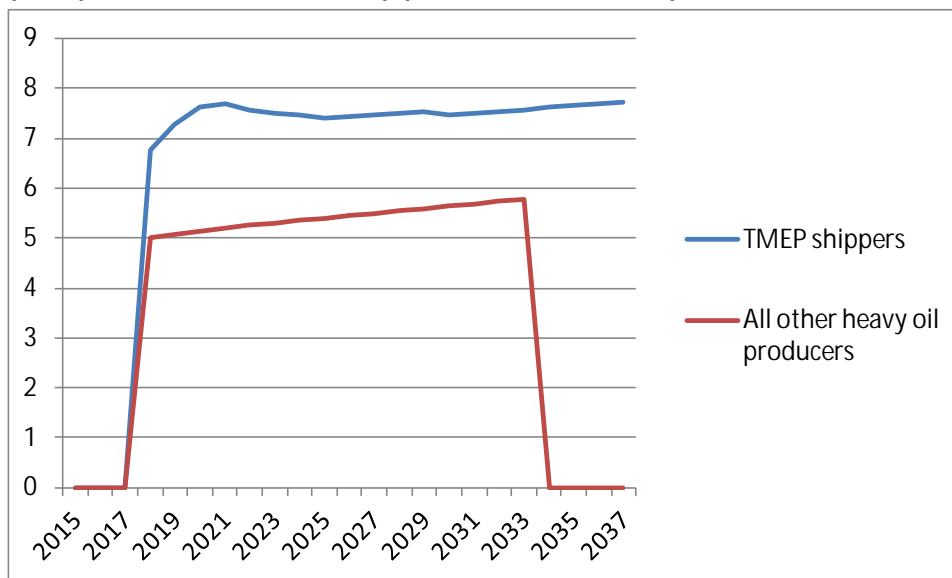
enough to drive positive economic impacts for the Canadian economy. In this study we do not consider the economic effects associated with how producers may make use of higher netbacks. Instead, the rest of this chapter discusses the industry revenue and fiscal implications of higher netbacks associated with pipeline capacity additions in each of the cases.

4.1 The Base Case

In the IHS base case, significant volumes of heavy oil are projected to begin flowing through the TMEP, Energy East, and Northern Gateway pipelines in late 2017. The resulting alleviation of the oversupply situation at Cushing leads to an increase in netbacks for all conventional heavy oil and oil sands producers operating in Western Canada, not just those producers that ship via the TMEP. This situation will persist until 2034, when IHS expects an oversupply situation at Cushing to resume.¹⁶

According to IHS, shippers of heavy oil on the TMEP will receive additional netback benefits from the market access provided by the TMEP, beyond the general industry benefits expected for all heavy oil producers. Heavy oil shippers on the TMEP that sell into California Asian markets are expected to garner higher prices for their products. This will mean a higher netback of about \$7-8 per barrel versus the \$5-6 per barrel that other heavy oil producers will experience.¹⁷ (See Chart 24.) As well, this benefit will persist beyond 2033.

Chart 24. Estimated Higher Netbacks for Oil Producers as a Result of Increased Pipeline Capacity (price premium attributable to pipeline additions, US\$ per barrel, 2012\$)



Source: IHS.

¹⁶ Kelly, Steve. *Trans Mountain Expansion Direct Evidence*.

¹⁷ In the IHS study, these benefits would be realized on volumes shipped to Asia and priced against Middle East crude imported into the region. The benefits for TMEP shippers are based on half of the TMEP firm commitments (equal to 707,500 B/D ÷ 2 = 353,750 B/D) being priced in China rather than in the U.S. Gulf Coast for the period 2018 to 2037.

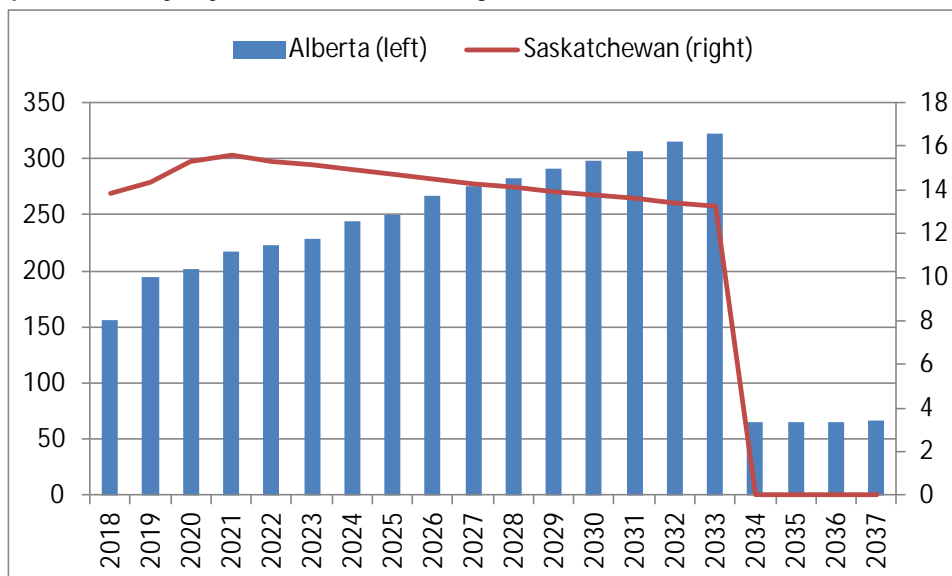
However, not all of the benefits experienced by heavy oil and bitumen producers are attributable to the market access provided by the TMEP. The results are dependent on all three planned pipelines being completed in the 2017/2018 timeframe. As such, IHS attributes 26.6 per cent (equivalent to TMEP's share of the combined assumed capacity additions) of the general industry benefits to TMEP. Thus, TMEP is expected to increase producer revenues by \$45.4 billion over the first 20 years of its operations, with \$37 billion being attributable to general industry benefits and an additional \$8 billion being attributable to TMEP enabling heavy oil shipments to Asia.

4.1.1 Fiscal Impacts: Royalties

Because the TMEP would increase the netbacks for producers without any attendant increase in producers' operating costs, both revenues and profits would be expected to rise by \$45.4 billion. This will have implications for the royalties and corporate income taxes that oil producers pay. In the case of royalties, we estimate that Alberta and Saskatchewan will experience a combined increase in royalties of \$4.6 billion over the first 20 years of pipeline operations.

At \$4.3 billion, Alberta will garner most of these royalty benefits, reflecting the fact that the province accounts for most of the heavy oil production in Western Canada. This corresponds to an annual average of \$217 million, which for comparison purposes, is equivalent to about 4 per cent of all oil royalty payments in Alberta in fiscal year 2012-13.¹⁸ However, the benefits will be highest during the 2018-2033 period, when every barrel of diluted bitumen and conventional heavy oil receives a higher price. (See Chart 25.)

Chart 25. Higher Netbacks Will Increase Royalty Collections
(provincial royalty collections due to higher netbacks, millions of 2012\$)



Source: The Conference Board of Canada.

¹⁸ Government of Alberta. *Budget 2013: Fiscal Plan Tables*.

Saskatchewan will also see higher royalty payments, although the gains will be commensurately lower in line with the province's lower production levels. Over the period 2018 through 2033, we estimate that the province would collect an additional \$230 million in royalty payments as a result of higher netbacks from the TMEP. However, since we do not expect any Saskatchewan oil to actually move through the TMEP, Saskatchewan producers will not experience any benefits after 2033.

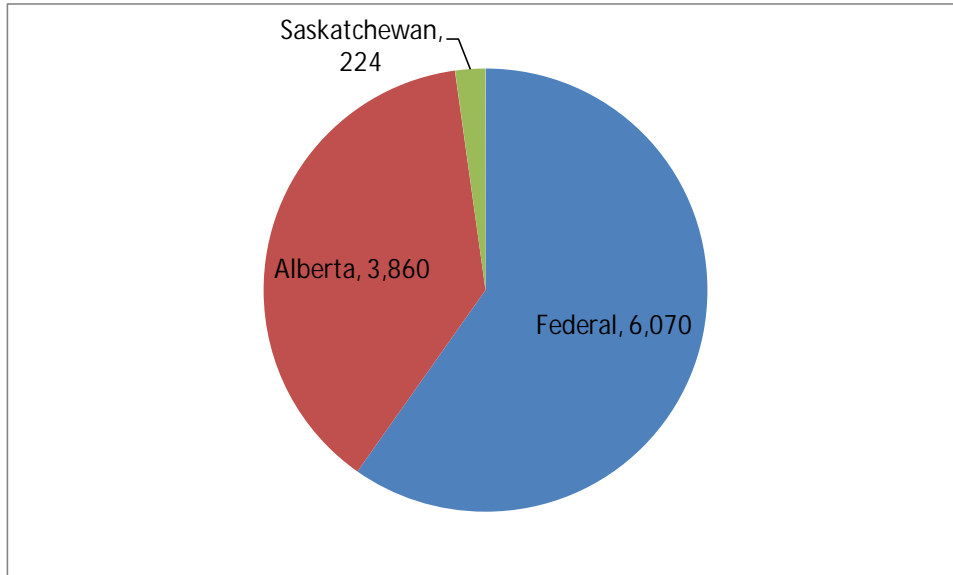
4.1.2 Fiscal Impacts: Income Taxes

Higher profits for oil producers as a result of higher netbacks will also generate significant corporate income tax effects at both the federal and provincial level. Income taxes are applied after royalties are deducted, but the direct link between higher prices and higher profits means that the provincial and federal tax rates are being applied to a sizeable increase in profits. We expect the corporate tax effects to be even larger than the royalty impacts, at \$10.2 billion between 2018 and 2037.

Again, as the largest producer, Alberta will garner a sizeable share of this total figure, at \$3.9 billion over the same period. Saskatchewan will also benefit, but the fiscal impact will be much smaller at \$224 million over the same period. The fact that Saskatchewan heavy oil production is only about one-tenth that of Alberta's and that the ratio is shrinking is one factor. As well, Saskatchewan only garners benefits between 2018 and 2033, when all Canadian heavy oil producers are expected to benefit from higher prices as a result of the TMEP.

As the sole producers of heavy oil and diluted bitumen in Canada, Alberta and Saskatchewan derive all of the benefit from higher provincial tax revenues. But the entire country will also benefit from higher federal corporate income tax collections, which are projected to be larger than those that accrue to Alberta and Saskatchewan combined. (See Chart 26.) Between 2018 and 2037 federal corporate income tax collections are expected to be \$6.1 billion higher as a result of the higher netbacks that result from the TMEP. Since federal revenues tend to be distributed back to the provinces on a per capita basis, this will generate significant benefits for all of Canada's regions.

Chart 26. Higher Netbacks Will Result in Sizeable Corporate Income Tax Benefits (corporate income tax effects due to higher netbacks, millions of 2012\$, 2018-2037)



Source: The Conference Board of Canada.

Thus, in the base case, the cumulative fiscal benefits of the TMEP are considerable. Canada as a whole derives an additional \$14.7 billion in fiscal revenues between 2018 and 2037. Alberta captures the largest share of this benefit. The combined royalty and provincial corporate income tax effects in the province total \$8.2 billion over a 20-year period, or \$410 million per year, which is equivalent to 1.1 per cent of provincial revenues in fiscal year 2012-13.¹⁹ But the benefits are not confined to Alberta. Saskatchewan directly garners \$454 million of the total fiscal effects between 2018 and 2037, while the rest will be spread across the provinces as part of federal disbursements.

4.2 The Low Production Case

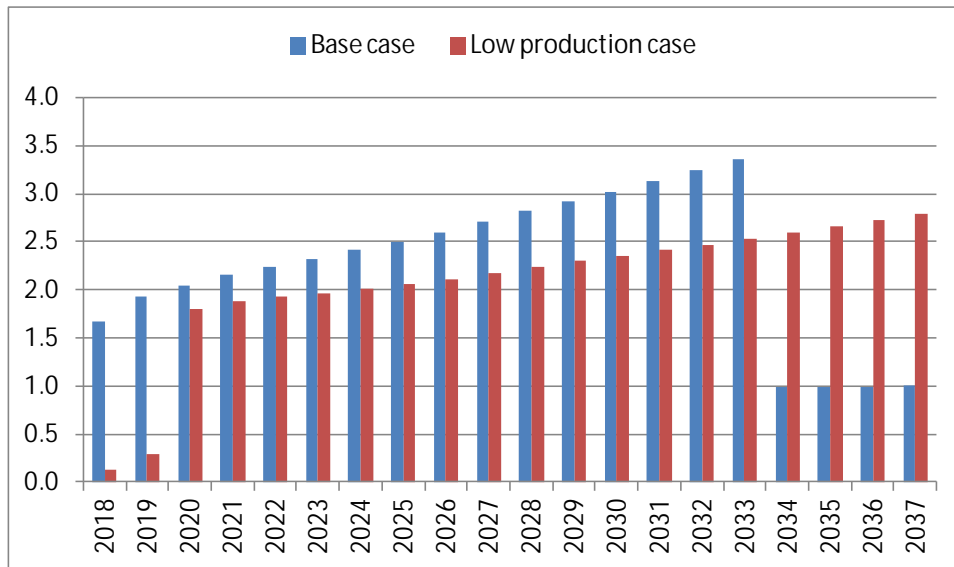
The IHS low production scenario assumes bitumen production is lower than in the base case, but conventional heavy production remains unchanged. In terms of higher netbacks, the key difference between the base case and the low production case is how long it takes for the available supply of oil to again exceed the existing pipeline capacity. In the base case this occurred in 2034, but this is not expected to happen before the end of the forecast period in the low production case. Also of note in the low production case is that the benefit of higher netbacks for non-TMEP shippers does not start until 2020.

In any given year before 2034, the total royalties and corporate income tax collections associated with heavy oil production will be lower in the low production case. Less production leads to lower revenues and profits, and thus lower royalties and corporate income tax collections. However, since the higher netback effects of the TMEP persist for a longer period of time in the low production scenario, IHS estimates oil industry revenues attributable to TMEP to be \$41.9 billion. (See Chart 27.) This is only modestly lower than in the base case.

Chart 27. Higher Netbacks Due to TMEP Will Contribute to Higher Oil Producer Revenues

¹⁹ Government of Alberta. *Budget 2013: Fiscal Plan Tables*.

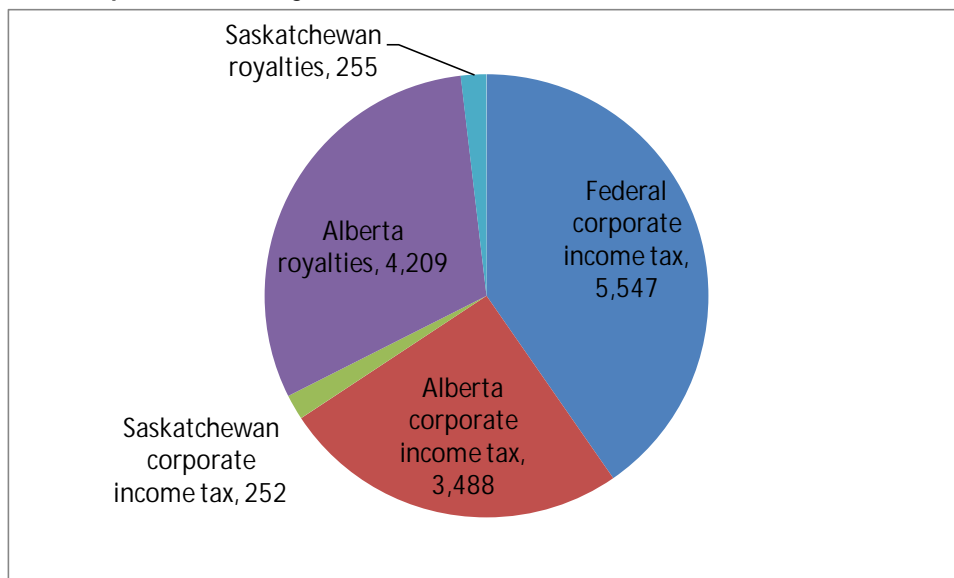
(increase in oil producer revenues attributable to TMEP, billions of 2012\$)



Source: IHS.

In total, government revenues are expected to be \$13.8 billion higher between 2018 and 2037 as a consequence of the higher netbacks that result from TMEP. Corporate income taxes will again account for the largest share of this total at \$9.3 billion. (See Chart 28.) The federal government will experience the largest share of corporate income tax collections (59.7 per cent), followed by Alberta (37.6 per cent), and Saskatchewan (2.7 per cent).

Chart 28. Federal Corporate Income Taxes Experience the Highest Fiscal Impact (fiscal impacts due to higher netbacks, millions of 2012\$, 2018-2037)



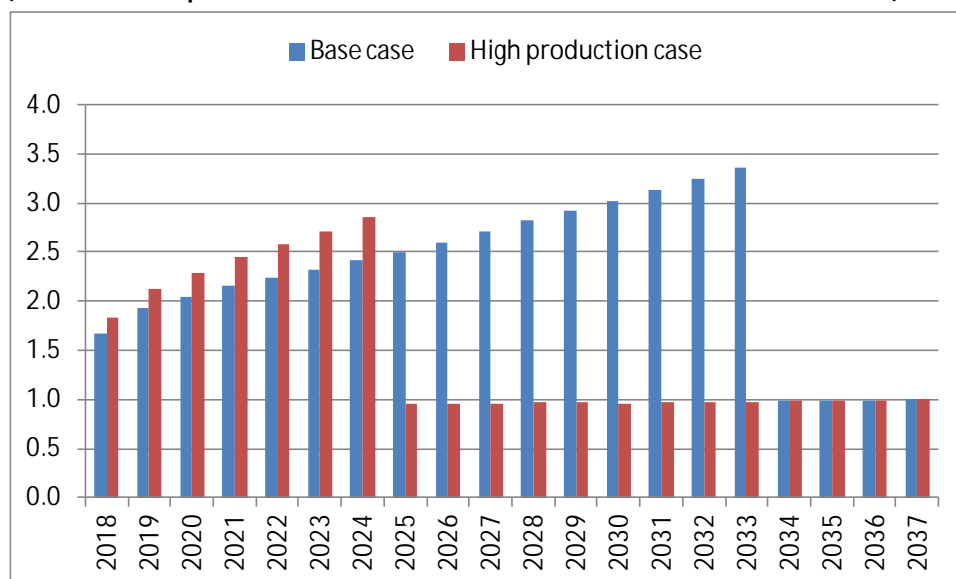
Source: The Conference Board of Canada.

Alberta’s royalty collections will be \$4.2 billion higher as a result of the higher netbacks over the TMEP’s first 20 years of operations. Saskatchewan also benefits from the higher netbacks on conventional heavy oil. Over the same period, its royalty collections are expected to be \$255 million higher. Unlike the base case, because the benefits for non-TMEP shippers will persist through the end of the forecast period, Saskatchewan will experience benefits through to 2037.

4.3 The High Production Case

In the IHS high production scenario bitumen production is expected to expand more quickly than in the base case, but conventional heavy production remains unchanged. In terms of higher netbacks, again the key difference in IHS’s analysis is how long it takes before the available supply of oil exceeds the existing pipeline capacity. In the base case this occurred in 2034, but in the high production case this occurs much sooner, in 2025. As a result, IHS estimates that total oil producer revenues from higher netbacks attributable to TMEP between 2018 and 2037 as a result higher netbacks to be only \$29.7 billion. Thus, the fiscal benefits associated with higher netbacks are the lowest in this scenario. (See Chart 29.)

Chart 29. Higher Netbacks Due to TMEP Will Contribute to Higher Oil Producer Revenues (increase in oil producer revenues attributable to TMEP, billions of 2012\$)

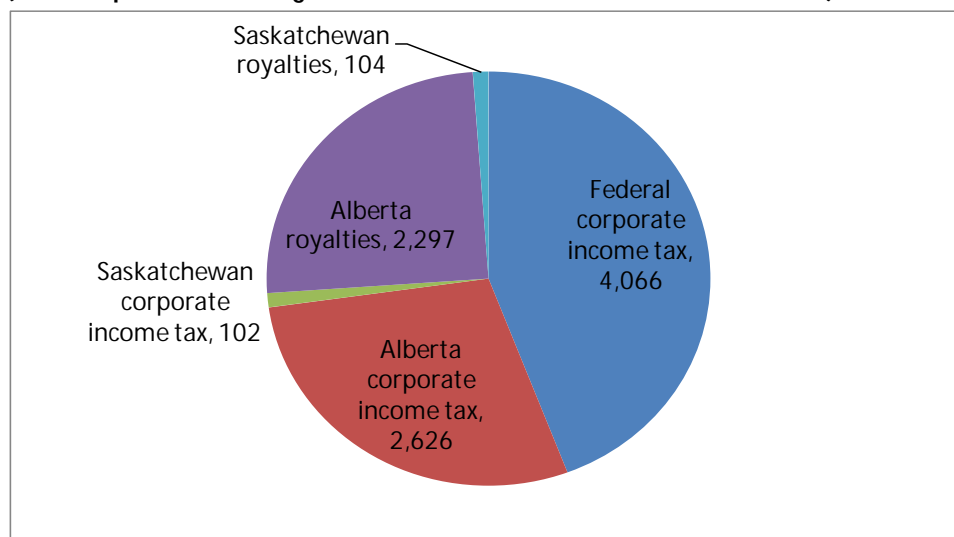


Source: IHS.

Nevertheless, the fiscal benefits are still significant in this case. In total, government revenues are expected to be \$9.2 billion higher between 2018 and 2037 as a result of the higher netbacks that the market access provided by the TMEP will generate. Corporate income tax collections will account for \$6.8 billion of this figure, with the federal government garnering the largest share at \$4.1 billion, followed by Alberta (\$2.6 billion) and Saskatchewan (\$102 million). (See Chart 30.) Royalty payments

account for the rest of the fiscal effects from higher netbacks, with Alberta's royalties being \$2.3 billion higher and Saskatchewan's being \$104 million higher.

Chart 30. Summary of the Fiscal Impact in the High Production Case
(fiscal impacts due to higher netbacks, millions of 2012\$, 2018-2037)



Source: The Conference Board of Canada.

4.4 Summary

The construction and operation of the TMEP and other pipelines is expected to result in higher netbacks to Canadian oil producers. One result of these higher netbacks is higher royalty and corporate income tax payments in the provinces of Saskatchewan and Alberta, as well as at the federal level. In the base case we expect these fiscal benefits to total \$14.7 billion over the first 20 years of the pipeline's operations. (See Table 7.) This figure ranges between \$9.2 billion in the high production case and \$13.8 billion in the low production case.

Table 7. Summary of the Fiscal Impacts of Higher Netbacks
(cumulative effects, 2018-2037)

	Atlantic Canada	Quebec	Ontario	Other Prairies	Alberta	British Columbia	Territories	Canada
	Base Case							
Total Impact (millions of 2012\$)	411.8	1,401.8	2,351.0	861.9	8,868.9	804.9	19.7	14,720.0
Provincial Corporate Income Tax	0.0	0.0	0.0	223.8	3,860.2	0.0	0.0	4,084.0
Per Capita Share of Federal Corporate Income Tax	411.8	1,401.8	2,351.0	408.2	672.7	804.9	19.7	6,070.0
Royalties	0.0	0.0	0.0	230.0	4,336.0	0.0	0.0	4,566.0
	Low Production Case							
Total Impact (millions of 2012\$)	376.4	1,281.1	2,148.5	880.5	8,311.6	735.5	18.0	13,751.7
Provincial Corporate Income Tax	0.0	0.0	0.0	252.5	3,487.8	0.0	0.0	3,740.3
Per Capita Share of Federal Corporate Income Tax	376.4	1,281.1	2,148.5	373.0	614.8	735.5	18.0	5,547.3
Royalties	0.0	0.0	0.0	255.0	4,209.0	0.0	0.0	4,464.0
	High Production Case							
Total Impact (millions of 2012\$)	275.8	938.8	1,574.6	478.9	5,373.3	539.1	13.2	9,193.8
Provincial Corporate Income Tax	0.0	0.0	0.0	101.6	2,625.7	0.0	0.0	2,727.3
Per Capita Share of Federal Corporate Income Tax	275.8	938.8	1,574.6	273.4	450.6	539.1	13.2	4,065.5
Royalties	0.0	0.0	0.0	104.0	2,297.0	0.0	0.0	2,401.0

Source: The Conference Board of Canada.

Chapter 5: Conclusion

Canadian benchmark oil prices have lagged considerably behind their global peers in recent years. Ultimately this means that Canada is not getting the full fiscal and economic benefits associated with exploiting its non-renewable oil resources. In response, there has been growing interest in developing new oil transportation infrastructure in North America. There are currently four major pipeline projects under consideration that would move oil away from Western Canada if completed, including the TMEP.

If approved, the TMEP will generate economic and fiscal benefits. These benefits will occur in three key areas. The first is during the development stage of the Project, when the pipeline is being developed and built. The second comes during the operational period of the Project, with economic impacts associated with running and maintaining the pipeline. The last comes from the expectation that the TMEP will lead to higher netbacks for producers of heavy oil in Western Canada. All three of these effects will generate economic and fiscal impacts.

Development phase—Including the direct, supply chain, and induced effects, the spending during the development phase of the Project will support 58,037 person-years of employment, and \$1.2 billion in federal (\$646 million) and provincial (\$568 million) government revenues. As the sites where the pipeline will be built, British Columbia and Alberta will account for the majority of these impacts. However, other provinces, and in particular Ontario, will benefit through supply chain effects and the redistribution of federal government revenues to the regions.

Operational phase—We estimate the operational impacts of the pipeline over its first 20 years of service under two scenarios, a minimum scenario based on the existing long-term contracts, and a maximum scenario based on the non-firm capacity in the pipeline being fully utilized. At a minimum, we expect pipeline operations to support 50,273 person-years of employment, and this figure rises to 65,184 if the non-firm capacity is fully utilized. In terms of fiscal effects, pipeline operations are expected to support between \$2.5 and \$3.3 billion in combined federal and provincial revenues, considerably above those from the development phase. British Columbia and Alberta enjoy the lion's share of these benefits; however, other provinces do benefit through supply chain effects and the redistribution of federal government revenues to the regions.

Higher netbacks—We estimate the fiscal impacts of higher netbacks under the three different cases developed by IHS. In the base case we expect these fiscal benefits to total \$14.7 billion over the first 20 years of the pipeline's operations. The federal corporate income tax effects account for the largest share of these effects at \$6.1 billion. The combined royalty and corporate income tax effect for Alberta is \$8.2 billion, and for Saskatchewan it is \$454 million. The cumulative fiscal effect ranges between \$9.2 billion in the high production case and \$13.8 billion in the low production case.

Table 8 summarizes the economic and fiscal impacts associated the TMEP using the minimum operating impacts and the base case for assessing the impact of higher netbacks. Between 2012 and 2037, the

Project is expected to generate 108,310 person-years of employment. As well, the Project will produce \$18.5 billion of fiscal benefits over the same period.

**Table 8. Summary of the Economic and Fiscal Impacts of the TMEP
(cumulative effects, 2012-2037)**

	Atlantic Canada	Quebec	Ontario	Other Prairies	Alberta	British Columbia	Territories	Canada
	Using Minimum Operational Effects and the Base Case for Higher Netbacks							
Employment effects (person-years)	617	3,372	11,004	2,124	24,926	66,132	135	108,310
Project development	289	1,402	4,659	1,099	14,632	35,864	92	58,037
Project operations	327	1,970	6,345	1,025	10,293	30,269	43	50,273
GDP effects (millions of 2012\$)	46.0	285.8	951.5	185.5	5,360.5	11,329.2	15.7	18,174.2
Project development	21.7	120.1	408.6	98.5	1,402.4	2,789.1	11.2	4,851.7
Project operations	24.3	165.6	542.9	87.0	3,958.1	8,540.2	4.5	13,322.5
Fiscal Impact (millions of 2012\$)	564.0	1,920.1	3,277.7	1,030.5	9,577.3	2,086.5	26.6	18,482.7
Project development	48.2	166.2	306.6	57.5	239.1	394.3	2.2	1,214.1
Project operations	104.0	352.1	620.1	111.1	469.3	887.3	4.7	2,548.6
Higher netbacks	411.8	1401.8	2351.0	861.9	8868.9	804.9	19.7	14,720.0

Source: The Conference Board of Canada.

Appendix A: Resume and Professional Qualifications of Glen Hodgson

Employment History

The Conference Board of Canada

Senior Vice-President and Chief Economist – November 2006 to present

Vice-President and Chief Economist – September 2004-November 2006

- Member of executive team.
- Lead a management group of seven directors and forty staff.
- Responsible for economic forecasting of the Canadian, provincial, metropolitan, U.S. and international economies, and for numerous economic analysis contracts annually.
- Also responsible for international development projects delivered for clients.
- Lead spokesman for the Conference Board via presentations, articles and media.

Export Development Canada (EDC)

Vice-President and Deputy Chief Economist – October 2001 to September 2004

- Co-led a group of approx. 55 staff (with six team leaders) analyzing and forecasting major global and Canadian economic trends and assessing economic, political, environmental and other international business risks.
- A lead spokesman for EDC via presentations, articles and media.

Vice-President, Policy and International Relations – 2000-2001

Director, Government and International Relations – 1998-2000

Director, Government Relations and Corporate Policy – 1994-1998

- Reporting to the President, directed a policy staff that grew progressively to eighteen.
- Responsible for many facets of EDC's business strategy and policy, and related domestic and international legislation and regulation.
- Managed the corporation's relationship with its stakeholders in Canada and internationally.

Department of Finance, Government of Canada

Senior Chief, International Finance and Development Division -- 1993-1994

- Co-directed a group of twenty responsible for the Canadian Government's international financial priorities and interests (G-7 financial issues, export credits, debt rescheduling, foreign aid policy, multilateral financial institutions, etc.)
- Provided Budget advice on national defense, foreign aid and international finance.

Departmental Secretary, Deputy Minister's Office -- 1991-92

- Acted as Executive Assistant to the Deputy while directing a staff of 12.
- Helped to manage the Department's relationship with the Minister of Finance, his staff and with other departments and agencies
- Coordinated multiple Federal Budgets; developed the Department's Corporate Plan.

Chief, International Development Finance -- 1988-91

- Directed a group of seven responsible for: Canada's membership in the IMF, World Bank, EBRD and the other regional development banks; foreign aid budgetary and policy issues; and export financing issues.

Economist, International Programs Division -- 1982-84

- Responsible for country risk analysis, debt rescheduling, export and development financing.

International Monetary Fund

Advisor/Assistant to the Executive Director for Canada, Ireland and the Caribbean on the Board of Directors -- 1984-88

- Advisor to the Canadian Executive Director on IMF lending, policy and administration.
- Represented the Executive Director in IMF Board discussions and on country missions.

Education

Ph.D. Candidate in Economics (ABD), McGill University, 1981

M.A. in Economics, McGill University, 1981

B.A. (Honours), University of Manitoba, 1978

Publications – Over 200 publications; full list available separately upon request.

Appendix B: Bibliography

Government of Alberta. *Budget 2013: Fiscal Plan Tables*. Edmonton: Government of Alberta, 2013.

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Kelly, Steve. *Trans Mountain Expansion Direct Evidence*. Calgary: IHS Global Canada Limited, 2013.

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Transmountain Pipeline. *TMEP Toll Application*. Calgary: Transmountain Pipeline, 2012.

Appendix C: Input/Output Models

Input/output (I/O) models are economic models that describe how goods and services flow through an economy. There are two key elements in an I/O model, geography and commodities. Commodities represent particular goods or services, and the I/O model encompasses information regarding which industries produce these commodities and how they are used; either as inputs into other industries, consumed domestically, or exported. The geography element tracks where production takes place, and how different commodities are traded across provincial and international boundaries.

One of the uses for I/O models is to calculate the economic impacts associated with different types of economic activity. Because the model describes how the supply chains work, we are able to “shock” the I/O model and observe how the impact feeds through the economy. “Shocks” are inputs into the model and can take different forms. For example, the effects of the TMEP’s operations in this report are measured using a “gross output” or revenue shock. Essentially we increase the revenues of the oil pipeline industry by a certain amount and observe the results. The shock associated with the development of the TMEP was implemented in a different way. We increased the demand for different types of commodities that will be used in the project, such as pipe, tanks, and construction labour.

The I/O model used in this analysis is produced and maintained by Statistics Canada. Statistics Canada updates the I/O tables used by the model annually as parts of the Canadian System of National Accounts (CSNA). The CSNA is a system of integrated statistical accounts consisting of four main components: input-output accounts (national and provincial), income and expenditure accounts (national and provincial), balance of payments and the financial and wealth accounts. The I/O tables cover all economic activities conducted in the market economies of each province and territory, encompassing persons, businesses, government and non-governmental (non-profit) organizations, and entities outside its jurisdiction that give rise to imports or exports (inter-provincially or internationally).

To compile the I/O accounts, Statistics Canada obtains source data from all relevant surveys as well as administrative sources such as tax records, professional and industry organizations, and non-government institutions every year for each province and territory. In the process of preparing statistical estimates, data from various sources are confronted, analysed by subject-matter experts and used to compile estimates that are consistent with all other estimates in the System and provide a valid and coherent statistical picture of the subject matter. Consistency is a key feature of the statistics produced by the Accounts.

The result is that Statistics Canada’s I/O model is the most comprehensive description of how economic activity flows through the Canadian economy. The model describes the flows for more than 700 different commodities and 300 different industries across all provinces and territories. The model solutions include both “open” results, which summarize the direct and indirect impacts of a shock, and “closed” results, which summarize the combined direct, indirect, and induced impacts. Key outputs from the model that can be used to describe the results of a shock include employment, GDP, labour income,

gross output, and international trade. The results described here used Statistics Canada's 2009 I/O model, the most current available at the time of the analysis.

Key Assumptions

Although I/O models can be useful tools for understanding the economic impacts associated with particular projects, it is also important to understand that a number of assumptions are embedded in the results. The following section discusses some of these major assumptions.

Fixed Production Patterns

The tables that underlay the I/O model are based on the supply chain relationship in the Canadian economy at a fixed point in time; in this particular case 2009. As such, the model results do not factor in how things like changes in relative prices for different inputs, productivity, and technology can impact supply chains over time. As well, trade flows do not take into account external factors, such as changes in exchange rates, the emergence of new trading partners, or changes in trade policy.

This assumption is also pertinent in the discussion of the induced effects. The model assumes fixed consumption and savings patterns for consumers over time. In reality, spending and saving patterns are influenced by a variety of factors including economic circumstances and demographics. As a result, the farther you look forward in time using an I/O model the less likely it is that the model accurately describes future economic activity.

Lack of Supply Constraints

Another key assumption embedded in the I/O results is that there are no supply constraints on the economy. This means that the model results assume that all of the inputs needed to conduct the shock are readily available, and that the modelled project will not be competing with others for resources. In reality, if a project is of significant size it may lead to higher prices and/or wages as the new project will draw resources away from other activities.

This is particularly pertinent in the discussion of the induced effects. The induced effects assume that the people employed as a result of the direct and indirect effects would otherwise be unemployed, but at least some of them would likely find other employment, though their pay may be less. Thus, including the induced effects likely overstates the total economic effects; however, not including them would definitely understand the total economic effects.

Industry Homogeneity

I/O models typically assume that all firms within an industry are characterized by a common production process. In practical terms, the model reflects an industry average, thus Trans Mountain's operations and business practices are assumed to be the same as other oil pipeline operators such as Enbridge or TransCanada. If Trans Mountain's production structure is significantly different from the industry average than the economic impact results may be different from what is characterized here.

Industry homogeneity also assumes a constant return to scale for all businesses in an industry; in other words the model assumes a linear relationship between inputs and outputs. In practice, many industries experience at least some economies of scale, which means there is an optimal scale at which businesses should operate. Thus, in the model each extra dollar of revenue or investment is assumed to result in the same relative increase in economic activity. In reality, that may not be strictly true.

Appendix B The Trans Mountain Expansion Project: Understanding the Economic Benefits for Canada and its Regions, The Conference Board of Canada

Insights. Understanding. Impact.



The Conference Board
of Canada

255 Smyth Road, Ottawa ON

K1H 8M7 Canada

Tel. 613-526-3280

Fax 613-526-4857

Inquiries 1-866-711-2262

conferenceboard.ca



**Appendix C Direct Evidence of John J. Reed of Concentric Energy Advisors, Inc. to
the National Energy Board**

NATIONAL ENERGY BOARD

IN THE MATTER OF the *National Energy Board Act*, R.S.C. 1985, c. N-7, as amended, (“*NEB Act*”) and the Regulations made thereunder;

IN THE MATTER OF the *Canadian Environmental Assessment Act*, S.C. 1992, c. 37, as amended, and the Regulations made thereunder;

AND IN THE MATTER OF an Application pursuant to Part III of the *NEB Act* by Trans Mountain Pipeline ULC as General Partner of Trans Mountain Pipeline L.P. (collectively “Trans Mountain”) for a certificate of public convenience and necessity authorizing the construction and operation of the expanded Trans Mountain Pipeline System.

**APPLICATION BY TRANS MOUNTAIN FOR A CERTIFICATE OF
PUBLIC CONVENIENCE AND NECESSITY AUTHORIZING THE
CONSTRUCTION AND OPERATION OF THE EXPANDED TRANS
MOUNTAIN PIPELINE SYSTEM**

November 30, 2013

DIRECT EVIDENCE OF JOHN J. REED

To: The Secretary
National Energy Board
444-7th Avenue S.W.
Calgary, AB T2P 0X8

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1 ***I. INTRODUCTION***

2 **Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3 A1. My name is John J. Reed. My business address is 293 Boston Post Road West, Suite
4 500, Marlborough, Massachusetts 01752.

5 **Q2. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?**

6 A2. I am Chairman and Chief Executive Officer of Concentric Energy Advisors, Inc.
7 (“Concentric”). Concentric is a management consulting firm specializing in financial
8 and economic services to the energy industry.

9 **Q3. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND
10 EXPERIENCE.**

11 A3. I have more than thirty-five years of experience in the North American energy
12 industry. Prior to my current position with Concentric, I served in executive
13 positions with various consulting firms and as Chief Economist with Southern
14 California Gas Company, North America’s largest gas distribution utility. I have
15 provided expert testimony on financial and economic matters on more than 150
16 occasions before the National Energy Board (“NEB” or “Board”), the Federal
17 Energy Regulatory Commission (“FERC”), provincial and state utility regulatory
18 agencies, various state and federal courts, and before arbitration panels in Canada
19 and the United States. A copy of my résumé and a listing of the testimony I have
20 sponsored is included as Attachment A.

21 **Q4. IN WHICH CASES HAVE YOU PREVIOUSLY TESTIFIED BEFORE
22 THE BOARD?**

23 A4. I have submitted evidence before the Board on behalf of the following parties in the
24 following proceedings:

- 25 • Alberta-Northeast (GH-1-87)
- 26 • Alberta-Northeast (GH-2-87)
- 27 • Alberta-Northeast (GH-5-89)
- 28 • Independent Petroleum Association of Canada (RH-2-91)

DIRECT EVIDENCE OF JOHN J. REED

- 1 • The Canadian Association of Petroleum Producers (RH-1-93)
- 2 • Maritimes & Northeast Pipeline (GH-6-96)
- 3 • Alliance Pipeline (GH-3-97)
- 4 • Maritimes & Northeast Pipeline (GH-3-2002)
- 5 • TransCanada PipeLines (RH-3-2004)
- 6 • Brunswick Pipeline (GH-1-2006)
- 7 • TransCanada PipeLines (RH-1-2007)
- 8 • Repsol Energy Canada (GH-1-2008)
- 9 • Maritimes & Northeast Pipeline (RH-4-2010)
- 10 • TransCanada PipeLines (RH-003-2011)
- 11 • Trans Mountain Pipeline (RH-001-2012)
- 12 • TransCanada PipeLines (RH-001-2013)
- 13 • NOVA Gas Transmission Ltd. Board File OF-Fac-Gas-NO81-2013-10 01

14 In addition to testifying, I have worked with numerous entities in the Canadian
15 energy industry during my career, assisting them with various strategic, regulatory
16 and toll-related issues.

17 **Q5. ON WHOSE BEHALF ARE YOU SPONSORING EVIDENCE IN THIS**
18 **PROCEEDING?**

19 A5. I am sponsoring evidence on behalf of Trans Mountain Pipeline ULC (“Trans
20 Mountain” or the “Company”).

21 **Q6. WHAT IS THE PURPOSE OF YOUR EVIDENCE?**

22 A6. The purpose of my direct evidence is to address two major areas: 1) a review and
23 assessment of whether the Trans Mountain Expansion Project (“TMEP” or the
24 “Project”) meets the Board’s standards for economic and financial feasibility, which
25 are important criteria for the determination of whether a project is in the public
26 interest; and 2) an overview of the benefits of the Project, in terms of energy industry
27 benefits and economic benefits.

1 **Q7. WHAT INFORMATION CONTAINED IN THE APPLICATION HAVE**
2 **YOU REVIEWED FOR THE DEVELOPMENT OF YOUR EVIDENCE?**

3 A7. I have reviewed Volumes 1, 2 and 5B of the application. My review began with the
4 chapters that included quantitative assessments of the benefits of the Project,
5 including the studies prepared by The Conference Board of Canada (“Conference
6 Board”), which has developed a report that evaluates the economic benefits of the
7 Trans Mountain Project, and by IHS Global Canada Limited (“IHS”), which has
8 developed a report that provides an independent assessment of the market for the
9 products shipped on the Project, the supplies available to the Project, and oil
10 industry benefits and impacts that are expected to result from the operation of the
11 Project. I have also focused on the information prepared by TERA Environmental
12 Consultants (“TERA”), which produced the Socio – Economic analysis included in
13 the application.

14 ***II. EXECUTIVE SUMMARY***

15 **Q8. PLEASE SUMMARIZE THE CONCLUSIONS OF YOUR EVIDENCE.**

16 A8. I have reviewed the Company’s application, the requirements of Section 52 of the
17 NEB Act, the Board’s Filing Manual as well as precedent from past Board decisions,
18 and have concluded that the Project is both economically and financially feasible and
19 would result in substantial benefits both to the Western Canadian oil industry and to
20 the Canadian, provincial and local economies. Regarding the economic and financial
21 viability of the Project, my conclusions are:

- 22 · The market study developed by IHS provides convincing evidence that
23 Western Canadian oil production will ensure more than adequate supplies of
24 oil to support the Project over its operating life. According to the IHS study,
25 even if all four of the major oil pipeline projects currently proposed in
26 Western Canada are built, the market can fully absorb the new capacity,
27 through production expansion, by approximately 2030.
- 28 · The potential for some level of under-utilization of the region’s aggregate
29 pipeline capacity during the 2017-2030 period does not indicate that the
30 TMEP, or any of the other proposed projects, are not economically feasible.
31 The TMEP provides a feasible and efficient means of addressing the
32 asymmetrical risk of too much/too little capacity. Some level of optionality
33 in capacity markets promotes economic efficiency, reflects the likelihood of

1 future additional demand and does not detract from the economic feasibility
2 of the TMEP. The relative attractiveness of markets can change quickly, as
3 supply and demand fundamentals shift. Having transportation infrastructure
4 that accommodates shifts in market preferences creates value, by providing
5 the option and ability to redirect flows as markets change.

- 6 · IHS estimates that in the base case, higher netback prices for heavy crude oil
7 production will provide total producer benefits of \$140 billion with \$37
8 billion attributable to the market access provided by the TMEP for the
9 forecast period (2017–2037).¹ In addition, the netback benefits attributed to
10 the TMEP that are associated with the access provided to Asian markets are
11 estimated at \$8 billion over the forecast period. Therefore, total benefits
12 attributable to TMEP are approximately \$45 billion (all figures in \$2012).²
- 13 · The Project will provide access to California, the U.S. Pacific Northwest and
14 other Pacific Rim markets. The Pacific Rim includes some of the fastest
15 growing oil markets in the world. The results of the IHS study also indicate
16 that the netbacks calculated to California and other Pacific Rim markets are
17 expected to remain at a premium to all other markets served by oil pipelines
18 connected to Western Canadian oil production over the entire study period.
- 19 · The Project has received binding long-term commitments for 100 percent of
20 the capacity reserved for firm service from 13 financially strong shippers.
21 These contracts are a clear indication that the Project can reasonably be
22 expected to be used at a high load factor. The take-or-pay provisions in the
23 Transportation Service Agreements (“TSAs”) ensure that fixed charges will
24 be paid over the first 15-20 years of operation. These contracts provide
25 evidence that the market views the Project as necessary and economical.
- 26 · These contractual commitments, coupled with the strong credit rating of the
27 Company’s parent, Kinder Morgan Energy Partners LP, and the fact that the
28 Project is designed to respond to the needs of shippers in the evolving
29 market for oil pipeline services, should make financing readily attainable.

30 The Project will help to realign Canada’s pipeline system with new market realities,
31 resulting in numerous benefits to the Western Canadian oil industry, specifically:

- 32 · The Project alleviates concerns over inadequate capacity and minimizes
33 apportionment by allowing shippers to execute long-term contracts for firm

¹ Benefits attributable to TMEP equate to approximately 26 percent of the total estimated benefits for the major planned export pipeline capacity expansions.

² All figures in this evidence and all figures cited from the IHS and Conference Board studies are in constant \$2012.

1 service, while also providing uncommitted land and Westridge Marine
2 Terminal (“Dock”) shippers with greater access to spot capacity.

- 3 · The Project will create a higher-value pathway to California and other Pacific
4 Rim markets, providing desired market diversification and, according to the
5 IHS study, higher netbacks for Western Canadian heavy crude oil producers.
- 6 · Through enhanced access to California and other Pacific Rim markets, the
7 Project offers producers an alternative to traditional North American
8 markets and greater market optionality, thus reducing the likelihood of a
9 recurrence of the price discounting of Canadian oil experienced over the past
10 several years.
- 11 · The sizing of the Project to meet contractual demand while providing a
12 reasonable level of uncommitted service promotes productive efficiency and
13 limits the risk of underutilization; at the same time, the Project’s firm service
14 contracts promote allocative efficiency by awarding capacity to the shippers
15 who value it the most, and the contract provision allowing for capacity
16 release into the secondary market ensures that capacity will continue to be
17 allocated to those shippers that value it most on an ongoing basis throughout
18 the Project’s life.

19 According to the Conference Board economic benefits study and the socio-
20 economic impacts calculated by TERA in the Environmental and Socio-economic
21 Assessment, the Project would also provide substantial macroeconomic benefits at
22 the federal and provincial levels. Specifically, those benefits include:

- 23 · An estimated 58,037 person-years of employment during the development
24 phase, and another 50,273 to 65,184 person-years of employment during the
25 first 20 years of operation;
- 26 · Total estimated GDP effects in Canada between 2012 and 2037 ranging from
27 \$18 billion to \$22 billion;
- 28 · Incremental government revenues from the construction and operation of
29 the Project over the first 20 years of \$3.76 billion to \$4.52 billion;
- 30 · An additional \$14.7 billion in income taxes and royalty payments at the
31 federal and provincial level as a result of higher netbacks to oil producers;
32 and
- 33 · Incremental property tax revenue of \$25.3 million per annum in Alberta and
34 British Columbia collectively.

1 III. BOARD'S STANDARDS FOR EVALUATING ECONOMIC AND FINANCIAL VIABILITY
2 OF THE PROPOSED PROJECT

3 Q9. HOW HAS THE BOARD TRADITIONALLY ASSESSED THE
4 ECONOMIC AND FINANCIAL VIABILITY OF A PROPOSED
5 PROJECT?

6 A9. Section 52 of the NEB Act states that when considering an application for a
7 certificate:

8 [T]he Board shall have regard to all considerations that appear to it to
9 be relevant, and may have regard to the following:

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

19 In practice, the Board's standard for determining if a project is economically
20 feasible—criterion (c) above—has been the presentation of satisfactory evidence that
21 criteria (a), (b) and (d) above have been met. In *Mackenzie*, the Board stated:

22 The National Energy Board takes the following criteria into
23 consideration when considering economic feasibility for facilities
24 built under the *National Energy Board Act*.

- 25
26 · the availability of markets for the gas flowing on the pipeline (will
27 the gas be purchased?);
28 · the availability of downstream pipeline capacity (will there be
29 sufficient pipeline capacity to move the gas from the end of the
30 [Project] to ultimate markets?);
31 · the long-term gas supply which is available to the pipeline (is
32 there sufficient gas to be transported?);
33 · the contractual commitments underpinning the project (will the
34 fixed cost component of the pipeline tolls be paid?); and

1 · the ability of the project to be financed (will investors fund the
2 pipeline?).³

3 The Board's threshold criteria for economic feasibility are also reflected, in more
4 abbreviated terms, in Guide A, Section A.3 of its Filing Manual, which states:

5 The overall purpose for filing information on facility economics is to
6 demonstrate that the applied-for facilities will be used, will be useful,
7 and that demand charges will be paid...⁴

8 **Q10. PLEASE EXPLAIN YOUR DISTINCTION BETWEEN FINANCIAL**
9 **AND ECONOMIC VIABILITY.**

10 A10. In my usage of these terms, "financial feasibility" refers to commercial matters and
11 focuses on the Board's criteria regarding the ability of a project to be financed and
12 whether a project's fixed charges are likely to be paid. Commercial matters include
13 factors such as the fairness and efficiency of the tolling principles proposed and the
14 contractual commitments that have been signed. The term "economic feasibility," as
15 I have used it, addresses the justification and need for a project within an industry
16 context and centers on the Board's criterion that a project be used and useful.
17 Economic feasibility is dependent on whether adequate commodity supply exists,
18 and whether there is market demand for a project, and examines the level of shipper
19 support for a project.

20 **Q11. ARE THERE OTHER STANDARDS USED BY THE BOARD TO**
21 **EVALUATE THE ECONOMIC AND FINANCIAL VIABILITY OF A**
22 **PROJECT?**

23 A11. Yes. While not addressed in every proceeding, there are a number of other standards
24 that the Board has applied in assessing the economic and financial feasibility of a
25 proposed project. With regard to economic feasibility, the Board also commonly
26 evaluates: (i) whether a project is consistent with the competitive context of the
27 market, and (ii) whether a project has been sized correctly.

³ NEB, Reasons for Decision, Volume 2, Chapter 7, GH-1-2004.

⁴ NEB Filing Manual, Guide A, Section A.3, p. 4A-62.

1 In terms of financial feasibility, the Board also has considered: (i) whether a project
2 can be financed without relying on tolls that create cross-subsidization, (ii) the
3 reasonableness of risk apportionment in the project's commercial terms, and (iii) the
4 competitiveness of a project, and its effect on the market.

5 In certain cases, the Board has placed considerable weight on these factors.
6 Therefore, in my evidence I have also addressed the Project in terms of each of these
7 additional criteria.

8 ***IV. FINANCIAL VIABILITY OF THE PROJECT***

9 **Q12. HAS THE BOARD PREVIOUSLY RULED ON THE TOLLING**
10 **PRINCIPLES PROPOSED FOR TMEP BY THE COMPANY?**

11 A12. Yes. Unlike many other large proposed pipeline projects before the Board, TMEP
12 has fully addressed all of the matters regarding Section IV of the *NEB Act* in a
13 separate proceeding filed in 2012. In its May 16, 2013 decision, the Board found
14 both the tolling principles and the terms and conditions in the Facilities Support
15 Agreements ("FSAs") and TSAs pertaining to TMEP to be appropriate.⁵

16 **Q13. ARE THE BOARD'S FINDINGS IN THE TMEP TOLLING**
17 **PROCEEDING RELEVANT TO AN ASSESSMENT OF THE PROJECT'S**
18 **FINANCIAL VIABILITY?**

19 A13. I believe they are. While there are no open issues regarding the tolling principles or
20 the terms and conditions of the FSAs and TSAs that the Company and its shippers
21 have signed, it is appropriate to consider many of the Board's findings in that
22 proceeding, since those matters relate to the financial feasibility of the Project. In
23 the tolling proceeding, the Board found that: (i) the proposed tolling principles were
24 just and reasonable as well as non-discriminatory; (ii) the terms and conditions of the
25 FSAs and TSAs were appropriate; and, (iii) the open season process was fair and
26 transparent.

⁵ NEB, Reasons for Decision, RH-001-2012.

1 **Q14. HOW DO THE APPROVED TOLLING PRINCIPLES SUPPORT THE**
2 **FINANCIAL VIABILITY OF THE PROJECT?**

3 A14. The Project's tolling principles have been designed so that an integrated, market-
4 based set of tolls are applicable to all service on TMEP after it is expanded, and the
5 tolling principles will be used for 20 years to derive predictable and stable tolls over
6 the life of the TSAs. The tolling principles reflect the costs of the Project and were
7 determined to be just and reasonable and to not create any unjust discrimination.
8 Adherence to cost causation principles in toll treatment, and the avoidance of unjust
9 discrimination, is viewed by the Board as a threshold criterion in assessing a project's
10 economic and financial feasibility.⁶

11 **Q15. HOW DO THE TERMS AND CONDITIONS IN THE FSAS AND TSAS**
12 **SUPPORT THE FINANCIAL VIABILITY OF THE PROJECT?**

13 A15. The terms and conditions in the FSAs and TSAs define the risk allocation between
14 the Project sponsor and the shippers. In *Alliance*, the Board stated:

15 In its application, Alliance declared itself to be "at-risk" with respect
16 to any underutilization of the applied-for facilities... This fact
17 addresses one potentially significant public interest consideration.⁷

18 I agree with the Board's assessment that risk apportionment is a significant public
19 interest consideration.

20 The risk apportionment in the Project's FSA and TSA terms and conditions, which
21 has already received Board approval, is reasonable and promotes productive
22 efficiency. By sharing the costs associated with construction cost overruns and
23 bearing the underutilization risk during the first 20 years of operations, the Company
24 is "at-risk" and has an incentive to construct and operate the Project as cost-
25 effectively as possible, while maintaining the high standards for constructing and
26 operating the Pipeline outlined in the Company's Application. Thus, productive
27 efficiency is strongly promoted.

⁶ NEB, Reasons for Decision, GH-001-2012, p. 41.

⁷ NEB, Reasons for Decision, GH-3-97, p. 13.

1 **Q16. HOW DOES THE BOARD'S VIEW ON THE CONSISTENCY OF THE**
2 **PROJECT'S UNDERPINNINGS WITH COMPETITIVE MARKET**
3 **PRINCIPLES AFFECT ITS ANALYSIS OF THE FINANCIAL VIABILITY**
4 **OF THE PROJECT?**

5 A16. As I stated in Section III of my evidence, the Board often examines whether a
6 proposed project was developed in a manner that was consistent with competitive
7 market principles. In its decision in the Project's 2012 tolls proceeding, it was the
8 Boards' view that the appropriateness of the open season process, the presence of
9 alternative sources of transportation, and the fact that the tolling methodology was
10 the result of arms-length negotiations between sophisticated parties have collectively
11 mitigated any concerns that the Company was able to abuse market power or
12 otherwise adversely affect competition in negotiating its tolling methodology. The
13 Board's decision in the tolls proceeding should also provide assurance that the
14 Project is financially viable.

15 **Q17. IN ASSESSING A PROPOSED PROJECT'S FINANCIAL VIABILITY, IS**
16 **IT THE BOARD'S PRACTICE TO CONSIDER OTHER COMPETING**
17 **PROJECTS?**

18 A17. While the Board sometimes considers the competitive framework in which a project
19 is being proposed, it does not typically assess or consider the relative merits of
20 competing projects. In *Keystone*, the Board stated:

21 It was suggested by the CEP in final argument that the Board should
22 consider the public interest broadly enough to review this application
23 in comparison or conjunction with other proposed projects. The
24 Board does not however have a practice of hearing facilities
25 applications on a comparative basis and has, in the case of *Sable*,
26 determined that it is not under a statutory obligation to hold
27 comparative hearings.⁸

28 In other words, the Board does not have a practice of picking winners and losers. In
29 assessing a project's economic and financial feasibility, the Board evaluates the effect
30 that project would have on market competition and intervenes only in instances

⁸ NEB, Reasons for Decision, OH-1-2007, p. 14.

1 where competitive market forces may be unable to be effective. When no
2 unreasonable adverse effect on competition is anticipated, it is the Board's view that
3 the market should decide if the project is eventually built. The Board has reiterated
4 this position on a number of occasions in past decisions. In *Keystone XL*, the Board
5 stated:

6 [I]n general, the public interest is served by allowing competitive
7 forces to work, except where there are costs that outweigh the
8 benefits.⁹

9 In *Mackenzie*, the Board stated:

10 Our approval gives Mackenzie gas an opportunity to compete. Denial
11 would block that opportunity indefinitely.¹⁰

12 As acknowledged in TMEP's application, the Project is one of a group of pipelines
13 that are being proposed to meet the market's need for additional pipeline capacity.
14 However, the financial feasibility of TMEP does not depend on the success or failure
15 of any of those other projects, and the Board's past standards do not suggest that a
16 comparison of the Project to those other projects is appropriate. The Project, and its
17 shippers, are fully prepared to proceed once the Board has granted the necessary
18 approvals, without regard to whether other competing projects move forward or not.

19 **Q18. IS THE COMPANY'S SIZING OF THE PROJECT CONSISTENT WITH**
20 **THE BOARD'S FINANCIAL VIABILITY STANDARDS?**

21 A18. Yes, it is. The Project has been sized to meet contractual demand plus anticipated
22 spot service. There is no unsold capacity other than the 20 percent of total nominal
23 capacity that the Board deemed appropriate to reserve for non-firm or spot service,
24 and virtually all of the TMEP's firm capacity is subscribed from the date of the
25 initiation of service of the Project. The need for and sizing of the Project is not
26 dependent on any forecasted market developments or future events.

⁹ NEB, Reasons for Decision, OH-1-2009, p. 32.

¹⁰ NEB, Reasons for Decision, Volume 2, Chapter 7, GH-1-2004.

1 **Q19. PLEASE COMMENT ON THE LIKELIHOOD THAT THE PROJECT'S**
2 **FIXED COSTS WILL BE PAID.**

3 A19. In light of all of the facts referred to in this section of my evidence, I have concluded
4 that there is a very high likelihood that the fixed charges on TMEP will be paid over
5 the first 20 years of service. The Project is consistent with the new market for oil
6 pipeline services in that it offers firm transportation under long-term contracts while
7 still offering spot service at a premium to the firm service. The project is also
8 responsive to shipper requests for long-term toll stability and predictability. A very
9 high level of support for the Project from 13 financially strong shippers has been
10 demonstrated by the long-term FSAs and TSAs that have been executed, and by
11 expressions of interest in spot service. In total, these facts fully support a conclusion
12 that the Project's fixed charges will be paid.

13 **Q20. WHAT HAVE YOU CONCLUDED WITH REGARD TO WHETHER**
14 **THE PROJECT IS LIKELY TO BE FINANCEABLE?**

15 A20. As discussed in TMEP's application, Trans Mountain Pipeline ULC expects to
16 finance the Project with equity supplied by the parent company Kinder Morgan
17 Energy Partners, L.P. ("KMP") and with corporate debt sourced from Canadian and
18 U.S. lenders. KMP expects to rely on a balanced capital structure (50% debt and
19 50% equity), and to be able to secure an investment-grade rating for the long-term
20 debt. This is consistent with the fact that KMP had its issuer rating of BBB
21 confirmed by Fitch earlier this year.¹¹ Based on the strength of the FSAs and TSAs
22 that credit-worthy shippers have signed, and on the approved tolling methodology, it
23 is reasonable to conclude that the Project is highly financeable. Furthermore, based
24 on my understanding of the Project's economics, risk apportionment and the level of
25 shipper support, I have concluded that the Project will be able to secure capital on
26 reasonable terms, and be financially feasible.

¹¹ KMP's current credit rating for long-term corporate debt is: BBB (stable) at Standard & Poor's Ratings Services; Baa2 (stable) at Moody's Investors Service Inc.; and, BBB (stable) at Fitch, Inc.

1 **V. ECONOMIC VIABILITY OF THE PROJECT**

2 **Q21. IN ASSESSING THE ECONOMIC VIABILITY OF PIPELINE**
3 **PROJECTS, WHAT CRITERIA DOES THE BOARD TAKE INTO**
4 **CONSIDERATION?**

5 A21. The Board has commented expansively in past decisions on the criteria to use when
6 considering the economic feasibility of new pipeline projects. In *Alliance*, the Board
7 stated:

8 As noted in Chapter 1, this assessment includes an evaluation of: (i)
9 the availability of long-term gas supply, (ii) the long-term outlook for
10 gas markets, (iii) the contractual commitments underpinning the
11 proposal, and (iv) project financing.¹²

12 In addition, Section A.3 of the NEB's Filing Manual states that filing information
13 related to economic viability should demonstrate that the applied-for facilities will be
14 used, will be useful, and that fixed charges will be paid and that sufficient funds will
15 be available for abandonment requirements.¹³

16 **Q22. DO THE LONG TERM CONTRACT COMMITMENTS THAT TMEP**
17 **HAS ENTERED INTO PROVIDE ASSURANCE THAT THE PIPELINE**
18 **WILL BE USED AT A HIGH LOAD FACTOR¹⁴?**

19 A22. Yes. The Project has firm commitments of approximately 708,000 bpd from 13
20 shippers that have signed 15 or 20 year contract commitments that underpin the
21 project. These contracts are a clear demonstration that the project can reasonably be
22 expected to be utilized at a high load factor. For example, a contract for 50,000 bpd
23 for 20 years could result in a take or pay commitment of approximately \$1.5 billion
24 dollars for the firm shipper. It can reasonably be assumed that such a commitment
25 by a shipper is not going to be made lightly or without a plan to ship oil. As
26 represented in the Project's tolling proceeding, there is strong shipper support for

¹² NEB, Reasons for Decision, GH-3-97, p. 12.

¹³ Funding requirements for pipeline abandonment is currently before the Board as part of its Land Matters Consultation Initiative ("LMCI"). An oral hearing is scheduled for January 2014 to consider the mechanisms proposed by federally regulated pipeline companies to set-aside and collect funds to cover the cost of future abandonment projects. Trans Mountain has filed an application for approval of its proposed set aside and collection mechanism in the LMCI proceeding.

¹⁴ A high load factor pipeline is a pipeline that is used at a high rate on a relatively constant basis.

1 the Project with contractual commitments for capacity. Those commitments are
2 held by a large number of financially strong shippers.

3 As noted by the Board in *Alliance*:

4 The Board is also of the view that the financial commitments that
5 shippers have made to pay \$8.2 billion in demand charges on the
6 Alliance system over the first 15 years of operation provides a
7 powerful incentive for shippers to acquire adequate gas supplies.
8 These companies, backed by their lenders, have made expert
9 determinations that they will have access to adequate gas supplies in
10 order to utilize their capacity entitlements on the Alliance Project.¹⁵

11 ***

12 The financial commitments of the Alliance shippers to the Project
13 provide strong evidence that the market will be adequate. The Board
14 recognizes the shippers' business expertise and their confidence that
15 the market opportunities merit the investments to which they have
16 committed.¹⁶

17 The same conclusion can reasonably be drawn from the facts that are presented in
18 this application for the TMEP. The firm shipper commitments are strong
19 indications that there is a need for the Project and that it is economically feasible.

20 **Q23. WILL THE PROJECT HAVE ACCESS TO LONG TERM SUPPLY?**

21 A23. Yes. As noted in the report developed by IHS and sponsored by Mr. Kelly, even if
22 all four major new pipelines¹⁷ that are currently proposed are built, the market can
23 fully absorb the new capacity over time through production growth. In addition, the
24 Project is fully consistent with the competitive context of the market as discussed
25 below. Shippers want access to multiple markets and see a benefit in the flexibility
26 of being able to go to a market that offers the highest netback at any point in time,
27 especially when market dynamics are unpredictable. Based on the analysis completed
28 by IHS, there is a potential for some level of under-utilization of the region's
29 aggregate pipeline capacity during the 2017-2030 period, if all proposed projects

¹⁵ NEB, Reasons for Decision, GH-3-97, p. 19.

¹⁶ *Ibid*, at 26.

¹⁷ These four projects are the TMEP, Northern Gateway, Keystone XL, and Energy East.

1 proceed as planned. However, that does not indicate that TMEP, or any of the other
2 proposed projects, are not economically feasible.

3 **Q24. WHAT HAS BEEN THE BOARD'S VIEW WHEN IT COMES TO THE**
4 **POSSIBLE UNDER-UTILIZATION OF PIPELINE CAPACITY?**

5 A24. In its decision for *Keystone XL*, the Board was clear that in the development of
6 pipelines both current and future requirements for transportation service must be
7 taken into consideration. The Board stated that:

8 The Board is of the view, however, that prudent design must
9 consider both the current and future requirements for transportation
10 service over the life of a Project to achieve the objective of efficiency.
11 The Board is satisfied that the Keystone XL Pipeline, as proposed,
12 reflects a reasonable balance of both the current and anticipated
13 requirements of shippers over the longer term, given the supply
14 potential of the WCSB and the size of the USGC market.¹⁸

15
16 These views are also relevant to the Board's evaluation of the current set of
17 proposed oil pipelines, including TMEP. Some level of optionality in capacity
18 markets promotes economic efficiency, reflects the likelihood of future additional
19 demand and does not detract from the economic feasibility of the Project.

20 **Q25. WHY IS THE POTENTIAL FOR SOME UNDERUTILIZED PIPELINE**
21 **CAPACITY NOT AN INDICATION THAT ONE OR MORE OF THE**
22 **PROPOSED PIPELINES IS NOT NEEDED?**

23 A25. The balance between production and take-away capacity shown in the IHS study
24 indicates that production is expected to grow to meet the full take-away capacity that
25 is built, and that even if all proposed pipeline projects proceed as planned, the new
26 capacity will be fully absorbed by 2030. In the intervening 10 years or so, the new
27 capacity provided by these pipelines will promote market competition and higher
28 netbacks to producers and will provide producers with the opportunity to develop
29 new supply areas confidently. The IHS analysis in which all four large pipeline
30 development projects come on-line by 2018 is not an actual forecast of pipeline

¹⁸ NEB, Reasons for Decision, OH-1-2009, p. 18.

1 capacity, rather, it is a simplifying assumption made by IHS in order to estimate the
2 netback benefits of the Project.

3 As seen in the time period from 2011 to present, insufficient pipeline capacity in the
4 market can result in severe price discounting for Western Canadian crude supplies.
5 IHS has estimated that in 2012 inadequate pipeline access for Alberta producers led
6 to large price discounts for Canadian crude, which, in aggregate, reduced producer
7 revenues by between \$15 and \$19 billion. Those foregone producer revenues should
8 be compared against the much lower costs to shippers of holding some excess
9 capacity. For example, using the lower end of this range, one year of lost revenues
10 (\$15 billion) is roughly equivalent to over 12 years of fixed toll charges on TMEP.
11 Given that highly asymmetrical cost/benefit relationship, producers can be seen as
12 making a rational economic decision by committing to TMEP and other projects on
13 an unconditional basis, even if some excess capacity may result if all projects are
14 developed as planned and on schedule. In addition, the Board's public interest
15 considerations should take into account a new dynamic in oil markets. The need for
16 new pipeline facilities is not simply the difference between projected supply and
17 current take-away capacity. The market also needs: i) flexibility; ii) diversity of
18 market access; iii) the ability to manage risk associated with competing in multiple
19 markets; and iv) the ability to manage development and operational risk.

20 **Q26. PLEASE EXPLAIN HOW THESE ADDITIONAL ISSUES CONTRIBUTE**
21 **TO THE NEED FOR NEW PIPELINE CAPACITY.**

22 A26. As discussed in the IHS study, Canadian crude production has historically relied on
23 refining markets in Canada, the U.S. Midwest the Pacific Northwest, which have
24 been accessed by a relatively small number of pipelines with dedicated markets.
25 However, the significant expansion of Western Canadian crude production,
26 combined with the increase in U.S. crude production and relatively stable refining
27 demand, has led to a new market structure in which producers have sought access to
28 an expanded set of market options for their production, and to transportation
29 infrastructure which can access those markets. In order to accommodate these
30 demands, the Canadian oil pipeline network needs to be reconfigured to go beyond

1 its traditional role of providing crude supply to refineries in the interior of the
2 continent, and also provide access to tidewater to achieve greater market reach.

3 The development of more of a “portfolio” approach to marketing also reflects the
4 fact that different markets offer significantly different netbacks to producers, and
5 that the relative attractiveness of markets can change quickly as supply and demand
6 fundamentals shift. A portfolio approach to marketing requires that the
7 transportation infrastructure accommodate shifts in market preferences, which in
8 turn creates value through having the option and ability to redirect flows as markets
9 change. The willingness of producers to commit to take-or-pay fixed charges for
10 pipeline capacity to multiple markets makes economic sense when viewed in this
11 context, and providing that optionality enables Canadian producers and resource
12 owners to maximize the value they derive from oil production.

13 Shippers also recognize that there are risks that some projects may not be developed
14 as planned or on schedule, and that even after commercial operation is achieved,
15 some amount of capacity may not be fully available at all times.

16 All of these facts contribute to the demand for additional capacity and justify the
17 economies of holding and paying for capacity that may not be used every day of the
18 year.

19 **Q27. IN ADDITION TO THE SIGNED AGREEMENTS FOR FIRM SERVICE**
20 **ON THE PROJECT, ARE THERE REASONS TO BELIEVE THAT SPOT**
21 **SERVICE WILL ALSO CONTRIBUTE TO THE ECONOMIC VIABILITY**
22 **OF THE PROJECT?**

23 A27. Yes. As compared to Gulf Coast, Midwestern or Eastern markets, TMEP will
24 provide a higher-value pathway for spot volumes because it will provide access to the
25 California and other Pacific Rim markets. As noted in the IHS report, the netback
26 price for crude delivered to Asia or California markets is expected to be higher than
27 the value of supplies delivered to U.S. Gulf Coast markets. Therefore, the value of
28 spot service on TMEP can reasonably be expected to be higher than on other
29 pipelines which access lower value markets, assuming that sufficient supplies will be

1 shipped on TMEP. The availability of spot service on TMEP, and its economic
2 advantage over competing routes, can be expected to contribute to the economic
3 feasibility of the Project.

4 **Q28. BASED ON THE FACTS DISCUSSED ABOVE, DOES THE PROJECT**
5 **MEET THE BOARD'S STANDARDS FOR CONCLUDING THAT A**
6 **PROJECT IS ECONOMICALLY FEASIBLE?**

7 A28. Yes it does. TMEP is highly likely to be used and useful and it should be expected to
8 operate at a high load factor. The Project is fully consistent with the Board's criteria
9 for assessing economic feasibility, and consistent with the new market dynamics
10 regarding the need for pipeline transportation optionality and flexibility.

11 ***VI. BENEFITS OF THE PROJECT***

12 **Q29. BRIEFLY DISCUSS THE OVERALL COMMERCIAL AND ECONOMIC**
13 **BENEFITS OF THE PROJECT.**

14 A29. TMEP provides significant benefits to Canada and will help realign Canada's pipeline
15 system with new market realities. The Project offers economic benefits to the
16 Western Canadian oil industry and to the federal government, the provinces and
17 local communities through which the expanded pipeline will run. Those benefits
18 have been quantified in reports provided by the Conference Board, IHS and TERA.

19 **Q30. PLEASE SUMMARIZE THE PROJECT BENEFITS.**

20 A30. The Project will provide the following benefits to WCSB oil producers and to
21 federal, provincial and local governments: 1) enhanced quality and value of service
22 for the Project's firm shippers; 2) enhanced access to California and other Pacific
23 Rim markets, providing essential market diversification for Canadian oil producers;
24 3) higher prices/netbacks to Canadian oil producers as quantified by IHS; 4) the
25 reduction in the likelihood of recurring price discounts for Canadian crude, based on
26 the existence of paths to multiple markets, and flexibility to target the highest
27 netback markets; 5) enhancement in secondary market competition to serve
28 uncommitted volumes; 6) promotion of competition among oil pipelines; 7)
29 increased flexibility and optionality in the entire oil pipeline transportation system; 8)

1 the promotion of economic efficiency in pipeline transport markets (both productive
2 and allocative); and 9) macroeconomic benefits in local, provincial and federal
3 economies.

4 **Q31. PLEASE DISCUSS HOW THE PROJECT WILL ENHANCE THE**
5 **QUALITY AND VALUE OF SERVICE TO ALL SHIPPERS.**

6 A31. Currently, with the exception of capacity reserved for the Firm 50 Dock shippers,¹⁹
7 the Trans Mountain Pipeline has inadequate capacity to meet the demands of its
8 Dock and land shippers. The Pipeline experiences substantial apportionment and
9 over-nominations monthly, and has for several years. This has been a substantial
10 problem for land shippers because they cannot secure committed capacity on the
11 pipeline and therefore cannot have any assurance of securing service to their
12 pipeline-connected refineries and terminals. This is also a significant problem for
13 Dock shippers because they have to bid monthly premiums significantly in excess of
14 the pipeline toll to secure capacity on the pipeline.²⁰ Collectively, for land and Dock
15 shippers, the existing Trans Mountain system is unable to provide the level of
16 predictability and certainty that the market needs (except for Firm 50 shippers).

17 Through the execution of the FSAs and TSAs, the committed shippers will be able,
18 once the Project has been completed, to gain firm access to capacity for 15 to 20
19 years, which will essentially eliminate the apportionment on Trans Mountain that
20 these shippers have faced. Uncommitted land shippers will have access to the
21 majority of the remaining spot capacity and an opportunity to access additional
22 capacity through the secondary market. Uncommitted Dock shippers will have
23 access to more capacity than is currently available and also have the opportunity to
24 access the secondary market. The Project will facilitate shippers' ability to arrange
25 long-term business with confidence since under the terms of the contracts, shippers
26 will have stable and predictable tolls for 20 years. Similarly, shippers will have more
27 capacity options available with the Project through spot transactions, enhancing the
28 quality and value of the capacity for all shippers. These improvements in the quality,

¹⁹ NEB, Reasons for Decision, RH-2-2011.

²⁰ Bid premiums totaled \$163 million in 2012.

1 reliability and availability of transportation service will improve the functionality and
2 efficiency of the market.

3 **Q32. PLEASE DESCRIBE HOW THE TRANS MOUNTAIN PROJECT**
4 **ENHANCES MARKET DIVERSIFICATION FOR CANADIAN OIL**
5 **PRODUCERS.**

6 A32. As discussed earlier in this evidence, in the Trans Mountain Expansion Application
7 and in the evidence of IHS, the primary purpose of the Project is to provide
8 additional needed transportation capacity to deliver growing oil production to West
9 Coast and offshore markets. Currently, Canadian oil is exported almost exclusively
10 to U.S. markets. With U.S. oil production increasing, developing another market for
11 Canadian oil is vital to ensuring that Canadian oil producers will receive full value for
12 their production and, in turn, ensures that Canadians will receive maximum benefits
13 from the development and sale of these natural resources. The Project provides
14 producers with the opportunity to market their products to offshore markets, and at
15 the same time, provides a price lift for all Canadian oil producers with the creation of
16 a new and higher-value outlet for Canadian oil. With the ability to sell Canadian oil
17 to offshore markets, shippers have the opportunity to reach the most attractive
18 markets through firm and spot service that is competitively and predictably priced.
19 As is true for virtually all commodity markets, the elimination of binding constraints
20 (which can be logistical, contractual, and financial) on the ability of products to reach
21 the highest value markets produces economic gains for producers, eliminates price
22 distortions that can otherwise lead to inefficient use of the commodity, and helps to
23 promote economically efficient investment decisions for producers and consumers.

24 **Q33. PLEASE DISCUSS THE PROJECT BENEFITS OF HIGHER**
25 **PRICES/NETBACKS TO ALL CANADIAN OIL PRODUCERS.**

26 A33. Oil is actively traded in large, highly liquid multinational markets in which arbitrage
27 opportunities are quickly exploited such that “the law of one price” prevails. In such
28 markets, prices are established by the economics of the marginal supplier and the
29 marginal consumer. Infrastructure developments which improve the efficiency of the
30 market or economically remove constraints, increase the total economic welfare of
31 all participants. By providing greater access for Canadian producers to a large,

1 valuable market that is not easily accessible with the current infrastructure, the
2 Project allows the entire Canadian producer community to profit from higher prices.
3 In this market, relieving delivery constraints to a higher-value market is functionally
4 equivalent to a sudden rise in demand from a large new market, lifting prices for
5 producers that would otherwise be constrained in reaching the higher-value market.
6 The IHS study estimated the effects that the Project's operation will have on
7 producer netbacks in the WCSB and concluded that development of the Project,
8 along with other planned major pipelines, will provide higher oil prices overall as
9 compared to a Reference scenario in which these projects are not built. In its
10 Expansion Scenario, IHS estimates that producer revenue benefits attributable to all
11 the planned major pipelines can be expected to be \$140 billion through 2037. Since
12 TMEP represents about 26 percent of the assumed capacity additions, the estimated
13 benefits attributable to the market access provided by TMEP equates to
14 approximately \$37 billion. In addition, the netback benefits attributed to TMEP
15 that are associated with the access provided to Asian markets are estimated at \$8
16 billion over the forecast period, resulting in total benefits attributable to TMEP of
17 approximately \$45 billion.

18 **Q34. HOW WILL THE PROJECT PROMOTE COMPETITION AMONG**
19 **PIPELINES?**

20 A34. As noted by the Board in past decisions, the public interest is best served by allowing
21 competitive forces to work. The Project promotes competition by giving shippers
22 enhanced options for marketing their products and as noted above, provides broader
23 market access by not only allowing shippers the ability to access the North American
24 market, but also the growing Asian market. As noted by the Board in the *Keystone*
25 *XL Pipeline Decision*:

26 Moreover, the Board is of the view that all western Canadian
27 producers are likely to benefit from the Keystone XL Pipeline over
28 the longer term, through broader market access, greater customer
29 choice and efficiencies gained through competition among
30 pipelines.²¹

²¹ NEB, Reasons for Decision, OH-1-2009, p. 33.

1
2 TMEP provides these same benefits to the market by creating new capacity for
3 producers and enabling a greater level of competition among pipelines for
4 uncommitted production.

5 **Q35. HOW WILL THE PROJECT ENHANCE SECONDARY MARKET**
6 **COMPETITION TO SERVE UNCOMMITTED VOLUMES?**

7 A35. As noted in Section 2.5 of the Application, the terms of the firm TSAs require
8 shippers to pay for the capacity whether or not it is used. As permitted under the
9 terms of the TSAs, shippers are able to resell or assign any capacity that they are not
10 using through secondary market transactions. That available capacity, competing
11 against the 20% of capacity reserved for spot shippers, other pipeline capacity and
12 rail options, will contribute to a competitive secondary market for transportation
13 capacity. The availability of this market will enhance service to uncommitted spot
14 shippers. Without the expanded firm services enabled by the Project, this level of
15 competition in the secondary market would not be possible.

16 **Q36. WILL THE DEVELOPMENT OF THE PROJECT PROVIDE FOR THE**
17 **EFFICIENT ALLOCATION OF AVAILABLE CAPACITY?**

18 A36. Yes it will. The efficient allocation of capacity, or assigning resources to their highest
19 value use (“allocative efficiency”), is an economic benefit that is realized by the
20 Project and is an objective that the Board has often noted for the regulation of
21 pipelines. Under the Project’s contracts, capacity has been awarded to shippers that
22 value it the most, through an open, transparent and non-discriminatory open season
23 process. Thus, in the first instance, the capacity rights have been allocated to those
24 shippers who most highly value the capacity. As discussed, the terms of the
25 contracts also allow shippers to trade their rights on a short or longer-term basis on
26 the secondary market. This will ensure that capacity is allocated to shippers who
27 most highly value it on an ongoing basis during the lifetime of the Project.
28 Therefore, allocative efficiency will be improved through the Project’s firm service
29 structure, its expansion of the secondary market, and its reliance on an integrated and
30 consistent set of market-based tolls.

1 **Q37. HOW WILL THE PROJECT'S NEW TOLLING STRUCTURE IMPROVE**
2 **ALLOCATIVE EFFICIENCY?**

3 A37. Trans Mountain's existing tolls are an unusual mix of cost-based tolls, market-based
4 tolls and rebates to shippers that were developed to deal with highly-constrained
5 access to the Dock within a cost-based regulatory paradigm. These tolls do not
6 provide a consistent, predictable or efficient price signal for firm and spot service on
7 the pipeline, and have led to a contentious and cumbersome nomination and
8 apportionment process. The new tolling principles, which are enabled by the
9 simultaneous expansion of the pipeline and movement to a greater reliance on firm
10 contracted service, will result in a consistent and efficient price signal to all market
11 participants and help to ensure that shippers which most highly value the service will
12 receive it.

13 **Q38. DOES THE PROJECT ALSO PROMOTE PRODUCTIVE EFFICIENCY**
14 **BY PROVIDING THE RIGHT INCENTIVES TO REDUCE THE COST**
15 **OF MEETING THE MARKET'S NEEDS?**

16 A38. Yes, it does. The Board-approved terms of the FSAs and TSAs provide effective
17 and equitable risk sharing for construction cost changes, and the fixed toll structure
18 provides strong protection for all shippers regarding toll escalation after commercial
19 operation is achieved. In addition, the Project has been sized to meet the contracted
20 demand and provide a reasonable level of uncommitted service, so that there is very
21 little risk of underutilized capacity. Taken together, these features clearly promote
22 productive efficiency, which the Board has also recognized as a goal of effective
23 regulation.

24 **Q39. DOES THE PROJECT PROVIDE MACROECONOMIC BENEFITS TO**
25 **THE FEDERAL, PROVINCIAL, AND LOCAL ECONOMIES.**

26 A39. Yes, the macroeconomic benefits of the Project will be substantial. As discussed in
27 the Conference Board report, total benefits during the development phase of the
28 Project support 58,037 person-years of employment, while the first 20 years of the
29 Project's firm service operation supports 50,273 person-years of employment, plus
30 an additional 14,911 person-years of employment if all spot capacity is utilized. The
31 Conference Board has also estimated that incremental government revenues from

1 spending on Project development and operations for the first 20 years range from
2 \$3.76 billion to \$4.52 billion, depending on the level of spot service utilization.²²
3 TERA has also estimated that the Project will produce additional property tax
4 benefits of approximately \$3.4 million (a 116% increase) annually in Alberta and
5 \$23.2 million (a 101% increase) annually in BC. Total fiscal impacts associated with
6 producers' higher netbacks, including income tax revenues and royalty payments are
7 estimated to be \$14.7 billion. Finally, total GDP effects from the construction and
8 operation of the Project in Canada between 2012 and 2037 are estimated to range
9 from \$18 billion (with long-term contract volumes) to \$22 billion (with spot
10 volumes), which does not include the potential impact on GDP of higher netbacks
11 to producers.²³ Clearly, the macroeconomic benefits are a multiple of the Project's
12 costs and will be felt throughout the local, provincial and federal economies and
13 governments.

14 ***VII. CONCLUSIONS***

15 **Q40. PLEASE SUMMARIZE THE CONCLUSIONS OF YOUR DIRECT**
16 **EVIDENCE.**

17 A40. The TMEP Application fully meets and conforms to the standards the Board has
18 established for finding that a proposed project is financially and economically
19 feasible. In addition, the Project is fully consistent with the market's preferences for
20 a new market-based structure for service on TMEP and on oil pipelines generally.
21 While the Board's decision in the TMEP tolling principles case recognized many of
22 these benefits, they will only become possible when the pipeline is in operation, so
23 the public interest consideration here should take these benefits into account. The
24 Project also provides extensive benefits to Canadians across the country, including
25 producers, residents of the areas through which the pipeline crosses, suppliers in
26 many provinces, local, provincial and federal governments and the overall Canadian
27 economy. The Project allows Canada to maximize the benefits it derives from the
28 development of natural resources, and provides a feasible and efficient means of

²² All Conference Board references are noted in 2012 dollars.

²³ Expansion of the Trans Mountain Pipeline: Understanding the Economic Benefits for Canada and its Regions, Conference Board of Canada, Table 6, at 42.

DIRECT EVIDENCE OF JOHN J. REED

1 addressing the asymmetrical risk of too much/too little capacity. TMEP's
2 development does not hinge on the success or failure of any other planned oil
3 pipeline projects; the shipper commitments are not contingent on what happens with
4 other projects, and shippers have provided clear and convincing support for the
5 development of this expanded path to high-value markets. The Board can, and
6 should, place considerable weight on the willingness of 13 major producers and the
7 Project sponsor to underwrite the cost of this project for up to 20 years. Taken
8 together, I believe that these facts provide a compelling case for concluding that the
9 Project is financially and economically feasible, and highly beneficial.

10 **Q41. DOES THIS CONCLUDE YOUR PREPARED EVIDENCE?**

11 A41. Yes.

John J. Reed
Chairman and Chief Executive Officer

John J. Reed is a financial and economic consultant with more than 35 years of experience in the energy industry. Mr. Reed has also been the CEO of an NASD member securities firm, and Co-CEO of the nation's largest publicly traded management consulting firm (NYSE: NCI). He has provided advisory services in the areas of mergers and acquisitions, asset divestitures and purchases, strategic planning, project finance, corporate valuation, energy market analysis, rate and regulatory matters and energy contract negotiations to clients across North and Central America. Mr. Reed's comprehensive experience includes the development and implementation of nuclear, fossil, and hydroelectric generation divestiture programs with an aggregate valuation in excess of \$20 billion. Mr. Reed has also provided expert testimony on financial and economic matters on more than 150 occasions before the FERC, Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. After graduation from the Wharton School of the University of Pennsylvania, Mr. Reed joined Southern California Gas Company, where he worked in the regulatory and financial groups, leaving the firm as Chief Economist in 1981. He served as executive and consultant with Stone & Webster Management Consulting and R.J. Rudden Associates prior to forming REED Consulting Group (RCG) in 1988. RCG was acquired by Navigant Consulting in 1997, where Mr. Reed served as an executive until leaving Navigant to join Concentric as Chairman and Chief Executive Officer.

REPRESENTATIVE PROJECT EXPERIENCE

EXECUTIVE MANAGEMENT

As an executive-level consultant, worked with CEOs, CFOs, other senior officers, and Boards of Directors of many of North America's top electric and gas utilities, as well as with senior political leaders of the U.S. and Canada on numerous engagements over the past 25 years. Directed merger, acquisition, divestiture, and project development engagements for utilities, pipelines and electric generation companies, repositioned several electric and gas utilities as pure distributors through a series of regulatory, financial, and legislative initiatives, and helped to develop and execute several "roll-up" or market aggregation strategies for companies seeking to achieve substantial scale in energy distribution, generation, transmission, and marketing.

FINANCIAL AND ECONOMIC ADVISORY SERVICES

Retained by many of the nation's leading energy companies and financial institutions for services relating to the purchase, sale or development of new enterprises. These projects included major new gas pipeline projects, gas storage projects, several non-utility generation projects, the purchase and sale of project development and gas marketing firms, and utility acquisitions. Specific services provided include the development of corporate expansion plans, review of acquisition candidates, establishment of divestiture standards, due diligence on acquisitions or financing, market entry or expansion studies, competitive assessments, project financing studies, and negotiations relating to these transactions.

LITIGATION SUPPORT AND EXPERT TESTIMONY

Provided expert testimony on more than 150 occasions in administrative and civil proceedings on a wide range of energy and economic issues. Clients in these matters have included gas distribution utilities, gas pipelines, gas producers, oil producers, electric utilities, large energy consumers, governmental and regulatory agencies, trade associations, independent energy project developers, engineering firms, and gas and power marketers. Testimony has focused on issues ranging from broad regulatory and economic policy to virtually all elements of the utility ratemaking process. Also frequently testified regarding energy contract interpretation, accepted energy industry practices, horizontal and vertical market power, quantification of damages, and management prudence. Has been active in regulatory contract and litigation matters on virtually all interstate pipeline systems serving the U.S. Northeast, Mid-Atlantic, Midwest, and Pacific regions.

Also served on FERC Commissioner Terzic's Task Force on Competition, which conducted an industry-wide investigation into the levels of and means of encouraging competition in U.S. natural gas markets and served on a "Blue Ribbon" panel established by the Province of New Brunswick regarding the future of natural gas distribution service in that province.

RESOURCE PROCUREMENT, CONTRACTING AND ANALYSIS

On behalf of gas distributors, gas pipelines, gas producers, electric utilities, and independent energy project developers, personally managed or participated in the negotiation, drafting, and regulatory support of hundreds of energy contracts, including the largest gas contracts in North America, electric contracts representing billions of dollars, pipeline and storage contracts, and facility leases.

These efforts have resulted in bringing large new energy projects to market across North America, the creation of hundreds of millions of dollars in savings through contract renegotiation, and the regulatory approval of a number of highly contested energy contracts.

STRATEGIC PLANNING AND UTILITY RESTRUCTURING

Acted as a leading participant in the restructuring of the natural gas and electric utility industries over the past fifteen years, as an adviser to local distribution companies, pipelines, electric utilities, and independent energy project developers. In the recent past, provided services to most of the top 50 utilities and energy marketers across North America. Managed projects that frequently included the redevelopment of strategic plans, corporate reorganizations, the development of multi-year regulatory and legislative agendas, merger, acquisition and divestiture strategies, and the development of market entry strategies. Developed and supported merchant function exit strategies, marketing affiliate strategies, and detailed plans for the functional business units of many of North America's leading utilities.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)

Chairman and Chief Executive Officer

CE Capital Advisors (2004 – Present)

Chairman, President, and Chief Executive Officer

DIRECT EVIDENCE OF JOHN J. REED

Navigant Consulting, Inc. (1997 – 2002)

President, Navigant Energy Capital (2000 – 2002)
Executive Director (2000 – 2002)
Co-Chief Executive Officer, Vice Chairman (1999 – 2000)
Executive Managing Director (1998 – 1999)
President, REED Consulting Group, Inc. (1997 – 1998)

REED Consulting Group (1988 – 1997)

Chairman, President and Chief Executive Officer

R.J. Rudden Associates, Inc. (1983 – 1988)

Vice President

Stone & Webster Management Consultants, Inc. (1981 – 1983)

Senior Consultant
Consultant

Southern California Gas Company (1976 – 1981)

Corporate Economist
Financial Analyst
Treasury Analyst

EDUCATION AND CERTIFICATION

B.S., Economics and Finance, Wharton School, University of Pennsylvania, 1976
Licensed Securities Professional: NASD Series 7, 63, 24, 79 and 99 Licenses

BOARDS OF DIRECTORS (PAST AND PRESENT)

Concentric Energy Advisors, Inc.
Navigant Consulting, Inc.
Navigant Energy Capital
Nukem, Inc.
New England Gas Association
R. J. Rudden Associates
REED Consulting Group

AFFILIATIONS

American Gas Association
Energy Bar Association
Guild of Gas Managers
International Association of Energy Economists
National Association of Business Economists

Appendix D **Notice Pursuant to Section 87(1) of the *National Energy Board Act* for
BC and Alberta**

TRACT:

**TRANS MOUNTAIN PIPELINE L.P. by the General Partner TRANS MOUNTAIN ULC
("Trans Mountain")**

**NOTICE PURSUANT TO SECTION 87(1) OF THE
NATIONAL ENERGY BOARD ACT
PROVINCE OF ALBERTA**

TO: ●

being the registered owner(s) (the "Owner") of the lands described as follows (the "Land"):

(For details on land description, see Schedule "A" attached to and forming part of this Notice)

AND TO: ●

being other persons, as far as can be ascertained, interested in the said Land

Trans Mountain hereby gives notice of the following:

1. Description of Lands Required for Pipelines (See attached Property Sketch)

To accommodate the construction and installation of the pipelines through your above described property, Trans Mountain requires a Permanent Easement and Temporary Working Space adjacent to the Permanent Easement.

The location of the Permanent Easement and Temporary Working Space is shown on the attached Property Sketch.

2. Details of Compensation Offered

In consideration of granting the aforesaid [check if applicable]:

- Permanent Easement to Trans Mountain, Trans Mountain shall offer to pay to the Owner a lump sum of _____ dollars (\$_____), *plus applicable Goods and Services Tax*, which sum is inclusive of the market value of the portion of the Land which comprises the Permanent Easement as set out in Paragraph 3 hereof. The proposed Permanent Easement Agreement will provide that, as an alternative to the lump sum payment, the Owner has the option of requiring the compensation to be paid by annual or periodic payments of equal or different amounts over a period of time
- Temporary Working Space to Trans Mountain, Trans Mountain shall offer to pay to the Owner a lump sum of _____ dollars (\$_____), *plus applicable Goods and Services Tax*, which sum is inclusive of the market

value of the portion of the Land which comprises the Temporary Working Space as set out in Paragraph 3 hereof.

3. Detailed Statement of Value of Lands Required

After having considered the current use of the Land and neighbouring lands, any probable change in use of the Land and neighbouring lands in light of current zoning laws and economic considerations, recent sales of similar lands in the vicinity of the Land and other relevant factors, Trans Mountain has determined that present market value of the [**check if applicable**]:

- Permanent Easement, ignoring any residual value to the Owner, is \$ _____ per hectare (\$ _____ per acre) *plus applicable Goods and Services Tax.*
- Temporary Working Space, accounting for an approximation of the reversionary value to the Owner, is \$ _____ per hectare (\$ _____ per acre), *plus applicable Goods and Services Tax.*

Trans Mountain will require only the limited rights as described in the Permanent Easement Agreement and Temporary Working Space Agreement, and the Owner will continue to be able to use the Permanent Easement area and Temporary Working Space subject to the conditions set out in the Agreements.

4. Description of Procedure for Approval of Detailed Route of Pipelines

Sections 34 through 39, inclusive, of the *National Energy Board Act* (the “Act”) establish a procedure for approval of the detailed route of a pipeline.

Those sections provide that after a pipeline company has submitted to the National Energy Board (the “Board”) a plan showing the proposed route of a pipeline, the company must serve on owners of lands proposed to be acquired and publish notices which describe the proposed detailed route of the pipeline and the location of the offices of the Board. Within thirty (30) days of service or last publication of such notice, an owner or person who anticipates that his/her land may be adversely affected by the proposed detailed route may oppose the detailed route by filing with the Board a written statement setting forth the nature of his/her interest in the land and the grounds for his/her opposition to that detailed route.

Where a written statement opposing the route is filed within the time limited therefore, the Board must, subject to certain exceptions, forthwith order that a public hearing be conducted within the area in which the lands to which the written statement relates are situated with respect to any grounds of opposition set out in such statement. At such hearing each person who properly filed a written statement will be allowed to make representations and the Board may allow any other interested person to make such representations as the Board deems proper. Following a hearing and after consideration of all representations made, the Board may either approve or refuse to approve the plan showing the proposed detailed route of the

pipeline as filed by the pipeline company and in granting any approval the Board may impose such terms and conditions as it considers proper. The Board may not give its approval to a plan unless it has taken into account all written statements properly filed with it and all representations made to it at a public hearing in order to determine the best possible route of the pipeline and the most appropriate methods and timing of constructing the pipeline.

If the Owner and Trans Mountain enter into a Permanent Easement Agreement Trans Mountain will discuss with you the specific route of the proposed pipeline right-of-way, as well as the proposed methods and timing of the construction. The Permanent Easement Agreement that you will be asked to sign will contain your acknowledgment that you are in agreement with the location of the right-of-way, the methods and timing of construction and that you will not object if Trans Mountain does not provide you with notice of the detailed route of the pipeline pursuant to s. 34(1) of the Act and further waive your right to request a hearing to settle the detailed pipeline route.

Initial

For the complete text of the provisions relating to the procedure for determination and approval of a pipeline route and the provisions that result in exemption from such procedures, reference should be made to those sections of the Act referenced in this Notice. The description of sections of the Act referenced in this Notice is subject to the express provisions of the Act.

5. **Description of Procedure Available for Negotiation and Arbitration of Compensation Payable**

Sections 88 through 103, inclusive, of the Act establish a procedure for negotiation and arbitration in the event that an owner of land and a pipeline company are unable to agree on any matter respecting the amount of compensation payable under the Act for the acquisition of lands, or for damages suffered as a result of the operations of the pipeline company or on any issue related to such compensation.

These sections provide, in effect, that if the pipeline company and an owner of lands have not agreed on any such issue either of them may serve notice of negotiation on the other and on the appropriate federal Minister (“Minister”) requesting that the matter be negotiated. Following service of such notice, the Minister must appoint a negotiator who must meet with the parties and, without prejudice to any subsequent proceedings, proceed to attempt to negotiate a settlement of the matter. Within sixty days after commencing the negotiation proceedings, the negotiator must report to the Minister the success or failure of the negotiations and submit a copy of his/her report to both parties.

If either an owner of the land or the pipeline company wishes to dispense with the negotiation proceedings or if the negotiation proceedings have not resulted in settlement of any compensation matter, either the pipeline company or the owner may serve notice of arbitration on the other and on the Minister requesting that the matter be determined by arbitration. Forthwith thereafter the Minister must, subject to certain exceptions, refer the matter to an Arbitration Committee consisting of not less than three members appointed by the Minister, none of whom will be a member, officer or employee of the Board. The

Arbitration Committee must then fix a suitable time and place for a hearing in order to determine all compensation matters referred to in the notice and serve notice of the hearing on the parties. Following such hearing, the Arbitration Committee will determine all compensation matters referred to it and in doing so must consider a number of factors set out in section 97 of the Act, where applicable.

For the complete text of the provisions relating to the procedure for negotiation and arbitration of compensation, reference should be made to those sections of the Act referenced in this Notice. The description of sections of the Act referenced in this Notice is subject to the express provisions of the Act.

6. Further Communications

This Notice is not an offer and does not obligate either the Owner or Trans Mountain to enter into an Agreement.

If you have any questions, please contact Trans Mountain, Suite 2700, Stock Exchange Tower 300 – 5th Avenue S.W., Calgary, Alberta, T21 5J2.

The address of the National Energy Board is 444 - Seventh Avenue S.W., Calgary, Alberta, T2P 0X8.

**TRANS MOUNTAIN PIPELINE L.P. by the
General Partner TRANS MOUNTAIN
PIPELINE ULC**

Per: _____

Print name and position

Per: _____

Print name and position

**TRANS MOUNTAIN PIPELINE L.P. by the General Partner TRANS MOUNTAIN ULC
("Trans Mountain")**

**NOTICE PURSUANT TO SECTION 87(1) OF THE
NATIONAL ENERGY BOARD ACT FOR EASEMENT
PROVINCE OF ALBERTA**

TO: The Crown in the Right of Alberta

being the registered owner(s) (the "Owner") of the lands described as follows (the "Land"):

(For details on land description, see Schedule "A" attached to and forming part of this Notice)

AND TO: All crown land disposition holders within the described lands as per Schedule A

being other persons, as far as can be ascertained, having a potentially relevant interest in the said land.

Trans Mountain hereby gives notice of the following:

1. Description of Lands Required for Pipeline

To accommodate the construction and installation of the proposed facilities, namely a pipeline through your above described property, Trans Mountain requires a Permanent Easement and Temporary Working Space adjacent to the Permanent Easement. The location of the lands required and a description of the required Permanent Easement and Temporary Working Space are shown on the Survey Plans attached as "Schedule B", which forms part of this Notice.

2. Details of Compensation Offered

In consideration of granting the aforesaid Permanent Easement to Trans Mountain, Trans Mountain shall offer to pay to the Owner a lump sum of _____ dollars (\$ _____), plus Goods and Services Tax, which sum is calculated in accordance with the provisions of Paragraph 3 hereof.

In consideration of granting the aforesaid Temporary Working Space to Trans Mountain, Trans Mountain shall offer to pay to the Owner a lump sum of _____ dollars (\$ _____), plus Goods and Services Tax, which sum is calculated in accordance with the provisions of Paragraph 3 hereof.

The proposed Agreement for Easement will provide that, as an alternative to the lump sum payment, the Owner has the option of requiring the compensation to be paid by annual or periodic payment of equal or different amounts over a period of time.

3. Detailed Statement of Value of Lands Required

The value of the portion of the lands which comprises the Permanent Statutory Right of Way is \$_____ per hectare, plus Goods and Services Tax.

The value of the portion of the lands which comprises the Temporary Working Space is \$_____ per hectare, plus Goods and Services Tax.

4. Description of Procedure for Approval of Detailed Route of Pipeline

Sections 34 through 39, inclusive, of the *National Energy Board Act* (the "Act"), unless waived under section 58 of the act, establish a procedure for approval of the detailed route of a pipeline.

Those sections provide that after a pipeline company has submitted to the National Energy Board (the "Board") a plan showing the proposed route of a pipeline, the company must serve on landowners of lands proposed to be acquired and publish notices which describe the proposed detailed route of the pipeline and the location of the offices of the Board. Within thirty (30) days of service or publication, an owner or person who anticipates that his/her land may be adversely affected by the proposed detailed route may oppose the detailed route by filing with the Board a written statement setting forth the nature of his/her interest in the land and the grounds for his/her opposition.

Where a written statement opposing the route is filed, the Board must, subject to certain exceptions, forthwith order that a public hearing be conducted with respect to such written opposition.

Following a hearing and after consideration of all representations made, the Board may either approve or refuse to approve the plan showing the proposed detailed route of the pipeline as filed by the pipeline company.

5. Description of Procedure Available for Negotiation and Arbitration of Compensation Payable

Sections 88 through 103, inclusive, of the Act establish a procedure for negotiation and arbitration in the event that an owner of land and a pipeline company are unable to agree on any matter respecting the amount of compensation payable under the Act for the acquisition of land, or on damages suffered as a result of the operations of the pipeline company or on any issue related to such compensation.

These sections of the Act provide that either party may serve notice of negotiation on the other and on the appropriate federal Minister ("Minister") requesting that the matter be negotiated. The Minister must then appoint a negotiator who must meet with the parties and proceed to attempt to negotiate a settlement of the matter.

If either the owner of the land or Trans Mountain wishes to dispense with the negotiation proceedings or if the negotiation proceedings have not resulted in settlement of any compensation matter, either the pipeline company or the owner may serve notice of arbitration on the other and on the Minister who must, subject to certain exceptions, refer the matter to an Arbitration Committee consisting of not less than three members appointed by

the Minister. Following a hearing, the Arbitration Committee will determine all compensation matters referred to it.

6. Further Communications

This Notice is not an offer and does not obligate either the Owner or Trans Mountain to enter into an Agreement.

If you have any questions, please contact Trans Mountain, Suite 2700, Stock Exchange Tower 300 – 5th Avenue S.W., Calgary, Alberta, T21 5J2. The address of the National Energy Board is 311 - 6 Ave SW, Calgary AB T2P 3H2.

**TRANS MOUNTAIN PIPELINE L.P. by the
General Partner TRANS MOUNTAIN
PIPELINE ULC**

Per: _____

Print name and position

Per: _____

Print name and position

NOTICE PURSUANT TO SECTION 87(1) OF THE
NATIONAL ENERGY BOARD ACT FOR EASEMENT

TRANS MOUNTAIN PIPELINE ULC
by the General Partner TRANS MOUNTAIN PIPELINE L.P.
SUITE 2700, STOCK EXCHANGE TOWER, 300 – 5TH AVENUE SW,
CALGARY, ALBERTA T21 5J2.

TRACT:

**TRANS MOUNTAIN PIPELINE L.P. by the General Partner TRANS MOUNTAIN ULC
("Trans Mountain")
NOTICE PURSUANT TO SECTION 87(1) OF THE
NATIONAL ENERGY BOARD ACT
PROVINCE OF BRITISH COLUMBIA**

TO: ●
being the registered owner(s) (the "Owner") of the lands described as follows (the "Land"):

(For details on land description, see Schedule "A" attached to and forming part of this Notice)

AND TO: ●
being other persons, as far as can be ascertained, interested in the said Land

Trans Mountain hereby gives notice of the following:

1. Description of Lands Required for Pipeline (See attached Property Sketch)

To accommodate the construction and installation of a pipeline through your above described property, Trans Mountain requires a Statutory Right of Way over part of the Land (the "SRW Area") and the right to use Temporary Working Space on part of the Land adjacent to the SRW Area.

The location of the SRW Area and Temporary Working Space is shown on the attached Property Sketch.

2. Details of Compensation Offered

In consideration of granting the aforesaid [check if applicable]:

- Statutory Right of Way to Trans Mountain, Trans Mountain shall offer to pay to the Owner a lump sum of _____dollars (\$_____), *plus applicable taxes*, which sum is inclusive of the market value of the portion of the Land which comprises the Statutory Right of Way as set out in Paragraph 3 hereof. The proposed Statutory Right of Way Agreement will provide that, as an alternative to the lump sum payment, the Owner has the option of requiring the compensation to be paid by annual or periodic payments of equal or different amounts over a period of time
- right to use the Temporary Working Space to Trans Mountain, Trans Mountain shall offer to pay to the Owner a lump sum of _____dollars(\$_____), *plus applicable taxes*, which sum is inclusive of

the market value of the portion of the Land which comprises the Temporary Working Space, accounting for an approximation of the reversionary value to the Owner, as set out in Paragraph 3 hereof.

3. Detailed Statement of Value of Lands Required

After having considered the current use of the Land and neighbouring lands, any probable change in use of the Land and neighbouring lands in light of current zoning laws and economic considerations, recent sales of similar lands in the vicinity of the Land and other relevant factors, Trans Mountain has determined that present market value of the [check if applicable]:

- SRW Area, ignoring any residual value to the Owner, is \$ _____per hectare (\$_____per acre) plus applicable taxes.

- Temporary Working Space, accounting for an approximation of the reversionary value to the Owner, is \$ _____per hectare (\$_____per acre), *plus applicable taxes.*

Trans Mountain will require only the limited rights as described in the Statutory Right of Way Agreement and Temporary Working Space Agreement, and the Owner will continue to be able to use the SRW Area and Temporary Working Space subject to the conditions set out in such acquisition agreements.

4. Description of Procedure for Approval of Detailed Route of Pipelines

Sections 34 through 39, inclusive, of the National Energy Board Act (the “Act”) establish a procedure for approval of the detailed route of a pipeline.

Those sections provide that after a pipeline company has submitted to the National Energy Board (the “Board”) a plan showing the proposed route of a pipeline, the company must serve on owners of lands proposed to be acquired and publish notices which describe the proposed detailed route of the pipeline and the location of the offices of the Board. Within thirty (30) days of service or last publication of such notice, an owner or person who anticipates that his/her land may be adversely affected by the proposed detailed route may oppose the detailed route by filing with the Board a written statement setting forth the nature of his/her interest in the land and the grounds for his/her opposition to that detailed route.

Where a written statement opposing the route is filed within the time limited therefore, the Board must, subject to certain exceptions, forthwith order that a public hearing be conducted within the area in which the lands to which the written statement relates are situated with respect to any grounds of opposition set out in such statement. At such hearing each person who properly filed a written statement will be allowed to make representations and the Board may allow any other interested person to make such representations as the Board deems proper. Following a hearing and after consideration of all representations made, the Board may either approve or refuse to approve the plan showing the proposed detailed route of the pipeline as filed by the pipeline company

and in granting any approval the Board may impose such terms and conditions as it considers proper. The Board may not give its approval to a plan unless it has taken into account all written statements properly filed with it and all representations made to it at a public hearing in order to determine the best possible route of the pipeline and the most appropriate methods and timing of constructing the pipeline.

If the Owner and Trans Mountain enter into a Statutory Right of Way Agreement Trans Mountain will discuss with you the specific route of the proposed pipeline right-of-way, as well as the proposed methods and timing of the construction. The Permanent Easement Agreement that you will be asked to sign will contain your acknowledgment that you are in agreement with the location of the right-of-way, the methods and timing of construction and that you will not object if Trans Mountain does not provide you with notice of the detailed route of the pipeline pursuant to s. 34(1) of the Act and further waive your right to request a hearing to settle the detailed pipeline route.

Initial

For the complete text of the provisions relating to the procedure for determination and approval of a pipeline route and the provisions that result in exemption from such procedures, reference should be made to those sections of the Act referenced in this Notice. The description of sections of the Act referenced in this Notice is subject to the express provisions of the Act.

5. **Description of Procedure Available for Negotiation and Arbitration of Compensation Payable**

Sections 88 through 103, inclusive, of the Act establish a procedure for negotiation and arbitration in the event that an owner of land and a pipeline company are unable to agree on any matter respecting the amount of compensation payable under the Act for the acquisition of lands, or for damages suffered as a result of the operations of the pipeline company or on any issue related to such compensation.

These sections provide, in effect, that if the pipeline company and an owner of lands have not agreed on any such issue either of them may serve notice of negotiation on the other and on the appropriate federal Minister (“Minister”) requesting that the matter be negotiated. Following service of such notice, the Minister must appoint a negotiator who must meet with the parties and, without prejudice to any subsequent proceedings, proceed to attempt to negotiate a settlement of the matter. Within sixty days after commencing the negotiation proceedings, the negotiator must report to the Minister the success or failure of the negotiations and submit a copy of his/her report to both parties.

If either an owner of the land or the pipeline company wishes to dispense with the negotiation proceedings or if the negotiation proceedings have not resulted in settlement of any compensation matter, either the pipeline company or the owner may serve notice of arbitration on the other and on the Minister requesting that the matter be determined by arbitration. Forthwith thereafter the Minister must, subject to certain exceptions, refer the matter to an Arbitration Committee consisting of not less than three members appointed by the Minister, none of whom will be a member, officer or employee of the Board. The Arbitration Committee must then fix a suitable time and place for a hearing in order to determine all compensation matters referred to in the notice and serve notice of the

hearing on the parties. Following such hearing, the Arbitration Committee will determine all compensation matters referred to it and in doing so must consider a number of factors set out in section 97 of the Act, where applicable.

For the complete text of the provisions relating to the procedure for negotiation and arbitration of compensation, reference should be made to those sections of the Act referenced in this Notice. The description of sections of the Act referenced in this Notice is subject to the express provisions of the Act.

6. Further Communications

This Notice is not an offer and does not obligate either the Owner or Trans Mountain to enter into an Agreement.

If you have any questions, please contact Trans Mountain, Suite 2700, Stock Exchange Tower 300 – 5th Avenue S.W., Calgary, Alberta, T21 5J2..

The address of the National Energy Board is 444 - Seventh Avenue S.W., Calgary, Alberta, T2P 0X8.

**TRANS MOUNTAIN PIPELINE L.P. by its
General Partner TRANS MOUNTAIN
PIPELINE ULC**

Per: _____

Print name and position

Per: _____

Print name and position

**TRANS MOUNTAIN PIPELINE L.P.
("Trans Mountain")
NOTICE PURSUANT TO SECTION 87(1) OF THE
NATIONAL ENERGY BOARD ACT
PROVINCE OF BRITISH COLUMBIA**

TO: The Crown in the Right of British Columbia

being the owner (the "Owner") of the lands described as follows (the "Land"):

(For details on land description, see Schedule "A" attached to and forming part of this Notice)

AND TO: All crown land tenure holders within the described lands as per Schedule A

being other persons, as far as can be ascertained, having a potentially relevant interest in the said land.

Trans Mountain hereby gives notice of the following:

1. Description of Lands Required for Pipeline

To accommodate the construction and installation of the proposed facilities, namely a pipeline through your above described property, Trans Mountain requires an easement without dominant tenement ("Right of Way") over part of the Land (the "RW Area") and the right to use the Temporary Working Space on part of the Land adjacent to the RW Area.. The location of the lands required and a description of the required RWArea and Temporary Working Space are shown on the Property Sketch attached as "Schedule B", which forms part of this Notice.

2. Details of Compensation Offered

In consideration of granting the aforesaid Right of Way to Trans Mountain, Trans Mountain shall offer to pay to the Owner a lump sum of _____ dollars (\$_____), plus Goods and Services Tax, which sum is calculated in accordance with the provisions of Paragraph 3 hereof.

The proposed Right of Way Agreement will provide that, as an alternative to the lump sum payment, the Owner has the option of requiring the compensation to be paid by annual or periodic payment of equal or different amounts over a period of time.

In consideration of granting the aforesaid right to use the Temporary Working Space to Trans Mountain, Trans Mountain shall offer to pay to the Owner a lump sum of _____ dollars (\$_____), plus Goods and Services Tax, which sum is calculated in accordance with the provisions of Paragraph 3 hereof.

3. Detailed Statement of Value of Lands Required

The value of the portion of the Land which comprises the RW Area is \$ _____ per hectare, plus Goods and Services Tax, according to the rates and fees prescribed by the Owner.

The value of the portion of the Land which comprises the Temporary Working Space is \$ _____ per hectare, plus Goods and Services Tax, according to the rates and fees prescribed by the Owner..

4. Description of Procedure for Approval of Detailed Route of Pipeline

Sections 34 through 39, inclusive, of the National Energy Board Act (the “Act”), unless waived under section 58 of the act, establish a procedure for approval of the detailed route of a pipeline.

Those sections provide that after a pipeline company has submitted to the National Energy Board (the “Board”) a plan showing the proposed route of a pipeline, the company must serve on landowners of lands proposed to be acquired and publish notices which describe the proposed detailed route of the pipeline and the location of the offices of the Board. Within thirty (30) days of service or publication, an owner or person who anticipates that his/her land may be adversely affected by the proposed detailed route may oppose the detailed route by filing with the Board a written statement setting forth the nature of his/her interest in the land and the grounds for his/her opposition.

Where a written statement opposing the route is filed, the Board must, subject to certain exceptions, forthwith order that a public hearing be conducted with respect to such written opposition.

Following a hearing and after consideration of all representations made, the Board may either approve or refuse to approve the plan showing the proposed detailed route of the pipeline as filed by the pipeline company.

5. Description of Procedure Available for Negotiation and Arbitration of Compensation Payable

Sections 88 through 103, inclusive, of the Act establish a procedure for negotiation and arbitration in the event that an owner of land and a pipeline company are unable to agree on any matter respecting the amount of compensation payable under the Act for the acquisition of land, or on damages suffered as a result of the operations of the pipeline company or on any issue related to such compensation.

These sections of the Act provide that either party may serve notice of negotiation on the other and on the appropriate federal Minister (“Minister”) requesting that the matter be negotiated. The Minister must then appoint a negotiator who must meet with the parties and proceed to attempt to negotiate a settlement of the matter.

If either the owner of the land or Trans Mountain wishes to dispense with the negotiation proceedings or if the negotiation proceedings have not resulted in settlement of any compensation matter, either the pipeline company or the owner may serve notice of arbitration on the other and on the Minister who must, subject to certain exceptions, refer

the matter to an Arbitration Committee consisting of not less than three members appointed by the Minister. Following a hearing, the Arbitration Committee will determine all compensation matters referred to it.

6. Further Communications

This Notice is not an offer and does not obligate either the Owner or Trans Mountain to enter into an Agreement.

If you have any questions, please contact Trans Mountain, Suite 2700, Stock Exchange Tower 300 – 5th Avenue S.W., Calgary, Alberta, T21 5J2.

The address of the National Energy Board is 311 - 6 Ave SW, Calgary AB T2P 3H2.

**TRANS MOUNTAIN PIPELINE L.P. by the
General Partner TRANS MOUNTAIN
PIPELINE ULC**

Per: _____

Print name and position

Per: _____

Print name and position

NOTICE PURSUANT TO SECTION 87(1) OF THE
NATIONAL ENERGY BOARD ACT FOR EASEMENT

TRANS MOUNTAIN PIPELINE L.P.
by the General Partner TRANS MOUNTAIN PIPELINE ULC
SUITE 2700, STOCK EXCHANGE TOWER, 300 – 5TH AVENUE SW,
CALGARY, ALBERTA T21 5J2.

Appendix E Agreement for Easement, Province of Alberta

TRACT:

**TRANS MOUNTAIN PIPELINE L.P. by the General Partner TRANS MOUNTAIN ULC
("Trans Mountain")
AGREEMENT FOR EASEMENT
PROVINCE OF ALBERTA**

I, (We) <>

(the "**Owner**"), being registered as owner or entitled to become registered as owner of an estate in fee simple, subject however to such encumbrances, liens and interests as appear on the Certificate of Title, in all that certain tract of land situated in the Province of Alberta being composed of:

as described in the Certificate of Title numbered _____ registered with the Land Titles Office for the North Alberta Land Registration District (the "**Lands**"),

and in consideration of the sum of _____ Dollars (\$ _____), the receipt of which is hereby acknowledged, now paid or payable to the Owner (or to others having an interest in the Lands by encumbrance or otherwise), by Trans Mountain, a corporation incorporated under the laws of Canada, and having its operating office in the City of Calgary, in the Province of Alberta, and in consideration of the covenants and conditions hereinafter mentioned,

DO HEREBY GRANT, CONVEY, SET OVER AND TRANSFER to Trans Mountain, for itself, its employees, agents, contractors, subcontractors, successors and assigns, an easement and right of way (also referred to as the "**right-of-way**"), across, over, under, in, through or on the Lands to survey, construct, operate, maintain, inspect, patrol (including aerial patrol), alter, remove, replace, reconstruct and repair two or more pipelines (subject to Clause 21 herein) and other facilities appurtenant, affixed or incidental thereto, including, but without limiting the generality of the foregoing, all such pipes, drips, valves, fittings, connections, meters, cathodic protection, equipment and other equipment and appurtenances, whether or not similar to the foregoing as may be useful or convenient in connection therewith or incidental thereto (hereinafter collectively referred to as the "**Pipeline**"), for the transportation, storage and handling of oil, other liquid and gaseous hydrocarbons and products thereof, together with the right of ingress and egress over the remainder of the Lands, to and from the right-of-way for Trans Mountain, its personnel, equipment, contractors and agents for all purposes necessary or incidental to the exercise and enjoyment of the rights herein granted.

The rights and easement are granted as and from the date hereof and for so long hereafter as Trans Mountain desires to exercise same on the following terms and conditions which are hereby mutually agreed to:

1. Trans Mountain shall, upon the completion of a legal survey plan, deposit for registration at the appropriate Land Titles Office a plan of survey limiting the right-of-way across, over, under, in, through or on the Lands to a strip of land being generally _____ in width within the Lands which right-of-way shall be substantially in the location as shown on the property sketch attached hereto. Trans Mountain shall file a plan of survey within a reasonable period of time having regard to

all circumstances. Following registration of such plan of survey Trans Mountain shall, if it has not already done so, forward to the Owner at the address set forth in Clause 20 hereof an extract from the plan of survey showing the precise location of the right-of-way across, over, under, in, through or on the Lands (the “**Surveyed Right-of-Way**”). Upon registration of the plan of survey, reference to “right-of-way” in this Agreement shall mean the Surveyed Right-of-Way.

2. Trans Mountain, having delivered or mailed to the Owner the extract from the plan of survey, shall as soon as it is practicable to do so, cause to be registered in the appropriate Land Titles Office, a document restricting the right-of-way to the Surveyed Right of Way. Notwithstanding the registration of such document Trans Mountain shall continue to be entitled to enjoy the right of ingress and egress to and from the Surveyed Right-of-Way across the remainder of the Lands as set out in the granting provision of this Agreement.
3. Trans Mountain shall pay the compensation to the Owner for the grant of easement and right of way as follows: Delete (a) or (b):

(a) one lump sum payment of _____ Dollars
(\$_____), plus Good and Services Tax
(initial)

- or -

(b) by annual or periodic payments of equal or different amounts over a period of time as set forth in Schedule One attached hereto and forming part hereof; (initial)

If the Lump Sum Payment option is chosen (option 3(a)), such payment shall be made on or before construction is commenced on the right-of-way. If option 3(b) is chosen the first of such payments shall commence on or before construction is commenced on the right-of-way. In the event that a lump sum payment or the first annual or periodic payment, as the case may be, has not been made before _____, 20____, then this Agreement shall terminate and be at an end for all purposes and Trans Mountain shall forthwith execute and register such documents as may be necessary to discharge this Agreement from the Certificate of Title for the Lands and shall notify the Owner of the registration of the discharge.

4. The Owner shall have the right fully to use and enjoy the right-of-way except as may be necessary for the purposes herein granted to Trans Mountain provided however that the Owner shall not, without the prior written consent of Trans Mountain, which consent shall not be unreasonably withheld, excavate, drill, install, erect, place, plant or permit to be excavated, drilled, installed, erected, placed, or planted on, over, under, across or through the right-of-way any pit, well, foundation, pavement, building, tree, or any other structure, installation, object or improvement.
5. Notwithstanding the provisions of Clause 4, Trans Mountain will not object to the Owner:

- (i) paving existing farm lanes, private roads, driveways, and sidewalks across the right-of-way;
- (ii) erecting fences across the right-of-way or any portion thereof; or
- (iii) constructing drains or repairing drains on the right-of-way or any portion thereof;

provided, however, that the Owner agrees to exercise a high degree of care in carrying out any excavation or drilling necessary for such fencing, paving or drainage, and in no event shall the Owner or his contractors perform such work in such a manner as to endanger or damage the Pipeline. Before the commencement of any such work, the Owner shall give to Trans Mountain at least five (5) days prior notice in writing so as to enable a representative of Trans Mountain to inspect the site of the proposed work and to advise how the work may be performed without damage to the Pipeline.

6. Trans Mountain will compensate the Owner for all damages suffered as a result of Trans Mountain's operations.
7. Trans Mountain will, as soon as weather and soil conditions permit and insofar as it is practicable so to do, bury and maintain the Pipeline in a manner that will not interfere with the drainage or ordinary cultivation of the Lands, and will restore all drains damaged or disturbed by the operation, according to good drainage practice.
8. Notwithstanding that in constructing, maintaining and operating its Pipeline Trans Mountain may install pipe and other equipment and appurtenances in, on, over, under, across or through the right-of-way in such a manner that it or they become affixed to the Lands, the title to such pipe and other equipment and appurtenances shall until surrendered, remain in Trans Mountain. Trans Mountain may at any time remove the whole or any part of the Pipeline.
9. Upon the discontinuance of the use of the said right-of-way and of the exercise of the rights hereby granted, Trans Mountain shall and will restore the right-of-way to the same condition, so far as it is practicable so to do, as the same were in prior to the entry thereon and the use thereof by Trans Mountain. Trans Mountain agrees to withdraw and discharge any registrations at the Land Titles Office pertaining to this Agreement upon the abandonment of the right-of- way.
10. Trans Mountain in performing and observing the covenants and conditions contained in this Agreement, shall peaceably hold and enjoy the rights and easement hereby granted without hindrance, molestation or interruption on the part of the Owner or of any person, firm or corporation claiming by, through, under or in trust for the Owner.
11. Either party shall have the absolute right to assign this Agreement in whole or in part, and upon such assignment, shall give to the other party written notice thereof within ten (10) days, but Trans Mountain need not give such notice upon assignment in the course of its corporate financing by way of a deed of trust, mortgage, debenture or a floating charge or upon assignment arising out of an amalgamation or merger.

12. This Agreement shall not affect or prejudice Trans Mountain's statutory rights to acquire an easement or any portion of the Lands under the provisions of the *National Energy Board Act* (the "Act"), or any other laws, which rights may be exercised at Trans Mountain's discretion in the event of the Owner being unable or unwilling for any reason to perform this Agreement or to give to Trans Mountain a clear and unencumbered title to the right-of-way and easement herein granted.
13. The Owner will, if so requested by Trans Mountain, execute such further documents of title and assurances in respect of the Lands as may be required to perfect Trans Mountain's interest in the Lands.
14. Nothing contained herein shall vest in Trans Mountain any title to mines or minerals in or under the right-of-way, except only the parts thereof that are necessary to be excavated, carried away or used in the construction of the Pipeline belonging to Trans Mountain.
15. Where Trans Mountain requires an above ground installation of the Pipeline upon the right-of-way (other than pipeline markers installed at property or fence lines) or requires any part of the right-of-way to be fenced, the Owner shall be entitled to additional compensation to be agreed upon between the parties, or failing agreement, pursuant to the procedure available for negotiation and arbitration under Part V of the Act.
16. Trans Mountain will not object to any application made by the Owner under Section 112 of the Act so long as the proposed crossing is made in accordance with good engineering practice and does not interfere with the operation of the Pipeline.
17. This Agreement is a covenant running with the Lands and the provisions of this Agreement shall extend to, be binding upon, and enure to the benefit of the heirs, executors, administrators, successors and assigns of the Owner and Trans Mountain, respectively.
18. Wherever the singular or masculine is used in this Agreement, it shall be construed as if the plural or feminine or the neuter, as the case may be, had been used where the context so requires.
19. It is agreed that the Owner shall have the right to transfer or convey his interest in the Lands and the covenants and conditions herein contained in one or more parcels and by one or more conveyances and that all the covenants and conditions herein contained shall extend to and be binding upon and enure to the benefit of each and all of the heirs, executors, administrators, successors, and assigns of the Owner in respect of each and every parcel transferred or conveyed.
20. All notices to be given hereunder may be given by registered letter addressed to Trans Mountain, Suite 2700, Stock Exchange Tower 300 – 5th Avenue S.W., Calgary, Alberta, T21 5J2, , and to the Owner at _____ or such other address as Trans Mountain and the Owner may respectively appoint, from time to time, in writing, and any such notice shall be deemed to be given to and received seven (7) days after the mailing thereof, postage prepaid.

21. Trans Mountain proposes to install two (2) pipelines in the right-of-way. Trans Mountain will only install an additional pipeline or pipelines in the right-of-way with the consent and agreement of the Owner, or, in the absence of such consent and agreement, in accordance with all authorizations and determinations, including with respect to any additional compensation payable, made under the Act.
22. The Owner agrees that Trans Mountain may, at its option, at any time in the course of operating the Pipeline enter upon the right-of-way with men and equipment and remove all shrubs and trees from the right-of-way.
23. Trans Mountain shall indemnify the Owner from all liabilities, damages, claims, suits and actions arising out of the operations of Trans Mountain on the Lands other than liabilities, damages, claims, suits and actions resulting from the negligence or willful misconduct of the Owner. Notwithstanding the foregoing, Trans Mountain shall not in any event be liable of any indirect or consequential damages.
24. The Owner confirms having the option of requiring the compensation for the rights herein granted to be made by one lump sum payment or by annual or periodic payments of equal or different amounts over a period of time and that the Owner has selected the method of compensation hereinbefore set out. The Owner further confirms that if the Owner has selected annual or other periodic payments, the amount of such compensation payable by Trans Mountain shall be reviewed every five (5) years if the period of compensation extends beyond five (5) years.
25. The Owner consents to the collection and use of his/her personal information within this form. Trans Mountain collects this type of personal information for the purposes of general land rights acquisition and regulatory disclosure. The Owner consents to the collection, use and disclosure of its personal information for these legitimate business purposes in relation to land matters of Trans Mountain.
26. The Owner acknowledges receipt of a notice given pursuant to Section 87(1) of the Act and given prior to the entering into of this Agreement, setting out or accompanied by:
 - (a) a description of the Lands of the Owner required by Trans Mountain for a section or part of the Pipelines;
 - (b) details of the compensation offered by Trans Mountain for such Lands required;
 - (c) a detailed statement made by Trans Mountain of the value of such Lands required in respect of which compensation was offered;
 - (d) a description of the procedure for approval of the detailed route of Trans Mountain's Pipelines; and
 - (e) a description of the procedure available for negotiation and arbitration under Part V of the Act in the event that the Owner and Trans Mountain are unable to agree on any matter respecting the compensation payable.

27. The Owner acknowledges that Trans Mountain has explained the specific route of the proposed pipeline right of way, as well as the proposed methods and timing of the construction of the Pipeline that will be installed therein. This Agreement confirms that the Owner is in agreement with the location of the pipeline right of way, and the methods and timing of construction of the Pipeline that will be installed therein. The Owner hereby waives any right to ask for a hearing to settle the detailed Pipeline route or the methods and timing of construction, and understands that Trans Mountain may not serve the Owner with further Notice of the detailed route of the Pipeline pursuant to s. 34 (1)(a) of the Act.

IN WITNESS WHEREOF the parties hereto have executed and delivered this Agreement as of the _____ day of _____, 20____.

SIGNED in the presence of:

Witness:

Owner:

Witness:

Owner:

**TRANS MOUNTAIN PIPELINE L.P.by the
General Partner TRANS MOUNTAIN
PIPLINE ULC**

Per: _____

Print name and position

Per: _____

Print name and position

CONSENT OF SPOUSE

I, _____ being married to the within named do hereby give my consent to the disposition of our homestead, made in this instrument, and I have executed this document for the purpose of giving up my life estate and other dower rights in the said property given to me by the *Dower Act*, to the extent necessary to give effect to the said disposition.

CERTIFICATE OF ACKNOWLEDGEMENT BY SPOUSE

1. This document was acknowledged before me by _____, apart from her husband (his wife).
2. _____, acknowledged to me that she (he):
 - (a) is aware of the nature of the disposition or agreement;
 - (b) is aware that the *Dower Act*, gives her (him) a life estate in the homestead and the right to prevent disposition of the homestead by withholding consent;
 - (c) consents to the disposition or agreement for the purpose of giving up the life estate and other dower rights in the homestead given to her (him) by the *Dower Act*, to the extent necessary to give effect to the said disposition or agreement;
 - (d) is executing the document freely and voluntarily without any compulsion on the part of her husband (his wife).

DATED at the _____ of _____, in the Province of Alberta, this _____ day of _____, 20_____.

A Commissioner for Oaths in and for the Province of Alberta

DOWER AFFIDAVIT

CANADA)	I, _____ of the
PROVINCE OF ALBERTA)	_____ of _____
TO WIT:)	in the Province of Alberta

MAKE OATH AND SAY:

1. THAT I am the Grantor named in the within Instrument.
2. THAT I am not married.

- OR -

3. THAT neither myself nor my spouse have resided on the within mentioned Land at any time since our marriage.

SWORN before me at the)
 _____ of)
 _____ in the)
 Province of Alberta, this ___ day of)
 _____, A.D. 20___)
)
)
 _____)
 A Commissioner for Oaths in and for the)
 Province of Alberta)

AFFIDAVIT OF EXECUTION

CANADA) I, _____ of the
PROVINCE OF ALBERTA) _____ of _____
TO WIT:) in the Province of Alberta

MAKE OATH AND SAY:

- 1. THAT I was personally present and did see _____ named in the within Instrument who is (are) personally known to me to be the person(s) named therein, duly sign and execute the same for the purpose named therein.
- 2. THAT the same was executed at the _____ of _____, in the Province of Alberta, and that I am the subscribing witness thereto.
- 3. THAT I know the said _____ named and he (she) (each) is in my belief, of the full age of eighteen years.

SWORN before me at the)
_____ of)
_____ in the)
Province of Alberta, this ___ day of)
_____, A.D. 20___) _____
)
)
)
A Commissioner for Oaths in and for the)
Province of Alberta)

CONSENT BY OCCUPANT(S)/PURCHASER(S) OR OTHER INTERESTED PARTIES

I (We), _____ of _____ in the Province of Alberta having an interest in the within Lands by virtue of an Agreement or Instrument dated the ___ day of _____; **DO HEREBY AGREE**, that all my (our) rights, interests and estate which are, or may be, affected by the Agreement for Easement shall be fully bound by the terms and conditions thereof both now and henceforth.

DATED at the _____ of _____, in the Province of Alberta, this _____ day of _____, 20___.

Witness:

Owner:

Witness:

Owner:

AFFIDAVIT OF EXECUTION

CANADA)	I, _____ of the
PROVINCE OF ALBERTA)	_____ of _____
TO WIT:)	in the Province of Alberta,

MAKE OATH AND SAY:

1. THAT I was personally present and did see _____ named in the within Instrument who is (are) personally known to me to be the person(s) named therein, duly sign and execute the same for the purpose named therein.
2. THAT the same was executed at the _____ of _____, in the Province of Alberta, and that I am the subscribing witness thereto.
3. THAT I know the said _____ named and he (she) (each) is in my belief, of the full age of eighteen years.

SWORN	before	me	at	the)	
_____				of)	
_____				in the)	
Province of Alberta,	this	___	day	of)	
_____,	A.D.	20__)	_____
)	
)	
_____)	
A Commissioner for Oaths in and for the)	
Province of Alberta)	

ATTACHED TO AND FORMING
PART OF THE AGREEMENT
FOR EASEMENT

SCHEDULE ONE
Annual or Periodic Payment

The consideration for this Agreement is the sum of _____ Dollars (\$_____) of lawful money of Canada to be paid on or before construction is commenced upon the Lands, the receipt of which is hereby acknowledged by the Owner, and thereafter the sum of _____ Dollars (\$_____) of lawful money of Canada to be paid on or before the anniversary date thereafter for a period of _____ (_____) years. The amount of any annual or periodic payment will be reviewed every five (5) years.

The Owner hereby agrees to and accepts the annual or periodic payment set out above.

Witness:

Owner:

Witness:

Owner:

Witness:

Owner:

FORM 31.1

**LAND TITLES ACT
(Section 161)**

AFFIDAVIT VERIFYING CORPORATE SIGNING AUTHORITY

I, _____ of _____ in the province of Alberta,
make oath and say:

1. I am an officer or a director of Trans Mountain named in the within or annexed instrument (or caveat).
2. I am authorized by the corporation to execute the instrument (or caveat) without affixing a corporate seal.

SWORN before me at the)
_____ of)
_____ in the)
Province of Alberta, this ___ day of)
_____, A.D. 20___)
)
)

A Commissioner for Oaths in and for the)
Province of Alberta)

Appendix F ***Land Title Act Form C and Statutory Right of Way Agreement, Province of British Columbia***

Tract: _____

**LAND TITLE ACT
FORM C**
(Section 233)

Province of British Columbia

GENERAL INSTRUMENT - PART 1

(This area for Land Title Office Use)

1. APPLICATION: (Name, address, phone number and signature of applicant, applicant's solicitor or agent)

<@>

Per: _____

2. PARCEL IDENTIFIER(S) AND LEGAL DESCRIPTION(S) OF LAND:*

(PID)

(LEGAL DESCRIPTION)

3. NATURE OF INTEREST:*

DESCRIPTION

DOCUMENT REFERENCE

PERSON ENTITLED TO INTEREST

(page and paragraph)

Statutory Right of Way

Entire Document

Transferee

4. TERMS: Part 2 of this instrument consists of (select one only):

(a) Filed Standard Charge Terms

D.F. Number:

(b) Express Charge Terms

Annexed as Part 2

(c) Release

There is no Part 2 of this instrument

A selection of (a) includes any additional or modified terms referred to in Item 7 or in a schedule annexed to this instrument. If (c) is selected, the charge described in Item 3 is released or discharged as a charge on the land described in Item 2.

5. TRANSFEROR(S):*

6. TRANSFEREE(S): (including postal address(es) and postal code(s))*

**TRANS MOUNTAIN PIPELINE ULC (Extra-Provincial Registration No. A0070893)
Suite 2700, 300 – 5th Avenue SW, Calgary, Alberta T2P 5J2**

7. ADDITIONAL OR MODIFIED TERMS:* n/a

8. EXECUTION(S): This instrument creates, assigns, modifies, enlarges, discharges, or governs the priority of the interest(s) described in Item 3 and the Grantor(s) and every other signatory agree to be bound by this instrument, and acknowledge(s) receipt of a true copy of the filed standard charge terms, if any.

	EXECUTION DATE			
Officer Signature(s)	Y	M	D	Party(ies) Signature(s)
<p>_____</p> <p>Name:</p> <p>_____</p> <p>Name:</p>	 	 	 	<p>TRANS MOUNTAIN PIPELINE ULC by its authorized signatory(ies):</p> <p>_____</p> <p>by its authorized signatory(ies):</p> <p>_____</p> <p>[TRANSFEROR]</p>

OFFICER CERTIFICATION:

Your signature constitutes a representation that you are a solicitor, notary public or other person authorized by the Evidence Act, R.S.B.C. 1996, c. 124, to take affidavits for use in British Columbia and certifies the matters set out in Part 5 of the Land Title Act as they pertain to the execution of this instrument.

* If space insufficient, enter “SEE SCHEDULE” and attach schedule in Form E.

Terms of Instrument – Part 2

TRACT: _____

**TRANS MOUNTAIN PIPELINE ULC
STATUTORY RIGHT OF WAY AGREEMENT
PROVINCE OF BRITISH COLUMBIA**

WHEREAS [REDACTED] (the “**Owner**”) is the registered owner of an estate in fee simple, subject however to such encumbrances, liens and interests as appear on the Indefeasible Title, in all that certain tract of land described in Item 2 of Part 1 of this General Instrument (the “**Lands**”);

AND WHEREAS Trans Mountain Pipeline ULC (“**Trans Mountain**”) has requested the Owner to grant the statutory right of way contained herein (the “**Statutory Right of Way**”) across, over, under, in, through or on that part of the Lands included in Statutory Right of Way Plan <@> (the “**SRW Area**”) on the terms and conditions set out herein;

AND WHEREAS the Statutory Right of Way herein granted is necessary for the operation and maintenance of Trans Mountain’s undertaking;

AND WHEREAS Trans Mountain has been designated under Section 218(1)(d) of the *Land Title Act* to be the grantee of the Statutory Right of Way and such designation has been deposited in the <@> Land Title Office under <@>.

NOW THEREFORE THIS INSTRUMENT WITNESSES that in consideration of the sum of [REDACTED] Dollars (\$ [REDACTED]), the receipt of which is hereby acknowledged, now paid or payable to the Owner, by Trans Mountain, and in consideration of the covenants and conditions on the part Trans Mountain hereinafter mentioned the Owner does:

HEREBY GRANT, CONVEY, SET OVER AND TRANSFER to Trans Mountain, for itself, its employees, agents, contractors, subcontractors, successors and assigns, a statutory right of way under Section 218 of the *Land Title Act* across, over, under, in, through or on the SRW Area to survey, construct, operate, maintain, inspect, patrol (including aerial patrol), alter, remove, replace, reconstruct and repair one or more pipelines (subject to Clause 19 herein) and other facilities appurtenant, affixed or incidental thereto, including, but without limiting the generality of the foregoing, all pipes, drips, valves, fittings, connections, meters, cathodic protection equipment, and other equipment and appurtenances whether or not similar to the foregoing (hereinafter collectively referred to as the “**Pipeline**”), for the transportation, storage and handling of oil, other liquid and gaseous hydrocarbons, and products thereof, together with the right of ingress and egress over the remainder of the Lands to and from SRW Area for Trans Mountain, its personnel, equipment, contractors and agents for all purposes necessary or incidental to the exercise and enjoyment of the rights herein granted. across, over, under, in, through or on the SRW Area.

The rights and statutory right of way hereinbefore granted shall take effect as and from the date hereof on the following terms and conditions which are hereby mutually agreed to:

1. Trans Mountain shall pay the compensation to the Owner for the grant of Statutory Right of Way as follows:

Delete (a) or (b):

(a) one lump sum payment of _____ Dollars
(\$ _____), plus applicable taxes (initial)

or

(b) by annual or periodic payments of equal or different amounts over a period of time as set forth in Schedule One attached hereto and forming part hereof; (initial)

If the Lump Sum Payment option is chosen (option 1(a)), such payment shall be made on or before construction of the Pipeline is commenced on the Lands. If option 1(b) is chosen the first of such payments shall commence on or before construction of the Pipeline is commenced on the Lands.

[Optional] In the event that the lump sum payment, or the first annual or periodic payment, as the case may be, has not been made before _____, 20_____, then the Statutory Right of Way shall terminate and be at an end for all purposes and Trans Mountain shall forthwith execute and register such documents as may be necessary to discharge this Agreement from the Indefeasible Title for the Lands and shall notify the Owner of the registration of the discharge.

2. The Owner shall have the right fully to use and enjoy the SRW Area subject to the rights of Trans Mountain under the Statutory Right of Way provided however that the Owner shall not, without the prior written consent of Trans Mountain, which consent shall not be unreasonably withheld, excavate, drill, install, erect, place, plant or permit to be excavated, drilled, installed, erected, placed, or planted on, over, under, across or through the SRW Area any pit, well, foundation, pavement, building, tree, crop other than an annual crop or any other structure, installation or object.
3. Notwithstanding the provisions of Clause 2, Trans Mountain will not object to the Owner:
 - (i) paving existing farm lanes, private roads, driveways, and sidewalks across the SRW Area;
 - (ii) erecting fences across the SRW Area or any portion thereof; or
 - (iii) constructing drains or repairing drains on the SRW Area or any portion thereof;

provided, however, that the Owner agrees to exercise a high degree of care in carrying out any excavation or drilling necessary for such fencing, paving or drainage, and in no event shall the Owner or his contractors perform such work in such a manner as to endanger or damage the Pipeline. Before the commencement of any such work, the Owner shall give to Trans Mountain at least five (5) days prior notice in writing so as to

enable a representative of Trans Mountain to inspect the site of the proposed work and to advise how the work may be performed without damage to the Pipeline.

4. Trans Mountain will compensate the Owner for all damages suffered as a result of its operations.
5. Trans Mountain will, as soon as weather and soil conditions permit and insofar as it is practicable so to do, bury and maintain the Pipeline in a manner that will not interfere with the drainage or ordinary cultivation of the Lands, and will restore all drains damaged or disturbed by the operation, according to good drainage practice.
6. Notwithstanding that in constructing, maintaining and operating its Pipeline Trans Mountain may install pipe and other equipment and appurtenances in, on, over, under, across or through the SRW Area in such a manner that it or they become affixed to the Lands, the title to such pipe and other equipment and appurtenances shall until surrendered, remain in Trans Mountain. Trans Mountain may at any time remove the whole or any part of the Pipeline.
7. Upon the discontinuance of the use of the SRW Area and of the exercise of the rights hereby granted, Trans Mountain shall and will restore the SRW Area to the same condition, so far as it is practicable so to do, as the same were in prior to the entry thereon and the use thereof by Trans Mountain. Trans Mountain agrees to withdraw and discharge any registrations at the Land Title Office pertaining to the Statutory Right of Way upon its abandonment of the SRW Area.
8. Trans Mountain in performing and observing the covenants and conditions contained in this Agreement, shall peaceably hold and enjoy the rights and Statutory Right of Way hereby granted without hindrance, molestation or interruption on the part of the Owner or of any person, firm or corporation claiming by, through, under or in trust for the Owner.
9. Trans Mountain shall have the absolute right to assign the Statutory Right of Way in whole or in part, and upon such assignment, shall give to the Owner written notice thereof within ten (10) days, but Trans Mountain need not give such notice upon assignment in the course of its corporate financing by way of a deed of trust, mortgage, debenture or a floating charge or upon assignment arising out of an amalgamation or merger.
10. This Agreement shall not affect or prejudice Trans Mountain's statutory rights to acquire a right of entry or any portion of the Lands under the provisions of the *National Energy Board Act* (the "**Act**"), or any other laws, which rights may be exercised at Trans Mountain's discretion.
11. The Owner will, if so requested by Trans Mountain, execute such further documents of title and assurances in respect of the Statutory Right of Way as may be required to perfect Trans Mountain's interest in the Lands under this Instrument.
12. Nothing contained herein shall vest in Trans Mountain any title to mines or minerals in or under the Lands or any part, except only as may be included in any rock, stone or soil that

are necessary to be excavated, carried away or used in the construction of the Pipeline belonging to Trans Mountain.

13. Where Trans Mountain requires an above ground installation of the Pipeline upon the SRW Area (other than pipeline markers installed at property or fence lines) or requires any part of the SRW Area to be fenced, the Owner shall be entitled to additional compensation to be agreed upon between the parties, or failing agreement, pursuant to the procedure available for negotiation and arbitration under Part V of the Act.
14. Trans Mountain will not object to any application made by the Owner under Section 112 of the Act so long as the proposed crossing is made in accordance with good engineering practice and does not interfere with the operation of the Pipeline.
15. This Agreement is a covenant running with the Lands and the provisions of this Agreement shall extend to, be binding upon, and ensure to the benefit of the heirs, executors, administrators, successors and assigns of the Owner and Trans Mountain, respectively.
16. Wherever the singular or masculine is used in this Agreement, it shall be construed as if the plural or feminine or the neuter, as the case may be, had been used where the context so requires.
17. It is agreed that the Owner shall have the right to transfer or convey his interest in the Lands and the covenants and conditions herein contained in one or more parcels and by one or more conveyances and that all the covenants and conditions herein contained shall extend to and be binding upon and ensure to the benefit of each and all of the heirs, executors, administrators, successors, and assigns of the Owner in respect of each and every parcel transferred or conveyed.
18. All notices to be given hereunder may be given by registered letter addressed to Trans Mountain, Suite 2700, Stock Exchange Tower 300 – 5th Avenue S.W., Calgary, Alberta, T21 5J2, and to the Owner at _____ or such other address as Trans Mountain and the Owner may respectively appoint, from time to time, in writing, and any such notice shall be deemed to be given to and received seven (7) days after the mailing thereof, postage prepaid.
19. Trans Mountain will only install an additional pipeline or pipelines in the SRW Area with the consent and agreement of the Owner, or, in the absence of such consent and agreement, in accordance with all authorizations and determinations, including with respect to any additional compensation payable, made under the Act.
20. The Owner agrees that Trans Mountain may, at its option, at any time in the course of operating the Pipeline enter upon the SRW Area with men and equipment and remove all shrubs and trees from the SRW Area.
21. Trans Mountain shall indemnify the Owner from all liabilities, damages, claims, suits and actions arising out of the operations of Trans Mountain other than liabilities, damages, claims, suits and actions resulting from the gross negligence or willful misconduct of the Owner.

22. The Owner confirms having the option of requiring the compensation for the rights herein granted to be made by one lump sum payment or by annual or periodic payments of equal or different amounts over a period of time and that the Owner has selected the method of compensation hereinbefore set out. The Owner further confirms that if the Owner has selected annual or other periodic payments, the amount of such compensation payable by Trans Mountain shall be reviewed every five (5) years if the period of compensation extends beyond five (5) years.
23. The Owner consents to the collection and use of his/her personal information within this Instrument. Trans Mountain collects this type of personal information for the purposes of general land rights acquisition and regulatory disclosure. The Owner consents to the collection, use and disclosure of its personal information for these legitimate business purposes in relation to land matters of Trans Mountain.
24. The Owner acknowledges receipt of a notice given pursuant to Section 87(1) of the Act and given prior to the entering into of this Agreement, setting out or accompanied by:
 - (a) a description of the lands of the Owner required by Trans Mountain for a section or part of the Pipelines;
 - (b) details of the compensation offered by Trans Mountain for such lands required;
 - (c) a detailed statement made by Trans Mountain of the value of such lands required in respect of which compensation was offered;
 - (d) a description of the procedure for approval of the detailed route of Trans Mountain's Pipelines; and
 - (e) a description of the procedure available for negotiation and arbitration under Part V of the Act in the event that the Owner and Trans Mountain are unable to agree on any matter respecting the compensation payable.
25. The Owner acknowledges that Trans Mountain has explained the specific route of the proposed pipeline right of way, as well as the proposed methods and timing of the construction of the Pipeline that will be installed therein. This Agreement confirms that the Owner is in agreement with the location of the pipeline right of way, and the methods and timing of construction of the Pipeline that will be installed therein. The Owner hereby waives any right to ask for a hearing to settle the detailed Pipeline route or the methods and timing of construction, and understands that Trans Mountain may not serve the Owner with further Notice of the detailed route of the Pipeline pursuant to Section 34 (1)(a) of the Act.

IN WITNESS WHEREOF the Owner and Trans Mountain have executed and delivered these presents as of the day and year first above written, on Part 1 of the Form C General Instrument attached to and forming part of this Instrument.

**ATTACHED TO AND FORMING PART OF THE
STATUTORY RIGHT OF WAY AGREEMENT**

SCHEDULE ONE

Annual or Periodic Payment

The consideration for this Agreement is the sum of Dollars (\$_____) of lawful money of Canada to be paid on or before construction is commenced on the Lands, the receipt of which is hereby acknowledged by the Owner, and thereafter the sum of Dollars (\$_____) of lawful money of Canada to be paid on or before the anniversary date thereafter for a period of _____ (_____) years. The amount of any annual or periodic payment will be reviewed every five (5) years if the period of compensation extends beyond five (5) years.

The Owner hereby agrees to and accepts the annual or periodic payment set out above.

Witness:

Owner:

Witness:

Owner:

Witness:

Owner:

Appendix G Agreement for Temporary Working Space, Province of Alberta

TRACT:
GST Reg. No:

**AGREEMENT FOR TEMPORARY WORKING SPACE
PROVINCE OF ALBERTA**

This Agreement dated the _____ day of _____, 20____ (the “**Effective Date**”).

BETWEEN:

_____ (the “**Owner**”)

- and -

**TRANS MOUNTAIN PIPELINE L.P. by the General Partner TRANS MOUNTAIN
PIPELINE ULC**

WHEREAS the Owner is registered as owner or entitled to become registered as owner of an estate in fee simple, subject however to such encumbrances, liens and interests as appear on the Certificate of Title, in all that certain tract of land situated in the Province of Alberta being composed of:

_____ (the “**Lands**”);

AND WHEREAS Trans Mountain has acquired an easement and right of way from the Owner through the Lands for the purpose of constructing two (2) pipelines and other incidental facilities (the “**Pipelines**”) all as more particularly described in an Agreement for Easement between the Owner and Trans Mountain;

AND WHEREAS Trans Mountain requires the right to use a portion of the Lands adjacent to its right of way as shown on the attached property sketch (and identified as “**Temporary Working Rights**” and /or “**Extra Temporary Working Rights**”) to facilitate the construction of the Pipelines (“**Temporary Working Space**”);

AND WHEREAS the Owner is willing to grant to Trans Mountain the use of the Temporary Working Space for and in consideration of the covenants and payments hereinafter set out;

NOW THEREFORE, the parties hereto agree as follows:

1. The sum of _____ Dollars (\$_____), plus *Goods and Services Tax*, shall be paid to the Owner before construction of the Pipelines is commenced on the Lands.
2. The Owner hereby grants to Trans Mountain, its employees, agents, contractors, subcontractors, successors and assigns, the right, license, liberty and privilege to clear, enter and use the Temporary Working Space with people, vehicles, supplies, and equipment from the Effective Date until completion of final reclamation and clean-up, for all purposes useful or convenient in connection with or incidental to the exercise and enjoyment of the rights and privileges provided for in the Agreement for Easement.

3. Trans Mountain shall compensate the Owner for all damage resulting from the use of the Temporary Working Space by Trans Mountain, its employees, agents, contractors, and subcontractors.
4. When Trans Mountain no longer requires the use of the Temporary Working Space and the rights hereby granted, and as soon as it is reasonably practical to do so, Trans Mountain shall restore the surface of the Temporary Working Space in accordance with all applicable laws and regulations.
5. This Agreement, including all covenants and conditions herein contained, shall extend to, be binding upon and enure to the benefit of the heirs, executors, administrators, successors and assigns of the Owner and Trans Mountain. In the event the Owner transfers his/her ownership in the Lands, the Owner agrees to provide fifteen (15) days prior notice of said transfer to Trans Mountain. Such notice shall include the name of the Owner, the legal description of the Lands, the name of the transferee, and the effective date of the transfer. If made in writing, the notice shall be mailed to Trans Mountain, Suite 2700, Stock Exchange Tower 300 – 5th Avenue S.W., Calgary, Alberta, T21 5J2, and shall be deemed to have been given to and received by Trans Mountain seven (7) days after the mailing thereof. Alternatively, the Owner may affect such notice by leaving a detailed message at *[NTD: insert Trans Mountain toll-free phone number]*.
6. Trans Mountain may, at any time for whatsoever reason or cause, at its election on notice in writing to the Owner, terminate this Agreement, and upon giving such notice, this Agreement shall be of no further effect and Trans Mountain shall stand relieved of all of its obligations hereunder other than those which accrued prior to the date of termination.
7. Trans Mountain shall indemnify and save harmless the Owner from any and all liabilities, damages, claims, suits or actions arising out of the use of the Temporary Working Space by Trans Mountain, its employees, agents, contractors, and subcontractors, other than liabilities, damages, claims, suits and actions resulting from the negligence or willful misconduct of the Owner. Notwithstanding the foregoing, Trans Mountain shall not in any event be liable for any indirect or consequential damages.
8. Trans Mountain and the Owner hereby agree and acknowledge that this Agreement does not create a lease and does not constitute a right or interest in land.

IN WITNESS WHEREOF the parties have executed and delivered this Agreement as of the date first above written.

Witness:

Owner:

Witness:

Owner:

**TRANS MOUNTAIN PIPELINE L.P. by the
General Partner TRANS MOUNTAIN
PIPELINE ULC**

Per: _____

Print name and position

Per: _____

Print name and position

Appendix H Agreement for Temporary Working Space, Province of British Columbia

TRACT:
GST Reg. No:

**AGREEMENT FOR TEMPORARY WORKING SPACE
PROVINCE OF BRITISH COLUMBIA**

This Agreement dated the _____ day of _____, 20 ____ (the “**Effective Date**”).

BETWEEN:

_____ (the “**Owner**”)

- and -

**TRANS MOUNTAIN PIPELINE L.P.
 (“**Trans Mountain**”)**

WHEREAS the Owner is registered as owner of an estate in fee simple, subject however to such encumbrances, liens and interests as appear on the Indefeasible Title, in all that certain tract of land situated in the Province of British Columbia described as:

_____ (the “**Lands**”);

AND WHEREAS Trans Mountain has acquired a Statutory Right of Way from the Owner over part of the Lands (the “**SRW Area**”) for the purpose of constructing a pipeline (the “**Pipeline**”) all as more particularly described in a Statutory Right of Way Agreement between the Owner and Trans Mountain;

AND WHEREAS Trans Mountain requires the right to use a portion of the Lands adjacent to the SRW Area as shown on the attached property sketch (and identified as “**Temporary Working Rights**” and /or “**Extra Temporary Working Rights**”) to facilitate the construction of the Pipeline (“**Temporary Working Space**”);

AND WHEREAS the Owner is willing to grant to Trans Mountain the use of the Temporary Working Space for and in consideration of the covenants and payments hereinafter set out;

NOW THEREFORE, the parties hereto agree as follows:

1. The sum of _____ Dollars (\$_____), *plus applicable taxes*, shall be paid to the Owner before construction of the Pipeline is commenced on the Lands (the date of such payment the “**Effective Date**”).
2. The Owner hereby grants to Trans Mountain, its employees, agents, contractors, subcontractors, successors and assigns, the right, license, liberty and privilege to clear, enter and use the Temporary Working Space with people, vehicles, supplies, and equipment from the Effective Date until completion of the construction and installation of the Pipeline within the Lands and final reclamation as provided below, for all purposes useful or convenient in connection with or incidental to the exercise and enjoyment of the rights and privileges provided for in the Statutory Right of Way Agreement.

3. Trans Mountain shall compensate the Owner for all damage resulting from the use of the Temporary Working Space by Trans Mountain, its employees, agents, contractors, and subcontractors.
4. *[When Trans Mountain no longer requires the use of the Temporary Working Space and the rights hereby granted, and as soon as it is reasonably practical to do so,]* Upon the completion of the construction and installation of the Pipeline within the Lands or any abandonment of such work Trans Mountain shall restore the surface of the Temporary Working Space to the extent it is practicable to do so in accordance with all applicable laws and regulations.
5. This Agreement, including all covenants and conditions herein contained, shall extend to, be binding upon and enure to the benefit of the heirs, executors, administrators, successors and assigns of the Owner and Trans Mountain. In the event the Owner transfers his/her ownership in the Lands, the Owner agrees to provide fifteen (15) days prior notice in writing of said transfer to Trans Mountain. Such notice shall include the name of the Owner, the legal description of the Lands, the name of the transferee, and the effective date of the transfer. The notice shall be mailed to Trans Mountain, Suite 2700, Stock Exchange Tower 300 – 5th Avenue S.W., Calgary, Alberta, T21 5J2, and shall be deemed to have been given to and received by Trans Mountain seven (7) days after the mailing thereof. Alternatively, the Owner may affect such notice by leaving a detailed message at *[NTD: insert Trans Mountain toll-free phone number]*.
6. Trans Mountain may, at any time *[prior to the Election Date?]* for whatsoever reason or cause, at its election on notice in writing to the Owner, terminate this Agreement, and upon giving such notice, this Agreement shall be of no further effect and the Company shall stand relieved of all of its obligations hereunder other than those which accrued prior to the date of termination.
7. Trans Mountain shall indemnify and save harmless the Owner from any and all liabilities, damages, claims, suits or actions arising out of the use of the Temporary Working Space by Trans Mountain, its employees, agents, contractors, and subcontractors, other than liabilities, damages, claims, suits and actions resulting from the gross negligence or wilful misconduct of the Owner.
8. Trans Mountain and the Owner hereby agree and acknowledge that this Agreement does not create a lease and does not constitute a right or interest in land.

IN WITNESS WHEREOF the parties have executed and delivered this Agreement as of the date first above written.

Witness:

Owner:

Witness:

Owner:

Witness:

Owner:

Appendix I Option to Purchase Agreements for BC and Alberta

**TRANS MOUNTAIN PIPELINE L.P. by its
General Partner TRANS MOUNTAIN
PIPELINE ULC**

Per: _____

Print name and position

Per: _____

Print name and position

Tract _____
GST Registration No. _____

OPTION TO PURCHASE - ALBERTA

THIS AGREEMENT dated the ____ day of _____, 20__.

BETWEEN:

**TRANS MOUNTAIN PIPELINE L.P. by the General Partner TRANS MOUNTAIN ULC
("Trans Mountain")
– and –**

(the "**Owner**")

WHEREAS:

A. The Owner is the registered owner of certain lands in or near _____, in the Province of Alberta, more particularly described as follows:

[insert legal description]

subject to the reservations and exceptions appearing in the existing Certificate of Title attached as Schedule "A" (the "**Property**");

B. Trans Mountain wishes to acquire lands as substantially shown on the plan attached as Schedule "B" (the "**Option Lands**"); and

C. The Owner has agreed to grant to Trans Mountain an option to purchase the Option Lands pursuant to the terms, provisions and conditions set forth in this Agreement.

In consideration of the sum of _____ Dollars (\$ _____), exclusive of Goods and Services Tax (the "**Consideration**") now paid by Trans Mountain to the Owner, receipt of which the Owner hereby acknowledges, the Owner and Trans Mountain agree as follows:

Grant of Option to Purchase

1. The Owner hereby grants to Trans Mountain the sole and exclusive option to purchase the Option Lands (the "**Option**") irrevocable within the time for exercise provided in Section 2 herein for the Purchase Price and on and subject to the terms and conditions set forth in this Agreement.

Exercise of Option

2. The Option may be exercised by Trans Mountain by notice in writing delivered or mailed to the Owner on or before 5:00 p.m. Mountain Standard Time on _____, _____, 20__.

3. Notice in writing mailed to the Owner of the exercise of the Option by Trans Mountain shall be deemed effective at the time and date such notice is mailed by Registered Mail addressed to the Owner at _____ in the Province of _____.
4. In the event that Trans Mountain does not exercise the Option, this Agreement shall be null and void and no longer binding on the parties, except the Owner shall be entitled to retain the Consideration.

Purchase Price

5. If the Option is exercised, Trans Mountain shall pay to the Owner compensation constituting the Purchase Price as hereinafter set out for the Option Lands. The Consideration paid to the Owner shall be credited towards the Purchase Price.
6. If the Option is exercised by Trans Mountain, Trans Mountain shall pay to the Owner a purchase price for the Option Lands calculated as follows:
 - (a) one lump sum of _____ Dollars (\$ _____) per hectare (\$ _____ per acre) multiplied by the area of the Option Lands in hectares (acres) determined, if required by either party, by a legal survey, (the "**Lump Sum Payment**") plus Goods and Services Tax ("**GST**"),
 - (b) annual or periodic payments of equal or different amounts over a period of time as set forth in Schedule "C".(the "**Purchase Price**")
7. The parties agree that on the Closing Date the Owner shall not collect GST from Trans Mountain in respect of the purchase and sale of the Option Lands, and Trans Mountain shall file returns and remit GST to the Canada Revenue Agency in respect of the purchase and sale of the Option Lands when and to the extent required by the *Excise Tax Act*. Trans Mountain shall provide the Owner a statutory declaration on closing confirming its GST registration number under the *Excise Tax Act* and any other matters reasonably required by the Owner.
8. Upon the exercise of the Option, this Agreement and the document by which the Option is exercised shall become a binding contract of sale and purchase and such sale and purchase shall be completed upon the terms provided herein.

Closing

9. On and subject to the terms and conditions hereof, vacant possession of the Option Lands shall be provided to Trans Mountain and the title to the Option Lands shall be transferred to Trans Mountain in accordance with Section 11 on the closing date, which shall be the last day of the 3rd month following the later of the month in which the Option is exercised, or the date upon which unconditional subdivision approval, if applicable, has been granted by the subdivision approval authority (the "**Closing Date**").

10. The Owner shall provide to Trans Mountain, in registerable form, a transfer of land, a statement of adjustments, and other conveyancing documents in a reasonable time prior to the Closing Date in order for Trans Mountain to confirm registration on or before the Closing Date.
11. On the Closing Date, Trans Mountain shall pay to the Owner, by cheque, the Lump Sum Payment or the first payment referred to in Schedule "C", subject to a credit in Trans Mountain's favor for the Consideration toward such payment and also subject to all usual adjustments including for rents, taxes, and interest, if any. The payment shall be held in trust by the Owner's solicitor until:
 - (a) title to the Option Lands has been issued in the name of Trans Mountain, subject only to non-financial instruments on the title to the Option Lands such as easements, utility rights-of-way and covenants that are normally found registered against property of this nature, all of which shall be in good standing, and such non-financial encumbrances that have been specifically accepted by Trans Mountain in writing at the time of its exercise of the Option. Unless otherwise agreed to in writing, the title to the Option Lands shall be transferred to Trans Mountain free and clear of all other liens, encumbrances, caveats, instruments, registrations and obligations except those implied by statute, and
 - (b) the Owner shall have delivered vacant possession of the Option Lands free and clear of any tenancy.

The Owner shall be solely responsible and shall pay for all of the costs of discharging any existing lien, mortgage, encumbrance, caveat or other instrument which is not permitted under Section 11(a).

Access

12. Upon the granting of the Option, Trans Mountain, its employees, agents, contractors, and sub-contractors may enter upon the Property at the sole risk of Trans Mountain and make all surveys, soil tests, environmental and geotechnical investigations, and such other examinations as Trans Mountain deems appropriate. Trans Mountain shall compensate any tenant on the Property for any damage to the tenant's crops. Trans Mountain shall restore or pay for the restoration of any damage resulting from such activities if this Option is not exercised.

Representations and Warranties

13. Notwithstanding any investigations of Trans Mountain, the Owner makes, and Trans Mountain is entitled to rely upon, the following representations and warranties in respect of the Property and the Option Lands both as of the date hereof and as of the Closing Date:
 - (a) the Owner is not now, nor will the Owner be within sixty (60) days after the Closing Date, a non-resident of Canada for purposes of Section 116 of the *Income Tax Act* of Canada;

- (b) the Owner is not aware of any contamination of or other adverse environmental concern related to the Option Lands or the Property;
 - (c) There are no actions, suits or proceedings commenced or, to the knowledge of the Owner, threatened against or affecting the Owner or the Option Lands or the occupancy or use of the Option Lands by the Owner, in law or in equity, which could affect the validity of this Agreement, the title to the Option Lands, the conveyance of the Option Lands to Trans Mountain, or the right of Trans Mountain from and after the Closing Date to own and develop the Option Lands;
 - (d) The Owner is not aware of any proposed expropriation of any part of the Option Lands;
 - (e) No person, firm or corporation (other than Trans Mountain) has any agreement or option or any right capable of becoming an agreement or option for the purchase of all or any part of the Option Lands;
 - (f) to the best of the Owner's knowledge, information and belief the Option Lands has not been subject to any prior use which might reasonably be expected to have resulted in deleterious or hazardous substances having been deposited or accumulated upon, within, or under the Option Lands; and
 - (g) the Option Lands are not subject to or affected by any encumbrances or adverse interests except as set out in Section 11 above, and also free and clear from any charges, claims or obligations of any party claiming by, through or under the Owner.
14. Without limiting the foregoing representations and warranties, Trans Mountain acknowledges that:
- (a) it is relying on its own investigations, analysis, appraisals, and estimates as to the value of the Option Lands and the suitability of the Option Lands for the use it intends; and
 - (b) it is obtaining all required regulatory and other approvals, including planning, development, zoning and building approvals and permits.

Conditions Precedent

15. The following conditions shall be conditions precedent to Trans Mountain's obligation to complete the purchase of the Option Lands following exercise of the Option:
- (a) Trans Mountain shall be satisfied, in its sole discretion, that all approvals or permits whatsoever, including without limitation, zoning, subdivision, regulatory, environmental, development and building permits, shall have been obtained or are obtainable on terms acceptable to it, in order for it to acquire the Option Lands and develop the Option Lands in accordance with its intended use;

- (b) Trans Mountain shall be satisfied, in its sole discretion, that environmental and geo-technical investigations do not reveal any conditions that would make the Option Lands unsuitable for its intended use;
 - (c) the Owner's representations and warranties shall be true and not misleading in any way and Trans Mountain shall not have become aware of any fact or thing which would reasonably lead it to believe otherwise; and
 - (d) the Owner shall have complied with Section 13.
16. If Trans Mountain has not delivered written notice to the Owner that the conditions precedent described in Section 15 have all been satisfied fourteen (14) days prior to the Closing Date, or Trans Mountain does not waive them, this Agreement shall terminate and be of no further force and effect.
17. If applicable, Trans Mountain shall have received subdivision approval in respect of the subdivision of the Option Lands from the Property from the subdivision approval authority by no later than _____, and in the event approval is not obtained by this date, the Agreement shall terminate and be of no further force and effect.

Miscellaneous

18. The parties agree that the Consideration does not include GST of _____ and that the Owner shall not collect GST from Trans Mountain in respect of the Consideration, and Trans Mountain shall file returns and remit GST to the Canada Revenue Agency in respect of the Consideration when and to the extent required by the *Excise Tax Act*.
19. The Owner agrees not to remove or allow the removal of any materials from the Option Lands (including any soil) while this Agreement remains in effect, or otherwise alter the Option Lands, or the use of the Option Lands, which may result in a material adverse impact on the Option Lands, or the use of the Option Lands by Trans Mountain, and the Owner shall deliver possession of the Option Lands in substantially the same condition as existed at the date of this Agreement.
20. The Owner shall execute all further deeds, documents and assurances, and shall do all such further things as may be reasonably required for the purpose of carrying out this Agreement according to its true meaning and intent.
21. This Agreement shall be binding upon and enure to the benefit of the heirs, executors, administrators, successors and assigns of the Owner and Trans Mountain, respectively.
22. If any provision contained in this Option or its application to any party hereto or circumstance shall, to any extent, be invalid or unenforceable, the remainder of this Option or the application of such provision to such parties or circumstances other than those to which it is held invalid or unenforceable shall not be affected.
23. Trans Mountain shall be responsible for:

- (a) all costs related to the obtaining of subdivision approval of the Option Lands, if applicable;
 - (b) the costs of a legal survey of the Option Lands; and
 - (c) the costs for the preparation and registration of any legal property or subdivision plans.
24. The Option Lands including all fixtures and other items to be purchased related to the Option Lands shall remain at the risk of the Owner until the Closing Date. In the event of loss, destruction or damage or any such property between the granting of the Option and the Closing Date, at Trans Mountain's option, either such loss will be repaired and corrected at the expense of the Owner, except to the extent that such loss is directly due to the actions of Trans Mountain or its representatives, or such loss will be dealt with in an equitable manner by way of an adjustment at closing.
25. Trans Mountain shall have the right at any time and from time to time to assign all of its rights and obligations under this Agreement. The Owner shall not, in whole or in part, assign his interest in this Agreement without the prior written consent of Trans Mountain.
26. Time shall be of the essence. The provisions hereof shall survive the registration of all conveyances and shall not merge therein or therewith.
27. The Agreement shall be governed by and interpreted in accordance with the laws of the Province of Alberta.
28. This Agreement shall enure to the benefit of, and be binding upon, the parties hereto and their respective successors and assigns.
29. The Owner acknowledges receiving a Notice pursuant to Section 87 (1) of the *National Energy Board Act* concerning the above property.
30. The Owner confirms having the option of requiring the Purchase Price to be made by one Lump Sum Payment or by annual or periodic payments of equal or different amounts over a period of time and that the Owner has selected the method of compensation hereinbefore set out. The Owner and Trans Mountain further confirm that if the Owner has selected annual or other periodic payments, the amount of such compensation payable to the Owner shall be reviewed every five years if the period of compensation extends beyond five years.
31. Until the Closing Date, Trans Mountain agrees as follows:
- (a) to pay compensation for all damages suffered by the Owner as a result of the operations of Trans Mountain on the Property;
 - (b) to indemnify the Owner from all liabilities, damages, claims, suits and actions arising out of the operations of Trans Mountain on the Property other than liabilities, damages, claims, suits and actions resulting from the gross negligence or wilful misconduct of the Owner;

- (c) that any use of the Option Lands by Trans Mountain shall be restricted to the purposes set out in Section 12, unless the Owner consents to any proposed additional use at the time of the proposed additional use.

IN WITNESS WHEREOF the parties hereto have duly executed this Agreement by their respective hands as of the day and year first above written.

Witness:

Owner:

Witness:

Owner:

**TRANS MOUNTAIN PIPELINE L.P. by the
General Partner TRANS MOUNTAIN
PIPELINE ULC**

Per: _____

Print name and position

Per: _____

Print name and position

SCHEDULE “A”

SCHEDULE “B”

SCHEDULE "C"

The Purchase Price is the sum of _____ Dollars (\$_____) of lawful money of Canada to be paid before construction is commenced on the said Option Lands and thereafter the sum of _____ Dollars (\$_____) of money of Canada to be paid in each and every year. This annual payment shall be made on or before the anniversary date of the first payment being made before construction is commenced, for a period of ____ years ("**term**").

**ALBERTA – THE DOWER ACT
CONSENT OF SPOUSE**

I, _____,
being married to the within named _____ do hereby give
my consent to the disposition of our homestead, made in the within instrument, and I have
executed this document for the purpose of giving up my life estate and other dower rights in the
said property given to me by THE DOWER ACT, to the extent necessary to give effect to the
said disposition.

CERTIFICATE OF ACKNOWLEDGEMENT BY SPOUSE

1. This document was acknowledged before me by _____
apart from her husband (his wife).

2. _____ acknowledged
to
me that she (he)
 - (a) is aware of the nature of the disposition or agreement;
 - (b) is aware that THE DOWER ACT, gives her (him) a life estate in the homestead
and the right to prevent disposition of the homestead by withholding consent;
 - (c) consents to the disposition or agreement for the purpose of giving up the life
estate and other dower rights in the homestead given to her (him) by THE
DOWER ACT, to the extent necessary to give effect to the said disposition or
agreement;
 - (d) is executing the document freely and voluntarily without any compulsion on the
part of her husband (his wife).

SWORN before me at the)

of _____ in)
the
Province of Alberta, this ___ day of)
_____, A.D. 20___)

A Commissioner for Oaths in and for the)
Province of Alberta)

AFFIDAVIT

CANADA
PROVINCE OF ALBERTA
TO WIT:

I, _____ of
_____, in the Province of Alberta,
_____, make oath and say:

- 1. That I am the Grantor named in the within instrument.
- 2. That I am not married.

-OR-

That neither myself nor my spouse have resided on the within mentioned land at any time since our marriage.

SWORN before me at the)
_____)
of _____ in)
the)
Province of Alberta, this ___ day of)
_____, A.D. 20___)
)
)
)
_____)
A Commissioner for Oaths in and for the)
Province of Alberta)

AFFIDAVIT OF EXECUTION

CANADA) I, _____ of the
)
PROVINCE OF ALBERTA) _____ of _____
)
TO WIT:) in the Province of Alberta

MAKE OATH AND SAY:

- 1. THAT I was personally present and did see _____ named in the within instrument, who is (are) personally known to me to be the person(s) named therein, duly sign, seal and execute the same for the purpose named therein.
- 2. THAT the instrument, was executed at the _____, of _____ in the Province of Alberta, and that I am the subscribing witness thereto.
- 3. THAT I believe the person(s) whose signatures I witnessed is (are) at least eighteen (18) years of age.

SWORN before me at the)
_____)
of _____ in)
the)
Province of Alberta, this ___ day of)
_____, A.D. 20___) _____
)
)
_____)
A Commissioner for Oaths in and for the)
Province of Alberta)

Tract _____
GST Registration No. of Trans Mountain _____

OPTION TO PURCHASE - BRITISH COLUMBIA

THIS AGREEMENT dated the _____ day of _____, 20__.

BETWEEN:

TRANS MOUNTAIN PIPELINE L.P.
(“Trans Mountain”)
– and –

(the “Owner”)

WHEREAS:

A. The Owner is the registered owner of certain lands in or near _____, in the Province of British Columbia, more particularly described as follows:

[insert legal description]

subject to the rights of way, easements and covenants in favour of utilities and public authorities as set out in Schedule “A” (the “**Property**”);

B. Trans Mountain wishes to purchase part of the Property (the “**Option Lands**”) substantially as shown on the plan attached as Schedule “B” (the “**Option Lands Plan**”); and

C. The Owner has agreed to grant to Trans Mountain an Option to Purchase the Option Lands pursuant to the terms, provisions and conditions set forth in this Agreement.

In consideration of the sum of _____ Dollars (\$_____), exclusive of Goods and Services Tax (the “**Consideration**”) now paid by Trans Mountain to the Owner, receipt of which the Owner hereby acknowledges, the Owner and Trans Mountain agree as follows:

Grant of Option to Purchase

1. The Owner hereby grants to Trans Mountain the sole and exclusive option to purchase the Option Lands, irrevocable within the time for exercise provided in Section 2 herein, on the terms and conditions hereinafter set forth (“**Option**”).

Exercise of Option

2. The Option may be exercised by Trans Mountain by notice in writing delivered or mailed on or before 5:00 p.m. Vancouver time on _____, _____, 20__.

3. Notice in writing mailed to the Owner of the exercise of the Option by Trans Mountain shall be deemed effective at the time and date such notice is mailed by Registered Mail addressed to the Owner at _____ in the Province of British Columbia.
4. In the event that Trans Mountain does not exercise the Option, this Agreement shall be null and void and no longer binding on the parties, except the Owner shall be entitled to retain the Consideration.

Purchase Price

5. If the Option is exercised, Trans Mountain shall pay to the Owner compensation constituting the purchase price (“**Purchase Price**”) for the Option Lands. The Consideration paid to the Owner shall be credited towards the Purchase Price.
6. If the Option is exercised by Trans Mountain, Trans Mountain shall pay to the Owner the Purchase Price for the Option Lands which shall be the sum of \$_____ per hectare (\$_____ per acre) multiplied by the area of the Option Lands in hectares (acres) determined by a legal survey carried out for the Section 114 Plan (hereinafter defined), plus Goods and Services Tax (“**GST**”).
7. The parties agree that on the Closing Date (as defined herein) the Owner shall not collect GST from Trans Mountain in respect of the purchase and sale of the Option Lands, and Trans Mountain shall file returns and remit GST to the Canada Revenue Agency in respect of the purchase and sale of the Option Lands when and to the extent required by the *Excise Tax Act*.
8. Upon the exercise of the Option, this Agreement and the document by which the Option is exercised shall become a binding contract of sale and purchase and such sale and purchase shall be completed upon the terms provided herein.

Permitted Encumbrances

9. The Option Lands will be free and clear of any encumbrances except the rights-of-way, easements and covenants in favour of utilities and public authorities set out in Schedule “A” to this Agreement (together the “**Permitted Encumbrances**”).

Closing

10. The closing date (the “**Closing Date**”) shall be the last day of the third month following the month in which the Option is exercised.

11. Trans Mountain covenants that prior to the Closing Date it shall cause to be prepared a plan of survey capable of being deposited in the land title office for the Property under Section 114 of the *Land Title Act* concurrently with the registration of the Form A, so as to effect, without approval by the approving officer under the *Land Title Act*, the subdivision of the Option Lands from the Property in the records of the land title office and the creation of a separate parcel for the Option Lands with an indefeasible title issued in the name of Trans Mountain (such plan the “**Section 114 Plan**”).
12. On or before the Closing Date, the Owner will deliver to Trans Mountain’s solicitors <@> (“**Trans Mountain’s Solicitors**”), on condition that the same will only be dealt with in accordance with Section 15 of this Agreement, the following documents duly signed, declared, executed (in registrable form where required) in accordance with their respective terms and the tenor thereof:
 - (a) a Form A transfer document for the Option Lands in registrable form, executed by the Owner and transferring the Option Lands to Trans Mountain Pipeline ULC (the “**Form A**”);
 - (b) a statement of adjustments;
 - (c) a statutory declaration of the Owner that the Owner is not a non-resident of Canada for the purposes of the *Income Tax Act* (Canada); and
 - (d) such further deeds, acts, things, certificates and assurances as may be requisite in the reasonable opinion of Trans Mountain’s Solicitors for more perfectly and absolutely assigning, transferring and conveying to Trans Mountain title to the Option Lands free and clear of any lien, charge, encumbrance or legal notation, other than the Permitted Encumbrances.
13. On or before the Closing Date, Trans Mountain will duly execute, as appropriate, and deliver to Trans Mountain’s Solicitors the following:
 - (a) a bank draft, certified cheque or solicitors trust cheque representing the Purchase Price subject to a credit in Trans Mountain’s favour for the Consideration toward such payment and also subject to all adjustments as provided for in the statement of adjustments aforesaid (the “**Net Purchase Price**”);
 - (b) a certificate of an authorized officer of Trans Mountain confirming Trans Mountain’s status as a GST registrant under the *Excise Tax Act* and any other matters reasonably required by the Owner; and
 - (c) the necessary documents for the deposit in the land title office for the Property of the Section 114 Plan.
14. All of the closing documents contemplated in Sections 12 and 13 will be prepared by Trans Mountain’s Solicitors and delivered to the Owner’s solicitors at least five business days prior to the Closing Date. All documents referred to in Sections 12 and 13 shall be in the form and substance reasonably satisfactory to the solicitors for the party entitled to delivery thereof.

15. Forthwith following the deliveries required under Section 12 and 13 having been completed Trans Mountain's Solicitors shall cause application for the registration of the Form A and for deposit of the Section 114 Plan to be made to the land title office for the Property and on receipt of a satisfactory application title search for the Property that evidences in the ordinary course of the operation of such land title office an indefeasible title will issue to the Option Lands in the name of Trans Mountain subject only to:
- (a) the Permitted Encumbrances; and
 - (b) any existing financial encumbrances granted by the Owner to be discharged in accordance with the procedure set out in Section 16 below,

Trans Mountain's Solicitors will pay to the Owner's solicitors by certified cheque or solicitor's trust cheque the Net Purchase Price

16. Notwithstanding anything contained herein to the contrary, if the Owner has existing financial charges which are to be discharged from title to the Option Lands after completion of the sale of the Option Lands to Trans Mountain, the Owner, while still required to cause the discharge of such charges, may wait to cause the discharge of the same until immediately after the receipt of the Purchase Price, but in this event, Trans Mountain shall pay the Net Purchase Price to the Owner's solicitor in trust, on undertakings to pay and discharge such financial charges from the Option Lands reasonably acceptable to Trans Mountain's Solicitors.

Adjustments

17. All usual adjustments of taxes, utilities, local improvement assessments, rent, security deposits, interest and all other charges and costs relating to the Option Lands, both incoming and outgoing, will be made as at the Closing Date. The Owner shall be responsible for all taxes, obligations and payments to the adjustment time, and Trans Mountain shall be responsible for all taxes, obligations and payments thereafter.

Possession

18. The Owner shall deliver vacant possession of the Option Lands to Trans Mountain on the Closing Date free and clear of any tenancy.

Risk

19. The Option Lands shall be at the risk of the Owner until 11:59 a.m. Vancouver Time on the Closing Date and thereafter at the risk of Trans Mountain.

Access

20. Upon the granting of the Option, Trans Mountain, its employees, agents, contractors, and sub-contractors may enter upon the Property at the sole risk of Trans Mountain and make all surveys, soil tests, environmental and geotechnical investigations, and such other examinations as Trans Mountain deems appropriate. Trans Mountain shall compensate any tenant on the Property for any damage to the tenant's crops resulting from Trans

Mountain's activities on the Property. Trans Mountain shall restore or pay for the restoration of any damage resulting from such activities if the Option is not exercised.

Subdivision

21. The Owner covenants with Trans Mountain that the Owner shall cooperate with Trans Mountain in obtaining all approvals or permits required for the subdivision of Option Lands from the Property including without limitation, all regulatory, environmental, developmental approvals (collectively, the "**Approvals**").
22. The Owner covenants with Trans Mountain that the Owner shall provide all consents required by Trans Mountain to allow for the Approvals and, if required, shall execute on behalf of Trans Mountain, or authorize the execution by Trans Mountain, of any applications, documents and instruments of any nature whatsoever in connection with the Approvals.

Representations and Warranties

23. Notwithstanding any investigations of Trans Mountain, the Owner makes, and Trans Mountain is entitled to rely upon, the following representations and warranties in respect of the Property and the Option Lands both as of the date hereof and as of the Closing Date:
 - (a) the Owner is not a non-resident of Canada for purposes of Section 116 of the *Income Tax Act* of Canada;
 - (b) the Owner is not aware of any contamination of or other adverse environmental concern related to the Option Lands or the Property;
 - (c) to the best of the Owner's knowledge, information and belief the Property and the Option Lands have not been subject to any prior use which might reasonably be expected to have resulted in Hazardous Substances (as hereinafter defined) having been deposited or accumulated upon, within, or under the Option Lands or the Property or having been released from the Option Lands or the Property; and
 - (d) the Owner has good and marketable title to the Option Lands, and is ready, willing and able to convey title to the Option Lands free and clear from any liens, encumbrances or adverse interests except the Permitted Encumbrances and any existing financial encumbrances granted by the Owner to be discharged in accordance with the procedure set out in Section 16, and also free and clear from any charges, claims or obligations of any party claiming by, through or under the Owner.
24. Without limiting the foregoing representations and warranties, Trans Mountain acknowledges that:
 - (a) it is relying on its own investigations, analysis, appraisals, and estimates as to the value of the Option Lands and the suitability of the Option Lands for the use it intends; and

- (b) it is obtaining all required Approvals.

Indemnity

25. The Owner covenants to indemnify and save harmless Trans Mountain and its agents, successors and assigns or any of them from and against any and all claims, actions, judgments, orders, suits, losses, damages, liabilities, fines, penalties, costs and expenses (including costs relating to environmental studies, investigations, excavations, inspections and remediation activities), and reasonable consultants, experts and legal fees and expenses as a result of or arising from:
- (a) any act, omission, negligence or misconduct of the Owner or any person for whom the Owner is in law responsible that is not in compliance with any federal, provincial, municipal or other governmental or regulatory statutes, bylaws, regulations and rules relating to the environment, occupational safety, health or transportation (“**Environmental Laws**”) in force on the Closing Date pertaining to the Option Lands or the Property or any activities conducted on the Option Lands or Property; or
 - (b) the release or presence upon, within, under or from the Option Lands or Property of any hazardous substance or pollutant or contaminant, toxic or dangerous waste, substance, chemical or material including, without limitation, gasoline and other petroleum substance or material which falls into the definition of waste, hazardous, toxic, dangerous goods or any variation of those terms or terms of similar import (“**Hazardous Substances**”) under any Environmental Laws at or prior to the Closing Date; or
 - (c) as a result of any breach of the Owner of any of the representations and warranties and covenants of the Owner contained herein.

Conditions Precedent

26. The following conditions shall be conditions precedent to Trans Mountain’s obligation to complete the purchase of the Option Lands following exercise of the Option:
- (a) Trans Mountain shall be satisfied, in its sole discretion, that all Approvals have been obtained or are obtainable on terms acceptable to it, in order for it use the Option Lands in accordance with its intended use;
 - (b) Trans Mountain shall be satisfied, in its sole discretion, that environmental and geo-technical investigations do not reveal any conditions that would make the Option Lands unsuitable for its intended use;
 - (c) the Owner’s representations and warranties shall be true and not misleading in any way and Trans Mountain shall not have become aware of any fact or thing which would reasonably lead it to believe otherwise; and
 - (d) the Owner shall have complied with Section 21.

27. If Trans Mountain does not give notice to the Owner that the conditions precedent described in Section 26 have been satisfied or are waived not later than fourteen (14) days prior to the Closing Date this Agreement shall terminate and be of no further force and effect.

Miscellaneous

28. The parties agree that the Consideration does not include GST of _____ and that the Owner shall not collect GST from Trans Mountain in respect of the Consideration, and Trans Mountain shall file returns and remit GST to the Canada Revenue Agency in respect of the Consideration when and to the extent required by the *Excise Tax Act*.
29. The Owner agrees not to remove or allow the removal of any materials from the Option Lands (including any soil) while this Agreement remains in effect, or otherwise alter the Option Lands, or the use of the Option Lands, which may result in a material adverse impact on the Option Lands, or the use of the Option Lands by Trans Mountain.
30. The Owner shall execute all further deeds, documents and assurances, and shall do all such further things as may be reasonably required for the purpose of carrying out this Agreement according to its true meaning and intent.
31. This Agreement shall be binding upon and enure to the benefit of the heirs, executors, administrators, successors and assigns of the Owner and Trans Mountain, respectively.
32. If any provision contained in this Agreement or its application to any party hereto or circumstance shall, to any extent, be invalid or unenforceable, the remainder of this Agreement or the application of such provision to such parties or circumstances other than those to which it is held invalid or unenforceable shall not be affected.
33. Trans Mountain shall be responsible for:
- (a) all costs related to the subdivision of the Option Lands from the Property, if applicable; and
 - (b) the costs of a legal survey of the Option Lands and the Section 114 Plan.
34. The Option Lands including all fixtures and other items to be purchased related to the Option Lands shall remain at the risk of the Owner until the Closing Date. In the event of loss, destruction or damage or any such property between the granting of the Option and the Closing Date, either such loss will be repaired and corrected at the expense of the Owner, except to the extent that such loss is directly due to the actions of Trans Mountain or its representatives, or such loss will be dealt with in an equitable manner by way of an adjustment of the Purchase Price. In the event the parties cannot agree on the adjustment it shall be settled by arbitration.
35. Trans Mountain shall have the right at any time and from time to time to assign all of its rights and obligations under this Agreement. The Owner shall not, in whole or in part, assign his interest in this Agreement without the prior written consent of Trans Mountain.

- 36. Time shall be of the essence. The provisions hereof shall survive the registration of all conveyances and shall not merge therein or therewith.
- 37. The Agreement shall be governed by and interpreted in accordance with the laws of the Province of British Columbia.
- 38. The Owner acknowledges receiving a Notice pursuant to Section 87 (1) of the *National Energy Board Act* concerning the above property.

IN WITNESS WHEREOF the parties hereto have duly executed this Agreement by their respective hands as of the day and year first above written.

Witness:

Owner:

Witness:

Owner:

**TRANS MOUNTAIN PIPELINE L.P. by its
General Partner TRANS MOUNTAIN
PIPELINE ULC**

Per: _____

Print name and position

Per: _____

Print name and position

SCHEDULE "A"

SCHEDULE "B"