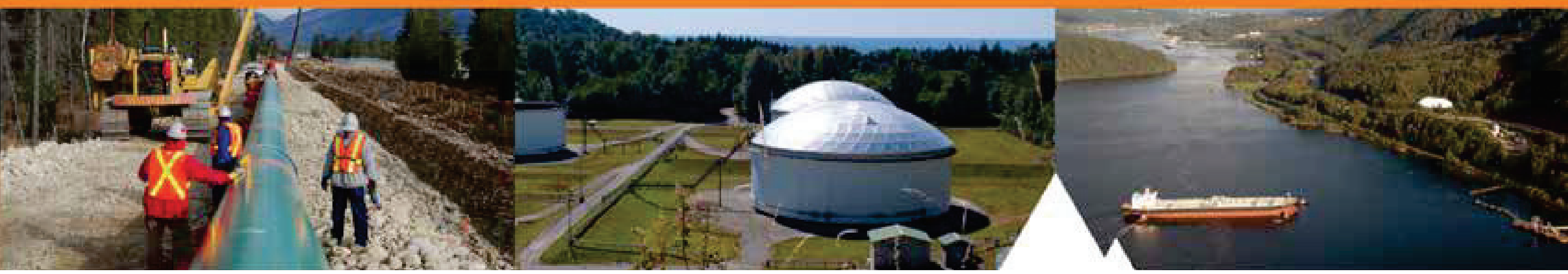
TRANSMOUNTAIN

CELEBRATING 60 YEARS OF SERVICE 1953 to 2013

Trans Mountain Pipeline ULC



Trans Mountain Expansion Project

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

December 2013

Volume 4a Project Design & Execution - Engineering

KINDER MORGAN CANADA

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

Application	
Transmittal - Letter to the National Energy Board	
Volume 1	Summary
Volume 2	Project Overview, Economics and General Information
Volume 3A	Public Consultation
Volume 3B	Aboriginal Engagement
Volume 3C	Landowner Relations
Volume 4A	**Project Design and Execution – Engineering**
Volume 4B	Project Design and Execution – Construction
Volume 4C	Project Design and Execution – Operations and Maintenance
Volume 5A	Environmental and Socio-Economic Assessment – Biophysical
Volume 5B	Environmental and Socio-Economic Assessment – Socio-Economic
Volume 5C	Environmental and Socio-Economic Assessment – Biophysical Technical Reports
Volume 5D	Environmental and Socio-Economic Assessment – Socio-Economic Technical Reports
Volume 6A	Environmental Compliance
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 7	Risk Assessment and Management of Pipeline and Facility Spills
Volume 8A	Marine Transportation
Volume 8B	Marine Environmental and Socio-Economic Technical Reports
Volume 8C	TERMPOL Reports

This volume contains:

Volume 4A

Section 1.0	Introduction
Section 2.0	Pipeline Design Principles
Section 3.0	Pipeline System Engineering and Design
Section 4.0	References
Section 5.0	Appendices

Appendix A	Configuration Map and Schematics
Appendix B	Figures
Appendix C	Drawings
Appendix D	Tables
Appendix E	Route Maps
Appendix F	KMC/TMEP Specifications to be Developed during Detailed Engineering and Design
Appendix G	Preliminary HDD Watercourse Crossing Plan and Profile Drawings
Appendix H	Terrain Mapping and Geohazard Inventory Report
Appendix I	Route Physiography and Hydrology Report
Appendix J	Seismic Assessment Desktop Study Report

TABLE OF CONTENTS

Page

LIST OF APPENDICES

LIST OF FIGURES

LIST OF TABLES

ABBREVIATIONS AND ACRONYMS

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

Term	Meaning
°C	degrees Celsius
AB	Alberta
AC	alternating current
AESO	Alberta Electric System Operator
AFC	Alberta Fire Code
AFD	axial flaw detection
AltaLink	AltaLink Management Ltd.
API	American Petroleum Institute
ARD	acid rock drainage
ARO	abrasion resistant overcoat
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
bbl/d	barrels per day
BC	British Columbia
BCCP	BC Coast Pilots
BCFC	BC Fire Code
BJ	BJ Services, now known as Baker Hughes
CAPP	Canadian Association of Petroleum Producers
Cat I	Category I
Cat II	Category II
Cat III	Category III
CCME	Canadian Council of the Ministers of the Environment
CEC	Canadian Electrical Code
CGA	Canadian Gas Association
CN	Canadian National
COMM	communication cable
CP	cathodic protection
CPCN	Certificate of Public Convenience and Necessity
CPR	Canadian Pacific Railway
CSA	Canadian Standards Association
cSt	centistokes
DC	direct current
DFO	Fisheries and Oceans Canada
DRA	drag-reducing agent
DWT	deadweight tonnes
EHHW	extreme highest high water
ELLW	extreme lowest low water
EPP	Environmental Protection Plan
ESB	electrical service building
ESD	emergency shut down
ETA	East Tank Area
ETEP	Edmonton Terminal Expansion Project
FBE	fusion bond epoxy
FCAW	flux core arc welding
FEI	FortisBC Energy Inc.

Term	Meaning
Fortis	FortisAlberta Inc.
FOTS	Fibre Optic Transmission System
HAZOP	Hazards and Operability
HCA	High Consequence Area
HDD	horizontal directional drill
HDPE	high density polyethylene
HMI	human-machine interface
HSMP	Health and Safety Management Plan
HVAC	Heating, Ventilation and Air Conditioning
HVP	high vapour pressure
I/O	input/output
IEEE	Institute of Electrical and Electronics Engineers
IFR	Internal Floating Roof
ILI	In-line Inspection
IR	infrared
KMC	Kinder Morgan Canada Inc.
kPa	kilopascal
kPag	kilopascal (gauge)
kW	kilowatt
LVP	low vapour pressure
mA	milliamp
MCCs	motor control centres
MFL	magnetic flux leakage
MLBV	mainline block valve
MPa	megapascal
MPR	motor protection relay
MOP	maximum operating pressure
MOV	motor operated valve
MVA	megavolt-amp
MW	megawatts
n/a	not applicable
NDT	non-destructive testing
NEMA	National Electrical Manufacturers Association
NEB	National Energy Board
NEB Act	*National Energy Board Act*
NFPA	National Fire Protection Association
NPS	nominal pipe size
NRH	not required hydraulically
OD	outside diameter
OPR	Onshore Pipeline Regulations
PCC	primary control centre
PLC	Programmable Logic Control
PMP	Procurement Management Plan
PMV	Port Metro Vancouver
PN	nominal pressure class
ppm	parts per million
psi	pounds per square inch
psig	pounds per square inch (gauge)
QMP	Quality Management Program

Term	Meaning
RI	remote impoundment
RIA	remote impoundment annex
RK	reference kilometre
RMF	Risk Management Framework
RMLBV	remote main line block valve
RTDs	resistance temperature detectors
SCADA	Supervisory Control and Data Acquisition
SCC	Stress Corrosion Cracking
SMAW	shielded metal arc welding
SMYS	specified minimum yield strength
SRY	Southern Railway of British Columbia
SSPC	The Society for Protective Coatings
TBD	to be determined
TLST	TransLink SkyTrain
TMEP	Trans Mountain Expansion Project
TMPL	Trans Mountain Pipeline
TMPL system	Trans Mountain pipeline system
TMX-Anchor Loop	TMX Anchor Loop Expansion Project
Trans Mountain	Trans Mountain Pipeline ULC
TVAU	tank vapour adsorption unit
UKC	under-keel clearance
UPS	uninterruptable power supply
US	United States
USCD	UltraScan Crack Detection
V	volt
VCU	vapour combustion unit
VFD	variable frequency drive
VRU	vapour recovery unit
WM	wall measurement
WTA	West Tank Area

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			--
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: • 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: • 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: • 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.e.*, 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 (*e.g.*, 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.e.*, 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: · 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 · Section 8.0 Volume 5B: ESA - Socio-Economic · Section 8.0	Volume 8A: Marine Transportation · 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 · Section 8.0 Volume 5B: ESA - Socio-Economic · Section 8.0	Volume 8A: Marine Transportation · 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 · Section 8.0 Volume 5B: ESA - Socio-Economic · Section 8.0	Volume 8A: Marine Transportation · 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 · Section 8.0 Volume 5B: ESA - Socio-Economic · Section 8.0	Volume 8A: Marine Transportation · Section 4.4	---
3.	Evaluate the significance of adverse residual cumulative effects against the defined criteria.	Volume 5A: ESA - Biophysical · Section 8.0 Volume 5B: ESA - Socio-Economic · Section 8.0	Volume 8A: Marine Transportation · 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 · Section 8.0 Volume 5B: ESA - Socio-Economic · Section 8.0	Volume 8A: Marine Transportation · 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 *NEB Onshore Pipeline Regulations (OPR)*.	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	---

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 *NEB OPR*.	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 *Canadian Environmental Assessment (CEA) Act, 2012* designated projects, identify which elements and monitoring procedures would constitute follow-up under the *CEA Act, 2012*.	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 · Sections 5.0, 6.0 and 7.0	N/A	---
Soil and soil productivity		Volume 5A: ESA - Biophysical · Sections 5.0, 6.0, 7.0 and 8.0 Volume 5C: ESA - Biophysical Technical Reports · Soil Assessment Technical Report Volume 7: Risk Assessment and Management of Pipeline and Facility Spills · Section 5.3, 6.0 and 7.0	N/A	---
Water quality and quantity (onshore and marine)		Volume 5A: ESA - Biophysical · Sections 5.0, 6.0, 7.0 and 8.0 Volume 5C: ESA - Biophysical Technical Reports · 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 · Section 7.0 · Quality Ecological Risk Assessment of Pipeline Spills Technical Report	Volume 8A: Marine Transportation · Sections 4.2, 4.3, 4.4, 5.6 and 5.7 Volume 8B: Technical Reports · Ecological Risk Assessment of Marine Transportation Spills Technical Report	---
Air emissions (onshore and marine)		Volume 5A: ESA - Biophysical · Sections 5.0, 6.0, 7.0 and 8.0 Volume 5C: ESA - Biophysical Technical Reports · 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 · Section 7.0	Volume 8A: Marine Transportation · Sections 4.2, 4.3, 4.4, 5.6 and 5.7 Volume 8B: Technical Reports · Marine Air Quality and Greenhouse Gas Emissions	---
Greenhouse gas emissions (onshore and marine)		Volume 5A: ESA - Biophysical · Sections 5.0, 6.0 and 7.0 Volume 5C: ESA - Biophysical Technical Reports · Air Quality and Greenhouse Gas Emissions Technical Report	Volume 8A: Marine Transportation · Sections 4.2 and 4.3 Volume 8B: Technical Reports · Marine Air Quality and Greenhouse Gas Emissions	---
Acoustic environment (onshore and marine)		Volume 5A: ESA - Biophysical · Sections 5.0, 6.0, 7.0, and 8.0 Volume 5C: ESA - Biophysical Technical Reports · Acoustic Environment Technical Report	Volume 8A: Marine Transportation · Sections 4.2, 4.3 and 4.4 Volume 8B: Technical Reports · Marine Noise (Atmospheric)	---
Fish and fish habitat (onshore and marine), including any fish habitat compensation required		Volume 5A: ESA - Biophysical · Sections 5.0, 6.0, 7.0 and 8.0 Volume 5C: ESA - Biophysical Technical Reports · 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 · Sections 6.0, 7.0 and 8.0 · Qualitative Ecological Risk Assessment of Pipeline Spills Technical Report	Volume 8A: Marine Transportation · Sections 4.2, 4.3, 4.4, 5.6 and 5.7 Volume 8B: Technical Reports · Marine Resources – 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
Wetlands		Volume 5A: ESA - Biophysical · Sections 5.0, 6.0, 7.0 and 8.0 Volume 5C: ESA - Biophysical Technical Reports · Wetland Evaluation Technical Report Volume 7: Risk Assessment and Management of Pipeline and Facility Spills · Sections 7.0 and 8.0 · Qualitative Ecological Risk Assessment of Pipeline Spills Technical Report	N/A	---
Vegetation		Volume 5A: ESA - Biophysical · Sections 5.0, 6.0, 7.0 and 8.0 Volume 5C: ESA - Biophysical Technical Reports · Vegetation Technical Report Volume 7: Risk Assessment and Management of Pipeline and Facility Spills · 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 · Sections 5.0, 6.0, 7.0 and 8.0 Volume 5C: ESA - Biophysical Technical Reports · 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 · Sections 6.0, 7.0 and 8.0 · Qualitative Ecological Risk Assessment of Pipeline Spills Technical Report	Volume 8A: Marine Transportation · Sections 4.2. 4.3, 4.4, 5.6 and 5.7 Volume 8B: Technical Reports · Marine Resources – Marine Transportation Technical Report · Marine Birds – Marine Transportation Technical Report · Ecological Risk Assessment of Westridge Marine Terminal Spills	---
Species at Risk or Species of Special Status and related habitat (onshore and marine)		Volume 5A: ESA - Biophysical · Sections 5.0, 6.0, 7.0 and 8.0 Volume 5C: ESA - Biophysical Technical Reports · 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 Volume 7: Risk Assessment and Management of Pipeline and Facility Spills · Sections 6.0, 7.0 and 8.0 · Qualitative Ecological Risk Assessment of Pipeline Spills Technical Report	Volume 8A: Marine Transportation · Sections 4.2. 4.3, 4.4, 5.6 and 5.7 Volume 8B: Technical Reports · Marine Resources – Marine Transportation Technical Report · Marine Birds – Marine Transportation Technical Report · Marine Transportation Spills Ecological Risk Assessment Technical Report	---

Filing #	Filing Requirement	In Application? References	Applicable Marine Transportation Elements	Not in Application? Explanation
	Human occupancy and resource use (onshore and marine)	Volume 5B: ESA - Socio-Economic · Sections 5.0, 6.0, 7.0 and 8.0 Volume 5D: ESA - Socio-Economic Technical Reports · Socio-Economic Technical Report · Managed Forest Areas Technical Report · Agricultural Assessment Technical Report Volume 7: Risk Assessment and Management of Pipeline and Facility Spills · Sections 6.0, 7.0 and 8.0	Volume 8A: Marine Transportation · Sections 4.2, 4.3, 4.4, 5.6 and 5.7 Volume 8B: Technical Reports · Marine Commercial, Recreational and Tourism Use – Marine Transportation Technical Report	---
	Heritage resources	Volume 5B: ESA - Socio-Economic · Sections 5.0, 6.0 and 7.0 Volume 7: Risk Assessment and Management of Pipeline and Facility Spills · Section 6.3.3	N/A	---
	Navigation and navigation safety	Volume 5B: ESA - Socio-Economic · Sections 5.0, 6.0 and 7.0 Volume 5D: ESA - Socio-Economic Technical Reports · Socio-Economic Technical Report	Volume 8A: Marine Transportation · Section 5.2	---
	Traditional land and resource use	Volume 5B: ESA - Socio-Economic · Sections 5.0, 6.0, 7.0 and 8.0 Volume 5D: ESA - Socio-Economic Technical Reports · Traditional Land and Resource Use Report · Pipeline and Facilities Human Health Risk Assessment Technical Report Volume 7: Risk Assessment and Management of Pipeline and Facility Spills · Sections 6.0, 7.0 and 8.0 · Qualitative Ecological Risk Assessment of Pipeline Spills Technical Report	Volume 8A: Marine Transportation · Sections 4.2, 4.3, 4.4, 5.6 and 5.7 Volume 8B: Technical Reports · Traditional Marine Use Report for Marine Transportation · Marine Transportation Human Health Risk Assessment Technical Report	---
	Social and cultural well-being	Volume 5B: ESA - Socio-Economic · Sections 5.0, 6.0, 7.0 and 8.0 Volume 5D: ESA - Socio-Economic Technical Reports · Socio-Economic Technical Report Volume 7: Risk Assessment and Management of Pipeline and Facility Spills · Sections 6.0, 7.0 and 8.0	N/A	---
	Human health and aesthetics	Volume 5B: ESA - Socio-Economic · Sections 5.0, 6.0, 7.0 and 8.0 Volume 5D: ESA - Socio-Economic Technical Reports · 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 · 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 · Qualitative Human Health Risk Assessment of Westridge Marine Terminal Technical Report Volume 8A: Marine Transportation · Sections 4.2, 4.3, 4.4, 5.6 and 5.7 Volume 8B: Technical Reports · Marine Transportation Human Health Risk Assessment Technical Report · Marine Transportation Spills Human Health Risk Assessment Technical Report	---

Filing #	Filing Requirement	In Application? References	Applicable Marine Transportation Elements	Not in Application? Explanation
Infrastructure and services		Volume 5B: ESA - Socio-Economic · Sections 5.0, 6.0, 7.0 and 8.0 Volume 5D: ESA - Socio-Economic Technical Reports · Socio-Economic Technical Report · Community Health Technical Report Volume 7: Risk Assessment and Management of Pipeline and Facility Spills · Sections 6.0, 7.0 and 8.0	Volume 8A: Marine Transportation · Sections 4.2, 4.3, 4.4, 5.6 and 5.7 Volume 8B: Technical Reports · Marine Commercial, Recreational and Tourism Use – Marine Transportation Technical Report	---
Employment and economy		Volume 5B: ESA - Socio-Economic · Sections 5.0, 6.0, 7.0 and 8.0 Volume 5D: ESA - Socio-Economic Technical Reports · 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: • 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: • 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.	• 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: · Section 7.0 Volume 5B ESA - Socio-economic: · Section 7.0 Volume 7 Risk Assessment and Management of Pipeline and Facility Spills Volume 8A Marine Transportation: · 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: · Section 8.0 Volume 5B ESA - Socio-economic: · Section 8.0 Volume 8A Marine Transportation: · Section 4.4
the significance of the effects referred to in paragraph (a);	s.19.1(b)	Volume 5A ESA - Biophysical: · Sections 7.0 and 8.0 Volume 5B ESA - Socio-economic: · Sections 7.0 and 8.0 Volume 8A Marine Transportation: · 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 *National Energy Board Act*, any interested party – that are received in accordance with this *act*;	s.19.1(c)	Volume 3A Public Consultation Volume 3B Aboriginal Engagement Volume 3C Landowner Relations Volume 5A ESA - Biophysical: · Section 3.0 Volume 5B ESA - Socio-economic: · Section 3.0 Volume 8A Marine Transportation: · 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: · Sections 7.0 and 8.0 Volume 5B ESA - Socio-economic: · 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: · 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: · Section 10.0 Volume 5B ESA - Socio-economic: · Section 10.0
the purpose of the designated project;	s.19.1(f)	Volume 5A ESA - Biophysical: · Section 2.0 Volume 5B ESA - Socio-economic: · Section 2.0 Volume 8A Marine Transportation: · Section 1.1

CONCORDANCE TABLE WITH THE *CEA ACT, 2012*

CEA Act, 2012 Requirement	Section in *CEA Act, 2012*	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 alterative 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 *Filing Requirements Related to the Potential Environmental and Socio-Economic Effects of Increased Marine Shipping Activities, Trans Mountain Expansion Project* (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 *CEA Act, 2012* 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 *Fisheries Act* and fish habitat as defined in subsection 34(1) of that *Act*;	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 *Species at Risk Act;*	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 *Migratory Birds Convention Act, 1994*, 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 *CEA Act, 2012* defines environmental effects as (b) a change that may be caused to the environment that would occur		
on federal lands,	s.5(1)(b)(i)	Volume 5A ESA - Biophysical: · Section 7.0 Volume 5B ESA - Socio-economic: · Section 7.0

CONCORDANCE TABLE WITH THE *CEA ACT, 2012*

CEA Act, 2012 Requirement	Section in *CEA Act, 2012*	Application Volume and Section
in a province other than the one in which the *act* 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 *CEA Act, 2012* 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. 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 m^3/d (300,000 bbl/d) using 23 active pump stations and 40 petroleum storage tanks. The expansion will increase the capacity to 141,500 m^3/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.

The existing TMPL system is approximately 1,147 km long commencing at a terminal in Sherwood Park, AB (Edmonton Terminal) and ending at the Westridge Marine Terminal in Burnaby, BC. The original pipeline, built in 1953, is a 610 mm (NPS 24) outside diameter (OD) pipeline. Since that time three segments of the original pipeline have been looped (or twinned): Edson, AB, to Hinton, AB (89 km) with 762 mm OD (NPS 30); Hinton, AB, to Hargreaves, BC (150 km) with 914 mm OD (NPS 36) and Darfield, BC, to Kamloops, BC (81 km) with 762 mm OD (NPS 30). The segments of the original TMPL NPS 24 pipeline that were looped by the NPS 30 and NPS 36 pipeline segments were deactivated and filled with nitrogen.

The Trans Mountain Expansion Project includes the proposed looping of the existing TMPL system with the exception of the Hinton to Hargreaves and the Darfield to Black Pines pipeline segments. The expanded TMPL system will consist of two independently operated pipelines from Edmonton Terminal to Burnaby Terminal. The “Line 1” pipeline will consist of NPS 24 and NPS 30 pipeline segments that are currently part of the existing TMPL system and will include two reactivated NPS 24 pipeline segments. The “Line 2” pipeline will consist of 987 km of new NPS 36 pipeline and two NPS 30 and NPS 36 pipeline segments that are currently part of the existing TMPL system.

The 1,147 km Line 1 pipeline will consist of:

- the existing 229 km of NPS 24 and 89 km of NPS 30 pipeline segments from Edmonton to Hinton;
- a reactivated 150 km of NPS 24 pipeline segment from Hinton to Hargreaves;
- the existing 273 km of NPS 24 pipeline segment from Hargreaves to Darfield;
- a reactivated 43 km of NPS 24 pipeline segment from Darfield to Black Pines; and
- the existing 325 km of NPS 24 and 38 km of NPS 30 pipeline segments from Black Pines to the Burnaby Terminal.

The 1,180 km Line 2 pipeline will consist of:

- approximately 339 km of new NPS 36 pipeline from Edmonton to Hinton;
- the existing 150 km of NPS 36 pipeline segment from Hinton to Hargreaves (built in 2008);
- approximately 279 km of new NPS 36 pipeline from Hargreaves to Darfield;
- the existing 43 km of NPS 30 pipeline segment from Darfield to Black Pines (built in 1957); and
- approximately 368 km of new NPS 36 pipeline from Black Pines to the Burnaby Terminal.

Other major components of TMEP will include:

- adding 12 new pump stations, 10 at existing pump station sites and two at a new common pump station site at Black Pines;
- adding 34 new pump units at the new pump stations;
- reactivating the existing pump station at Niton, AB;
- re-connecting Jasper Pump Station to Line 1 and adding drag-reducing agent (DRA) injection capability;

- adding one new pump unit at Sumas Pump Station to support additional deliveries to the Puget Sound Pipeline;
- adding 20 new storage tanks, 5 at Edmonton Terminal, 1 at Sumas Terminal, and 14 at Burnaby Terminal;
- adding one or more pressure reducing stations in the vicinity of Hope, BC;
- adding 16 new sending and receiving traps, at eight pump station or terminal sites on Line 1 and Line 2, for the handling of in-line inspection and cleaning tools (pigs);
- removing the trap site at Hargreaves, BC;
- adding two parallel 4 km, NPS 30 pipelines (complete with traps) from Burnaby Terminal to the Westridge Marine Terminal, in addition to the existing NPS 24 pipeline; and
- removing the existing tanker loading dock at the Westridge Marine Terminal and constructing one new dock complex with a total of three Aframax-capable berth faces and a utility dock.

The expanded Line 1 pipeline will be capable of transporting an annual average of 55,640 m^3/d (350,000 bbl/d) and will provide a batched transportation service for refined products and light crude oils. Line 1 will also be capable of transporting heavy crude oil at a reduced rate.

The new Line 2 pipeline will be capable of transporting an annual average 85,850 m^3/d (540,000 bbl/d) of heavy crude oils and will be capable of transporting light crude oils, if necessary.

The expanded Westridge Marine Terminal will be capable of loading up to three Aframax class vessels simultaneously and is intended to handle up to 100,160 m^3/d (630,000 bbl/d) at loading rates of 111,290 m^3/d (700,000 bbl/d) per vessel.

A Configuration Map and System Schematics of the proposed TMPL system post-expansion are provided in Appendix A.

1.2 Purpose of Volume 4A

This document is part of the Application being made to the NEB by Trans Mountain, under Section 52 of the *NEB Act*, for a CPCN for TMEP.

This document provides a comprehensive overview of:

- the proposed pipeline corridor selection process that will be used for the determination of the pipeline route centreline and footprint; and
- the engineering design principles, the engineering design criteria, and the preliminary engineering design for the pipelines, the pump stations, the terminals (including Westridge Marine Terminal), the power supplies, the sending and receiving traps, the mainline block valves (MLBVs), and other ancillary facilities.

2.0 PIPELINE DESIGN PRINCIPLES

2.1 Regulatory Statutes and Requirements

The Trans Mountain Expansion Project will be subject to the regulatory jurisdiction of the NEB of Canada under the auspices of the *NEB Act*, the regulatory requirements of the NEB Onshore Pipeline Regulations (OPR), and the regulatory requirements of:

- the Canadian Environmental Assessment Agency;
- Fisheries and Oceans Canada (DFO);
- Transport Canada (*Navigable Waters Protection Act*); and
- provincial, municipal, railway and utility authorities having jurisdiction, which will require the acquisition of numerous approvals, permits, licences, notifications and authorizations in connection with the design, construction and operation of TMEP and the expanded TMPL system.

2.2 Compliance with National Energy Board Onshore Pipeline Regulations and CSA Z662

The Trans Mountain Expansion Project and the expanded TMPL system will be designed, constructed, operated, maintained, deactivated and abandoned in accordance with the NEB OPR, which incorporate, by reference, the Canadian Standards Association (CSA) Z662-11, Oil and Gas Pipeline Systems (CSA Z662).

Where inconsistencies occur between the OPR and CSA Z662 or any other codes, standards, specifications and recommended practices used in the design, construction, operation and maintenance of TMEP and the expanded TMPL system, the OPR will prevail to the extent of the inconsistency.

2.3 CSA Z662 Annex E

Leak detection systems and procedures will be in compliance with CSA Z662, Annex E, Recommended Practice for Liquid Hydrocarbon Pipeline System Leak Detection.

2.4 Non-routine Project Design

There are no non-routine design aspects associated with the TMEP.

2.5 Industry Codes, Standards, Specifications and Recommended Practices

In addition to the latest version of CSA Z662, the requirements of the latest version of the industry codes, standards, specifications, and recommended practices listed in Table 5.1.1 in Appendix D will, where applicable, be incorporated into the design, construction, operation, and maintenance of the expanded TMPL system and its associated facilities.

2.6 Kinder Morgan Canada Standards, Specifications, Manuals, and Recommended Practices

Table 5.1.2 in Appendix D lists KMC standards, specifications, manuals, and recommended practices that will, where applicable, be adopted by Trans Mountain and used in the design, construction, operation, and maintenance of TMEP and the expanded TMPL system. Additional KMC standards, specifications, manuals, and recommended practices may be developed and adopted during the detailed engineering and design phase. TMEP-specific standards, specifications, and manuals may also be developed.

2.7 Quality Management Program

A Quality Management Program (QMP) for the engineering, procurement, and construction of TMEP will be developed during the detailed engineering and design phase. The QMP will address or encompass the following elements.

2.7.1 Engineering

As specified in Section 2.2, TMEP will be designed, constructed, and operated to meet or exceed applicable regulatory requirements of the NEB OPR, the CSA Z662 standard, and the codes, standards, specifications, and recommended practices referenced in CSA Z662.

Where engineering standards and specifications are not readily available or do not adequately address the subject, additional or supplemental standards and specifications will be developed. Appendix F identifies a preliminary list of engineering specifications that will be developed during the detailed engineering and design phase.

In connection with the QMP, design verification of the detailed engineering and design of the TMEP will be carried out in accordance with the requirements of Section 3.2.5, and all design elements of the pipeline will be subject to constructability assessments (Section 3.2.4).

2.7.2 Materials, Equipment, and Services Procurement

Procurement of materials, equipment, and services will be undertaken in accordance with the Kinder Morgan Procurement and Administrative Policies and Procedures, which apply to all Kinder Morgan entities in the Canada and the United States, and as such will be adopted by Trans Mountain. A Procurement Management Plan (PMP), specific to TMEP, will be developed during the detailed engineering and design phase. Quality assurance procedures specific to TMEP for materials/equipment, and construction will be developed during the detailed engineering and design phase in accordance with KMC Standards PM-3501, Materials and Equipment Quality Assurance and PM-3511, Construction Quality Assurance (currently under development).

2.7.3 Construction

A TMEP specific Health and Safety Management Plan (HSMP) for construction will be developed during the detailed engineering and design phase. The Health and Safety Management Plan will be in accordance with the KMC Health & Safety Standards Manual, the KMC Contractor Environmental/Safety Manual, and PM-3201, Construction Health & Safety Management (currently under development). See Volume 4B, Section 5.

Where construction standards and specifications are not readily available or do not adequately address the subject, additional or supplemental standards and specifications will be developed. Appendix F identifies a preliminary list of construction specifications that will be developed during the detailed engineering and design phase.

A joining program (Section 3.2.14), which includes welding specifications, welding procedures and non-destructive testing (NDT) specifications, will be developed in accordance with the NEB OPR and CSA Z662.

Environmental protection and inspection requirements for construction will be defined in the Environmental Protection Plan (EPP) (Volume 6B).

2.7.4 Quality Audits

Periodic internal audits will be conducted for all construction aspects of TMEP. The prime objective of the audits will be to document compliance. Identified deficiencies will be documented for resolution and follow-up.

Construction work audits will be carried out as defined in the Contractor's project-specific safety plan and the EPP.

2.7.5 Management of Change

A management of change procedure for engineering, procurement, and construction will be developed during the detailed engineering and design phase.

2.7.6 Documentation

Documentation for the engineering, procurement, and construction will be managed in accordance with KMC Standard PM-4701 Document Control and other accepted document management procedures and practices.

2.8 Pipeline Corridor and Route Centreline Selection Process

2.8.1 Pipeline Corridor Selection Objectives, Strategies and Criteria

Early in the Project planning process, Trans Mountain decided that the Line 2 pipeline segments should be contiguous with the existing 18 m (60 ft.) 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 Aboriginal communities, landowners, community representatives, and stakeholders 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, fibre optic cables and other utilities;
- or, if that is not feasible, install the Line 2 segments in a new easement selected to balance a number of engineering, construction, environmental, and socio-economic factors; and lastly
- in the event a new easement is necessary, minimize the length of the new easement before returning to the TMPL easement or other rights-of-way.

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 in Table 4.2.1 of Volume 2.

While the proposed TMEP 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.

The strategies for the selection of the corridor were as follows:

- initiate desktop studies with emphasis on the assessment of the TMPL easement;
- acquire all applicable data sets for the desktop studies;
- initiate communications with landowners prior to any ground-based field reconnaissance;
- complete a field assessment of the existing TMPL right-of-way to establish the feasibility of locating significant segments of Line 2 abutting the TMPL right-of-way;
- where abutting the existing TMPL right-of-way is not feasible, identify alternative routing for desktop review and subsequent field assessment;
- assess alternative corridors for Line 2 and recommend a proposed Line 2 alternative corridor;
- once a proposed Line 2 alternative corridor has been identified, provide the information to other disciplines to allow commencement of their assessments;
- acquire engineering, constructability, geotechnical, environmental, socio-economic, operations, maintenance, and cost data in support of the proposed Line 2 alternative corridor;
- consult with stakeholders and Aboriginal communities in order to gain insight into the acceptability of the Line 2 alternative corridor from all parties impacted or involved; and
- define the proposed Line 2 pipeline corridor based on the results of the corridor selection process.

In addition to adhering to the routing criteria and corridor selection strategies, the following guidelines were used to enable decision making and maintain consistency:

- minimize the length of the TMEP Line 2 pipeline;
- avoid areas that have significant environmental value or restrictions;
- minimize routing through areas of extensive urban development;

- be consistent with established land use planning;
- avoid areas of potential geotechnical or geological hazards;
- avoid areas of extremely rough terrain or areas that have limited access;
- minimize the number of watercourse, highway, road, railway and utility crossings;
- establish the crossing of watercourses at as close as is practical to right angles; and
- minimize locating the pipeline within lands where limited rights are available.

2.8.2 Pipeline Corridor Selection Process

Selection of the pipeline corridor for TMEP Line 2 involved a number of distinct stages described below.

2.8.2.1 Office Based (Desktop) Analyses

The first corridor assessment activity involved the gathering of all available data as part of office based or desktop analyses. The data came in a variety of forms and from a number of sources. In most instances, there were gaps in either the type of data or the extent of the data. A preliminary assessment of the type, extent, cost, time to acquire, and value of the various data was refined, followed by a prioritization by the routing specialists for the acquisition of any missing data.

The essential data for corridor assessment was generally comprised of the following data types:

- imagery;
- digital elevation model data;
- federal and provincial government (base vector layers, raster maps, etc.) data;
- survey data;
- preliminary geotechnical and environmental data; and
- existing Trans Mountain data.

2.8.2.2 Field Assessment of Existing TMPL Right-of-Way

The primary criterion established for the selection of the TMEP Line 2 pipeline corridor was to locate it abutting the existing TMPL easement. Consequently, the routing field crews initiated their work along the existing TMPL easement, travelling by 4 × 4 trucks, all-terrain vehicles, snowmobiles, helicopter, and on foot.

The primary element assessed by the routing specialists was constructability; in other words, can the pipeline be reasonably constructed adjacent to the assessed TMPL easement? However, a significant number of other factors that are critical to the acceptability of a particular corridor were considered, such as the potential for detrimental environmental effects, land use issues, undesirable watercourse crossing locations, poor configuration or alignment for trenchless crossing techniques and, in some instances, geotechnical or geological concerns.These factors, supplemented by the routing specialist comments, formed the overall assessment of the TMPL easement under consideration. Based on this assessment, the TMEP Line 2 pipeline corridor was classified according to four distinct assessment classifications. The definition of each of these assessment classifications is provided in Table 5.1.3 in Appendix D.

2.8.2.3 Alternative Pipeline Corridors

Where the alignment adjacent to the existing TMPL easement was not considered a viable alternative for the Line 2 pipeline, a review was initiated to identify and evaluate alternative corridors. The routing specialists first undertook a desktop review including any available field data of alternative corridors, and then refined one or more proposed new corridor alignments for consideration.

The rejection of some sections of the TMPL easement as an acceptable corridor was initially decided upon by the routing specialists. However, in order to ensure that the evaluation was appropriate and generally endorsed by the TMEP team, regular weekly meetings were held to provide a broader base of input to the decision making process. The meetings consisted of representatives from a corridor review team that included engineering, construction, environment, geotechnical, and operations.

The corridor review team reviewed the alternative corridors identified by the routing specialists and those considered acceptable were nominated for further field evaluation. Following a corridor review meeting, the data associated with proposed alternative corridors was sent to meeting participants for further in-house evaluation. The participants then undertook a desktop assessment of the applicable issues, primarily to identify any specific issues that might rule out an alternative corridor. In the absence of any evidence that a selected alternative corridor was not acceptable, the routing specialists then commenced field studies.

The field assessment of alternative corridors was similar to that done along the TMPL easement, although access to private lands was not always available. Following the field assessment of the alternative corridors, the data was once again reviewed by the corridor review team. From this review, the team identified those alternative corridors which appeared acceptable and which warranted further investigation before inclusion in the pipeline study corridor.

2.8.2.4 Pipeline Study Corridor

Once the routing field work was completed on the proposed alternative corridors (either along TMPL easement or TMEP Line 2 alternatives), the corridor assessment then involved further detailed assessments by other disciplines to ensure that there were no significant impediments to endorsing a particular alternative corridor. The additional assessments normally included the following elements, in no specific order:

- engineering;
- geotechnical and seismicity;
- constructability;
- environmental, including archaeology;
- Aboriginal communities input;

- public and community input;
- land and right-of-way;
- operations and maintenance;
- costs (capital and operating); and
- socio-economics including land use.

In addition to formal assessments, members of the Aboriginal communities, landowners, the general public, various levels of government, major infrastructure owners, and other stakeholders were engaged to incorporate any additional criteria or commentary on the proposed Line 2 pipeline study corridor.

In these instances, the input received formed a part of the database and decision making process.

Further information on Aboriginal communities and stakeholder engagement is included in Volume 3A, Public Consultation and 3B, Aboriginal Engagement.

2.8.2.5 Selection of Proposed Pipeline Corridor

Where major deviations were necessary from the TMPL easement, an evaluation of viable alternative corridors was undertaken by members of the routing team representing engineering, constructability, geotechnical, environmental, socio-economic, Aboriginal engagement, stakeholder engagement, and other disciplines. These alternative corridor evaluations are presented in Section 4 of Volumes 5A and 5B.

The proposed pipeline corridor is on or adjacent to the existing TMPL easement for 73 per cent of the total length of new pipeline. Approximately 17 per cent follows other existing rights-of-way and 10 per cent will be on new corridor. For purposes of Trans Mountain's NEB application, the proposed pipeline corridor is generally 150 m in width centred on the existing TMPL easement except where deviations are required as identified above. The proposed pipeline corridor is shown on the Proposed Line 2 Pipeline Corridor Route Maps in Appendix E and the preliminary environmental alignment sheets in Volume 6E.

2.8.3 Detailed Route Centreline and Footprint

For purposes of Trans Mountain's NEB application, it was necessary to identify a proposed pipeline corridor prior to filing to focus environmental and other studies. It is recognized that additional landowner, stakeholder, environmental, socio-economic, geotechnical, and other information will come forward that will lead to improvements in the location of the pipeline corridor. In addition, the pipeline routing experts are continuing to refine the proposed 150 m corridor and narrow it down to a pipeline construction right-of-way. These improvements will adopt the routing criteria, strategies, and guidelines identified above without jeopardizing pipeline safety and security.

A Route Physiography and Hydrology Report (Appendix I) was prepared on the physical geography of the proposed route including topography, surficial geography, bedrock geology, climate and stream flow data on watercourses being crossed.

2.9 Conditions Not Specifically Addressed in CSA Z662 or Onshore Pipeline Regulations

It is anticipated that there will be localized areas along the pipeline route where physical conditions or construction circumstances are encountered that are not specifically or adequately addressed in sufficient detail within CSA Z662 or the OPR. These conditions and circumstances typically include:

- blasting rock adjacent to existing pipelines, roads, railways and utilities;
- mitigating potential slope instability;
- dealing with the potential for seismic activity;
- watercourse scour and erosion;
- controlling pipe buoyancy; and
- high voltage alternating current (AC)/direct current (DC) interference.

Where these conditions or circumstances are encountered, the appropriate qualified engineering specialists will evaluate and prepare detailed engineered designs such that the design, construction and operation of the pipeline will implicitly meet the safety and integrity requirements of CSA Z662 and the OPR. All such designs will be reviewed by qualified professional engineers who are certified accordingly.

2.9.1 Blasting

It is anticipated that blasting of bedrock along the right-of-way will be required as part of grading or trench excavating activities during construction. Blasting adjacent to existing pipelines and other infrastructure has been safely completed for many years within the pipeline industry.

The Trans Mountain Anchor Loop Project Blasting Specification will be refined during the detailed engineering and design phase to become the TMEP Blasting Specification and will specifically address adjacent facilities along the proposed pipeline route to ensure these are not adversely affected. Techniques to be incorporated into the specification include using instrumentation to monitor the shock waves associated with blasting activities and limit the intensity of the shock waves, specifying the borehole pattern and the space between the boreholes, specifying the type and quantity of explosives used, and using of blasting mats or other devices to control projectiles.

In conjunction with the TMEP Blasting Specification, safety precautions will be employed as required. These safety precautions may include:

- public notification;
- coordination of blasting activities with the use of adjacent roads and railways such that traffic is not significantly affected;
- inspection of the road or railway after blasting to determine if the road or railway has been impaired and that it is safe for use; and

- where specific circumstances warrant, reducing the operating pressure on the adjacent existing pipeline.

2.9.2 Terrain Stability

Route selection for the new segments of the proposed Line 2 pipeline was conducted so as to avoid or minimize exposure to known locations of slope instability, potential for rock falls, debris flows, seismicity, sedimentation and erosion. These terrain stability considerations along with their standard mitigation measures are summarized in Table 5.1.4 in Appendix D. The entire pipeline route has been evaluated for terrain stability by qualified engineering consultants and the results have been reported in the Terrain Mapping and Geohazard Inventory Report included in Appendix H. This evaluation has included the potential for terrain hazards (geohazards) to initiate outside of the proposed corridor and have an effect on the pipeline as well as the potential for construction and long-term operation of the pipeline to have an effect on the stability of the surrounding terrain. The KMC Natural Hazards Management Program database for the existing TMPL system was also used as a source to identify specific risk areas.

During grading of the new right-of-way, the potential for localized instability and rock fall concerns will be identified. In these instances, qualified geotechnical engineers will review the locations of concern and, where warranted, prepare site-specific mitigative designs.

Through regular patrol of the pipeline right-of-way during operations, slopes will be monitored for potential rock fall, slope instability and slope erosion, and where required, timely mitigation will be implemented.

2.9.3 Seismic Hazards

The TMEP Line 2 pipeline and facilities, including tanks, will be designed for seismic loading corresponding to a two per cent probability of exceedance in 50 years (equivalent to a return period of 2,475 years), which is consistent with the current requirements of the National Building Code of Canada.

As part of preliminary studies, a screening level assessment of two of the most dominant seismic hazards, liquefaction potential and seismically induced landslides, has been completed along the entire pipeline corridor and is included in the Seismic Assessment Desktop Study Report in Appendix J. Those areas along the route identified as having elevated liquefaction or landslide potential will then have site-specific studies and investigations undertaken during the detailed engineering and design phase to ensure the adequacy of the pipeline design.

Although no active faults (where rupture has occurred in the last 11,000 years) have been identified in BC, studies will be conducted as part of the detailed engineering and design phase in an attempt to further confirm the presence or absence of active faults crossing or running close to the route. In the event that a potentially active fault is discovered, the pipeline design will be site specifically modified to accommodate the direction and possible magnitude of movement across the fault.

At major watercourse crossings, and other areas where lateral spreading as a result of liquefaction has the potential to occur, the pipeline will be designed to resist the potential ground movement (both transient and permanent) associated with the design level event.

2.9.4 Watercourse Scour and Bank Mitigation

Watercourses crossed by the pipeline have been evaluated, catchment areas calculated and peak flows determined or calculated by a qualified hydrological engineer and the results are included in the Route Physiography and Hydrology Report in Appendix I. During the detailed engineering and design phase, the notable watercourse crossings will be designed for scour and bank stability to meet the conditions of a 1 in 200 year flood event and, as such, the proposed Line 2 pipeline will be sufficiently buried, or otherwise protected, to ensure its long-term integrity.

2.9.5 Buoyancy Control

Buoyancy control will be required for the new segments of the proposed Line 2 pipeline at larger watercourse crossings and wetlands. A variety of techniques are available to control buoyancy including concrete bolt-on weights, concrete saddle weights, continuous concrete coating, screw anchors, and gravel or sand filled bag weights. During the detailed engineering and design phase, qualified engineers will specify the type and amount of weighting so that the pipeline will have sufficient negative buoyancy. During trench excavation the extent of the locations requiring buoyancy control will be re-confirmed.

Specifications for the different methods to be used for buoyancy control will be developed during the detailed engineering and design phase.

2.9.6 High Voltage Alternating Current/Direct Current Interference

Special consideration will be given to areas along the pipeline where interference from high voltage AC/DC currents may occur. These areas include places where the pipeline crosses or parallels high voltage power lines. These areas will require special grounding procedures (including installation of test stations) in order to ensure safety during construction and operations.

In locations where the new pipeline runs parallel to high voltage AC power lines, each location will be evaluated and special designs will be developed as required for mitigating the potential for mutual interference between the pipeline and the power line in accordance with CAN/CSA-C22.3 No. 6 – M91: Principles and Practices of Electrical Coordination between Pipelines and Electric Supply Lines.

The detailed AC/DC mitigation requirements of the pipeline will be determined during the detailed engineering and design phase.

2.10 Watercourse Crossing Methods

To determine the most suitable construction method for a pipeline watercourse crossing consideration must be given to a number of factors, such as:

- hydrological issues such as flow volumes, depth, width and channel stability, including scour;
- fish and fish habitat, including the species and life stages that are anticipated to be present in the potential zone of influence at the crossing location at the time of construction;

- geotechnical issues including the stability of the bank and valley slopes, subsurface conditions and the risk of debris flow;
- construction issues including complexity, crossing configuration, topography, risk, safety, schedule, and cost;
- regulator, resource manager, Aboriginal community, other community, and stakeholder input; and
- permanent and temporary access to watercourses, and across watercourses.

Watercourse crossing construction methods include open cut (Section 2.10.1), isolated methods (Section 2.10.2), and trenchless methods (Sections 2.10.3 to 2.10.7).

2.10.1 Open Cut Crossing

Open-cut crossings allow for excavation of the pipeline trench through a frozen, dry or wet channel with no requirement to separate the flow in the construction area from the rest of the channel so that flow is not interrupted. This method is often used for smaller watercourse crossings, where there are no fisheries or water quality considerations, for watercourses that are dry or frozen to the bottom during construction or for large watercourses where other crossing methods cannot be employed or are not preferred.

Two types of open cut crossing techniques are proposed:

- mainline trenching; and
- designed open cut.

Mainline trenched crossings will be used to cross watercourses that do not have defined banks and can be installed by the mainline construction team. This technique does not typically require additional temporary workspace at the crossing site because no sag bends or over-bends are required, and the minimum cover is typically 0.9 m, thus minimizing surface disturbance impacts.

Designed open cut crossings will be used to cross watercourses with defined banks, and will require additional temporary workspace at the crossing site for storage of additional grade and trench material.

2.10.2 Isolated Crossing Methods

Two types of isolated crossing methods are being considered:

- isolated using pumps, with or without dams; and
- isolated using dams and flumes.

Isolated techniques divert flow around or across the construction zone using pumps and flumes to allow ditch excavation, pipe installation and backfilling to occur away from flowing water. Isolated techniques are used for small or medium sized watercourses where there is fisheries habitat at the crossing location.

2.10.3 Bore

A bore installation involves the excavation of bell-holes on either side of the watercourse crossing to enable a boring machine to drill a horizontal path for the pipeline under the scour depth of the channel. Casing is sometimes used to stabilize the path prior to pulling the pipe through. A bored crossing is typically limited to 100 m in length and is dependent on soil conditions and suitable staging areas on either side of the channel. An alternative contingency crossing method is also identified in the event that the bore is determined to be not feasible, or is unsuccessful.

2.10.4 Horizontal Directional Drill

A horizontal directional drill (HDD) installation is constructed using highly specialized equipment to drill a long, deep path at least 1.5 m in diameter (for NPS 36 pipe) at a minimum depth of 10 m underneath the watercourse and pull the welded pipe string back through. This method can be used for large watercourse crossings, but depends on the type of substrate and topography of the valley. However, an HDD for NPS 36 pipe cannot generally be shorter than 600 m because of the need to limit combined bending and axial stress during pipe string pulling and during pipeline operation. It also should not be longer than about 1,500 m because of the increased risks from greater lengths during drilling, reaming and pipe installation. The pipeline right-of-way can approach a watercourse at far shallower angles than 90 degrees resulting in the need for the pipe string to be located on a false right-of-way at close to 90 degrees to the watercourse. Timing is also an important consideration for longer drills, because the window for completing an HDD crossing may be limited in a winter construction season. Extensive geotechnical investigations are required to determine the feasibility of an HDD at the selected watercourse crossing. A contingency open cut crossing plan will also be developed for use if the HDD method is determined to be not feasible, or is unsuccessful.

2.10.5 Micro-tunnelling

Micro-tunnelling for an NPS 36 pipeline that uses the carrier pipe itself is presently limited to a maximum feasible length of about 400 m. Micro-tunnelling will be considered for watercourse crossings where an HDD crossing is not feasible and where fisheries and other considerations preclude a trenched crossing. A micro-tunnel is constructed using a highly specialized boring machine that is remotely controlled, steerable and uses slurry, auger, or vacuum spoil removal to install the pipeline.

2.10.6 Tunnelling

Tunnels are typically constructed using tunnel boring machines, drill and blast methods, or a combination of both. Tunnel support needs will depend on the quality of the rock encountered during construction and will typically vary from localized rock bolts, in locations with good rock quality, to heavy ground support (consisting of pattern bolting with steel sets and shot-crete lining or precast concrete panels) in sections with poor rock quality.

2.10.7 Aerial

An aerial crossing requires construction of a bridge or a supporting structure to carry the pipe over the watercourse. It is preferred at crossings where other methods are not feasible due to geological and topographic conditions such as at steep, narrow ravines.

2.11 Watercourse Crossing Method Selection

To facilitate the watercourse crossing selection process, a fish and fish habitat Risk Management Framework (RMF) was developed. The RMF is a refinement of the framework proposed by DFO in the Practitioners Guide to the Risk Management Framework for the DFO Habitat Management Staff, Version 1.0 (DFO 2013). The RMF borrows from the methods described in the Pipeline Associated Watercourse Crossings Guidelines, 3rd Edition (2005) by the Canadian Association of Petroleum Producers (CAPP), and refines them by using the specific biophysical features of each watercourse to determine the sensitivity of the habitat and the proposed construction methods in order to establish the scale of negative effects. This allows the risk associated with each crossing to be categorized after consideration of the site-specific crossing methods and incorporation of standardized and project-specific mitigation measures.

The RMF is designed as an iterative process for locating crossings, revising crossing techniques and modifying mitigation measures. This approach fulfils the locate, redesign and mitigate requirements of the DFO Policy for the Management of Fish Habitat, 1986. The residual risk can then be managed through additional mitigation (*e.g.*, best practices) where appropriate and possible, or habitat compensation if a harmful alteration, disruption or destruction of fish habitat occurs.

As a component of the RMF, the fish and fish habitat sensitivity was a key parameter in the crossing method selection process at each pipeline watercourse crossing. The sensitivity of each watercourse is provided in the Fisheries Alberta and BC Technical Report(s) in Volume 5C. The crossing method selection process was conducted in two stages, an initial screening process and a further crossing review.

2.11.1 Stage 1: Initial Screening Process

The first stage, an initial screening process, determines if a crossing method can be selected or if a more detailed Stage 2 crossing review is required. A Stage 2 crossing review is required if a watercourse meets either of the following threshold conditions:

- high fish and fish habitat sensitivity and flow rate of greater than 1.5 m^3/s anticipated at the time of construction and/or channel width greater than 10 m; or
- significant engineering or constructability issue.

The decision flowchart for this initial screening process is illustrated in Figure 5.1.1 in Appendix B.

The proposed crossing methods for watercourses that do not meet these threshold conditions is either open cut, where watercourses are dry or frozen to the bottom at the time of construction, or isolation, if flowing at the anticipated time of construction.

A watercourse is defined as having bed and banks that are continuous for a minimum of 100 m. Of the 468 watercourse crossings meeting this definition, 384 of the crossings were classified as Stage 1 crossings. Potential watercourses investigated that were found to not meet this definition (*i.e.*, did not have defined bed and banks of at least 100 m) were typically classified as non-classified drainage (NCD), no visible channel (NVC), wetland, or swamp (*i.e.*, bodies of standing water or wet ground, with or without wetland characteristics, respectively).

2.11.2 Stage 2: Review Crossings

Watercourses for which a crossing method is not selected in the Stage 1 initial screening phase require a detailed Stage 2 crossing review. Stage 2 of the crossing method selection process encompassed a detailed crossing review of the remaining 84 of the 468 defined watercourse crossings. The review of these crossings included assessments in the following areas:

- environmental;
- geotechnical;
- hydrotechnical;
- constructability;
- schedule; and
- construction timing.

The decision flowchart for the review crossings is illustrated in Figure 5.1.2 in Appendix B. The proposed crossing method for each of these review crossings was initially determined using the following general criteria:

- is a trenched crossing method feasible (*i.e.,* open cut if the watercourse is dry, frozen to the bottom, or isolated) where there is a history of previous successful trenched crossings without significant environmental impacts;
- HDD crossings are preferred for large watercourses (with widths greater than 100 m) that have high fisheries sensitivity;
- bore crossings are preferred for medium-sized watercourses (with widths between 10 m and 100 m) with flow greater than 8 m^3/s during construction that have high fisheries sensitivity;
- isolation methods are preferred for smaller crossings (with widths of less than 10 m and flow of less than 3 m^3/s during construction); and
- aerial crossings should be considered for ravine type watercourses where topography and geological constraints make other crossing methods very difficult.

Proposed trenchless crossings will have an isolated crossing method as a contingency or an open cut crossing method as an alternative contingency.

Due to the higher risks associated with trenchless methods, proposed HDD and bore crossings will be subject to detailed engineering analyses to confirm technical feasibility (geotechnical, constructability, access, cost, schedule), which could result in some of the proposed crossing methods to be changed to the contingency crossing methods.

The proposed crossing method for each Stage 2 review crossing will be further refined by taking into account the results of the fish and fish habitat RMF, as well as additional studies, fieldwork, regulatory discussions and consultations. At all trenchless crossings, a contingency crossing method and the timing of construction will also be identified.

The preliminary watercourse Stage 2 review crossings are as specified in Table 5.1.5 in Appendix D.

The final crossing methods and timing for all review crossings will be finalized during the detailed engineering and design phase.

2.12 Potential Application of Horizontal Directional Drill Method

2.12.1 Horizontal Directional Drill Feasibility Studies

The 84 watercourse crossings on the proposed TMPL Line 2 pipeline route listed in Table 5.1.5 were evaluated further for the technical feasibility of using an HDD installation technique. The preliminary geotechnical investigations were limited to locations with existing clear access. At those locations where permits were received, one or two boreholes were drilled and soil samples collected. In addition, a geophysical program comprised of ground penetrating radar and/or electrical resistivity tomography surveys were also completed along both approaches for about half of the crossings evaluated.

The HDD feasibility assessments for the watercourses where geotechnical borehole and geophysical programs have been completed up to November 2013 are presently in preparation and will be submitted in second quarter 2014. Additional geotechnical and geophysical investigations will be carried out during the detailed engineering and design phase.

2.12.1.1 Potential Horizontal Directional Drill Watercourse Crossings

Early assessments indicate that the application of the HDD crossing technique may be feasible for 21 major watercourses on the proposed route, as specified in Table 5.1.6 in Appendix D.

All HDD watercourse crossings will be conducted in accordance with an HDD Specification to be developed during the detailed engineering and design phase.

Preliminary HDD watercourse crossing drawings are provided in Appendix G.

2.12.1.2 Horizontal Directional Drill Contingency Crossing Method

Concurrent with the field investigations and in advance of finalizing an HDD as the crossing method to be utilized, an isolated or open-cut watercourse crossing methodology and design will be developed for each crossing.

If, after attempting an HDD crossing during construction, it is determined that installing the pipeline successfully (without damage or in a timely manner) is unlikely due to unexpected ground conditions or other reasons, the contingency crossing methodology identified in Table 5.1.6 in Appendix D will be implemented.

2.13 Tunnels

The need for construction of tunnels will be determined during the detailed engineering and design phase and the type, and extent of the tunnel support systems required will be determined during detailed design and construction.

3.0 PIPELINE SYSTEM ENGINEERING AND DESIGN

3.1 Hydraulic Design

3.1.1 Fluid Type and Composition

A larger volume of the wide slate of crude oil types presently shipped through the existing TMPL system will be transported through the TMEP pipelines. Table 5.1.7 in Appendix D provides information regarding the physical characteristics and components of the various crude oil types to be transported.

While a few isolated instances of localized internal corrosion have been identified, the existing pipeline has not experienced systemic internal corrosion caused by the crude oil types currently being transported. The products proposed to be transported in the existing active, reactivated, and new pipeline segments are very similar to those currently being transported. These products do not contain any substances in the concentrations required to promote internal corrosion. Therefore, TMEP is not considered to increase the risk of internal corrosion.

3.1.2 Hydraulic Analyses

Single-phase steady state pipeline hydraulic analyses were undertaken to evaluate the hydraulic characteristics of the TMEP pipeline systems. These analyses considered a wide range of pipeline diameters and design pressures in order to optimize the size of the new pipeline segments, the number and location of pump stations, and the size of the pumps. This iterative approach was undertaken to achieve the lowest combination of capital and operating costs per barrel transported. New pump stations were identified to provide the required flow rates and the associated pressure profiles for the various crude oil types and refined products that will be transported.

A transient analysis will be performed during the detailed engineering and design phase to further evaluate the specific operational conditions anticipated.

3.1.3 System Capacity

Line 1 has been designed so that it will have a sustainable annual average pipeline capacity of approximately 55,640 m^3/d (350,000 bbl/d), based on an assumed slate of light crude oils and refined products. Line 1 will also be capable of transporting heavy crude oil at a reduced capacity.

Line 2 has been designed so that it will have a sustainable annual average pipeline capacity of approximately 85,850 m^3/d (540,000 bbl/d), based on an assumed slate of heavy crude oils. Line 2 will also be capable of transporting light crude oils, if necessary.

Line 1 and Line 2 combined will be able to provide a batched transportation service for a variety of crude oil types and products, with a combined sustainable annual average capacity of approximately 141,500 m^3/d (890,000 bbl/d). The peak (instantaneous or design) capacities of the pipelines will be higher than the sustainable capacities to allow for planned shutdowns for maintenance, unplanned shutdowns caused by equipment or power failures, operational flexibility (*i.e.,* timing of deliveries), and hydraulic calculation uncertainty. Typically, for pipeline systems, the factor (often called the “availability factor”) used to establish peak capacity is 0.95 (*i.e.*, the peak capacity will be 1.053 times the required sustainable capacity). The availability factor for TMEP has been selected as 0.95 for preliminary design purposes but may be revised during the detailed engineering and design phase, after consideration of a number of reliability and operating parameters. In the final design, the availability factors are not expected to be less than 0.90 for either pipeline.

3.1.4 Crude Oil Properties

The proposed Line 2 pipeline will transport a variety of low vapour pressure (LVP) crude oil types, as indicated in Section 3.1.1. The Line 2 pipeline will be operated as a batched pipeline, and therefore the hydraulic analyses assumed that the crude oils with the highest viscosity, those in the diluted bitumen family, will govern the flow rate in the pipeline.

3.1.5 Hydraulic Design Results

For Line 2, using a design flow rate of 90,370 m^3/d (568,400 bbl/d), based on an initial availability factor of 0.95, a 914 mm OD (NPS 36) pipeline with 11 new pump stations, 10 at existing pump station sites and 1 at a new site at Black Pines, BC, was selected as the optimum configuration.

For Line 1, using a design flow rate of 58,570 m^3/d (368,400 bbl/d), based on an initial availability factor of 0.95, Niton Pump Station will need to be reactivated, DRA injection will be required at Jasper, and one new pump station will be required at a new site at Black Pines.

The hydraulic analyses also determined that the existing Albreda, Stump, Hope, and Wahleach Pump Stations (all in BC) will not be required for regular operation of Line 1 or Line 2. These stations will be deactivated unless reliability studies undertaken during the detailed engineering and design phase indicate that their continued availability is beneficial. Should it be determined that deactivation of these pump stations is appropriate, a separate application for deactivation will made.

Table 3.3.4 provides a summary of the planned changes to pump stations and pump units at each pump station on the TMPL system.

3.1.6 Non-hydrocarbon Products

The expanded TMPL pipeline system will carry only crude oils and refined petroleum products.

3.2 Pipeline System Design

3.2.1 Pipeline System Classification

Due to the nature of the crude oil types and refined petroleum products to be transported, the expanded TMPL system will continue to be classified as a LVP pipeline system as defined in CSA Standard Z662-11, Oil and Gas Pipeline Systems (CSA Z662). Therefore, pipeline design, materials, welding, fabrication, non-destructive testing, and hydrostatic pressure testing for the new pipeline segments will conform to the requirements of CSA Z662 for LVP liquids and to the requirements of all applicable codes, standards, specifications, and recommended practices that are incorporated by reference in CSA Z662. In addition, the reactivated pipeline segments will be hydrostatically pressure tested in accordance with CSA Z662.

3.2.2 Design Inputs

Design inputs and requirements will be identified, documented, and their selection reviewed by Trans Mountain for adequacy. Incomplete, ambiguous, or conflicting design requirements will be resolved with those responsible for imposing the requirements, where possible. Otherwise sound engineering judgement will be applied.

3.2.3 Hazards and Operability Reviews

Formal Hazards and Operability (HAZOP) reviews of the various elements of the pipeline system, following established and accepted practices, will be completed during the detailed engineering and design phase. Design changes recommended in the HAZOP reports will be incorporated, as appropriate.

3.2.4 Constructability Assessments

The design of the pipeline system will be subject to constructability assessments during the detailed engineering and design phase and appropriate revisions to improve constructability will be incorporated.

3.2.5 Design Verification

Design verification reviews of the various elements of the pipeline systems will be undertaken near completion of the detailed engineering and design phase. The reviews will verify that the designs are being carried out in accordance with the design inputs and the applicable regulations, codes, standards, specifications, and recommended practices. The design verification process will include review of the engineering design calculations, documents, and drawings. The design verification results will be documented.

3.2.6 Design Changes

All proposed design changes will be documented in accordance with management of change procedures to be developed during the detailed engineering and design phase, prior to implementation.

3.2.7 Stress Analyses

During the detailed engineering and design phase, stress analyses will be carried out on the pipeline to comply with CSA Z662 and sound engineering practices. The sites and locations of most significance will include mainline block valve and sending/receiving trap sites, seismic locations, potential unstable soil slopes, tie-ins, and muskeg locations. Pipe stresses will be analyzed and will consider hoop stress, thermal expansion, combined axial and bending forces, bends (field and induction), pipe lowering-in, wheel loading of road, highway and railway crossings, soil restraint conditions, and soil induced pipeline displacements. Mitigation will involve a combination of increased pipe wall thickness, minimizing, where possible, critical bend angles and radii, anchoring, modifying crossing designs, strain-based design considerations, and if necessary, adjusting the pipeline alignment.

3.2.8 Pipe Material, Grade, and Category

Pipe for TMEP, including line pipe and heavy-wall pipe (but excluding facilities pipe), will be made of low carbon, high strength, low alloy, Grade 483 steel with a minimum temperature rating of -5°C for below grade pipe and -45°C for above grade pipe.

The NPS 36 and NPS 30 pipe will be manufactured in accordance with CSA Z245.1, Steel Pipe and KMC Standard MP2120 Main Line Pipe Material Requirements (Mill Run Quantities), as refined during the detailed engineering and design phase. All mainline pipe will be manufactured using standard manufacturing procedures for longitudinal and/or helical seam (spiral) submerged arc welded pipe with controlled rolling practices utilized to improve strength, ductility, weld-ability and toughness properties.

For LVP pipelines, CSA Z662 specifies that pipe, as a minimum, must comply with requirements for Category I (Cat I). However, TMEP will specify pipe that meets the stricter criteria of Category II (Cat II) in order to maximize fracture initiation resistance and ensure premium product quality. As such, all pipe material to be installed below grade for the proposed Line 2 pipeline will be Cat II pipe and all pipe material to be installed above grade will be Category III (Cat III) pipe.

For the two reactivated sections of the TMPL Line 1 pipeline, some additional NPS 24 pipe will be required for reconnecting and for any required repairs. This pipe will have specifications similar to the NPS 30 and NPS 36 pipe except the yield strength will be adjusted to be a closer match to the existing Grade 359 pipe and the pipe manufacturing process is likely to be electric welded.

3.2.9 Class Locations

The Line 2 pipeline has been classified as an LVP pipeline and, therefore, the location factor specified in Table 4.2 of CSA Z662 for all Class Locations is constant at 1.0, except for uncased railway crossings where a location factor of 0.625 is required. Therefore, from a pipeline design perspective, delineation of the pipeline route into Class Locations is not required.

A risk assessment as described in Volume 7, Section 3.1 is ongoing and will identify where risk mitigation is required. This may be achieved, in part, through assigning the equivalent of Location Factors at specific locations.

3.2.10 *Maximum Design and Operating Pressure*

New pipeline segments will be hydrostatically tested in accordance with CSA Z662 to provide a point-to-point maximum operating pressure (MOP) that is expected to vary between 6,000 and 10,000 kPa. The higher MOP values will generally occur at the low points and the lower MOP values will occur at the high points.

The existing 151 km of NPS 36 pipeline segment from Hinton, AB to Hargreaves, BC that will become part of the Line 2 pipeline is already licenced to operate at 9,930 kPa with a short section at 10,875 kPa.

The existing 43 km of NPS 30 pipeline between Darfield, BC and Black Pines, BC that will become part of Line 2 has variable wall thickness resulting in design pressure ranging between 7,460 kPa and 10,480 kPa. This segment was hydrostatically tested in 2004 in two test sections in accordance with CSA Z662 to provide a point-to-point MOP that varies between 3,659 kPa and 8,223 kPa. The higher MOP values generally occur at the low points and the lower MOP values generally occur at the high points.

The two segments of the deactivated NPS 24 pipeline, between Hinton and Hargreaves and Darfield and Black Pines, that will be reactivated and become part of Line 1, will be hydrostatically tested to a maximum stress level of 100 per cent of the specified minimum yield strength (SMYS). These segments will also have a point-to-point MOP, which will vary and which will be set at 80 per cent of the test pressure at each point.

3.2.11 Design Temperatures

For the Line 2 pipeline, the maximum design temperature will be 50°C, the minimum design temperature below grade will be -5°C and the minimum design temperature above grade will be -45°C.

3.2.12 Pipe Wall Thicknesses

The formula in Clause 4.3.5.1 of CSA Z662 will be used to determine the minimum wall thickness of the line pipe used for the Line 2 pipeline.

The line pipe wall thickness will be selected in accordance with a maximum design stress level of 80 per cent of the SMYS. A risk assessment will be undertaken and it is expected that heavier wall pipe will be specified at specific locations, such as at highway and road crossings, larger watercourse crossings, and for some areas designated as high consequence areas (HCAs).

The wall thickness at the proposed HDD crossings will be determined through stress analysis to comply with maximum stresses allowed for in CSA Z662.

The NPS 36 line pipe will have a minimum pipe wall thickness of 11.8 mm and the NPS 30 line pipe will have a minimum pipe wall thickness of 9.8 mm. Table 5.1.8 in Appendix D outlines the preliminary pipe wall thicknesses for the various applications that are to be utilized in constructing the TMEP Line 2 pipeline and the Burnaby to Westridge Marine Terminal pipelines.

3.2.13 Pipe Lengths

Table 5.1.9 in Appendix D summarizes the estimated pipe lengths for the preliminary pipe wall thicknesses along the Line 2 pipeline route. Typically the average pipe joint length will be 24 m long in cross-country situations while in some urban areas and other restricted access sections along the pipeline route, pipe lengths could be reduced to 18 m or 12 m.

3.2.14 Joining Program

3.2.14.1 Welding of Line Pipe

All welding and repair welding will be performed in accordance with approved welding specifications, welding procedures, welding procedure qualification tests, and non-destructive testing specifications that will be specifically developed for the selected pipe materials and welding consumables. Actual samples of project pipe will be used to qualify welding procedures and welders.

Production welding of the pipeline will be performed by a combination of manual and mechanized methods in accordance with a Shielded Metal Arc Welding (SMAW), a Flux Core Arc Welding (FCAW), and a Mechanized Welding Specifications that will be developed during the detailed engineering and design phase. Welding procedures for both girth welds and repair welding will be provided by the contractor and approved for use, in advance, by Trans Mountain.

For tie-ins, a low hydrogen manual SMAW procedure and/or semi-automatic FCAW procedure will be used. The NDT of all tie-in welds will be delayed for 18 hours following weld completion.

All welds and weld repairs will be examined in accordance with a Non-destructive Testing Specification, which will be developed during the detailed engineering and design phase. Weld repairs will typically be done using a low hydrogen SMAW procedure.

3.2.14.2 Welding of Fabricated Assemblies

Welding of fabricated assemblies will be carried out in accordance with a Fabrication Welding Specification which will be developed during the detailed engineering and design phase.

Welding procedures for fabricated assemblies shall be provided by the contractor and approved for use, in advance, by Trans Mountain.

3.2.14.3 Tie-in Welding and Required Carbon Equivalent

As part of the process to tie in the existing TMPL segments into the proposed Line 2 pipeline, welding will be necessary on the existing TMPL while it is liquid-filled. The carbon equivalent of the existing TMPL is typically less than 0.50 per cent but may be greater at the tie-in location. Appropriate metallurgical tests will be conducted prior to initiating the tie-in to ensure application of appropriate welding specifications and welding procedures. Trans Mountain is currently developing welding procedures for conditions where the pipeline is liquid-filled and the carbon equivalent is equal to, or less than 0.52 per cent.

The carbon equivalent of the new pipe material for TMEP will be specified to be lower than 0.40 per cent in accordance with Table 5 of CSA Z245.1.

3.2.15 Remote Mainline Block Valves

3.2.15.1 Remote Mainline Block Valve Locations

The proposed locations of RMLBVs, those MLBVs not located at pump stations, will initially be determined in accordance with CSA Z662, Clause 4.4, Valve Location and Spacing. To limit the consequences associated with a pipeline leak or rupture, the following additional factors will also be considered in selecting the proposed RMLBV locations: topography, the location of environmentally sensitive features and terrain, population density, accessibility of electrical power, maintenance flexibility, release volume analyses, release volume dispersion modelling, and the risks to HCAs.

Table 5.1.12 in Appendix D summarizes the preliminary locations of the proposed RMLBVs and check valves for the Line 2 pipeline. The proposed RMLBV and check valve locations for the Line 2 pipeline may be adjusted slightly to optimize functionality and minimize aesthetic impacts.

Table 5.1.11 in Appendix D summarize the new RMLBVs and check valves to be installed in the reactivated NPS 24 segments for Line 1. It also outlines the existing valves that will have actuators installed so they can be automated.

Final valve site locations will be established during the detailed engineering and design phase.

3.2.15.2 Remote Mainline Block Valve and Check Valve Design Features

All new RMLBVs will be ANSI Class 600, full-port, through conduit, slab gate type, of weld-end design and will be automated. Each gate valve assembly will have pipe risers on either side complete with isolation valves and provision for bypass piping.

All new RMLBVs will be installed below grade. Some elements of the RMLBV assemblies will rise above grade, including the stem (and possibly the bonnet), the actuator, the drain and emergency sealant injection piping, and the bypass piping.

Some RMLBV assemblies may include fittings for the installation of pipeline cleaning and in-line inspection tool detection instruments (“pig sigs”).

Check valves will be installed at suitable locations such as at the downstream side of major watercourse crossings (*e.g.,* rivers), where generally ascending topography is favourable for a check valve function. Check valves will be full-port, swing-type, and of weld–end design. Each check valve assembly will have pipe risers on either side complete with isolation valves and provision for bypass piping. Each check valve will also have a means of being manually operated.

All valves to be installed below grade will meet Cat II material requirements and will be rated for at least -5°C. All valves to be installed above grade (such as the bypass valves on the RMLBV assemblies) will meet Cat II material requirements and will be rated for -45°C. All valves will be suitable for the crude oil products to be transported, and will be designed, manufactured and installed in accordance with the requirements of CSA Z245.15, Steel Valves or American Petroleum Institute (API) Specification 6D, Pipeline Valves or API Specification 6H, End Closures, Connectors, and Swivels, where applicable, and in accordance with KMC Standard MP1300 Valve Selection and Specification and its referenced standards.

3.2.15.3 Valve Actuators

The majority of the RMLBVs in Line 2 and some of the RMLBVs in the Line 1 sections that will be reactivated will be remotely operable using the Supervisory Control and Data Acquisition (SCADA) system. The actuators will be electric or will be powered by an alternate method, such as pressurized nitrogen. Additional information on RMLBV sites and automation can be found in Section 3.5.2.

3.2.16 Fittings and Flanges

3.2.16.1 Below Grade Fittings and Flanges

All fittings and flanges to be installed below grade will be rated for -5°C, be suitable for the crude oil products to be transported, and be designed and manufactured in accordance with the requirements of CSA Z245.11, Steel Fittings (Cat II) and CSA Z245.12, Steel Flanges (Cat II), respectively and in accordance with the KMC 2000 series standards and specifications.

3.2.16.2 Above Grade Fittings and Flanges

All fittings and flanges to be installed above grade will be rated for -45°C, be suitable for the crude oil products to be transported, and be designed and manufactured in accordance with the requirements of CSA Z245.11, Steel Fittings (Cat II) and CSA Z245.12, Steel Flanges (Cat II), respectively and in accordance with the KMC 2000 series standards and specifications.

3.2.17 Depths of Cover

The depths of cover for the Line 2 pipeline will be a minimum of 0.9 m in mineral soil and 0.6 m in rock. Additional cover will be required at road crossings, watercourse crossings, railway crossings and other locations as conditions require. The depths of cover in these circumstances will be the greatest of:

- that specified in CSA Z662, Clause 4.11, Cover and Clearance;
- that specified in the crossing agreements and applicable regulations of other authorities; or
- that (additional cover) which may be established during the detailed engineering and design phase.

Table 5.1.13 in Appendix D identifies typical surface structures or features and the respective minimum depths of cover required. The minimum depth of cover may be reduced where excavation or boring through rock is required.

Additional detail on minimum cover at crossings is provided in the typical drawings included in Appendix C.

3.2.18 Clearance Between Adjacent Facilities

In accordance with CSA Z662, Clause 4.11, Cover and Clearance, a minimum clearance of 0.3 m will apply to the crossing of existing buried facilities such as foreign pipelines, buried electrical cables, fibre optic cables, and utilities (water and sewer pipes).

In urban areas a minimum clearance of 0.7 m will apply, where practical, and a precast slab will be installed between the new TMEP pipeline and the adjacent facility. A Typical Foreign Pipeline Crossing drawing is included in Appendix C.

3.2.19 Parallel Facilities

In accordance with CSA Z662, Clause 4.11, Cover and Clearance, the clearance between the new TMEP pipeline and any other parallel pipeline, cable or other utility will not be less than 1.0 m, regardless of who owns the other facility.

Typically, the TMEP Line 2 pipeline centreline will be offset from the existing TMPL pipeline centreline, in areas where these pipelines will be parallel, by a minimum of 5 m, except at locations of extreme congestion where the separation may be decreased on a case-by-case basis.

3.2.20 Crossings

Crossings of watercourses, wetlands, drainage ditches, pipelines, highways, roads, railways, municipal water and sewer lines, communications, power cables, and foreign utilities will be individually assessed in order to determine the most appropriate crossing method and design for each location.

3.2.20.1 Watercourse Crossings

Watercourses encountered along the pipeline route include major rivers, streams, wetlands, extensive floodplains, and intermittent drainage channels. To promote a consistent approach to pipeline watercourse crossings throughout Canada and to aid in developing a common understanding between industry, regulators and other stakeholders, a CAPP/ Canadian Energy Pipeline Association/Canadian Gas Association (CGA) document, Pipeline Associated Watercourse Crossings Guidelines, 3rd Edition (Canadian Association of Petroleum Producers, Canadian Energy Pipeline Association and Canadian Gas Association 2005), was refined and this document will be used to assess, plan, construct, operate and maintain the pipeline associated watercourse crossings. Tables 5.1.5 and 5.1.6 in Appendix D provide preliminary lists of the watercourse crossings that will be encountered along the pipeline route.

All watercourse crossings will have either a site-specific engineered crossing design that will address geotechnical, fisheries, navigability, and water quality issues or will make reference to a generic typical watercourse crossing design. Induction bends, buoyancy control and extra cover will be incorporated as needed to achieve an appropriate design.

Detailed crossing design drawings will be prepared during the detailed engineering and design phase and will incorporate the requirements specified in each crossing permit.

3.2.20.2 Highway, Road, and Railway Crossings

For highway, high-use gravel roads and railways, the preferred crossing method is a bore crossing method (*i.e.*, thrust or auger). Low-use gravel roads, minor roads and trails will typically be specified as conventional open cut crossings.

For hammer-bore or auger-bore crossing techniques, an uncased crossing is preferred. However, contingency designs will be provided for NPS 42 and NPS 48 cased crossings in the event that significant cobbles or boulders are encountered during construction that would prevent the successful completion of an uncased crossing.

During the installation of these crossings, provincial, municipal or railway authorities may specify traffic and general safety controls to be implemented.

Table 5.1.14 in Appendix D provides a preliminary list of the highway, road and railway crossings along the pipeline route.

3.2.20.3 Foreign Pipeline, Overhead Power Line, Buried Cable and Utility Crossings

Tables 5.1.15, 5.1.16 and 5.1.17 in Appendix D provide preliminary lists of the foreign pipeline, overhead power line, buried cable and utility crossings along the pipeline route.

3.2.21 Corrosion Control

3.2.21.1 General

Corrosion on the pipelines will be prevented through a combination of external pipe coatings and an impressed current cathodic protection (CP) system.

3.2.21.2 Coatings

The external factory-applied coating for the linepipe will generally be fusion bond epoxy (FBE), in accordance with CSA Z245.20, Plant-applied External Coatings for Steel Pipe, and KMC Standard GC3105, External Fusion Bond Epoxy Coating.

Where additional mechanical protection is needed (*e.g.*, at bored crossings, in rocky terrain, and at HDD watercourse crossings), special factory-applied coating protection products (*e.g.*, dual-layer FBE, urethane, commonly known as abrasion resistant overcoat [ARO], in accordance with GC3105, or three-layer polyethylene, in accordance with CSA Z245.20 and supplementary specifications to be developed during the detailed engineering and design phase), will be utilized. In some situations the use of select backfill materials or other suitable mechanical damage protection may also be a viable option to ARO or multi-layer coating, and will be used where practical to do so.

Above grade installations, such as RMLBV stems, actuators, and bypasses will be painted in accordance with KMC Standard GC3101 External Coating of Piping, Components, and Structural Steel.

Below grade installations that cannot be FBE coated, including induction bends and RMLBV assemblies, will be coated with a spray grade epoxy or epoxy/urethane in accordance with a

Two-part Spray Applied Coating Specification which will be developed during the detailed engineering and design phase.

Field girth welds will be coated in accordance with a Two-part Girth Weld Coating Specification which will be developed during the detailed engineering and design phase. Three-layer coated pipes will be coated with a two-part coating plus a polyethylene shrink sleeve in accordance with a Girth Weld Shrink Sleeve Specification, which will be developed during the detailed engineering and design phase.

Coating of exothermic welds will be carried out in accordance with an Exothermic Weld (Cadweld) Coating Specification, which will be developed during the detailed engineering and design phase.

All coating systems will be applied by qualified and approved applicators.

The pipeline will not be coated internally.

Table 5.1.18 in Appendix D summarizes the estimated length of pipe for each primary coating type that will potentially be used along the pipeline route.

3.2.21.3 Cathodic Protection System

Cathodic protection will be used as a secondary corrosion control measure for the pipeline. CP will be applied by impressed current ground-beds located along the pipeline. The final number, types and specific site locations of ground-beds and rectifiers will be determined during the detailed engineering and design phase of the Project.

The CP system will be common to both the Line 1 and Line 2 pipelines. Some modifications and additions to the existing CP ground-beds will be required.

Test stations will be attached to the Line 2 pipeline at locations approximating those on the existing pipeline, as well as at other locations, as needed. If practical, test station spacing will be kept to a maximum of 5 km.

The CP system for the pipeline will be designed and installed in accordance with the applicable codes and regulations and KMC's engineering standards and specifications. Ongoing CP monitoring will be in accordance with CSA Z662 and CGA Recommended Practice OCC-1-2013, Recommended Practice for the Control of External Corrosion on Buried or Submerged Metallic Piping Systems. Where segments of the pipeline will be in proximity to, or parallel to, AC power lines, the design will be in accordance with CSA Z662 and CSA/CAN-C22.3 No. 6: Principles and Practices of Electrical Coordination Between Pipelines and Electric Supply Lines. The CP system will be designed to connect to the local power grid.

Where Line 1 and Line 2 pipelines share a common right-of-way, the pipelines will be made electrically continuous through continuity bonding. The continuity bonding will be provided by multiple negative cables at the CP ground-bed locations, plus at other intermediate bond locations, as deemed necessary.

Test stations for long-term monitoring of CP levels, in accordance with CSA Z662, will be installed at appropriate intervals along the pipeline to confirm the effectiveness of the applied CP current and permit pipeline access for other corrosion control monitoring activities. Test stations will also be installed at cased road and railway crossings, if present, and at other existing pipeline crossings, as necessary.

The pipelines will be electrically isolated from the pump stations so that the available pipeline CP current remains with the pipelines. Monolithic (weld-in type) isolators will be installed where the pipelines enter and exit the pump stations. Standard flange insulation kits will be employed to isolate drain lines or other piping that may bypass the monolithic isolators on the pipeline.

3.3 Facilities Design - Pump Stations

3.3.1 Overview

The TMPL currently has 23 active pump stations, as listed in Table 3.3.1.

TABLE 3.3.1

ACTIVE PUMP STATIONS ON TMPL

Number	Pump Station	Number	Pump Station
1.	Edmonton	12.	Blue River
2.	Stony Plain	13.	Finn
3.	Gainford	14.	McMurphy
4.	Chip	15.	Blackpool
*NRH	Niton	16.	Darfield
5.	Wolf	17.	Kamloops
6.	Edson	18.	Stump
7.	Hinton	19.	Kingsvale
8.	Jasper	20.	Hope
9.	Rearguard	21.	Wahleach
10.	Albreda	22.	Sumas
11.	Chappel	23.	Port Kells

Note: *Not required hydraulically; currently deactivated.

The scope of the pump station work for TMEP will include the following:

- 11 new Line 2 pump stations including 1 at a new site at Black Pines, BC, and 2 (Wolf and Blue River) which will replace the existing pump stations, utilizing the existing electrical infrastructure;
- 1 new Line 1 pump station at Black Pines, BC;
- re-activation of the de-activated pump station at Niton, AB, for Line 1 operation; and
- addition of a unit to the Sumas Pump Station to support increased volumes to the Puget Sound system.

After completion of TMEP, Line 1 will have 19 active pump stations as listed in Table 3.3.2.

TABLE 3.3.2

LINE 1 PUMP STATIONS AFTER TMEP

Number	Pump Station	Number	Pump Station
1.	Edmonton	12.	McMurphy
2.	Stony Plain	13.	Blackpool
3.	Gainford	14.	Darfield
4.	Chip	15.	**Black Pines
5.	Niton	16.	Kamloops
6.	Edson	NRH*	Stump
7.	Hinton	17.	Kingsvale
8.	Jasper	NRH*	Hope
9.	Rearguard	NRH*	Wahleach
NRH*	Albreda	18.	Sumas
10.	Chappel	19.	Port Kells
11.	Finn		

Notes: *Not required hydraulically; however, may be kept in service for reliability.

**Black Pines will be at a new site.

The existing pump stations at Albreda, Stump, Hope, and Wahleach are not hydraulically required and will be idle under normal operating scenarios. However, a reliability study will be completed during the detailed engineering and design phase to determine if the continued availability of these pump stations will improve the reliability of the system. If not, a future application may be filed for their formal deactivation.

After completion of TMEP, Line 2 will have 11 active pump stations as listed in Table 3.3.3.

TABLE 3.3.3

LINE 2 PUMP STATIONS AFTER TMEP

Number	Pump Station
1.	Edmonton
2.	Gainford
3.	Wolf
4.	Edson
5.	Hinton
6.	Rearguard
7.	Blue River
8.	Blackpool
9.	*Black Pines
10.	Kamloops
11.	Kingsvale

Note: *Black Pines will be at a new site.

Of the 12 new pump stations, all but two will be co-located with existing pump stations. All of the new pump stations at existing sites will be constructed entirely on Trans Mountain owned land except for the Hinton and Rearguard, which will require some additional adjacent land. The

Line 1 and Line 2 pump stations at Black Pines will be constructed on a new common site. Final determination of the location of this site will be made during the detailed engineering and design phase, based on hydraulic optimization, and geotechnical and environmental considerations.

Fundamental to a design having multiple pump stations on common sites is the need to ensure outages impacting one pump station do not impact operation of the second pump station. Infrastructure provided by utilities such as power and communications will be common to both pump stations. Emergency shut down (ESD) systems and other protective devices common to the site will also be common to both pump stations. All other dedicated pump station functions will operate independently.

The new Line 2 Wolf and Blue River pump stations will utilize electrical and control infrastructure from the existing pump stations which will not be required on Line 1.

Several modifications to existing pump stations will be required, including re-connecting the existing pump station at Jasper, AB, to Line 1 and adding the capability for DRA injection.

Table 3.3.4 summarizes the planned mainline pumping units for the TMPL system, after TMEP. This table will be updated during the detailed engineering and design phase.

TABLE 3.3.4

SUMMARY OF PUMPS AND MOTORS FOR LINE 1 AND LINE 2 AFTER TMEP

Pump Station	Line 1					Line 2				
	KP	Site Status	kW	# x HP		KP**	Site Status	kW	# x HP	
Edmonton	0.0	Existing	1,865	4 x 2,500	*	0.0	New	3,730	5 x 5,000	*
Stony Plain	49.5	Existing	3,730	2 x 5,000	*					
Gainford	99.4	Existing	1,492	3 x 2,000	*	117.4	New	3,730	3 x 5,000	
Chip	147.0	Existing	3,730	2 x 5,000	*					
Niton[1]	173.4	Reactivated	1,492	2 x 2,000						
Wolf[2]	188.0	Deactivated				206.1	New	3,730	2 x 5,000	
Edson	228.8	Existing	1,492	3 x 2,000	*	247.2	New	3,730	3 x 5,000	
Hinton	317.8	Existing	3,730	2 x 5,000		339.4	New	3,730	3 x 5,000	
Jasper[3]	369.5	Existing	1,865	2 x 2,500						
Rearguard	476.8	Existing	3,730	2 x 5,000		498.3	New	3,730	2 x 5,000	
Albreda4	519.1	Deactivated								
Chappel	555.5	Existing	3,730	2 x 5,000	*					
Blue River[2]	588.9	Deactivated				614.6	New	3,730	3 x 5,000	
Finn Creek	612.5	Existing	3,730	2 x 5,000	*					
McMurphy	645.0	Existing	1,492	2 x 2,000						
Blackpool	710.0	Existing	3,730	2 x 5,000		736.9	New	3,730	3 x 5,000	
Darfield	742.0	Existing	1,492	2 x 2,000						
Black Pines	784.8	New	1,865	2 x 2,500		811.8	New	3,730	2 x 5,000	
Kamloops	823.0	Existing	447.6	1 x 600		850.9	New	3,730	4 x 5,000	*
			1,492	4 x 2,000						
			1,865	2 x 2,500						
Stump[4]	862.7	Deactivated								
Kingsvale	924.9	Existing	1,865	3 x 2,500	*	955.5	New	3,730	2 x 5,000	
Hope[4]	1011.8	Deactivated								
Wahleach[4]	1045.9	Deactivated								
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 s pare unit retained for increased system reliability.

** Kilometre posts may differ from Line 1 to Line 2 because of route differences.

[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 m m (NPS 36) line to the 609.6 m m 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 US Puget Sound line will require additional horse power at Sumas.

All new pump stations will use variable frequency drives (VFDs) for starting and controlling the speed of the mainline motors. As a minimum, one VFD will be installed at all locations with the exception of Edmonton and Kamloops, which are deemed critical pump stations. Edmonton will have a second VFD installed as a back-up system. Hydraulic considerations require a dedicated VFD for each unit at Kamloops.

Initial discussions with BC Hydro suggest that additional VFDs, as many as one per pump unit, may be required in the North Thompson Area at both existing and new pump stations. The final configuration of VFDs will be established during the detailed engineering and design phase.

At existing pump stations, where new Line 2 pump stations are required, the operator buildings will be modified to house communications and control equipment common to both pipelines. Communications and control equipment previously located in the existing electrical service buildings (ESBs) will be relocated to the operator buildings. Minor revisions to the control infrastructure of the existing ESBs will be required to accommodate this change. The new pump station at Black Pines will have one new operator building installed for both pipelines.

New pump stations will be similar in design to the existing pump stations constructed in 2006 and 2007, for example at Chappel, BC (Figure 3.3.1).

Figure 3.3.1 Chappel Pump Station

Each pump station will include the following major components and will be contained within a fenced and gravelled site:

- electrical sub-station;
- ESB;

- operator building with lunchroom, washroom, emergency shower, communications, control, and human-machine interface (HMI);
- mainline pumps and motors;
- pump station piping and pump unit valves;
- VFD(s);
- Pump building with fire detection, combustible gas detection, containment and hydrocarbon detection;
- waste oil sump and re-injection system;
- site containment with hydrocarbon detection;
- sending and receiving traps, where required, with containment and hydrocarbon detection;
- an MLBV, a mainline check valve, and pump station suction and discharge valves;
- site security; and
- building security.

Noise levels will be at or below the location-specific permissible limits of the applicable regulations of the authorities having jurisdiction. Where necessary to meet these limits, pumps, blowers, and other noise emitting equipment will be placed in noise reduction enclosures or other noise reduction methods will be employed.

3.3.2 Maximum Operating Pressure

The MOP at Line 1 pump stations will be as prescribed in the existing Operating Limits and Protective Device Settings document.

The MOP at all Line 2 pump stations, including inlet and outlet piping, will be 9,930 kPa. The diameter of pump station piping will be 610 mm.

3.3.3 Civil

All soils design information required for the pump stations will be obtained by geotechnical consultants. Final design of all foundations will be based on the recommendations of the geotechnical consultants and the applicable provincial building code.

The overall physical boundaries of the land for each pump station will vary by location. For most existing pump station locations, the new pump stations will be located within the existing Trans Mountain property boundaries. It is anticipated that property extensions will be required at the Hinton and Rearguard pump stations.

The developed area required for new pump stations at existing pump station sites will be approximately 100 m × 100 m. Any previously undisturbed areas will be stripped of organic topsoil, which will be stockpiled. The new Black Pines Pump station will require a developed area of approximately 150 m × 150 m for both the Line 1 and Line 2 pump stations. The final layout and size of the pump station will be determined during the detailed engineering and design phase.

Storm-water and any leaked hydrocarbons from process areas will drain into a catchment area. Surface water that is contained in the catchment area will be observed for hydrocarbons prior to being released to local drainage courses. Any water containing hydrocarbons will be treated prior to release or disposed of. Hydrocarbon detection equipment will be installed at each pump station to allow early detection of a leak from process piping.

Site traffic areas will be finished with compacted crushed gravel over compacted pit run.

Sites will be enclosed by 1.8 m fencing topped with barbed wire. Emergency egress gates will be installed on each fence line. Substation fencing will conform to applicable installation codes.

3.3.4 Structural Steel

All structural and miscellaneous steel will be designed to withstand anticipated dead and superimposed loads. Design of all structural and miscellaneous steel will meet the requirements of the applicable provincial building code and CSA S16.

3.3.4.1 Platforms and Stairways

Platforms and stairways will be provided to the size and extent necessary to ensure safe access to all valves and monitoring equipment. The extent and size of platforms and stairways will be determined during the detailed engineering and design phase.

3.3.4.2 Pipe and Cable Tray Supports

Pipe and cable tray supports will be constructed of structural steel of sufficient size and spacing to support the anticipated loads and stresses. The exact size and location of supports will be determined during the detailed engineering and design phase.

3.3.5 Buildings

The pump building will be pre-fabricated in a shop and erected on-site. All other buildings will be pre-fabricated, preassembled on structural steel skids, and have any housed equipment installed and tested prior to delivery. Building designs will meet the requirements of local building codes (including climatic and seismic requirements).

3.3.5.1 Building Descriptions

Typical pump building dimensions will be approximately 24 m long × 16 m wide × 7 m high for two unit arrangements. Actual pump building sizes will be determined during the detailed engineering and design phase.

Each pump station will have a dedicated ESB. A typical ESB will be no larger than 17 m × 4.2 m × 4.2 m. Actual ESB sizes will be determined during detailed engineering and design phase. All man doors will be equipped with panic hardware, door closers, and wire-reinforced, double-glazed windows.

There will be a common operator building at each shared pump station site. At existing sites, the operator building will also serve the new pump stations. The HMI, programmable logic controller (PLC) equipment and voice and data communication equipment will be located in the operator buildings. The existing operator buildings may require minor modifications to house new equipment.

A typical operator building will be approximately 12 m × 4 m × 4 m. The operator buildings will be equipped with washroom facilities, including a self-contained water supply and sewer holding tank. Actual building size will be determined during the detailed engineering and design phase. Operator building exterior walls, trim, canopies and roof panels will be pre-painted to be consistent with existing buildings at existing sites.

Table 3.3.5 lists the proposed buildings for the new pump stations.

TABLE 3.3.5

PROPOSED BUILDINGS FOR NEW PUMP STATIONS

Pump Station	Building Description	Quantity	Size (m)
Edmonton	Pump Building	1	60 m × 16 m × 6.5 m
	ESB	1	14 m × 4.2 m × 4.2 m *
	VFD Building	2	8 m × 4.2 m × 4.2 m *
Gainford	Pump Building	1	36 m × 16 m × 6.5 m
	ESB	1	9 m × 4.2 m × 4.2 m *
	VFD Building	1	8 m × 4.2 m × 5 m *
Wolf	Pump Building	1	36 m × 16 m × 6.5 m
	ESB	NA	Use Existing
	VFD Building	NA	Use Existing
Edson	Pump Building	1	36 m × 16 m × 6.5 m
	ESB	1	9 m × 4.2 m × 4.2 m*
	VFD Building	1	8 m × 4.2 m × 4.2 m *
Hinton	Pump Building	1	36 m × 16 m × 6.5 m
	ESB	1	9 m × 4.2 m × 4.2 m*
	VFD Building	1	8 m × 4.2 m × 4.2 m *
Rearguard	Pump Building	1	23 m × 16 m × 6.5 m
	ESB	1	9 m × 4.2 m × 4.2 m*
	VFD Building	1	8 m × 4.2 m × 4.2 m *
Blue River	Pump Building	1	36 m × 16 m × 6.5 m
	ESB	NA	Use Existing
	VFD Building	NA	Use Existing
Blackpool	Pump Building	1	36 m × 16 m × 6.5 m
	ESB	1	9 m × 4.2 m × 4.2 m*
	VFD Building	1	8 m × 4.2 m × 4.2 m *
Black Pines	Pump Building	2	23 m × 16 m × 6.5 m
	ESB	2	9 m × 4.2 m × 4.2 m*
	VFD Building	2	8 m × 4.2 m × 4.2 m *
Kamloops	Operator Building	1	10 m × 4.2 m × 3.4 m
	Pump Building	1	48 m × 16 m × 6.5 m
	ESB	1	18 m × 6 m × 5 m*
	VFD Building	4	8.5 m × 4.2 m × 4.2 m*
Kingsvale	Pump Building	1	23 m × 16 m × 6.5 m
	ESB	1	9 m × 4.2 m × 4.2 m*
	VFD Building	1	8 m × 4.2 m × 4.2 m *

Note: *all building sizes will be finalized during the detailed engineering and design phase.

3.3.6 Pumps and Motors

Each pump station will utilize electrically driven centrifugal pumps, connected in series.

The number and horsepower of the pumps at each pump station was determined by hydraulic analysis and will be further refined during the detailed engineering and design phase.

It is anticipated that the pumps will be horizontal single stage, rated at PN 100 (9,930 kPa) on both the suction and discharge sides.

The pumps will have a leak detection system that will activate an alarm in the Control Center in the event of the failure of a mechanical seal.

3.3.7 Piping

Piping design, materials, welding, fabrication, non-destructive testing and pressure testing will conform to CSA Z662 for LVP liquids. Pump station piping design will incorporate the following features:

- optimized for equipment geometry, operating and maintenance accessibility, hydraulic efficiency, and space efficiency;
- above grade, where possible, with the exception of drain piping in certain cases;
- pipe stresses within allowable limits based on computational stress analysis; and
- designed in accordance with the parameters in Table 3.3.6.

TABLE 3.3.6

NEW PUMP STATION DESIGN CRITERIA

Item	Line 1	Line 2
Pipe Size	508 mm (NPS 20)	610 mm (NPS 24)
Design Pressure	9,930 kPa (1,440 psig)	9,930 kPa (1,440 psig)
Pressure Class	PN 100	PN 100
Minimum Design Temperature	-29°C	-29°C
Maximum Design Temperature	38°C	38°C
Material Grade	290 (MPa)	359 (MPa)

All stations will require isolation from the pipeline CP system. This will be accomplished with the use of insulating kits on the first flange pair entering the station and the last flange pair exiting the station. To ensure continuity in the CP system, a jumper will be installed on the pipeline upstream of the first isolation kit and connected to the pipeline downstream of the second isolation kit. CP will be provided for below grade piping at pump stations as required.

Thermal relief valves will be provided to protect piping and equipment connected to the pipe. In general, any section of pipe that can be isolated during operations or maintenance will have a thermal relief valve installed. The discharge from thermal relief valves will drain to the waste oil sump. The sump will also collect fluids from wetted pump seals, pipe, scraper trap, and equipment drains. Recovered hydrocarbons will be re-injected into the main line on the suction side of the pump station.

3.3.7.1 Materials

Pipe, fittings, and flanges will meet the requirements of CSA Z245.1 Steel Pipe, CSA Z245.11 Steel Fittings, CSA Z245.12 Steel Flanges and the KMC 2000 series standards and specifications. Valves will meet the requirements of CSA Z245.15 Steel Valves and KMC Standard MP1300 Valve Selection and Specification and its associated standards and specifications. Material grades and wall thicknesses will be determined in accordance with the applicable standards and specifications identified in Tables 5.1.1 and 5.1.2 in Appendix D, including MP1110 Station & Terminal Piping Design. The operating pressure will not be greater than 80 per cent of the test pressure.

3.3.7.2 Welding and Fabrication

Welding and fabrication of piping will be in accordance with the applicable standards and specifications listed in Tables 5.1.1 and 5.1.2 in Appendix D.

3.3.7.3 Non-destructive Testing

Non-destructive testing of pipe welding will be in accordance with applicable standards and specifications listed in Tables 5.1.1 and 5.1.2 in Appendix D.

3.3.7.4 Hydrostatic Pressure Testing

All piping will be hydrostatically pressure tested in accordance with the applicable standards and specifications listed in Tables 5.1.1 and 5.1.2 in Appendix D, including MP4111 Station Hydrostatic Testing.

Piping spools constructed in fabrication shops will be hydrostatically pressure tested prior to delivery to site. Site fabricated pipe will be hydrostatically pressure tested at site.

3.3.8 Sump Tanks

At each pump station, thermal relief valve discharge lines and selected drain lines associated with the process piping will be routed to a below grade sump tank. The tank will be sized to allow the drain-down of a significant portion of the process piping. Final sizing will be determined during the detailed engineering and design phase.

A lift pump and reinjection pump will be installed at each tank to allow re-injection of the sump contents into the pipeline. Pump-out to a tanker truck will also be possible through an above ground connection.

The sump tank design will include vents and access openings high enough to prevent spillage during equipment drain down.

Sump tanks will be constructed from fibre-glass (or a similar composite material) and will be of double-wall design. The interstitial space between the two shells will be monitored to assess the integrity of the tank.

3.3.9 Heating, Ventilation and Air Conditioning

Heating, Ventilation and Air Conditioning (HVAC) equipment will be selected as appropriate for the pump, ESB, VFD, and operator buildings. The pump building will be ventilated but not heated or air-conditioned. HVAC equipment selection will be finalized during the detailed engineering and design phase.

3.3.10 Electrical Power Supply

In Alberta the electric utility owners (AltaLink Management Ltd. [AltaLink] and FortisAlberta Inc. [Fortis]) will design and construct any new substations, power lines, and electrical transmission or distribution systems connections and improvements. Trans Mountain will be responsible for a portion, up to the full amount, of the cost of new power infrastructure and existing infrastructure improvements AltaLink and Fortis in conjunction with the Alberta Electric System Operator (AESO) will determine the cost contribution required and the method of recovery (initial payment, recovery through amortized power fees, or a combination of both).

In BC, only the transmission system connections and improvements will be designed and constructed by BC Hydro. Trans Mountain will design and construct the power lines from the BC Hydro transmission system connection points to the new pump stations. Trans Mountain will be responsible for some portion, up to the full amount, of the cost of the transmission system connections and improvements. BC Hydro will determine the cost contribution required and the method of recovery (initial payment, recovery through amortized power fees, or a combination of both).

Based on the preliminary engineering, the following new power lines will be required:

- a 138kV power line from a transmission (AltaLink) system connection point to Edmonton Terminal;
- a 138 kV or 25 kV power line from a yet to be determined transmission (AltaLink) or distribution (Fortis) connection point to Edson Pump Station;
- a 138 kV power line from a yet to be determined BC Hydro transmission system connection point on Line 1L210 or a new line originating in Kamloops to Black Pines Pump station (approximately 4 km in length); and
- a 138 kV power line from a yet to be determined BC Hydro transmission system connection point on Line 1L251 to the Kingsvale Pump station (approximately 24 km in length).

It is anticipated that upgrades to the existing deep system infrastructure will be required to support these new power feeds and the additional loads at pump station sites that have adequate existing power lines. Studies have been initiated with AltaLink and Fortis in Alberta and BC Hydro to determine the scope and cost of the changes.

Table 3.3.7 identifies the changes required to existing pump station substations, based on preliminary engineering:

TABLE 3.3.7

SUBSTATION CHANGES

Site	Substation Changes
Edmonton, AB	New
Gainford, AB	Upgrade
Edson, AB	New
Blackpool, BC	Upgrade
Kamloops, BC	New
Kingsvale, BC	New
Sumas, BC	Upgrade

Typically, the ESBs at sites with a single VFD will house medium-voltage switch gear, the VFD, motor control centres (MCCs), the control system, and miscellaneous other equipment. Separate VFD buildings will be used at pump stations with more than one VFD.

The ESBs and the VFD buildings will be of modular design with the electrical equipment pre-installed, wired, and pre-commissioned prior to shipment to site.

An uninterruptable power supply (UPS) system, suitably sized to provide two full cycles (two times open to close and two times close to open) of the pump station ESD isolation valves plus six hours of all other essential service load, will be provided to maintain essential power in the event of loss of the utility power supply.

Area lighting will be directional and targeted to the greatest extent practical to reduce extraneous lighting impact on the adjacent community.

3.3.11 Area Classification

Area classification will conform to the latest edition of API Recommended Practice 505, Recommended Practice for Classification of Location for Electrical Installation at Petroleum Facilities Classified as Class 1, Zone 0, Zone 1 and Zone 2 or the Canadian Electrical Code, as adopted or modified by provincial regulations, whichever is most stringent.

3.3.12 Power, Control, and Grounding Distribution

Cable trays will be used to support power and control cables within the ESB, the VFD building (if separate), the pump building, and around the site, where possible. TECK 90 HL cable will be used where possible and, where not possible or practical, rigid conduit will be used. Rigid PVC conduit will be used where sleeves are required for concrete penetrations.

There will be a buried ground grid around the operator building, ESB(s), VFD buildings, and around each pump station. All ground grids will be bonded together in two places. During the detailed engineering and design phase, an overall site grounding study will be performed to address issues of safe ground potential rise and step and touch potentials.

3.3.13 Station Services Power

A 4160/600 or 4160/480 volt transformer will be installed at each pump station to provide service voltage for auxiliary services including valve actuators and HVAC units. A fused load break switch will be used to protect the transformer.

3.3.14 Instrumentation, Control, and Communications

The following instrumentation, control, and communication equipment will be provided at each pump station:

- ultrasonic flow meter (for leak detection);
- pressure transmitters;
- temperature sensors;
- multi band infrared (IR) fire detectors;
- combustible gas detectors;
- hydrocarbon detection in containment areas;
- densitometer;
- pipeline cleaning and in-line inspection tool detectors;
- sump level transmitter (radar) with low-low and high-high level alarms and a separate switch incorporating high and low level alarms;
- PLC-based control system;
- HMI computer control system;
- primary data communications (land line);
- secondary data communications (satellite);
- telephone communications; and
- private radio communications system.

The ESB and VFD buildings at each pump station will have smoke detectors to detect fires arising from electrical faults. Building high and low temperature alarms will also be provided to prevent overheating or freezing.

Communication tower and antenna requirements will be determined during the detailed engineering and design phase.

3.3.14.1 Leak Detection Meter

Each new pump station will have an ultrasonic meter installed on the discharge side. The flows measured will be used by the computational pipeline monitoring (leak detection) system.

3.3.15 Protection Systems

The pump station protection system logic will be governed by the Operating Limits and Protective Device Settings document, which will be enhanced to include the new pump stations in the expanded TMPL system. A shut-down key will also be developed during the detailed engineering and design phase.

3.3.15.1 Pump Protection

All mainline pump units will be equipped with a pressure transmitter on the pump inlet piping at a point downstream of the pump suction valve. This transmitter will be connected to the local PLC and effect an immediate trip of the affected pump unit if suction pressure drops below the unit low suction set-point prescribed in the Operating Limits and Protective Device Settings document.

The pumps will also be protected for high bearing temperature, high case temperature, seal failure, excessive discharge piping pressure and excessive vibration.

3.3.15.2 Motor Protection

The mainline motors will be protected by fuses, coordinated as determined in the coordination study and by a motor protection relay (MPR) providing:

- ground fault;
- zero sequence;
- time-over-current;
- phase sequence;
- phase unbalance;
- over/under frequency;
- over/under voltage;
- diminished thermal capacity start prevention;
- under current or under power; and
- differential protection.

Resistance temperature detectors (RTDs) will also be connected to the MPR and will be used to measure winding temperature, drive-end and opposite-drive-end bearing temperature and provide high temperature protection. The MPR will provide integral display of motor electrical and temperature data. This data will also be sent to the pump station PLC where it will be routed to the HMI and SCADA systems.

Velocity transmitters will be installed for vibration measurement. They will be mounted as close as practical to the motor shaft centre line at each bearing. The transmitter output will be connected to an analog input card in the PLC. The PLC will initiate a unit lockout if the vibration exceeds the protective device setting.

3.3.15.3 Fire Detection

Fire in the pump building will be detected by one multi-spectrum IR flame detector per pump unit. Each device will be a stand-alone unit with contact outputs wired to the PLC for both fire and protective device fault. Both contacts will be included in the ESD circuit.

3.3.15.4 Combustible Gas Detection

Combustible gas detection will be installed within 15 cm of the pump building floor near the air intake to each mainline motor. Detectors will be stand-alone units with contact outputs for explosive atmosphere and for protective device faults wired to the PLC. Both contacts will be included in the ESD circuit.

3.3.15.5 Over-pressure Detection

Pipeline overpressure protection will be provided by PLC monitored redundant pump station discharge pressure transmitters, located downstream of the pump station discharge valve. The highest pressure measured by the pressure transmitters will be selected and the PLC will cause the action prescribed in the Operating Limits and Protective Device Settings document to occur should the licensed MOP of the pipeline be exceeded.

3.3.15.6 Emergency Shut Down System

The pump stations will be designed with ESD systems, in accordance with the requirements of CSA Z662, the parameters of which will be detailed in the Operating Limits and Protective Device Settings document.

Pump station ESD push-buttons will be provided at the following locations at each pump station:

- inside the area fence at the entrance to the pump station (in a weather-proof enclosure);
- in the ESB on the front of the pump station control panel; and
- at the pump building, outside, near the main door.

An ESD may also be originated from the Primary Control Centre (PCC) or from the local HMI.

An automatic ESD may be initiated by a fire detector, a fire detector fault switch, a combustible gas detector, a combustible gas detector fault switch, a floor sump high level switch or hydrocarbon detector, a waste oil sump high level switch, waste oil sump high-high level switch, or main line high discharge pressure transmitter.

Initiation of an ESD will result in the immediate stopping of all running pump units, the closing of the station suction and discharge valves, the closing of the unit suction and discharge valves (if utility power is available), and the shutdown of any booster pumps and waste oil sump lift/injection pumps.

Loss of PLC function will initiate the same actions as a "fail safe" pump station ESD, shutting down the pump units and isolating the pump station by closing the pump station suction and discharge valves. To restore normal operations, a local reset will be required.

3.3.16 Control System

Mainline flow rates will be set at the initiating pump stations for Line 1 and Line 2. Both initiating pump stations will be located at Edmonton Terminal. Along with flow control, discharge pressure over-ride control, low suction pressure over-ride control and kilowatt consumption control are available to ensure protection of the system. The primary control parameter for each pump station downstream of Edmonton will be discharge pressure but with suction pressure and kW consumption overrides. Controllers will be integral to the PLC and the final control devices will be a pump station control valve or the VFD(s).

The discharge pressure controller maximum set point will be based on the licensed MOP. If pressure control, through the operation of the pump station control valve or VFD(s), is unable to prevent the discharge pressure from exceeding the pump station discharge pressure set point, a pump unit ESD will be initiated automatically.

Pump station suction pressure control will be provided by a suction pressure controller. Surge control features will be incorporated into the final design.

The Control System will be configured to “fail safe”.

3.3.17 Supervisory Control and Data Acquisition

As is the case for the existing TMPL system, the expanded TMPL system will be monitored and controlled by Control Centre Operators (CCOs) at the PCC using a SCADA system. The PCC is located in Sherwood Park, AB and is operated 24 hours per day, seven days per week. A back-up control centre is also available should the PCC become unavailable. Additional information on the SCADA system is included in Volume 4C, Section 7.1.

The existing SCADA system and supporting communications system infrastructure will be expanded to accommodate the new instrumentation and control signals for the TMEP pump stations.

Parameters that will be monitored by the SCADA system at each of the new pump stations include but are not limited to:

- suction and discharge pressure;
- temperature;
- unit and pump station power;
- product density;
- sump tank level;
- unit alarms; and
- pump station alarms.

Communications between the PCC and each pump station will be continuously monitored. In the event that the communication link with a pump station is lost, the CCO will initiate a transfer to the back-up communications system for that pump station only. The local HMI will log all alarms and analog process variables. The PLC will take any local action required. All pump unit and pump station ESD systems will remain active. Alarm status will be displayed in the HMI and will be archived locally as well as at the PCC.

If a complete SCADA communication system loss occurs, the PLC logic will shut down one pump unit at a time, until no units are running. Field operations staff may be dispatched to the site to control the pump station as directed by the CCO. The opening and closing of valves and the starting and stopping of the pump units will be controlled locally through the HMI. All protection systems will remain operational during local operation.

3.3.18 Corrosion Control

Pump station piping, with a few exceptions (such as some drain piping) will be installed above grade. Above and below ground piping will be coated with materials suitable for the application.

3.3.19 Miscellaneous Pump Station Changes

Niton Pump Station, which has been deactivated since 2006, will be reactivated (on Line 1). Inspection and testing procedures will be developed to ensure that the station can be safely returned to service.

The existing NPS 36 sending trap at Hinton Pump Station will be removed and replaced by an NPS 24 sending trap (on Line 1). The station piping will be reconfigured accordingly.

The piping at Jasper Pump Station will be reconfigured so that the station will operate on Line 1. In addition, based on preliminary hydraulic analysis, it has been determined that the injection of a DRA will be required. The station will be fitted with a DRA injection system. Jasper Pump Station will also require a new VFD to replace the current obsolete one.

An NPS 24 sending trap and an NPS 24 receiving trap will be added at Rearguard Pump Station (Line 1).

An NPS 36 receiving trap will be added at Darfield Pump Station (Line 2) and the NPS 24 sending trap (Line 1) will be removed.

Additional VFDs may be required at existing pump stations in the North Thompson region due to the limited capacity of the transmission system. The need for additional VFDs will be determined during the detailed engineering and design phase in conjunction with BC Hydro.

3.4 Facilities Design - Terminals

The terminals scope for TMEP will include work at the following locations:

- Edmonton Terminal;
- Sumas Terminal;
- Burnaby Terminal; and
- Westridge Marine Terminal.

After all crude oil and refined products storage tanks (*i.e.*, excluding auxiliary tanks) currently being constructed or planned for other projects have been completed, these four terminals will have 57 tanks with a combined total shell capacity of approximately 1,718,690 m^3 (10,810,000 bbl). These tanks will be referred to herein as the existing tanks. A preliminary assessment indicates that for TMEP, 20 new tanks will be required at these locations ranging in size from 11,920 m^3 (75,000 bbl) to 63,600 m^3 (400,000 bbl) and having a combined total shell capacity of approximately 876,040 m^3 (5,510,000 bbl). These tanks will be referred to herein as the new tanks. In addition, one tank in Edmonton (Tank 9) and one tank in Burnaby (Tank 74) will be demolished to make room for the new tanks. The new tanks will retain the numbering designations of the demolished tanks. The location, number and capacity of the new tanks are shown in Table 3.4.1.

After the demolition of the two existing tanks and the addition of the 20 new TMEP tanks, there will be a total of 75 tanks at these locations, having a total shell capacity of approximately 2,569,280 m^3 (16,160,000 bbl). The locations, numbers, and capacities of all of the tanks are summarized in Table 3.4.2. The two existing active storage tanks at Kamloops Terminal are not included as there are no tank changes planned at that location.

The number and sizes of new tanks are based on preliminary engineering. Further studies are underway to verify that the numbers and sizes are optimal. New tanks will be constructed within the existing terminal property lines, requiring no additional new land.

Note, the shell capacities of each tank referred to herein are calculated in United States (US) petroleum barrels and rounded to the nearest 5,000. Working volumes (the volume contained between the low working levels and the high working levels) vary for both existing and new tanks, depending on tank design, although they generally are or are expected to be in the range of 85 to 90 per cent of the shell volumes.

TABLE 3.4.1

NEW TANK SIZES AND LOCATIONS

Site	# Tanks	Tank Size							
		m^3	11,920	27,820	34,980	39,750	45,310	53,260	63,600
		bbl	75,000	175,000	220,000	250,000	285,000	335,000	400,000
Edmonton	5		1		2				2
Sumas	1			1					
Burnaby	14					2	10	2	
Total	20		1	1	2	2	10	2	2

Note:

* Relief tanks and process tanks not included.

TABLE 3.4.2

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, ETEP Phase I & 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.

The tanks and their associated infrastructure will be designed to meet the Canadian Council of the Ministers of the Environment (CCME) Standard 1326, The Environmental Code of Practices for Aboveground and Underground Storage Tank Systems Containing Petroleum and Allied Petroleum Products, API Standard 650 (API 650) Welded Steel Tanks for Oil Storage, and CSA Standard Z662, Oil and Gas Pipeline Systems, with foundation design based on Provincial Building Code requirements and local geotechnical conditions.

Tank spacing will be in accordance with National Fire Protection Association (NFPA) Standard 30, and the National, Alberta and BC fire codes, with spacing between adjacent tanks equal to or greater than the sum of their respective diameters divided by four.

Secondary containment will be designed in accordance with CSA Z662, NFPA Standard 30, and the National, Alberta and BC fire codes, where applicable.

Each tank will be equipped with a radar gauging system for liquid level measurement and overfill protection. Redundant instrumentation for overfill protection will be provided.

Fire protection will be in accordance with NFPA Standard 30, other NFPA standards, as applicable, and the National, Alberta, and BC fire codes.

All terminal piping will conform to the requirements of CSA Z662 for LVP liquids and to the requirements of all applicable codes, standards, specifications and recommended practices that are incorporated by reference in CSA Z662.

Tanks will be hydrostatically tested on-site after construction. Piping spools constructed in fabrication shops will be hydrostatically pressure tested prior to delivery to site. Field fabricated pipe will be hydrostatically pressure tested at site.

3.4.1 Edmonton Terminal

3.4.1.1 Overview

The Edmonton Terminal is divided into two areas:

- East Tank Area (ETA); and
- West Tank Area (WTA).

East Tank Area Tanks and Volumes

Prior to the Edmonton Terminal Expansion Project (ETEP) Phase I, ETEP Phase II, and Tank 29 and 30 projects, the ETA had nine existing tanks ranging in size from 23,850 m^3 (150,000 bbl) to 26,230 m^3 (165,000 bbl) for a total shell capacity of approximately 217,020 m^3 (1,365,000 bbl).

Currently, 16 tanks associated with the three expansion projects and ranging in size from 34,980 m^3 (220,000 bbl) to 63,600 m^3 (400,000 bbl) are in various stages of development, from planned to complete. When all of the tanks are in service, they will add a combined shell capacity of approximately 845,830 m^3 (5,320,000 bbl) in the ETA.

When all of the tanks are in service the total shell capacity of the ETA will be approximately 1,062,850 m^3 (6,685,000 bbl).

West Tank Area Tanks and Volumes

Currently the WTA has ten existing tanks ranging in size from 12,720 m^3 (80,000 bbl) to 37,360 m^3 (235,000 bbl) for a total shell capacity of approximately 211,460 m^3 (1,330,000 bbl).

The ETEP Phase I, ETEP Phase II, and Tank 29 and 30 projects will not add any additional capacity to the WTA.

For TMEP, five new tanks are proposed for the WTA, ranging in size from 11,920 m^3 (75,000 bbl) to 63,600 m^3 (400,000 bbl), for a total shell capacity of approximately 209,070 m^3 (1,315,000 bbl). To make room for the new Tank 4, Tank 9 will be demolished and replaced with a new tank.

When all of the tanks are in service, the total capacity of the WTA will be approximately 407,810 m^3 (2,565,000 bbl).

Edmonton Terminal Total Tanks and Volumes

When TMEP is complete, there will be a total of 39 tanks at Edmonton Terminal, having a total shell capacity of approximately 1,470,660 m^3 (9,250,000 bbl).

The general scope of TMEP at Edmonton Terminal, excluding the Edmonton Terminal Line 2 mainline pump station (see Section 3.3), includes:

- five new external floating roof tanks;
- demolition of one tank;
- a remote impoundment annex (RIA);

- modifications to the WTA containment, access road, and storm-water drainage systems;
- large bore tank lines and process piping;
- a valve manifold, booster pumps, and meters;
- an expanded and enhanced fire-protection system; and
- three ESBs, one VFD building and one foam building.

Figure 3.4.1 shows the general arrangement of the TMEP tanks and terminal facilities well as the existing tanks and terminal facilities and those under construction or planned as part of the ETEP Phase I, ETEP Phase II, and Tanks 29 and 30 projects.

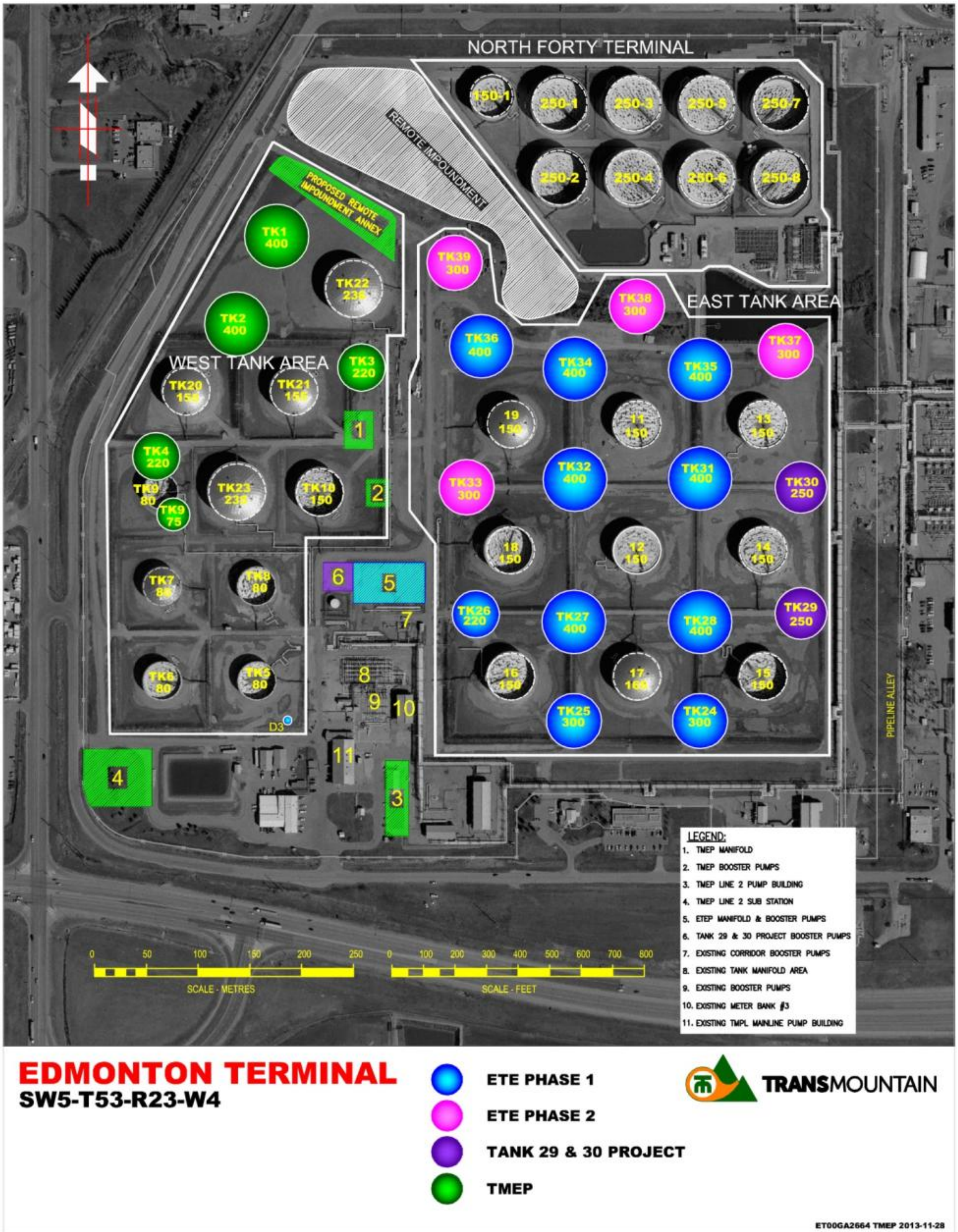


Figure 3.4.1 Edmonton Terminal Proposed Plot Plan

3.4.1.2 Civil

Major civil work will include:

- construction of the tank foundations;
- the construction of a new RIA at the north end of the site;
- installation of a new drainage system to take runoff from the WTA to the RIA;
- construction of internal access roads;
- raising of the existing west perimeter road; and
- construction of prefabricated or field installed retaining wall systems.

The tank foundations will likely be deep soil/concrete mix columns with a mass soil/concrete mix and granular bridging pad, similar to those installed for ETEP. The tank foundation design will be finalized after geotechnical investigation is completed during the detailed engineering and design phase.

The WTA will be re-graded to direct the drainage of storm water and hydrocarbon spills (in the event of a failure) to the RIA.

Culverts will be used at internal road crossings and at other locations along the drainage courses to provide traffic crossings. The culverts placed in the internal east-west roads will be equipped with shut-off valves to allow intermediate segregation of storm water or spilled hydrocarbons if appropriate.

Modifications will be made to the existing perimeter berms to accommodate the new tanks. To optimize the area available for new tanks, the existing perimeter berm on the west side of the WTA will be removed and replaced with a pre-cast concrete or cast-in-place concrete retaining wall system. In addition, the existing intermediate berms will be removed and new interior access roads will be added. The majority of the existing west road will be raised to allow access to the interior road system. A concrete retaining wall will also be installed on the west side of the west road. The existing road on the north side of the WTA will be moved further north to provide space for the new RIA.

The new manifold will be partially located in a below grade concrete vault. A lift station will be installed to pump any collected surface water to the new RIA. Drain lines will be electrically heat traced and insulated.

3.4.1.2.1 Secondary Containment

The tanks to be added in the WTA for TMEP require that additional containment capacity be provided in accordance with CSA Z662 and the Alberta Fire Code (AFC), specifically 100 per cent of the working volume of the largest tank plus 10 per cent of the working volume of the other tanks that share the common impoundment. This containment capacity will be partially provided by the remote impoundment (RI), recently constructed to serve the ETA. The remaining containment capacity will be provided within the WTA common impoundment area.

The RI is sized, based on the requirements of NFPA 30 for RI, to have a capacity equal to the working volume of the largest tank in the ETA (approximately 385,000 bbl). Since the RI is normally open to the ETA common impoundment, the RI has additional capacity for all of the water that can collect in the RI from a 1 in 100 year 24 hour precipitation event (approximately 200,000 bbl). Since the largest tank being added in the WTA is equivalent to the size of the largest tank in the ETA, the RI can also serve the WTA in accordance with NFPA 30. However, the combination of the 1 in 100 year 24 hour accumulated precipitation from the ETA and WTA will exceed the additional design capacity of the RI. Therefore, a new storm water retention area, the RIA, will be constructed at the north end of the WTA to handle accumulated precipitation from the WTA.

The RIA will have a lower level outlet and an upper level outlet connecting to the existing RI. Both outlets will be equipped with automated valves. The valve on the lower level outlet will be normally closed while the valve on the upper level outlet will be normally open.

Storm water from the WTA will first collect in the RIA and will be released into the RI if space is available and following storm water management procedures to be developed. Hydrocarbon spills will fill any remaining space in the RIA, and then overflow into the RI through the upper level outlet. The automated valve on this outlet will close if the liquid level in the RI reaches its design capacity and the remaining volume will be contained in the WTA common impoundment.

The RIA will be lined with an impervious membrane. The RIA will be formed by excavation, and have a combination of concrete and mechanically stabilized earthen walls.

3.4.1.2.2 Earthworks

The excavation of tank lines, grading of the WTA, removal of existing berms, construction of the new RIA and excavation of new tanks foundations will result in a large volume of excavated materials. The majority of the excavated material will be stored or disposed of off-site due to the lack of available storage on-site. New berms, ramps and roads will be constructed using some of the excavated material.

3.4.1.3 Structural

Pipe supports and buildings will be mounted on concrete or steel pile foundations designed using geotechnical information specific to the site.

3.4.1.4 Storage Tanks

Table 3.4.3 provides a list of new tanks to be constructed at Edmonton Terminal for TMEP.

TABLE 3.4.3

TMEP TANKS AT EDMONTON TERMINAL

Tank #	Capacity		Location	Service	Current Status	Comments
	(m^3)	(bbl)				
1	63,600	400,000	WTA	CC	P	
2	63,600	400,000	WTA	CC	P	
3	34,980	220,000	WTA	CC	P	
4	34,980	220,000	WTA	CC	P	
9	11,920	75,000	WTA	CC	E/P	To be demolished and replaced for TMEP
Total	209,070	1,315,000				

Notes: WTA - West Tank Area

CC - Common Carrier

P - Planned, E - Existing

Table 3.4.4 provides a list of all tanks that will be at Edmonton Terminal after TMEP.

TABLE 3.4.4

EDMONTON TERMINAL TANKS AFTER TMEP

Tank #	Capacity		Location	Service	Current Status	Comments
	(m^3)	(bbl)				
1	63,600	400,000	WTA	CC	P	
2	63,600	400,000	WTA	CC	P	
3	34,980	220,000	WTA	CC	P	
4	34,980	220,000	WTA	CC	P	
5	12,720	80,000	WTA	CC	E	
6	12,720	80,000	WTA	CC	E	
7	12,720	80,000	WTA	CC	E	
8	12,720	80,000	WTA	CC	E	
9	11,920	75,000	WTA	CC	E/P	To be demolished and replaced for TMEP
10	23,850	150,000	WTA	CC	E	
11	23,850	150,000	ETA	CC	E	
12	23,850	150,000	ETA	CC	E	
13	23,850	150,000	ETA	CC	E	
14	23,850	150,000	ETA	CC	E	
15	23,850	150,000	ETA	CC	E	
16	23,850	150,000	ETA	CC	E	
17	26,230	165,000	ETA	CC	E	
18	23,850	150,000	ETA	CC	E	
19	23,850	150,000	ETA	CC	E	

TABLE 3.4.4

EDMONTON TERMINAL TANKS AFTER TMEP (continued)

Tank #	Capacity		Location	Service	Current Status	Comments
	(m^3)	(bbl)				
20	24,640	155,000	WTA	CC	E	
21	24,640	155,000	WTA	CC	E	
22	37,360	235,000	WTA	CC	E	
23	37,360	235,000	WTA	CC	E	
24	47,700	300,000	ETA	M (KMCT)	E	ETEP Phase I
25	47,700	300,000	ETA	M (KMCT)	E	ETEP Phase I
26	34,980	220,000	ETA	CC	UC	ETEP Phase I
27	63,600	400,000	ETA	M (KMCT)	UC	ETEP Phase I
28	63,600	400,000	ETA	M (KMCT)	UC	ETEP Phase I
29	39,750	250,000	ETA	M (KMCT)	UC	Tank 29 & 30 Project
30	39,750	250,000	ETA	M (KMCT)	UC	Tank 29 & 30 Project
31	63,600	400,000	ETA	M (KMCT)	E	ETEP Phase I
32	63,600	400,000	ETA	M (KMCT)	E	ETEP Phase I
33	47,700	300,000	ETA	M (KMCT)	UC	ETEP Phase II
34	63,600	400,000	ETA	M (KMCT)	E	ETEP Phase I
35	63,600	400,000	ETA	M (KMCT)	UC	ETEP Phase I
36	63,600	400,000	ETA	M (KMCT)	E	ETEP Phase I
37	47,700	300,000	ETA	M (KMCT)	UC	ETEP Phase II
38	47,700	300,000	ETA	M (KMCT)	UC	ETEP Phase II
39	47,700	300,000	ETA	M (KMCT)	UC	ETEP Phase II
Total	1,470,660	9,250,000				

Notes: E - Existing
P - Planned
CC - Common Carrier
M (KMCT) - Merchant (leased to Kinder Morgan Canada Terminals)
UC - Under Construction
F - Future

Tanks and their foundations will be designed in accordance with API 650 and the CCME guidelines. All tanks will have steel pontoon floating roofs and mechanical seals.

Tanks will be provided with nozzles to allow for process connections, maintenance access and the future installation of propeller mixers and/or jet mixers. The final number and sizes of nozzles and will be determined during the detailed engineering and design phase.

Tanks will be externally coated with a zinc primer/urethane top-coat system. The exterior color will be white. The tank floor top and the interior 1 m (3.3 ft.) of the lower shell will be coated with epoxy.

Spacing between adjacent tanks will be in accordance with AFC and NFPA 30, specifically no less than the sum of their respective diameters divided by four.

3.4.1.5 Buildings

Three new ESBs, one VFD building and one foam building will be required for the WTA and associated infrastructure. All buildings will be pre-fabricated and pre-assembled, complete with the equipment they will house, off-site.

HVAC and smoke detectors will be provided, as necessary or as required by regulation.

3.4.1.6 Mechanical

3.4.1.6.1 Booster Pumps

Six API 610 vertical can-type booster pumps of approximately 800 HP each will be installed in the WTA. One of the pumps will be a spare.

Two of the booster pumps, rated at 1,220 m^3/hour (184,000 bbl/d) each and configured in parallel, will be required for the delivery of light crude to Line 1 at a total flow rate of 2,440 m^3/hour (368,400 bbl/d).

Three of the booster pumps, rated at 1,255 m^3/hour (189,500 bbl/d) each and configured in parallel, will be required for the delivery of heavy crude to Line 2 at a total flow rate of 3,765 m^3/hour (568,400 bbl/d).

One additional booster pump will be added to the ETEP booster pump area to meet the increase flow rate on Line 2.

Each of the booster pump motors will be controlled by a VFD.

3.4.1.7 Piping

Tank lines will generally be below ground, but they will be above ground where they connect to the tanks or the manifold. Tank lines will be designed to be “pig-able”. Manifold, pump, meter, and interconnection piping will generally be above ground except at road and other crossings.

3.4.1.7.1 Design Pressure

The design pressure of Edmonton Terminal piping is 1,900 kPag (276 psig) with the exception of the S-header and some of the connections to it which have a design pressure of 4,960 kPag (720 psig). The design pressure of the new piping in the WTA will be consistent with the existing Edmonton Terminal piping. Booster pumps will be sized to produce 450 kPag (65 psig) at the mainline pump suction headers and will be selected such that their shut-off pressure will not exceed 1,900 kPag.

3.4.1.7.2 Materials

Pipe, fittings, and flanges will meet the requirements of CSA Z245.1 Steel Pipe, CSA Z245.11 Steel Fittings, CSA Z245.12 Steel Flanges and the KMC 2000 series standards and specifications. Valves will meet the requirements of CSA Z245.15 Steel Valves and KMC Standard MP1300 Valve Selection and Specification and its associated standards and specifications. Material grades and wall thicknesses will be determined in accordance with the applicable standards and specifications identified in Tables 5.1.1 and 5.1.2 in Appendix D, including MP1110 Station & Terminal Piping Design. The operating pressure will not be greater than 80 per cent of the test pressure.

3.4.1.7.3 Welding and Fabrication

Welding and fabrication of piping will be in accordance with the applicable standards and specifications listed in Tables 5.1.1 and 5.1.2 in Appendix D.

3.4.1.7.4 Non-destructive Testing

Non-destructive testing of pipe welding will be in accordance with applicable standards and specifications listed in Tables 5.1.1 and 5.1.2 in Appendix D.

3.4.1.7.5 Hydrostatic Pressure Testing

All piping will be hydrostatically pressure tested in accordance with the applicable standards and specifications listed in Tables 5.1.1 and 5.1.2 in Appendix D, including MP4111 Station Hydrostatic Testing.

Piping spools constructed in fabrication shops will be hydrostatically pressure tested prior to delivery to site. Site fabricated pipe will be hydrostatically pressure tested at site.

3.4.1.8 Auxiliary Systems

3.4.1.8.1 Sump Tanks

Thermal relief valve discharge lines and selected drain lines associated with the process piping in the WTA valve manifold and booster/metering area will be routed to below grade sump tanks. The tank will be sized to allow the drain-down of a significant portion of the process piping. Final sizing will be determined during the detailed engineering and design phase.

A lift pump and reinjection pump will be installed at each tank to allow re-injection of the sump contents back into the process piping or into the site waste-oil tank. Pump-out to a tanker truck will also be possible through an above ground connection.

The sump tank design will include vents high enough to prevent spillage during equipment drain down.

Sump tanks will be constructed from fibre-glass (or a similar composite material) and will be of double-wall design. The interstitial space between the two shells will be monitored to assess the integrity of the tank.

3.4.1.9 Electrical

The general scope of the electrical system will include:

- a power feed from the new TMEP substation 4160 V secondary;
- three ESBs; and
- one VFD building.

3.4.1.10 Instrumentation

The general scope of the instrumentation will include:

- a radar gauging system on each storage tank, with high level and low level sensing and overfill protection capability;

- a redundant overfill protection system on each storage tank;
- a fire detection system on each storage tank;
- a leak detection system under each storage tank and in the interstitial space of the sump tank(s);
- a hydrocarbon detection system in each storage tank containment area and selected other containment areas;
- booster pump and piping pressure and temperature sensors and transmitters for measurement and protection;
- ultrasonic meters;
- densitometer(s), viscometer(s), and automatic sampler(s);
- bi-directional, positive displacement meter prover; and
- waste oil sump level and control instrumentation.

3.4.1.10.1 Instrumentation Characteristics and Features

Instrumentation will have the following characteristics and features:

- All applicable field instruments will have integral secondary sealing as required by Rule 18-072, 1 and 2, and 18-108, 1 and 2 of Canadian Electrical Code (CEC) C22.1.
- Transmitters will be two-wire 4 to 20 mA DC with digital communications superimposed on the analog signal.
- Transmitters will be provided with local analog displays integral to the unit. The displays will be removable without interrupting the transmitter output signal.
- Trip settings will be implemented in the PLC and derived from the analog signal.
- Instruments will be selected such that the manufacturer's stated safe working pressure and temperature meets or exceeds that of the associated piping design pressure and temperature.
- Wetted parts will be 316SS with BUNA-N elastomers, unless indicated otherwise on data sheets.
- Storage tanks will be fitted with two stilling wells. One stilling well will be dedicated to primary level measurement and temperature measurement with a manual gauging provision. The second stilling well will be provided for the secondary gauging system, to provide redundant tank overfill protection.
- Sump tank level will be monitored with a guided wave radar transmitter for primary level, and a multipoint displacer level switch. A switch for interstitial

sump tank leak detection will be provided. An analog output proportional to tank level will be transmitted to the PLC. Set-points for low-low level and high-high level will be provided. The multi-point displacer level switch will provide high level alarming and primary shutdown control of the sump pump system.

- Each booster pump and associated piping will be provided with suction and discharge pressure indicating transmitters, suction and discharge pressure gauges, a seal failure detection switch, and a discharge line pressure safety valve. Seal failure switches will be thermal dispersion flow sensors. Booster pump vibration will utilize a seismic transmitter producing a 4-20 mA output. Booster pump control and protective functions will be achieved using VFDs and a PLC.
- Booster pump temperature protection will be provided using the winding and bearing RTDs on the booster pump and motor.
- Storage tank fire detection will consist of multi-spectrum IR flame detectors installed along the rim. A detected fire will prompt the PLC to initiate a fire alarm both locally and in the control centre. Once the fire has been field verified, the control centre operator will activate the fire suppression system.
- The sampling system design will address multiple batches and will limit the requirement for operator switching.

3.4.1.10.2 Custody Transfer Quality Metering System

A custody transfer quality metering system will be installed in the WTA.

The metering system will consist of five meter runs and one spare meter run. The meters will be ultrasonic.

One additional ultrasonic meter run will be installed in the existing ETEP metering system to accommodate higher TMEP flow rates.

Measurement accuracy will meet or exceed *Canadian Weights and Measures Regulation Part IV* of +/- 0.25 per cent. The proving method will be a permanent bi-directional, positive displacement meter prover.

The custody transfer quality metering system will include instrumentation to provide continuous monitoring of fluid characteristics (including temperature, pressure, viscosity, and density), an automatic sampler, and flow computers.

3.4.1.11 Protection Philosophy

3.4.1.11.1 Fire Protection Systems

The design of the WTA fire protection system will be consistent with the system that serves the ETA, developed and installed as part of the ETEP. Water will be supplied from the expanded fire-water reservoir and the new fire-water pumps. The fire-water pumps will provide sufficient capacity for the storage tank seal-area fire-suppression systems, for full surface fire-fighting (by a portable foam cannon), and for cooling of adjacent tanks (by portable monitors).

A new foam supply building, with sufficient foam storage (or the ability to rapidly replenish from on-site portable foam concentrate totes) for tank seal-area and full-surface fire-fighting, will be installed to serve the WTA.

Storage tanks will be fitted with seal-area foam pourers permanently connected to the fire-water/foam supply system. The foam supply to each tank will be activated by automated valves.

Three lateral underground fire-water/foam mains connect to form a loop for supply redundancy, will serve the WTA. Approximately 15 high volume hydrants will be located throughout the WTA.

The design of the fire protection system will be finalized during the detailed engineering and design phase.

3.4.1.11.2 Emergency Shutdown System

All equipment added for TMEP will be integrated into the existing Edmonton Terminal ESD system, which will be expanded and enhanced as necessary.

3.4.1.12 Control

The control system for the new facilities will be integrated with the existing Edmonton Terminal control system and will comply with existing control philosophies. The majority of operational functions will normally be controlled from the PCC or SCC by CCOs using the SCADA system, although operational staff will be present at the site 24 hours per day, seven days per week. The function of the SCADA system for the Edmonton Terminal will be very similar to the function for a pump station. Additional details on the function of the SCADA system are included in Section 3.3.17 and in Volume 4C, Section 7.1.

New control panels housing remote input/output (I/O) racks will be provided in each of the new ESBs. An existing UPS will provide power to the new remote I/O racks. Additional HMIs will not be required. HMI upgrades and reconfiguration will be performed as necessary to incorporate status, analog information, and control of the additional tanks, piping, valves, alarms, equipment, process data, and trends. Where possible, tank and meter display screens will be the same as currently in use.

The metering system will be controlled by flow computers and a PLC, consistent with those currently in service.

Control and shutdown functions for the protection of equipment and systems will be installed at the equipment and will be independent of inputs from SCADA or operation of the SCADA system.

The existing Operating Limits and Protective Device Settings document will be updated to include settings and functionality for all new equipment.

3.4.1.12.1 Communication

The existing wired and fiber optic industrial network will be expanded to provide communications between PLCs and equipment. Communications to the PCC and SCC SCADA systems will be by leased land line. Back-up communications will be provided by satellite. A new PLC will be provided to facilitate data sharing with customers or to receive or provide leak detection information to facilities that are integrated with Edmonton Terminal. Those sharing data will provide the necessary interface and communications circuits.

3.4.2 Sumas Terminal (also known as Sumas Tank Farm)

3.4.2.1 Overview

Sumas Terminal is located approximately 6 km northeast of the City of Abbottsford, BC.

The tanks at the Sumas Terminal are normally used to hold batches of crude oil to be shipped south on the Puget Sound Pipeline to the refineries at Ferndale (Cherry Point) or Anacortes in Washington State.

Figure 3.4.2 provides a current aerial picture of Sumas Terminal.

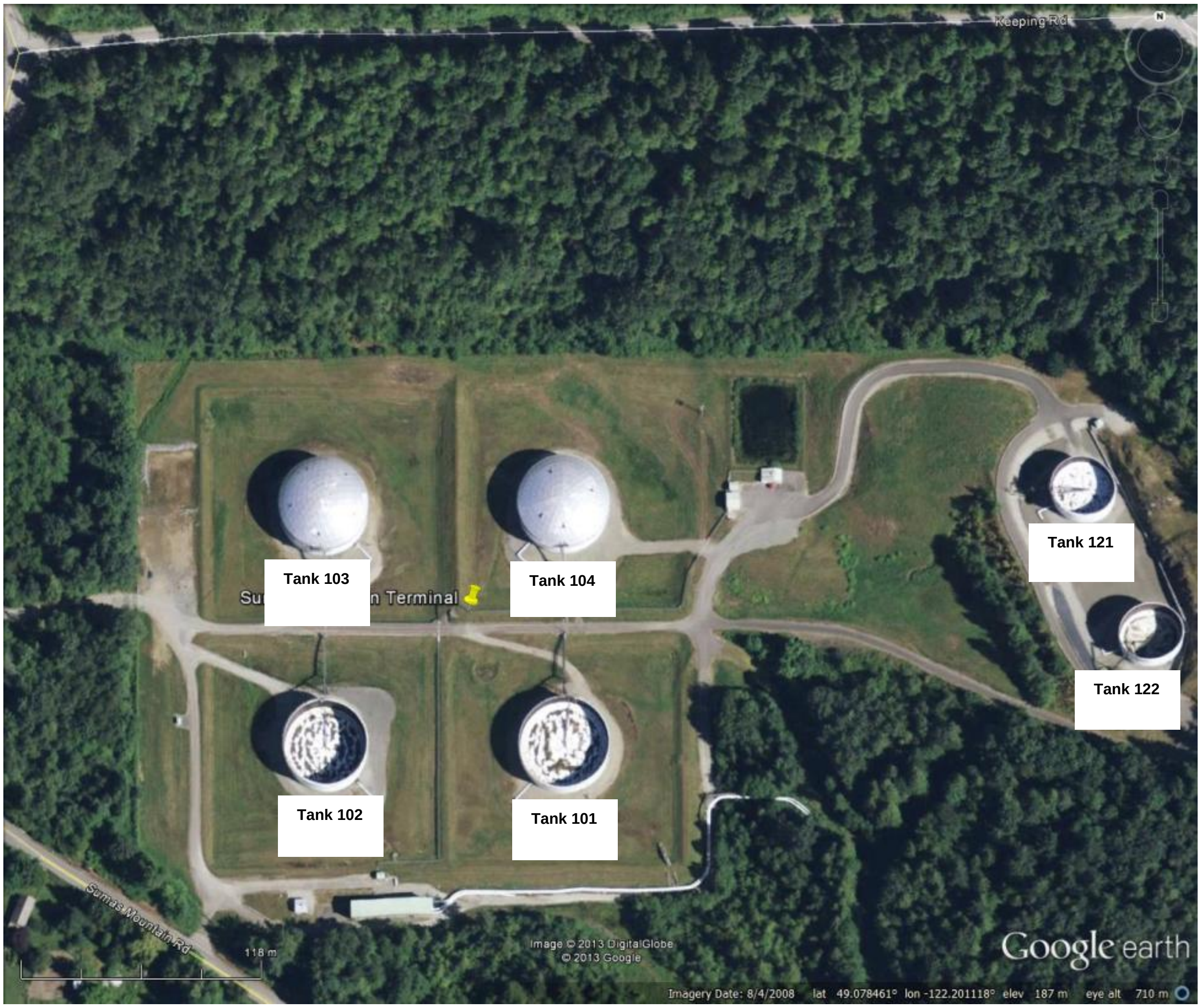


Figure 3.4.2 Sumas Terminal

Sumas Terminal currently has six tanks ranging from 8,740 m^3 (55,000 bbl) to 24,640 m^3 (155,000 bbl) for a total shell capacity of approximately 113,680 m^3 (715,000 bbl).

For TMEP, one new tank having a shell capacity of 27,820 m^3 (175,000 bbl) is proposed.

When TMEP is complete, there will be a total of seven tanks at Sumas Terminal, having a total shell capacity of approximately 141,500 m^3 (890,000 bbl).

The general scope of TMEP at Sumas Terminal includes:

- one new tank, with an internal floating roof, a fixed roof, and a tank vapour adsorption unit (TVAU);
- modifications to the existing containment, access road, and storm-water drainage systems;
- a new large bore tank line;
- modifications to the existing valve manifold;
- a new incoming feeder pipeline from a nearby connection with Line 2; and
- leak detection meters on the Line 2 feeder pipeline.

Figures 3.4.3 and 3.4.4 show the western (lower) part of the site with the new tank.

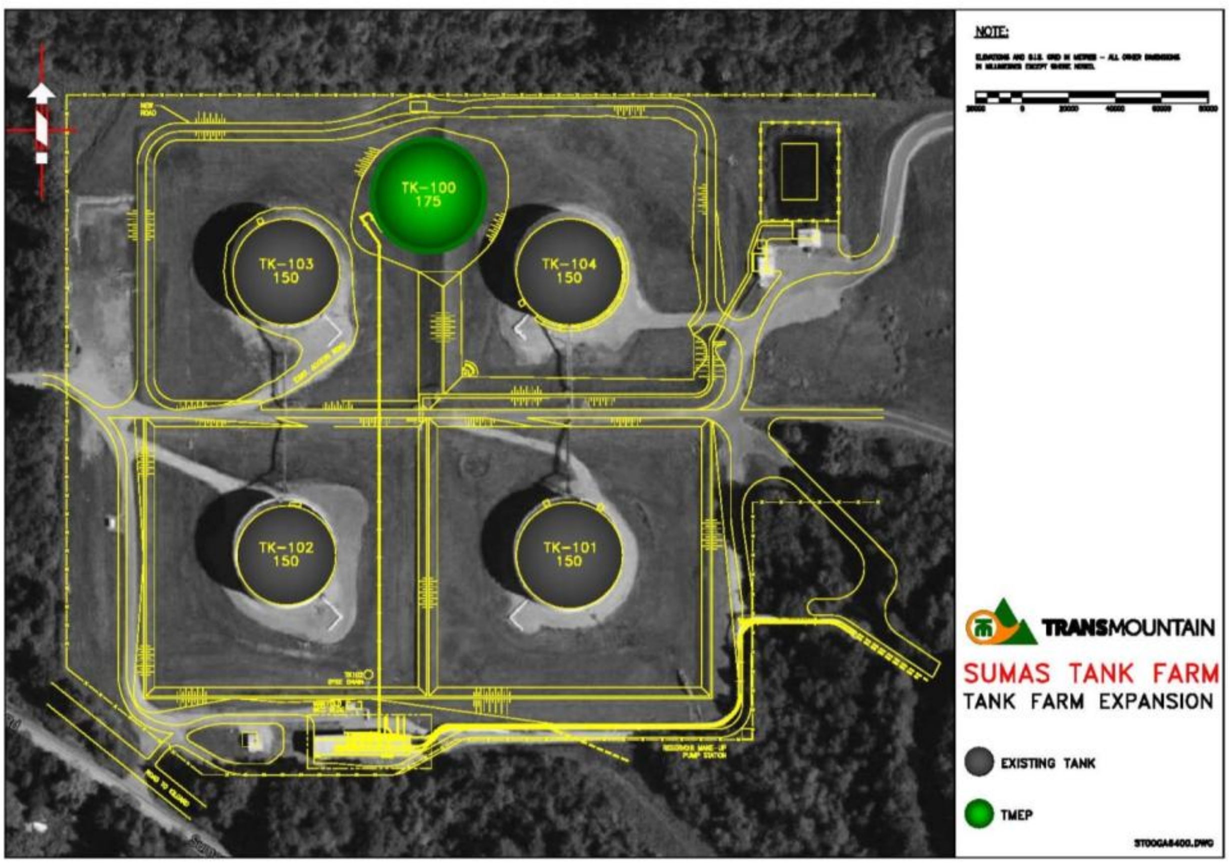


Figure 3.4.3 Sumas Terminal Proposed Plot Plan

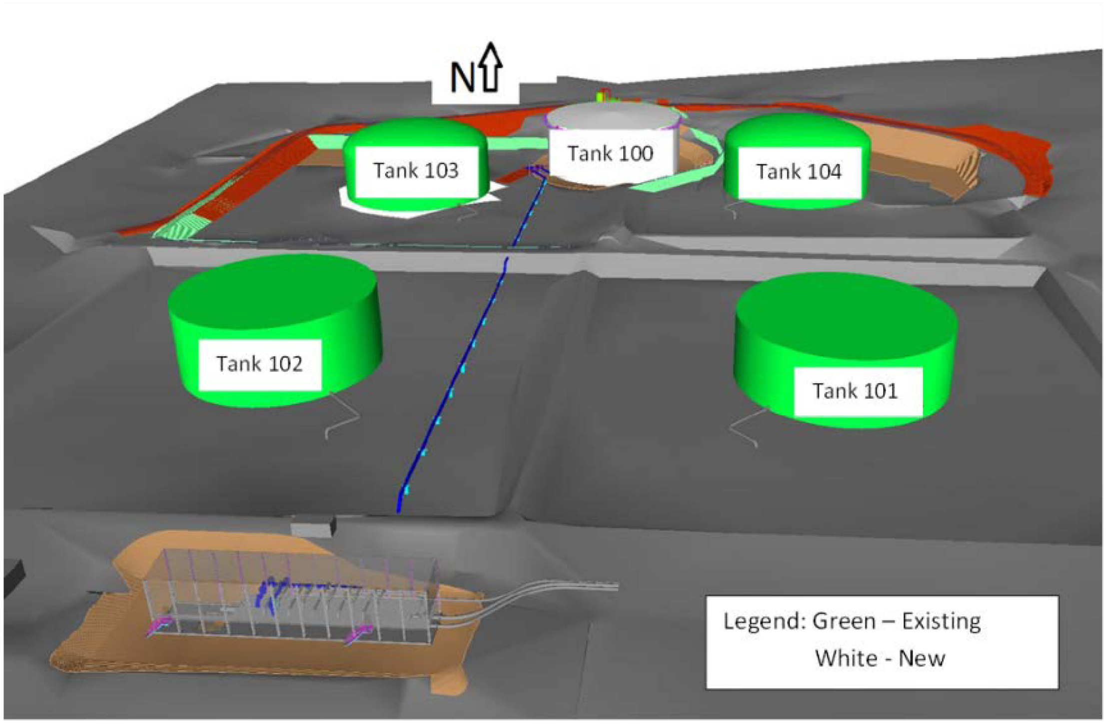


Figure 3.4.4 Sumas Terminal Proposed Layout

3.4.2.2 Civil

Major civil work will include:

- modifications to the Tank 103 and Tank 104 secondary containment areas;
- installation of a membrane liner in the Tank 103 and 104 secondary containment area;
- subsurface dewatering to be installed under the secondary containment liner; and
- addition of an access road north of the new tank.

3.4.2.2.1 Secondary Containment

The berm between Tank 103 and Tank 104 will be partially removed to allow space for the installation of the new tank (Tank 100) and replaced with a concrete wall. Some of the cut slope northeast of Tank 104 will be removed to retain the existing containment capacity in the Tank 104 containment area. Tank 100 will share containment with Tank 103. The realignment of the berm between Tank 103 and Tank 104 and the excavation for the Tank 100 foundation and associated perimeter space will ensure that the shared containment capacity is in accordance with CSA Z662 and the BC Fire Code (BCFC), specifically 100 per cent of the working volume of the Tank 100 plus 10 per cent of the working volume of Tank 103.

The shared containment area will be lined with an impervious membrane liner. Storm-water runoff will be collected in the lower part of the shared containment area for observation prior to release to the natural drainage course on the south side of the property. As an additional precaution, discharging storm water will flow through an oil/water separator with a tilted plate interceptor.

The containment and storm-water drainage design will be finalized during the detailed engineering and design phase.

3.4.2.2.2 Earthworks

In addition to the secondary containment modifications, a new access road will be constructed along the north side of the containment area. The new road will be paved.

The partial removal of the existing berm, the excavation for the tank foundation, and the regrading of the Tank 103 and Tank 104 containment areas will result in a large volume of excavated materials. Excess excavated material may be stored on-site or disposed of off-site.

3.4.2.3 Structural

Pipe supports and buildings will be mounted on concrete or steel pile foundations designed using geotechnical information specific to the site.

3.4.2.4 Storage Tanks

See Table 3.4.5 for a list of tanks that will be at Sumas Terminal after TMEP.

TABLE 3.4.5

TANKS AT SUMAS TERMINAL AFTER TMEP

Tank Number	Capacity		Service	Current Status	Roof
	(m^3)	(bbl)			
Tank 100	27,820	175,000	Puget	P	IFR
Tank 101	23,850	150,000	Puget	E	EFR
Tank 102	23,850	150,000	Puget	E	EFR
Tank 103	23,850	150,000	Puget	E	IFR
Tank 104	24,640	155,000	Puget	E	IFR
Tank 121	8,740	55,000	Puget	E	EFR
Tank 122	8,740	55,000	Puget	E	EFR
Total	141,500	890,000			

Notes: P - Planned
E - Existing
EFR - External Floating Roof
IFR - Internal Floating Roof

Tank 100 and its foundation will be designed in accordance with API 650 and the CCME guidelines. It will have a steel pontoon or light-weight aluminum floating roof with mechanical seals and a fixed steel cone or dome roof or a fixed aluminum dome roof.

Tank 100 will be provided with nozzles to allow for process connections, maintenance access and the future installation of propeller mixers and/or jet mixers. Tank 100 will also be fitted with a TVAU for odour control. The final number and sizes of the nozzles and the specification for the TVAU will be determined during the detailed engineering and design phase.

Tank 100 will be externally coated with a zinc primer/urethane top-coat system. The exterior colour will be white. The tank floor top and the interior 1 m of the lower shell will be coated with epoxy.

Spacing between Tank 100 and Tanks 103 and 104 will be in accordance with BCFC and NFPA 30, specifically no less than the sum of their respective diameters divided by four.

3.4.2.5 Mechanical

New valves will be added at the existing manifold to connect the Tank 100 tank line to the outbound lines to Sumas Station.

3.4.2.6 Piping

3.4.2.6.1 Design Pressure

The design pressure of the Sumas Terminal piping is 4,960 kPag (720 psig). The design pressure of the new piping will be consistent with the existing piping.

3.4.2.6.2 Design Flow Rates

Hydraulic design will be such that Tank 100 can receive at the TMEP Line 2 design flow rate of 3,765 m^3/hour (568,400 bbl/d) and discharge at the future Puget Sound Pipeline design flow rate of 1,570 m^3/hour (236,800 bbl/d).

3.4.2.6.3 Materials

Pipe, fittings, and flanges will meet the requirements of CSA Z245.1 Steel Pipe, CSA Z245.11 Steel Fittings, CSA Z245.12 Steel Flanges and the KMC 2000 series standards and specifications. Valves will meet the requirements of CSA Z245.15 Steel Valves and KMC Standard MP1300 Valve Selection and Specification and its associated standards and specifications. Material grades and wall thicknesses will be determined in accordance with the applicable standards and specifications identified in Tables 5.1.1 and 5.1.2 in Appendix D, including MP1110 Station and Terminal Piping Design. The operating pressure will not be greater than 80 per cent of the test pressure.

3.4.2.6.4 Welding and Fabrication

Welding and fabrication of piping will be in accordance with the applicable standards and specifications listed in Tables 5.1.1 and 5.1.2 in Appendix D.

3.4.2.6.5 Non-Destructive Testing

Non-destructive testing of pipe welding will be in accordance with applicable standards and specifications listed in Tables 5.1.1 and 5.1.2 in Appendix D.

3.4.2.6.6 Hydrostatic Pressure Testing

All piping will be hydrostatically pressure tested in accordance with the applicable standards and specifications listed in Tables 5.1.1 and 5.1.2 in Appendix D, including MP4111 Station Hydrostatic Testing.

Piping spools constructed in fabrication shops will be hydrostatically pressure tested prior to delivery to site. Site fabricated pipe will be hydrostatically pressure tested at site.

3.4.2.7 Electrical

The additional electrical load at Sumas Terminal will be small and can be accommodated with the existing power service. The power line that runs west to east, on the north side of the property will be replaced with an upgraded power line further north to allow for the construction of the new roadway.

Cable trays will be added as required. Road crossings will be underground in precast concrete trenches with removable covers. Tray supports will be attached to the new pipe racks, where possible.

Area lighting will be directional and targeted to the greatest extent practical to reduce extraneous lighting impact on the adjacent community.

3.4.2.8 Instrumentation

The general scope of the instrumentation will include:

- a radar gauging system on Tank 100, with high level and low level sensing and overfill protection capability;
- a redundant overfill protection system on Tank 100;
- a fire detection system on Tank 100;
- a leak detection system under Tank 100;
- a hydrocarbon detection system in the new shared containment areas;
- piping pressure and temperature sensors and transmitters for measurement and protection; and
- ultrasonic meters (for leak detection) on the Line 2 feeder pipeline.

The characteristics and features of the instrumentation will be as per Section 3.4.1.10.1, as applicable, except that the tank fire detection system will be other than IR. IR detectors cannot be used on fixed-roof tanks.

3.4.2.9 Protection Philosophy

3.4.2.9.1 Fire Protection Systems

The fire protection system for Tank 100 will be an extension of the existing fire protection system which has recently been upgraded. Storage tanks will be fitted with seal-area foam pourers permanently connected to the fire-water/foam supply system.

3.4.2.9.2 Emergency Shutdown System

All equipment added for TMEP will be integrated into the existing Sumas Terminal ESD system, which will be expanded and enhanced as necessary.

3.4.2.10 Control

The control system for the new facilities, including the Line 2 take-off facility, will be integrated with existing Sumas Terminal control system and will comply with existing control philosophies. The majority of operational functions will normally be controlled from the PCC or SCC by CCOs using the SCADA system. The function of the SCADA system for Sumas Terminal will be very similar to the function for a pump station. Additional details on the function of the SCADA system are included in Section 3.3.17 and in Volume 4C, Section 7.1.

New control panels housing remote I/O racks will be provided where required. An existing UPS will provide power to the new remote I/O racks. Additional HMIs will not be required. HMI upgrades and reconfiguration will be performed as necessary to incorporate status, analog information, and control of the additional tank, piping, valves, alarms, equipment, process data, and trends. Where possible, tank and meter display screens will be the same as currently in use.

Control and shutdown functions for the protection of equipment and systems will be installed at the equipment and will be independent of inputs from SCADA or operation of the SCADA system.

The existing Operating Limits and Protective Device Settings document will be updated to include settings and functionality for all new equipment.

3.4.2.10.1 Communication

The existing wired and fiber optic industrial network will be expanded to provide communications between PLCs and equipment. Communications to the Primary and Secondary Control Center SCADA systems will be by leased land line. Back-up communications will be provided by satellite.

3.4.3 Burnaby Terminal

3.4.3.1 Overview

Burnaby Terminal is located on the south slope of Burnaby Mountain in the City of Burnaby, BC, and the greater Vancouver metropolitan area (Figure 3.4.5).

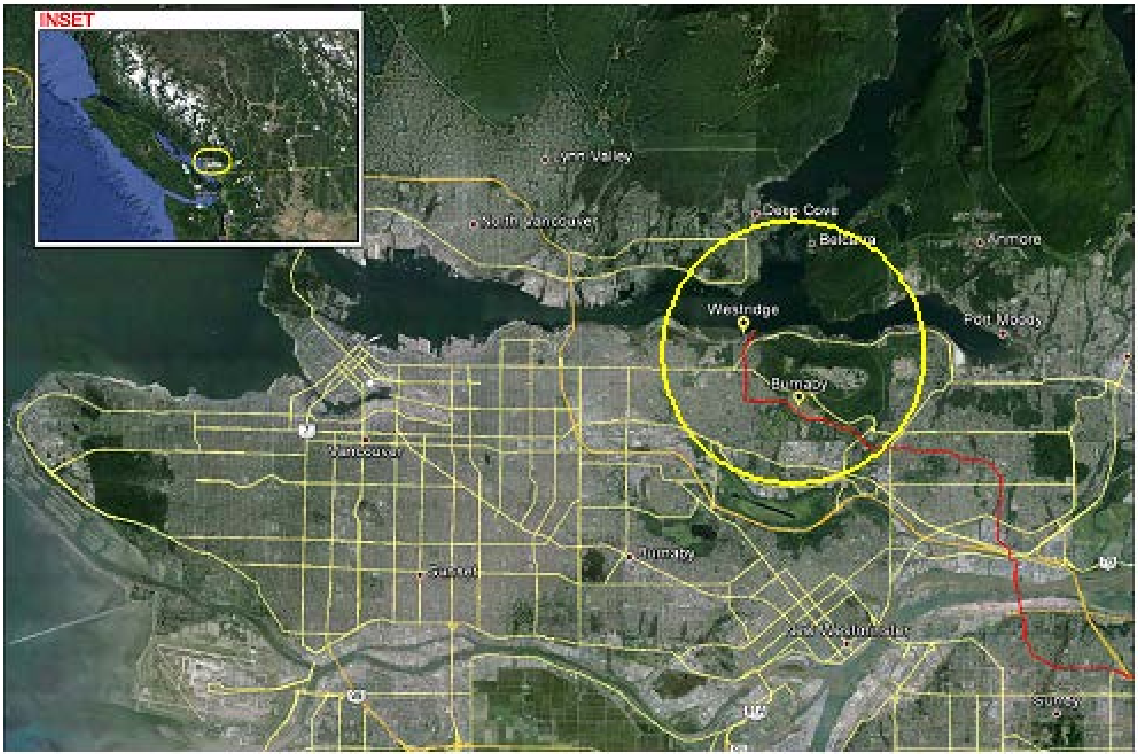


Figure 3.4.5 Burnaby Terminal Location

Currently Burnaby Terminal has 13 existing tanks ranging in size from 12,720 m^3 (80,000 bbl) to 24,640 m^3 (155,000 bbl) for a total shell capacity of approximately 267,900 m^3 (1,685,000 bbl).

For TMEP, 14 new tanks are proposed, ranging in size from 39,750 m^3 (250,000 bbl) to 53,620 m^3 (335,000 bbl), for a total shell capacity of approximately 639,140 m^3 (4,020,000 bbl). To make room for the new Tank 74, existing Tank 74 will be demolished.

When all of the tanks are in service, the total capacity of Burnaby Terminal will be approximately 894,320 m^3 (5,625,000 bbl).

Figure 3.4.6 provides an aerial view of the existing site.

Figure 3.4.6 Burnaby Terminal

The general scope of TMEP at Burnaby Terminal includes:

- 14 new storage tanks;
- demolition of 1 tank;
- new containment areas, access roads, and storm-water drainage systems;
- a partial RI area and an intermediate storm-water retention area;
- large bore tank lines and process piping;
- a valve manifold, booster pumps, and leak detection meters;
- receiving and sending traps on the incoming (from Edmonton) and outgoing (to Westridge) pipelines;
- an expanded and enhanced fire-protection system; and
- four ESBs, one VFD building and one foam building.

Within the property, one new 914 mm (NPS 36) diameter inbound pipeline segment will be installed to receive oil from Edmonton and two new 762 mm (NPS 30) diameter outbound pipeline segments will be installed to transport oil to Westridge Marine Terminal. These will connect with the new mainline pipelines that will be constructed outside the property. The existing 609 mm diameter (NPS 24) outbound pipeline to Westridge Marine Terminal will remain in service but may be extended and/or rerouted within Burnaby Terminal.

Figures 3.4.7 and 3.4.8 show the general arrangement of the TMEP tanks and terminal facilities as well as the existing tanks and terminal facilities.

Figure 3.4.7 Burnaby Terminal Proposed Plot Plan

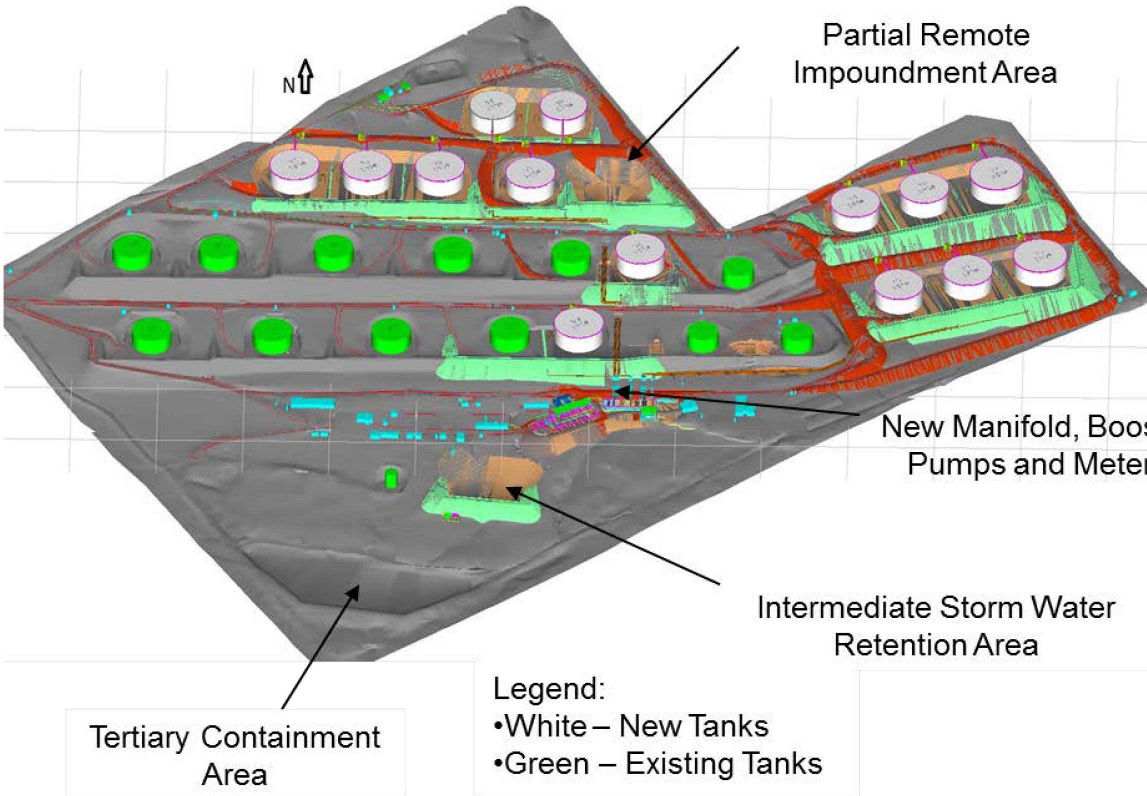


Figure 3.4.8 Burnaby Terminal Proposed Layout

3.4.3.2 Civil

Major civil tasks will include:

- removal of trees in and around the natural drainage courses in the construction areas;
- rerouting of the natural drainage courses into below-ground culverts or above-ground channels as appropriate;
- re-grading of the undeveloped areas to allow 14 storage tanks to be installed;
- construction of the tank foundations;
- construction of secondary containment;
- construction of a new partial RI area near Tank 97 and Tank 98;
- installation of a new drainage system to direct runoff from the new containment areas;
- construction of access roads; and
- construction of foundations for pumps, meters, and pipe supports.

Preliminary geotechnical information suggests that the likely tank foundation design will be a concrete ring wall with granular fill inside the ring and that the likely equipment and pipe support foundations will be spread footings. The designs will be confirmed after the geotechnical program has been completed during the detailed engineering and design phase.

The tanks will be located on a slope and it is expected that the excavations to create the foundation and containment terraces will require permanent shoring.

The various tributaries of Eagle Creek are currently routed through culverts in the lower portion of the site. The upper portions of these tributaries will either be rerouted through culverts that join the existing culverts or redirected through new culverts or open channels through the site, whichever is most practical.

3.4.3.2.1 Storage Tank Secondary Containment

Due to space limitations, the storage tanks that will be added for TMEP at Burnaby Terminal will generally share containment areas with other tanks and containment capacity will be provided in accordance with CSA Z662 and the BCFC, specifically 100 per cent of the working volume of the largest tank plus 10 per cent of the working volume of the other tanks that share the common containment area. The containment for Tanks 96, 97, and 98 will be partially provided by the RI adjacent to the tanks. In addition, existing Tanks 71, 73, 85, and 86 will be annexed into shared containment areas. When TMEP is complete there will be 17 tanks within shared containment areas and 9 tanks with individual containment areas (Table 3.4.6).

All secondary containment areas will have impermeable membrane liners covered with gravel for protection. All secondary containment areas will be provided with a level alarm, a hydrocarbon detector, and a motor operated valve (MOV). If open for storm-water drainage, the MOV will close if hydrocarbons are detected.

Sub-surface drains will be installed under the secondary containment liners to prevent “floating” of the liners. The sub-surface drainage system will be independent of the containment drainage system and will discharge to the existing tertiary containment area.

TABLE 3.4.6

BURNABY TERMINAL SECONDARY CONTAINMENT TANK GROUPS

Tank	Group	Current Status	Containment Type
71	1	E	Shared
72	n/a	E	Individual
73	1	E	Shared
74	2	E/P	Shared
75	3	P	Shared
76	2	P	Shared
77	3	P	Shared
78	2	P	Shared
79	3	P	Shared
80	4	P	Shared
81	n/a	E	Individual
82	n/a	E	Individual
83	n/a	E	Individual

TABLE 3.4.6

BURNABY TERMINAL SECONDARY CONTAINMENT TANK GROUPS (continued)

Tank	Group	Current Status	Containment Type
84	n/a	E	Individual
85	1	E	Shared
86	4	E	Shared
87	n/a	E	Individual
88	n/a	E	Individual
89	1	P	Shared
90	n/a	E	Individual
91	5	P	Shared
93	5	P	Shared
95	5	P	Shared
96	6	P	Shared with partial RI
97	n/a	P	Individual with partial RI
98	6	P	Shared with partial RI

Notes: n/a = not applicable

P = Planned

E = Existing

To achieve efficient storm-water management, the new shared secondary containment areas will be connected to an intermediate storm water retention area via below-ground piping. This in turn will be connected to the tertiary containment area, also via below-ground piping. The existing secondary containment areas are connected directly to the tertiary containment area.

Storm-water released from the intermediate containment area will flow through an oil/water separator en-route to the tertiary containment area. The intermediate storm-water retention area will be sized to provide surge capacity, *i.e.,* to allow storm-water to be released from multiple shared containment areas without exceeding the capacity of the oil/water separator. The intermediate retention area will have an impermeable membrane liner and a level alarm, hydrocarbon detector, and a MOV. If open for storm-water drainage, the MOV will close if hydrocarbons are detected.

The management of storm-water release from the tertiary containment area will be unchanged from the current operation.

3.4.3.2.2 Earthworks

The excavation of tank lines, the grading of the site, the removal of some of the existing berms, the excavation of the partial RI, and excavation for the new tank foundations will result in a large volume of excavated materials. Some of the excavated material will be stored or disposed of off-site due to the lack of available storage on-site. New berms, ramps, and roads will be constructed using some of the excavated material, provided that it is suitable.

Roads will be designed to enable vehicle access around the entire perimeter of the tanks, where feasible. The new roads will tie in to the existing site roads. Roads will be separated from secondary containment walls, where practical. Main roads will be two lanes, 6 m wide. Secondary containment access roads will be 4 m wide. Roads to the manifold, booster pump, and meter areas will allow servicing by mobile cranes. All new roads will be paved.

Storm water surface run-off from other than containment areas will be directed into open ditches. The minimum ditch depth will be 600 mm. Ditches will be concrete lined in steep and high flow areas. Ditched run-off will flow to existing site ditches and/or culverts and then to the existing tertiary containment area.

Culverts for the redirection of the Eagle Creek tributaries will be designed for gravity flow. Culverts will be concrete pipe with manholes at selected points of slope and direction change and will be equipped with entry/exit headwalls, rip rap erosion control, and energy dissipaters. No culverts will run under tanks. Filled creek beds will be provided with drainage for residual groundwater flows. In some cases, the Eagle Creek tributaries may be redirected through appropriately designed open channels.

3.4.3.3 Structural

Pipe and equipment supports and buildings will be mounted on concrete or steel pile foundations or concrete spread footings designed using geotechnical information specific to the site.

3.4.3.4 Storage Tanks

Table 3.4.7 provides a list of new tanks to be constructed at Burnaby Terminal for TMEP. Table 3.4.8 provides a list of the tanks that will be at Burnaby Terminal after TMEP.

TABLE 3.4.7

TEMP TANKS AT BURNABY TERMINAL

#	Tank #	Capacity		Service	Current Status	Roof
		(m³)	(bbl)			
1	74*	45,310	285,000	CC	E/P	IFR
2	75	45,310	285,000	CC	P	IFR
3	76	45,310	285,000	CC	P	IFR
4	77	45,310	285,000	CC	P	IFR
5	78	53,260	335,000	CC	P	IFR
6	79	53,260	335,000	CC	P	IFR
7	80	45,310	285,000	CC	P	IFR
8	89	45,310	285,000	CC	P	IFR
9	91	45,310	285,000	CC	P	IFR
10	93	45,310	285,000	CC	P	IFR
11	95	45,310	285,000	CC	P	IFR
12	96	39,750	250,000	CC	P	IFR
13	97	45,310	285,000	CC	P	IFR
14	98	39,750	250,000	CC	P	IFR
	Total	639,140	4,020,000			

Notes: * Tank 74 is currently 12,720 m^3 (80,000 bbl) and will be replaced with a 45,310 m^3 (285,000 bbl) tank

CC - Common Carrier

P - Planned

E - Existing

IFR - Internal Floating Roof

TABLE 3.4.8

BURNABY TERMINAL TANKS AFTER TMEP

#	Tank #	Capacity		Service	Current Status	Roof**
		(m^3)	(bbl)			
1	71	12,720	80,000	CC	E	EFR
2	72	12,720	80,000	CC	E	EFR
3	73	12,720	80,000	CC	E	IFR
4	74*	45,310	285,000	CC	E/P	IFR
5	75	45,310	285,000	CC	P	IFR
6	76	45,310	285,000	CC	P	IFR
7	77	45,310	285,000	CC	P	IFR
8	78	53,260	335,000	CC	P	IFR
9	79	53,260	335,000	CC	P	IFR
10	80	45,310	285,000	CC	P	IFR
11	81	23,850	150,000	CC	E	IFR
12	82	23,850	150,000	CC	E	EFR
13	83	23,850	150,000	CC	E	EFR
14	84	23,850	150,000	CC	E	EFR
15	85	23,850	150,000	CC	E	EFR
16	86	23,850	150,000	CC	E	IFR
17	87	24,640	155,000	CC	E	IFR
18	88	24,640	155,000	CC	E	IFR
19	89	45,310	285,000	CC	P	IFR
20	90	24,640	155,000	CC	E	IFR
21	91	45,310	285,000	CC	P	IFR
22	93	45,310	285,000	CC	P	IFR
23	95	45,310	285,000	CC	P	IFR
24	96	39,750	250,000	CC	P	IFR
25	97	45,310	285,000	CC	P	IFR
26	98	39,750	250,000	CC	P	IFR
	Total	894,320	5,625,000			

Notes: * Tank 74 is currently 12,720 m^3 (80,000 bbl) and will be replaced with a 45,310 m^3 (285,000 bbl) tank

CC - Common Carrier

P - Planned

E - Existing

EFR - External Floating Roof

IFR - Internal Floating Roof

Tanks and their foundations will be designed in accordance with API 650 and the CCME Guidelines. They will have steel pontoon or light-weight aluminum floating roofs with mechanical seals and fixed steel cone or dome roofs or fixed aluminum dome roofs.

Tanks will be provided with nozzles to allow for process connections, maintenance access and the future installation of propeller mixers and/or jet mixers. They will also be fitted with a TVAU for odour control. The final number and sizes of the nozzles and the specification for the TVAU will be determined during the detailed engineering and design phase.

Although all of the TMEP tanks have been initially designated as internal floating roof tanks with TVAU odor control units, the product assignments for the tanks have yet to be determined. If during the detailed engineering and design phase it can be determined with a high degree of certainty that specific tanks are likely to be in long-term service with low-odor products, these tanks may be designated as external floating roof tanks without odor control, assuming the overall hydrocarbon and odor emissions objectives of the regulators having jurisdiction can still be met.

Tanks will be externally coated with a zinc primer/urethane top-coat system. The exterior colour will be determined with City of Burnaby and public input. The tank floor top and the interior of the lower 1 m of shell will be coated with epoxy.

Spacing between adjacent tanks will be in accordance with BCFC and NFPA 30, specifically no less than the sum of their respective diameters divided by four. Set backs from property lines will be in accordance with NFPA 30 and Burnaby City requirements.

3.4.3.5 Buildings

Four new ESBs, one VFD building and one foam building will be required to support the TMEP infrastructure at Burnaby Terminal. All buildings will pre-fabricated and pre-assembled, complete with the equipment they will house, off-site.

HVAC and smoke detectors will be provided, as necessary or as required by regulation.

3.4.3.6 Mechanical

Noise levels will be at or below the location-specific permissible limits of the applicable legislation. Where necessary to meet these limits, pumps, blowers, and other noise emitting equipment will be placed in noise reduction enclosures or other noise reduction methods will be employed.

3.4.3.6.1 Booster Pumps

Up to eight API 610 horizontal, split case, booster pumps of up to 500 HP (373 kW) each will be installed.

In an eight pump configuration, two pumps, rated at 2,320 m^3/hour (350,000 bbl/d) each and configured in parallel, will be required for the delivery to each of the Westridge Marine Terminal pipelines at a total flow rate per pipeline of 4,640 m^3/hour (700,000 bbl/d). The other two pumps will be spares. Other configurations with different numbers and sizes of pumps are possible and may be considered. The number and size of the pumps will be finalized during the detailed engineering and design phase.

Each of the booster pump motors will be controlled by a VFD.

3.4.3.6.2 Auxiliary Pump

A new pump will be provided for Tank 99 (Waste Oil tank). The pump will transfer collected products to the appropriate tanks via a transfer header. The pump will have sufficient head to enter any of the new tanks at high operating liquid levels. The pump capacity will be determined during the detailed engineering and design phase.

3.4.3.7 Piping

Tank lines will be above ground, where practical, but will be below ground at certain road or other crossings, or where they must transect containment berms. Tank lines will be designed to be “pig-able”. Manifold, pump, meter, and interconnection piping will generally be above ground except at road and other crossings.

3.4.3.7.1 Design Pressure

The design pressure of the existing Burnaby Terminal tank lines and manifold piping is 4,960 kPag (720 psig), consistent with a pressure rating of PN 50 (ANSI 300#). However, the current full-flow pressure relief set-point is at or below 1,900 kPag (276 psig), consistent with a pressure rating of PN 20 (ANSI 150#). Therefore, the design pressure of the new interconnection piping, tank lines, and manifold piping will be 1,900 kPag or PN 20, as is the industry standard for terminal facilities with pressure relief systems. The Westridge Marine Terminal booster pumps will be selected such that their shut-off pressure will not exceed the MOP of the Westridge Marine Terminal pipelines.

3.4.3.7.2 Design Flow Rates

The design flow rates at Burnaby Terminal are listed in Table 3.4.9.

TABLE 3.4.9

DESIGN FLOW RATES

Pipe	Design Flow Rate	
	m^3/hour	bbl/d
Line 1 Inlet	2,440	368,400
Line 2 Inlet	3,765	568,400
Westridge Marine Terminal Pipelines	4,635	700,000
Westridge Marine Terminal Pipelines (Pump Back)	to be determined (TBD)	TBD

3.4.3.7.3 Pressure Relief

Full-flow pressure relief with a set-point at or below 1,900 kPag (276 psi) will be provided upstream of the first valve downstream of the pressure class transition between the incoming mainlines (PN 100 or ANSI 600#) and the manifold interconnection piping (PN 20 or ANSI 150#). The relief line will be connected to Tank 80 and Tank 89 and the flow path to one of them will be normally open.

With two tanks capable of providing relief service, one will always be available when the other is taken out of service for API 653 inspection. Sufficient relief capacity will always be reserved in the selected tank.

3.4.3.7.4 Materials

Pipe, fittings, and flanges will meet the requirements of CSA Z245.1 Steel Pipe, CSA Z245.11 Steel Fittings, CSA Z245.12 Steel Flanges and the KMC 2000 series standards and specifications. Valves will meet the requirements of CSA Z245.15 Steel Valves and KMC Standard MP1300 Valve Selection and Specification and its associated standards and specifications. Material grades and wall thicknesses will be determined in accordance with the applicable standards and specifications identified in Tables 5.1.1 and 5.1.2 in Appendix D, including MP1110 Station and Terminal Piping Design. The operating pressure will not be greater than 80 per cent of the test pressure.

3.4.3.7.5 Welding and Fabrication

Welding and fabrication of piping will be in accordance with the applicable standards and specifications listed in Tables 5.1.1 and 5.1.2 in Appendix D.

3.4.3.7.6 Non-destructive Testing

Non-destructive testing of pipe welding will be in accordance with applicable standards and specifications listed in Tables 5.1.1 and 5.1.2 in Appendix D.

3.4.3.7.7 Hydrostatic Pressure Testing

All piping will be hydrostatically pressure tested in accordance with the applicable standards and specifications listed in Tables 5.1.1 and 5.1.2 in Appendix D, including MP4111 Station Hydrostatic Testing.

Piping spools constructed in fabrication shops will be hydrostatically pressure tested prior to delivery to site. Site fabricated pipe will be hydrostatically pressure tested at site.

3.4.3.8 Auxiliary Systems

3.4.3.8.1 Waste Oil Tank

The existing Tank 99, which is in waste oil service, will be connected to the thermal relief discharge lines and selected drain lines on the new manifold and booster pump piping.

3.4.3.8.2 Fire Protection Systems

The Burnaby Terminal fire-protection system will be expanded and enhanced to be generally consistent with the recently upgraded fire-protection system in Edmonton. Some upgrading of the existing fire-protection system at Burnaby Terminal is currently being carried out. The expansions and enhancements associated with TMEP will build on the current upgrades.

For TMEP, the fire-water reservoir will be expanded. In addition, a make-up water connection will be requested from the City of Burnaby to supplement or replace the current Eagle Creek water supply. New higher capacity fire-water pumps will be installed. The fire-water pumps will provide sufficient capacity for the storage tank seal-area fire-suppression systems, for full surface fire-fighting (by a portable foam cannon), and for cooling of adjacent tanks (by portable monitors).

A new foam supply building, with sufficient foam concentrate storage (or the ability to rapidly replenish from on-site portable foam concentrate totes) for tank seal-area and full surface fire-fighting, will also be installed.

Storage tanks will be fitted with seal-area foam pourers permanently connected to the fire-water/foam supply. The foam supply to each tank will be activated by automated valves.

Fire-water and foam will be distributed by underground mains, connected to form a loop for supply redundancy. High volume hydrants will be located throughout the terminal.

The design of the fire protection system will be finalized during the detailed engineering and design phase.

3.4.3.9 *Electrical*

Burnaby Terminal will have enough increase in power consumption to require a service upgrade by BC Hydro. Approximately 5 MW of additional power will be required for booster pumps and ancillary devices.

Currently the site has two separate feeds from BC Hydro: a lower feed from Shellmont Street and an upper feed from Aubrey Street. BC Hydro will perform a study during the detailed engineering and design phase to determine what reinforcements to their electrical system are required.

A new 12.5 kV to 4,160 V, 7.5 MVA transformer will be required to service the existing and new loads.

Four new ESBs, distributed around the site, will be required to house switch-gear, MCCs, and control panels. One VFD building will be required for the booster pumps.

A standby generator will be installed to provide emergency power to all MOVs and designated emergency equipment during a power outage. A UPS will be installed to maintain communications and critical information during the transfer from utility power to generator power.

Area lighting will be directional and targeted to the greatest extent practical to reduce extraneous lighting impact on the adjacent community.

3.4.3.10 *Instrumentation*

The general scope of the instrumentation will include:

- a radar gauging system on each storage tank, with high level and low level sensing and overfill protection capability;
- a redundant overfill protection system on each storage tank;
- a fire detection system on each storage tank;
- a leak detection system under each storage tank and in the interstitial space of the sump tank(s);
- a hydrocarbon detection system in each storage tank containment area and selected other containment areas;
- booster pump and piping pressure and temperature sensors and transmitters for measurement and protection;
- ultrasonic meters (for leak detection on the Westridge delivery lines); and
- densitometer(s).

The characteristics and features of the instrumentation will be as per Section 3.4.1.10.1, as applicable, except that the tank fire detection system will be other than IR. IR detectors cannot be used on fixed-roof tanks.

3.4.3.10.1 Leak Detection Metering System

One ultrasonic meter will be installed on each of the three pipelines to Westridge Marine Terminal for leak detection system flow measurement. Each meter will be rated for a flow rate of 4,635 m^3/hour (700,000 bbl/d). The leak detection meter runs will include instrumentation to provide continuous monitoring of fluid characteristics (including temperature, pressure, viscosity, and density), and flow computers.

3.4.3.11 Protection Philosophy

3.4.3.11.1 Emergency Shutdown System

All equipment added for TMEP will be integrated into the existing Burnaby Terminal ESD system, which will be expanded and enhanced as necessary. Additional integration will be developed between the ESD systems at Burnaby and at Westridge Marine Terminal. A standby generator will ensure essential services and ESD functionality during power outages.

3.4.3.12 Control System

The control system for the new facilities will be integrated with the existing Burnaby Terminal control system and will comply with existing control philosophies. The majority of operational functions will normally be controlled from the PCC or SCC by CCOs using the SCADA system, although operational staff will be present at the site 24 hours per day, seven days per week. The function of the SCADA system for Burnaby Terminal will be very similar to the function for a pump station. Additional details on the function of the SCADA system are included in Section 3.3.17 and in Volume 4C, Section 7.1.

New control panels housing remote I/O racks will be provided in each of the new ESBs. The UPS will provide power to the new remote I/O racks. Additional HMIs will be added as required. Upgrading and reconfiguration of the existing HMIs will be performed, as necessary, to incorporate status, analog information, and control of the additional tanks, piping, valves, alarms, equipment, process data, and trends. Where possible, tank and meter display screens will be the same as currently in use.

Control and shutdown functions for the protection of equipment and systems will be installed at the equipment and will be independent of inputs from SCADA or operation of the SCADA system.

The existing Operating Limits and Protective Device Settings document will be updated to include settings and functionality for all new equipment.

3.4.3.12.1 Communications

The existing wired and fibre optic industrial network will be expanded to provide communications between PLCs and equipment. Communications to the primary and secondary control centre SCADA systems will be by leased land line. Back-up communications will be provided by satellite.

An additional communications link will be installed between Burnaby Terminal and Westridge Marine Terminal to allow instantaneous response to alarms originating at either location.

3.4.4 Westridge Marine Terminal

3.4.4.1 Overview

Westridge Marine Terminal is located on the south shore of Burrard Inlet, east of the Second Narrows, in the City of Burnaby. Westridge Marine Terminal is 4 km, via the existing pipeline route, and 2.6 km, via a direct route, from Burnaby Terminal (Figures 3.4.9 and 3.4.10).

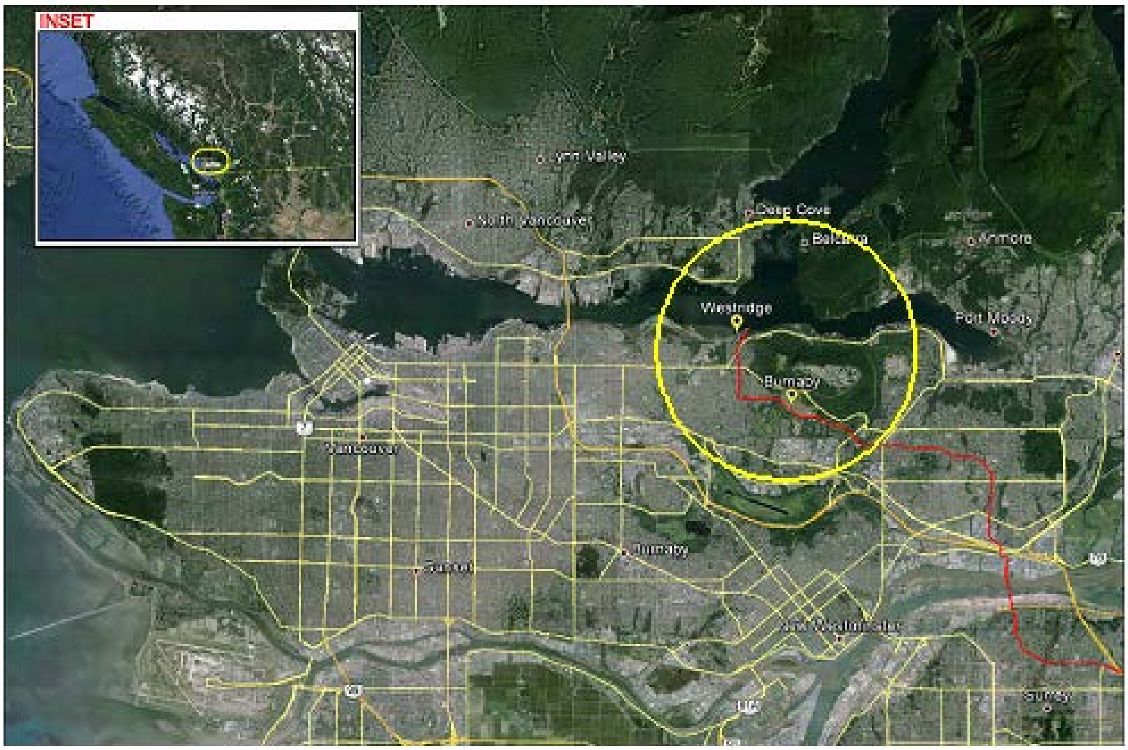


Figure 3.4.9 Westridge Marine Terminal Location

Figure 3.4.10 Burnaby Terminal and Westridge Marine Terminal Proximity

The purpose of Westridge Marine Terminal is:

- loading various types of crude oil onto Aframax or Panamax class tankers or tank barges; and
- unloading jet fuel from tankers and barges.

Westridge Marine Terminal currently has one dock with one berth. In addition to the dock, Westridge Marine Terminal has three storage tanks, having a total volume of 62,800 m^3 (395,000 bbl), currently used for storing jet fuel. Received jet fuel is delivered to the Vancouver International Airport by Trans Mountain's affiliate, Trans Mountain (Jet Fuel) Inc.

Figure 3.4.11 shows a recent photograph of Westridge Marine Terminal.

Figure 3.4.11 Westridge Marine Terminal

3.4.4.1.1 History

The existing dock was constructed in 1957. It has been upgraded to handle the mooring lines loads from Aframax class vessels. The deck length of 4.2 m was extended to 8.1 m and five additional 914 mm diameter pipe piles were added to each mooring dolphin. More significant upgrades will be required by 2020 to keep the dock in service. With TMEP, the existing dock will be demolished.

Figure 3.4.12 shows a historical photograph of Westridge Marine Terminal.

Figure 3.4.12 Westridge Marine Terminal Historical Photograph

3.4.4.1.2 Utilization

Typically five tankers and three barges are loaded and one or two barges are unloaded each month. The number of loadings fluctuates based on market conditions. With TMEP, it is expected that the number of loadings will increase to the equivalent of up to 34 Aframax class tankers. The number of barge loadings and un-loadings is not expected to change.

Vessels calling at Westridge Marine Terminal currently account for about 3 per cent of the total traffic that moves through the Port of Vancouver, officially known as Port Metro Vancouver (PMV). With TMEP, this is expected to rise to about 14 per cent.

3.4.4.1.3 Second Narrows Requirements

The immersed depth (or draft) of loaded vessels transiting the Second Narrows is limited to 13.0 m, under the current PMV operating rules. This is expected to increase to 13.5 m in the near future. PMV also limits laden tanker transits to near slack water (low current) during daylight hours and requires a minimum of 10 per cent of the draft as the under-keel clearance (UKC) at the edges of a channel 2.85 times the beam of the vessel. The latter requirement results in the UKC at the vessel, if the vessel is in the centre of the channel, being much greater than 10 per cent of the draft.

The Second Narrows navigational restrictions and the tidal cycles limit the number of vessels that can load to a 13.0 m draft. A preliminary analysis shows that average drafts (for Aframax vessels) of between 11.6 m and 12.4 m will be required to utilize enough of the transit windows to achieve the required Westridge Marine Terminal capacity. For typical Aframax vessels, this draft range corresponds to a heavy oil capacity of approximately 87,400 m^3 (550,000 bbl) and a light oil capacity of about 92,200 m^3 (580,000 bbl). These capacities have been used to determine the estimate of 34 Aframax tanker loadings per month.

3.4.4.1.4 Proposed Expansion

The general scope of TMEP at Westridge Marine Terminal includes:

Dock Facilities

- one new dock complex with three berths, each capable of loading up to Aframax class vessels, and one berth capable of receiving jet fuel; and
- a small utility dock with multiple berths for tugs, pilot boats, spill response vessels and equipment, and boom boats.

The Westridge Marine Terminal docks will be equipped with:

- fender and mooring structures;
- vessel access towers;
- delivery and receipt piping systems, including loading and unloading arms;
- vapour recovery systems; and
- a fire-protection system.

Foreshore Facilities

- a densified and expanded foreshore area;
- three receiving traps;
- a valve manifold, complete with interconnecting piping;
- custody transfer meters;
- two vapour recovery units (VRUs), complete with synthetic oil tanks, process vessels, piping, and transfer pumps;
- one vapour combustion unit (VCU);
- a nitrogen purge system;
- one pipeline pressure relief tank;
- a fire-protection system (fire water and foam), complete with a fire-water pump house;
- a storm-water handling system, complete with an oil/water separator; and
- a standby generator.

Figures 3.4.13 to 3.4.15 show conceptual representations of the Westridge Marine Terminal after TMEP.

The objectives for the development of the layout of the dock complex were to:

- provide the highest level of navigational safety, both for vessels berthing at Westridge Marine Terminal and for other vessels transiting the inlet or at one of the four anchorages nearby;
- provide three Aframax capable berths, allowing capacity for vessels to wait for cargo or transit windows and reduce pressure on the anchorages (and the number of vessel movements);
- allow the existing dock to remain in service during the construction of the new dock complex, and specifically until the new Berth 1 can be commissioned;
- minimize the overall footprint and the impact to community views; and
- eliminate deep-water dredging and reduce the amount of dredging for the foreshore expansion.

During the development of the dock complex layout, approximately 20 different possible layouts were considered. The layout selected has been reviewed and conditionally approved as most optimal for navigational safety by senior representatives of PMV, the Pacific Pilotage Authority and the BC Coast Pilots (BCCP). It is unlikely that the layout will materially change during the detailed engineering and design phase.

Opportunities to eliminate the pipeline pressure relief tank are being investigated. If possible, this will reduce the size of the foreshore expansion. The foreshore arrangement shown also considers the VRU technology selected during conceptual design and allows space for three VRUs. The planned reduction to two VRUs and the consideration of other vapour recovery technologies may result in reduction of the foreshore expansion.

Additional tanker support systems that are being considered include the ability to refuel tankers from barges and the future provision of shore power to reduce on-board generator use. Currently less than 5 per cent of the international tanker fleet is equipped to take shore power, so the consideration is for reserved space for future shore-power facilities only.

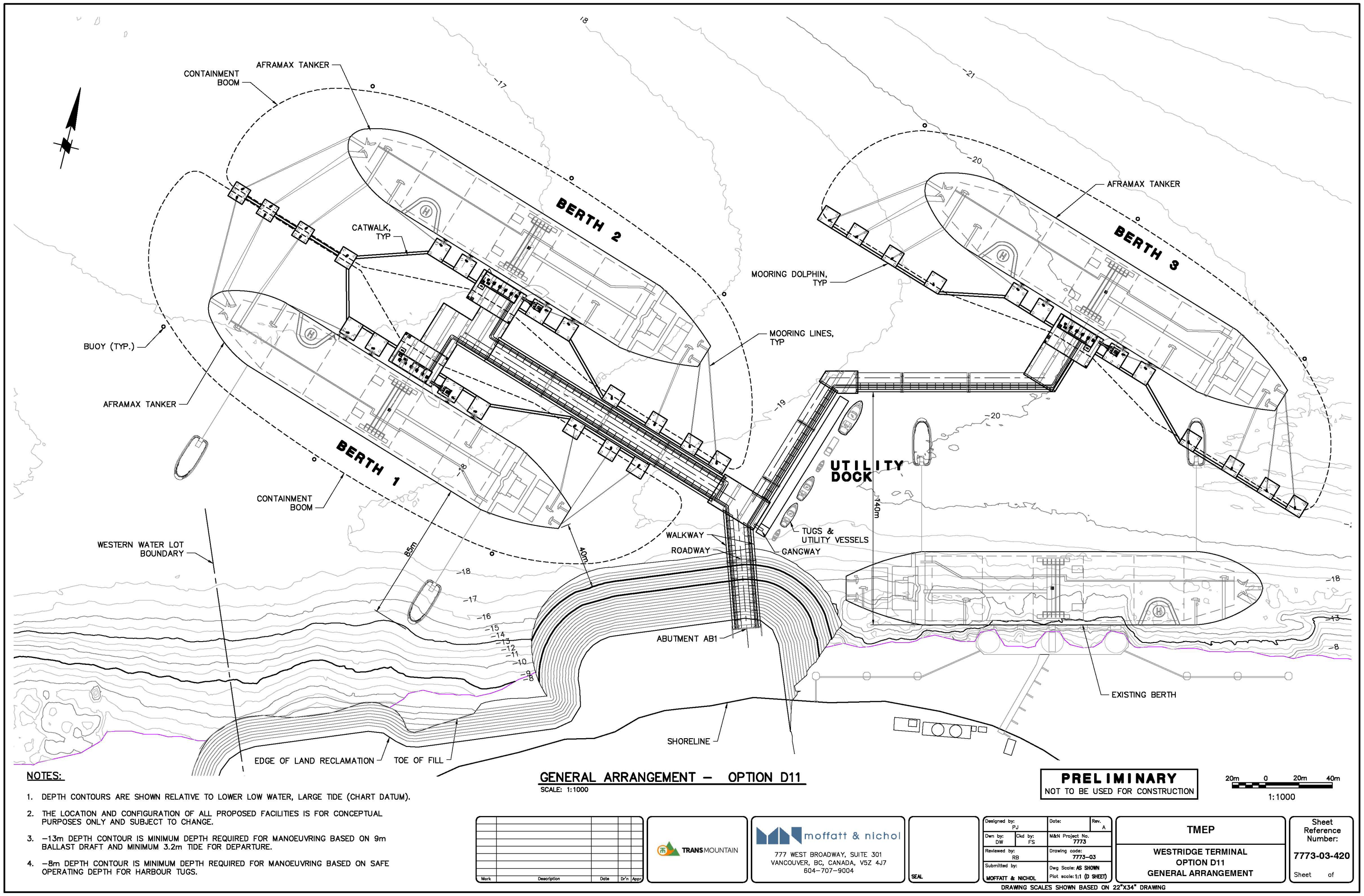


Figure 3.4.13 Westridge Marine Terminal Proposed Dock Plan

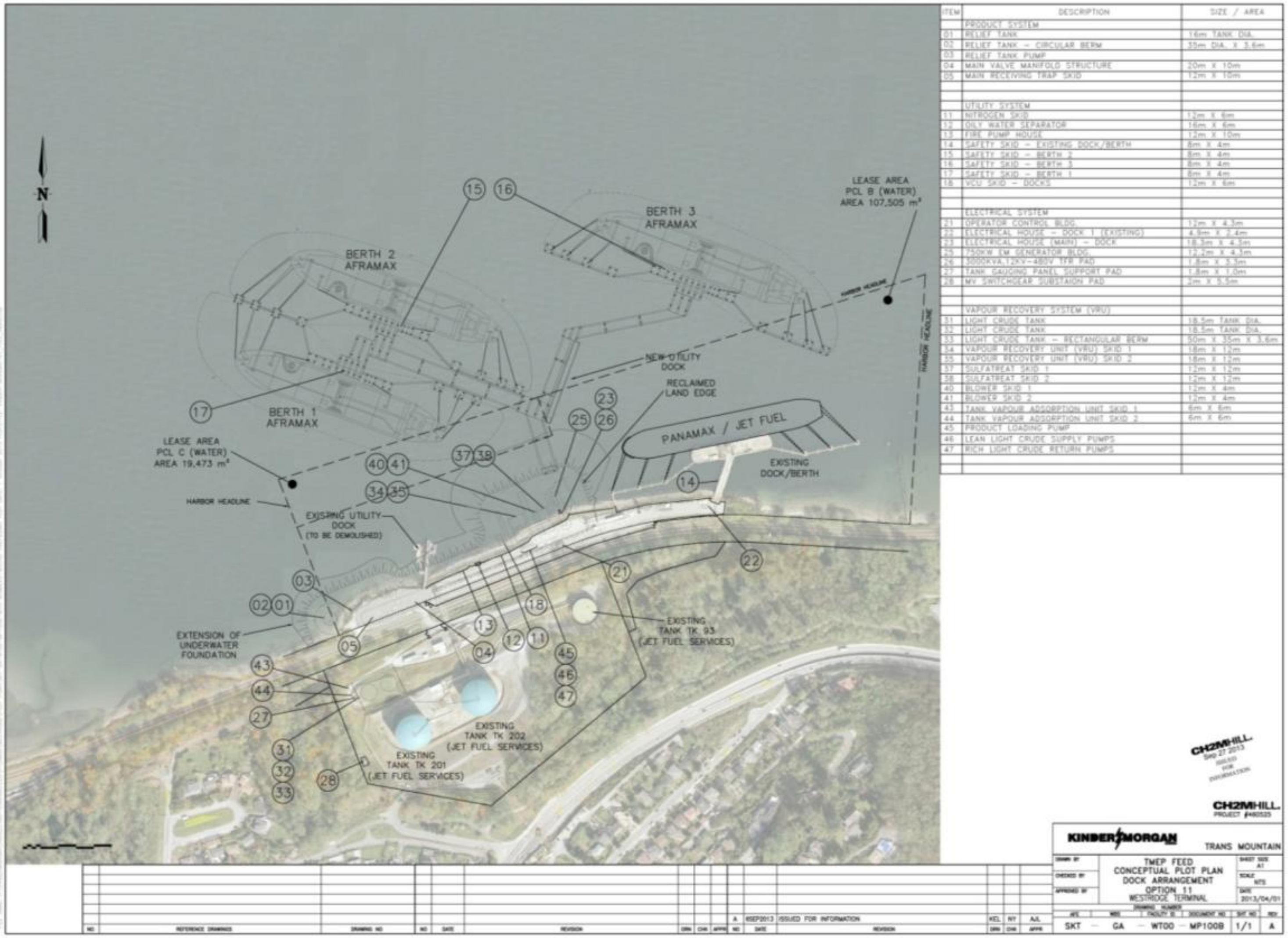


Figure 3.4.14 Westridge Marine Terminal Proposed Plot Plan

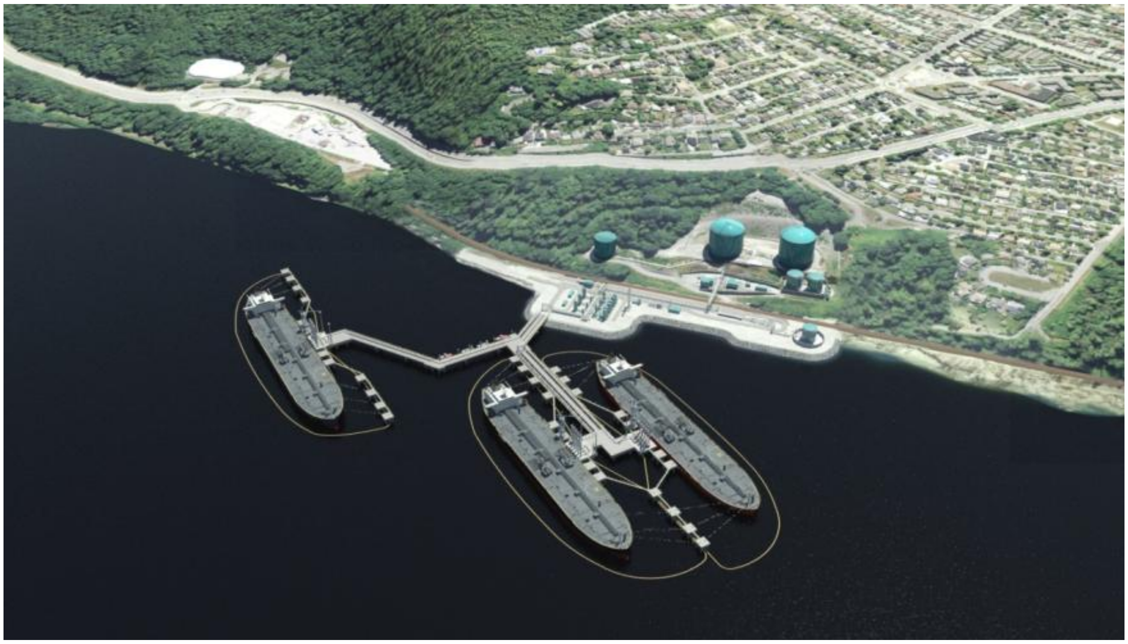


Figure 3.4.15 Westridge Marine Terminal Artistic Image

Batches of oil destined for Westridge Marine Terminal will be collected in the storage tanks at Burnaby Terminal and delivered via two new 762.0 mm (NPS 30) diameter pipelines and the existing 609.6 mm (NPS 24) diameter pipeline. Each pipeline will have a capacity of 4,635 m^3/hour (700,000 bbl/d), except that the existing line will only be capable of this flow rate when delivering light oil. The three delivery lines will terminate at receiving traps located at Westridge Marine Terminal. Interconnecting piping and a valve manifold will allow any of the three pipelines to deliver to any of the three berths. The pipelines will be designed to operable simultaneously.

Custody transfer meters, located just downstream of the manifold, will be provided on each of the loading lines. A control valve will also be provided on each loading line to modulate the loading flow rate.

Two VRUs and one VCU will be located at Westridge Marine Terminal. The vapour streams displaced from the vessels during loading will normally go to the VRUs, which will remove odorous components and capture the majority of the hydrocarbon vapors for reinjection onto the vessels being loaded or future vessels. During periods when one of the VRUs is shut down for maintenance or repair, the VCU will be used. The VCU will also be used if three vessels are being loaded simultaneously, which is expected to be less than 5 per cent of the time. One of the VRU designs under consideration requires two small tanks for synthetic crude used as part of the capture and reinjection cycle. The design of the VRU/VCU system will be finalized during the detailed engineering and design phase.

3.4.4.2 Civil

Due to limited existing space, the foreshore will have to be expanded beyond the current shore-line to accommodate the required infrastructure.

Westridge Marine Terminal will also have the following civil infrastructure components:

- an improved site access road, if practical;
- security fencing, including access/emergency egress gates;
- an expanded parking area for staff, contractors, and those attending vessels; and
- municipal water and sewage connections.

Access to the site will be via the existing road from Bayview Drive off of Inlet Drive. There is currently a manned security gate at the access road (Figure 3.4.16). A second access road, for emergency use only, may be considered.

The design of the civil infrastructure will be finalized during the detailed engineering and design phase.

Figure 3.4.16 Westridge Marine Terminal Road Access

3.4.4.2.1 Secondary Containment

Each berth will be provided with a spill containment boom sized to encircle an Aframax class vessel. Loading of a vessel will not start before the deployment of the boom. The boom will remain in place until the loading arms have been retracted and secured.

Secondary containment for the VRU tanks and the relief tank will be provided in accordance with CSA Z662 and the BCFC.

All new process facilities, including the receiving traps, piping manifold, vapour recovery equipment, and loading platforms, will be located within secondary containment. Storm water from these process areas will be directed to one or more below grade collection tanks on the foreshore for observation. Storm water discharged from the collection tank(s) will flow through an oil/water separation system prior to release into Burrard Inlet. Details of the containment and water treatment system will be determined during the detailed engineering and design phase.

Storm-water from non-process areas, including roadways, will be allowed to drain directly to Burrard Inlet.

3.4.4.2.2 Earthworks

During the detailed engineering and design phase, a detailed topographical survey will be completed to allow for the determination of cut and fill volumes to be expected during construction. A bathymetric survey will also be required. A detailed geotechnical survey of both the shore and seabed will also be completed to determine foundation design parameters. The investigation will include boreholes, cone penetration tests, a seismic scan of the seabed, and chemical sampling.

There is a risk of liquefaction of the existing fill soils, in the foreshore area, during an earthquake. Densification of the existing soils will be necessary to mitigate this risk. Dredging, fill, densification, and rock armouring will be required to establish the expanded foreshore area.

3.4.4.2.3 Dock Pile Foundations

It is estimated that approximately 200 piles will be installed for the new dock complex. Piles are required to support the access trestles, breasting dolphins, mooring dolphins, and loading platforms. Based on the assumptions regarding the existing seabed, the preliminary configuration of piles is assumed to be 1.4 m diameter vertical steel pipe piles for the dolphins and 1.2 m diameter vertical steel pipe piles for the platforms and trestles. Vertical piles are anticipated for ease of construction. Vertical piles are also generally better suited to zones of high seismicity.

Depending on the geotechnical conditions, piles may need to be embedded or socketted into bedrock to achieve sufficient loading capacity. One method of constructing such sockets is to install a temporary outer casing down to bedrock level, remove the material inside the casing, drill a socket, and fill it with tremie concrete. The pile is then placed into the socket and the casing is removed (Figure 3.4.17).

Piles will be fabricated and coated at a mill, transported to the contractor’s laydown area in approximately 22 m lengths, and then spliced to full length. The finished piles will be transported to Westridge Marine Terminal by barge.

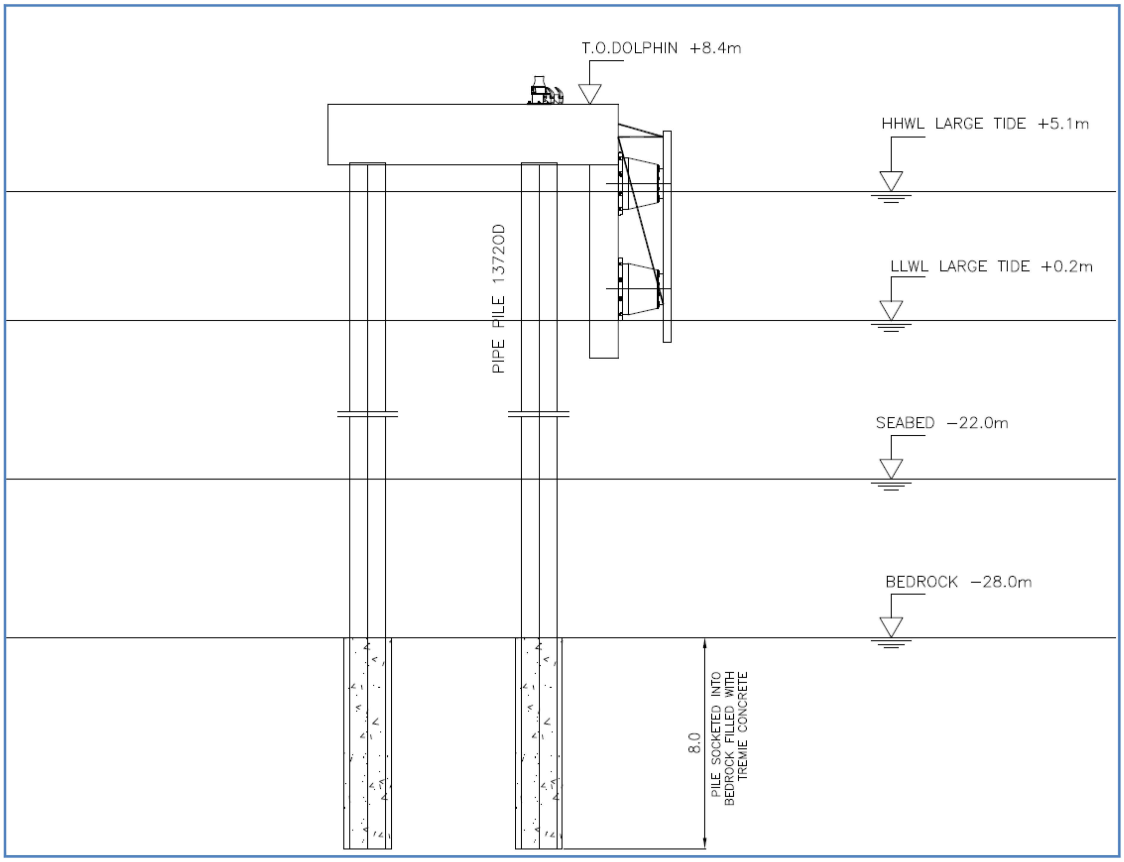


Figure 3.4.17 Typical Dolphin and Pile Foundation

3.4.4.3 Structural

Preliminary structural layout and design of the dock complex was based on a number of considerations and parameters as described in Sections 3.4.4.3.1 through 3.4.4.3.3. Final design of the dock complex will be based on further developed and refined considerations and parameters. Section 3.4.4.3.4 describes some proposed structural features of the dock complex.

3.4.4.3.1 Berthing and Mooring Study

A preliminary vessel berthing and mooring study was conducted to determine the maximum line forces that can be expected for the design vessels under foreseeable environmental conditions.

Fully-laden and ballasted states were considered as these will likely govern the design forces and will be somewhat conservative for partially-laden vessels. Forces from smaller vessels and barges will not govern the design, but an analysis was carried out to verify the mooring arrangement for these vessels.

Berthing force calculations were carried out based on the standard energy-based methods recommended by the Permanent International Association of Navigation Congresses, and a preliminary selection of fenders was made to estimate the berthing reaction forces on the structures.

A static mooring analysis was carried out using OPTIMOOR Mooring Analysis software. Assessment of dynamic effects will be done at a later stage. Based on previous experience with analyses for the Vancouver area, wave heights and periods within Burrard Inlet are too small to create dynamic motions in vessels of the design size.

3.4.4.3.2 Meteorological and Ocean Conditions

Tides and Water Levels

The site water level is dominated by semi-diurnal mixed tides propagating from the Pacific Ocean through the Strait of Georgia. It is characterized by two high water periods and two low water periods per day with inequality between consecutive high waters and low waters. Table 3.4.10 shows a summary of different tidal elevations derived from the Canadian Hydrographic Services.

TABLE 3.4.10

CHARACTERISTIC WATER LEVELS AND DATUM IN THE BURRARD INLET

Parameter	Vancouver Ch #3494 (m)	Deep Cove Ch #3494 (m)
EHHW (m CD)	5.6	n/a
HHWLT (m CD)	5.0	5.0
HHWMT (m CD)	4.4	4.3
MWL (m CD)	3.1	3.0
Chart Datum (CD)	0.0	0.0
LLWMT (m CD)	1.1	1.0
LLWLT (m CD)	-0.1	-0.1
ELLW (m CD)	-0.3	n/a

Notes: EHHW: Extreme Highest High Water (highest recorded)

HHWLT: Higher High Water Large Tide

HHWMT: Higher High Water Mean Tide

MWL: Mean Water Level

CD: Chart Datum, the plane of Lowest Normal Tides to which charts and water levels are referred

LLWMT: Lower Low Water Mean Tide

LLWLT: Lower Low Water Large Tide

ELLW: Extreme Lowest Low Water (lowest recorded)

For the Vancouver Harbour area, Geodetic Datum is 3.1 m above CD (BC Ministry of Environment 1995)

n/a = not applicable

Apart from tide, water levels are also affected by episodes of storm surge and tsunamis. In their hazard analysis of historic records, BC Ministry of Health Services has reported two occurrences of storm surge affecting West Vancouver – the first one in 1967 and the second in 1982. The storm surge in both cases was estimated at 0.9 m. There is no specific data for the Westridge Marine Terminal; however, the storm surge effect is expected to be minor. The highest and lowest recorded water levels (extreme highest high water [EHHW] and extreme lowest low water [ELLW]) in Vancouver Harbour are 5.6 m and -0.3 m, respectively. The difference of 0.6 m between EHHW and Higher High Water Large Tide is an indication of storm surge.

A review of publicly available information suggests that hazard from local tsunamis is ‘very low’ for the area. A landslide at the head of Indian Arm may be a possible source of a tsunami type event; however, there are no records of such an event ever occurring.

As in other coastal locations around the world, a rise in water level due to the effects of climatic change is expected. According to an assessment by DFO, by the year 2100, the Fraser River Delta could experience a mean relative sea level rise of 0.55 m with contributions of 0.29 m from global eustatic rise, 0.28 m from deltaic subsidence, and -0.02 m from glacial isostatic adjustment.

Wind

The Vancouver area is dominated by northwesterners in the summer and southeasterners in the winter with local winds varying in magnitude and direction as affected by the mountainous terrain.

In winter months, Indian Arm can experience a Squamish Wind or Arctic outflow.

In the absence of site-specific wind data, data obtained from the Halibut Bank buoy in the Strait of Georgia and some historical wind records maintained by PMV were used.

A summary of the available Halibut Bank wind data is presented in Table 3.4.11. The 1-year wind speed is inferred from empirical relationships. A weather station was recently installed at Westridge Marine Terminal. Data from this station will be available by early 2014 and will be used during the detailed engineering and design phase.

TABLE 3.4.11

SUMMARY OF EXCEEDANCE AND RETURN PERIOD ALL-DIRECTION WIND SPEEDS (HALIBUT BANK)

Description	Wind Speed (m/s)
50^{th} percentile exceedance	4.0
10^{th} percentile exceedance	8.0
1^{th} percentile exceedance	13.0
1-year return period	15.8
10-year return period	20.5
25-year return period	22.3
30-year return period	22.5
50-year return period	23.5
100-year return period	24.7

The National Building Code of Canada has prescribed wind pressures for different regions. For the Burnaby (Simon Fraser University) area, the prescribed 1 in 10 year, 1 in 30 year and 1 in 100 year wind pressures are 0.36 kPa, 0.44 kPa, and 0.53 kPa, respectively. These pressures translate to 23.6 m/s, 26.1 m/s, and 28.6 m/s, representing 3-second gusts.

Wave Activity

Westridge Marine Terminal is not exposed to swells propagating from the Pacific Ocean. Wave activity is dominated by local wind action and the available fetch. A spectral wave modeling technique was used to determine possible wave action. A total of 13 scenarios combining different wind speeds and directions were examined. The 1 in 100 year north-northeasterly wind generates the highest waves, characterized by a significant wave height of 0.72 m, a maximum wave height of 1.47 m, and a peak wave period of about three seconds.

The 50th, 10th, and 1st percentile significant wave heights measured by the Halibut Bank buoy are 0.13 m, 0.63 m, and 1.40 m, respectively.

Currents

A depth-averaged two-dimensional computer model was applied to predict currents at Westridge Marine Terminal. Simulations during a spring tide with a tidal range of about 4.0 m on January 2012 show that maximum shore-parallel depth-averaged flood and ebb currents of 0.47 m/s could develop. The corresponding surface current is estimated to be 0.52 m/s. An acoustic doppler current profiling instrument was recently deployed off Westridge Marine Terminal. The data is expected to be available in early 2014 and will be used to verify and calibrate existing models during the detailed engineering and design phase.

3.4.4.3.3 Vessel Characteristics

The existing berth at Westridge Marine Terminal has a water depth of 15 m, which is sufficient to handle vessels up to approximately 13.5 m draft. This draft corresponds to Aframax cargo sizes of between 95,390 m^3 (600,000 bbl) and 111,290 m^3 (700,000 bbl), depending on the beam of the vessel and the density of the oil. Fully-laden Aframax vessels (at a draft of about 15 m) can load up to about 119,200 m^3 (750,000 bbl) of heavy oil. Given the Second Narrows restrictions, the new berths will only be designed to load vessels to 13.5 m draft.

The berths will be designed to moor vessels of various sizes up to Aframax class. Typical dimensions of these vessels are shown in Table 3.4.12 and Table 3.4.13. As noted, Panamax and Aframax class vessels will be restricted to 13.5 m, less than their maximum design drafts.

TABLE 3.4.12

OIL VESSEL PARAMETERS

Parameter	Drakes Bay Oil Barge	Handymax Class	Panamax Class	Aframax Class
Capacity - Volume (bbl)	100,000	300,000	495,000	750,000
Capacity - Tonnage (DWT)	17,300	50,000	75,000	117,000
Length Overall (m)	115.8	190	232	250
Beam (m)	23.2	32.2	32.2	44.0
Maximum Draft (m)	7.9	11	14	15.1

TABLE 3.4.13

JET FUEL VESSEL PARAMETERS

Parameter	Crowley 650	Handy Class	Handymax Class
Capacity (bbl)	178,000	120,000	300,000
Deadweight (DWT)	27,000	20,000	50,000
Length Overall (m)	179	150	190
Beam (m)	23	24	32
Maximum Draft (m)	8	10	11

3.4.4.3.4 Vessel Berths

Each berth will require the following major structural components:

- an access trestles with a road, walkway, and pipe racks;
- berthing and mooring structures connected with catwalks; and
- a loading platform with a gangway tower.

Access Trestles and Catwalks

Each access trestle will have a 4.9 m wide roadway and pipe racks on one or both sides. The roadway will be suitable for trucks, mobile cranes, and emergency vehicles. The roadways and pipe racks will likely each be supported by two structural steel plate girders. The roadways and pipe racks will be independent of each other. The trestle spans will be in the range of 40 m. The roadway surface will be created by a cast-in-place deck slab. See Figure 3.4.18.

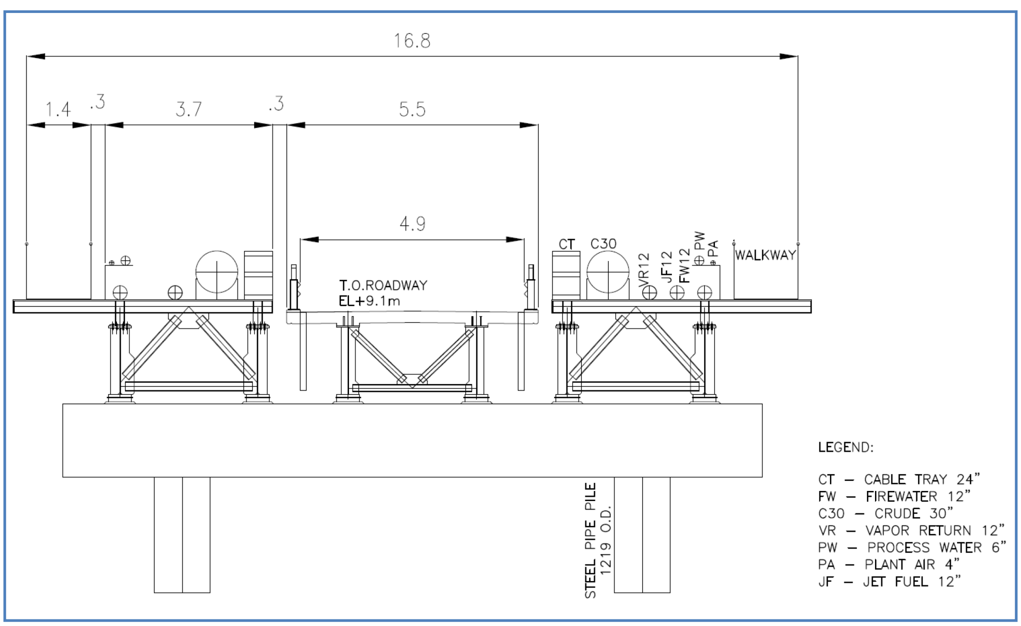


Figure 3.4.18 Typical Access Trestle Section

Breasting Dolphins

The primary functions of the breasting dolphins are to absorb the energy of the berthing vessel and to provide contact points and spring line mooring points for the moored vessel. Each breasting dolphin will support an independent fender system which consists of a fender panel supported by rubber energy absorbing elements located behind the panel. Each breasting dolphin will also support a quick release hook and an electric capstan. The breasting dolphin structures will be accessed via catwalks. Each breasting dolphin will be equipped with a ladder extending from the top of the dolphin to approximately 1.0 m below the lower low water level (large tide) to permit access from the water, if required.

Mooring Dolphins

The primary function of the mooring dolphins is to provide bow and stern line mooring points. Each mooring dolphin will be equipped with a quick release mooring hook and an electric capstan. The mooring dolphins are accessed via catwalks. Each dolphin will be equipped with a ladder extending from the top of the dolphin to 1.0 m below the lower low water level (large tide) to permit access from the water, if required.

Mooring Hooks

Breasting and mooring dolphins will be equipped with double quick release mooring hooks with the following features:

- one-man manual release in the proximity of the hook;
- electrical release via remote control from a central monitoring system;
- load monitoring capability instrumented to provide remote load readout for each hook from a central monitoring station; and
- an electric capstan for hauling mooring lines into position using lighter messenger lines.

Gangway Tower

Each berth will be provided with an articulated telescopic gangway tower for ship to dock access. All movements of the gangway will be self-supporting and self-actuating, not requiring assistance from other lifting or pulling equipment. In the stored position, the gangway will fold clear of the edge of the loading platform. The gangway will be designed to retract and clear the vessel during an emergency.

The gangway height will be adjustable for the full range of tides and vessel freeboards. The gangway will be equipped with a telescopic access ramp. The end of the gangway will have the ability to turn 90 degrees after clearing a vessel's rail to provide flexibility in accommodating vessels with different deck configurations.

The gangway tower will be located between the loading arms and the vessel wheelhouse, to facilitate evacuation.

The gangway tower will support an integrated stores crane and a fire-fighting monitor. A lay down area adjacent to the gangway tower will allow for truck loading and unloading. The crane will be capable of 360 degree rotation (Figure 3.4.19).

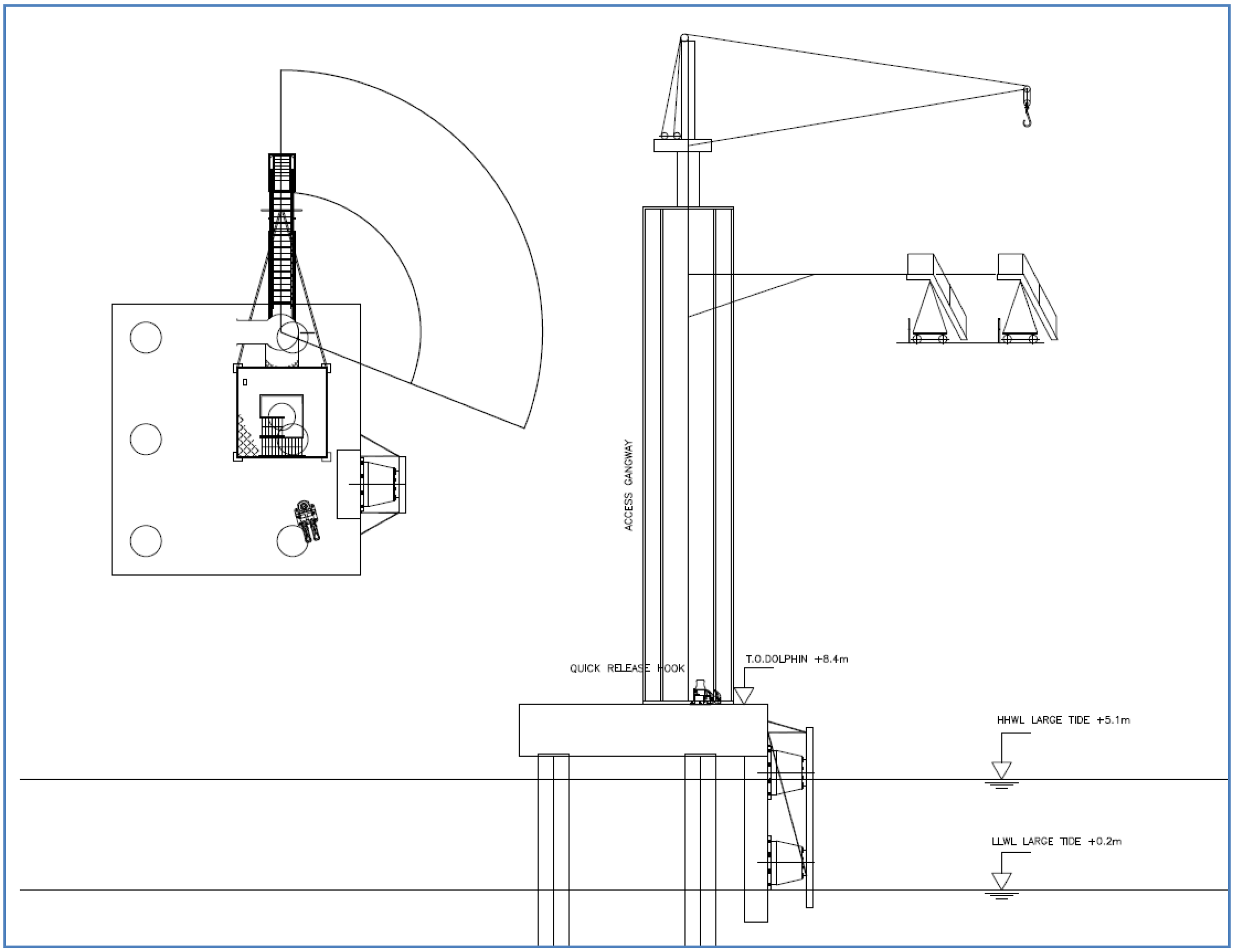


Figure 3.4.19 Typical Gangway Tower

3.4.4.4 Storage Tanks

Table 3.4.14 indicates the tanks that may be constructed at the Westridge Marine Terminal.

TABLE 3.4.14

TANKS UNDER CONSIDERATION FOR THE WESTRIDGE MARINE TERMINAL

Tank	Service	Type	Diameter		Capacity	
			(m)	(ft.)	(m^3)	(bbl)
XX1	Synthetic Crude (VRU)*	IFR	18.5	60	4,000	25,000
XX2	Synthetic Crude (VRU)*	IFR	18.5	60	4,000	25,000
XX3	Pipeline Surge Tank**	IFR	TBD	TBD	TBD	TBD

Notes: * Alternate VRU technologies are being considered, which may not require these tanks.

** The possible elimination of this tank is being investigated.

IFR = Internal Floating Roof

Tanks and their foundations will be designed in accordance with API 650 and the CCME guidelines. They will have steel pontoon or light-weight aluminum floating roofs with mechanical seals and fixed steel cone or dome roofs or fixed aluminum dome roofs.

Tanks will be provided with nozzles to allow for process connections, maintenance access and the future installation of propeller mixers and/or jet mixers. They will also be fitted with a TVAU for odour control. The final number and sizes of the nozzles and the specification for the TVAU will be determined during the detailed engineering and design phase.

Tanks will be externally coated with a zinc primer/urethane top-coat system. The exterior color will be determined with City of Burnaby and public input. The tank floor top and the interior of the lower 1 m of shell will be coated with epoxy.

Spacing between adjacent tanks will be in accordance with BCFC and NFPA 30, specifically no less than the sum of their respective diameters divided by four. Setbacks from property lines will be in accordance with NFPA 30 and Burnaby City requirements.

3.4.4.5 Buildings

See Table 3.4.15 for a preliminary list of various buildings to be constructed on the foreshore at the Westridge Marine Terminal.

TABLE 3.4.15

PROPOSED BUILDINGS FOR THE WESTRIDGE MARINE TERMINAL

Building Description	Quantity	Size (m)
Fire Pump House	1	12 × 10
Operator Control Building	1	18.3 × 4.2
Electrical Building (Main) Dock 2	1	18.3 × 4.2
Generator Building	1	5 × 2.5
VRU Pump Building	2	5 × 2.5

3.4.4.6 Mechanical

Noise levels will be at or below the location-specific permissible limits of the applicable legislation. Where necessary to meet these limits, pumps, blowers, and other noise emitting equipment will be placed in noise reduction enclosures or other noise reduction methods will be employed.

3.4.4.6.1 Vapour Recovery Units

Two VRUs will recover and recycle the majority of hydrocarbon vapours displaced from vessels during crude oil loading.

The existing dock utilizes a thermal oxidation unit (a type of VCU), which is highly effective at destroying volatile organic compounds and odorous compounds but consumes a considerable amount of propane feed gas during some stages of vessel loading. The significant increase in the amount of vapour to be handled as a result of TMEP makes the sole use of thermal oxidation technology less desirable and the primary use of vapour recovery technology more appropriate.

The preliminary VRU technology selected includes an absorption vessel for removing odorous sulfur compounds and an activated carbon adsorption vessel for removing hydrocarbons heavier than ethane. Gases generated by vessels for cargo tank inerting, such as nitrogen and carbon dioxide, and the lighter hydrocarbon vapours, specifically methane and ethane, cannot be captured by the adsorption vessel and will be vented to atmosphere.

The VRU process requires regeneration of the activated carbon bed through the reversal of the flow through it. The preliminary process selected for the treatment and recycle of the hydrocarbon laden regeneration vapour stream is absorption into a synthetic crude oil stream supplied from a VRU tank. The enriched synthetic crude oil will be held in another VRU tank for eventual reinjection onto the vessel being loaded or onto a future vessel. This is the most common, commercially available technology for VRU systems. Since the absorption method requires two large tanks and a continuous supply of synthetic crude oil, various other options for the treatment and recycle of the regeneration stream are being considered, including liquefaction by compression or refrigeration, with the goal of reducing the complexity, the capital cost, and the operating cost of the system, while achieving equivalent or better levels of vapour recovery and recycle. The final technology selection and design of the VRUs will be completed during the detailed engineering and design phase.

3.4.4.6.2 Vapour Combustion Unit

One thermal oxidation type VCU, similar to that currently in service, will also be provided. Fuel for the VCU will be either propane or natural gas. The VCU will be used only when one of the VRUs is unavailable due to maintenance or repair (expected to be less than five per cent of the time) or when three vessels are simultaneously loading (also expected to be less than five per cent of the time). Given its low utilization (less than half of the utilization of the existing VCU), a much higher cost VRU is not considered necessary or appropriate for the third vapour handling unit.

3.4.4.6.3 Potable Water/Sewage System

A connection to the Burnaby City water and sewage system will be preferred. If such connections are not available, water and sewage will be trucked to and from the site and will be stored in tanks located near the new operation building. Potable water will be piped to each of the three berths.

3.4.4.6.4 Loading and Vapour Recovery Arms

To achieve the peak loading rate of 4,635 m^3/hour (700,000 bbl/d) it is expected that each berth will require three 406 mm (NPS16) diameter loading arms. A spare loading arm may be provided at one or more berths for redundancy. Berth 1 will also be fitted with one 305 mm (NPS12) diameter jet fuel unloading arm.

Each berth will also be fitted with one 305 mm (NPS12) diameter vapour recovery arm.

The spacing between loading arms will be approximately 4.0 m.

3.4.4.7 Piping

Dock lines, tank lines, manifold, pump, meter, and interconnection piping will be above ground where practical, but may be below ground at certain road or other crossings. Dock lines and tank lines will be designed to be "pig-able".

3.4.4.7.1 Design Pressure

The design pressure of the Westridge Marine Terminal process piping upstream of the last valve prior to the loading arms will be either 1,900 kPag (276 psig) consistent with a pressure rating of PN 20 (ANSI 150#), if pipeline pressure relief is provided, or 4,960 kPag (720 psig) consistent with a pressure rating of PN 50 (ANSI 300#), if pipeline pressure relief is not provided. The determination of the provision of pipeline relief will be made during the detailed engineering and design phase. The design pressure of the piping downstream of the last valve prior to the loading arms will be 1,900 kPag (276 psig), since vessels are protected by pressure relief systems. The design pressure of the vapour recovery system piping will be 1,900 kPag (276 psig) unless otherwise determined during the detailed engineering and design phase.

3.4.4.7.2 Design Flow Rates

Process piping will be designed for the peak loading rate of 4,635 m^3/hour (700,000 bbl/d). The design flow rate is intended to allow an Aframax class vessel to load a cargo of 106,500 m^3 (670,000 bbl) in 24 hours, allowing for one hour of ramp up and one hour of ramp down. A 44 m beam Aframax class vessel with a 106,500 m^3 cargo of 900 kg/m^3 density oil will have a draft of 13.5 m, the draft limit expected to be in force at the time the new Westridge Marine Terminal dock enters service.

3.4.4.7.3 Pipeline Pressure Relief

If the design pressure of the Westridge Marine Terminal process piping upstream of the last valve prior to the loading arms is selected as 1,900 kPag (276 psig) consistent with a pressure rating of PN 20 (ANSI 150#), full-flow pressure relief and a dedicated relief tank will be provided. The volume of the relief tank will be finalized during the detailed engineering and design phase.

3.4.4.7.4 Materials

Pipe, fittings, and flanges will meet the requirements of CSA Z245.1 Steel Pipe, CSA Z245.11 Steel Fittings, CSA Z245.12 Steel Flanges and the KMC 2000 series standards and specifications. Valves will meet the requirements of CSA Z245.15 Steel Valves and KMC Standard MP1300 Valve Selection and Specification and its associated standards and specifications. Material grades and wall thicknesses will be determined in accordance with the applicable standards and specifications identified in Tables 5.1.1 and 5.1.2 in Appendix D, including MP1110 Station and Terminal Piping Design. The operating pressure will not be greater than 80 per cent of the test pressure.

3.4.4.7.5 Welding and Fabrication

Welding and fabrication of piping will be in accordance with the applicable standards and specifications listed in Tables 5.1.1 and 5.1.2 in Appendix D.

3.4.4.7.6 Non-destructive Testing

Non-destructive testing of pipe welding will be in accordance with applicable standards and specifications listed in Tables 5.1.1 and 5.1.2 in Appendix D.

3.4.4.7.7 Hydrostatic Pressure Testing

All piping will be hydrostatically pressure tested in accordance with the applicable standards and specifications listed in Tables 5.1.1 and 5.1.2 in Appendix D, including MP4111 Station Hydrostatic Testing.

Piping spools constructed in fabrication shops will be hydrostatically pressure tested prior to delivery to site. Site fabricated pipe will be hydrostatically pressure tested at site.

3.4.4.8 Auxiliary Systems

3.4.4.8.1 Sump Tanks

Thermal relief valve discharge lines and selected drain lines associated with the process piping in the Westridge Marine Terminal receiving trap area, valve manifold, and metering area will be routed to one or more below grade sump tanks. The tanks will be sized to allow the drain-down of a significant portion of the process piping. Final sizing will be determined during the detailed engineering and design phase.

A lift pump and reinjection pump will be installed at each tank to allow re-injection of the sump contents back into the process piping. Pump-out to a tanker truck will also be possible through an above ground connection.

The sump tank design will include vents high enough to prevent spillage during equipment drain down.

Sump tanks will be constructed from fibre-glass (or a similar composite material) and will be of double-wall design. The interstitial space between the two shells will be monitored to assess the integrity of the tanks.

A storm water sump tank will be located below each loading platform containment area. Although the sump tanks are intended for storm water, their capacities will be equal to 30 seconds of the full flow from one loading arm in case of a leak. Each sump tank will have a separate sump pump which will direct the contents of the tanks to the foreshore collection tank(s). The sump tanks will be emptied prior to arrival of each new vessel.

3.4.4.8.2 Fire Protection Systems

A new fire-protection system will be provided at the Westridge Marine Terminal.

Fire-Water System

The fire-water system will have the following features:

- a new backflow preventer on the existing City of Burnaby fire water main;
- two new submersible pumps, taking water from Burrard Inlet; and
- fire mains constructed of high density polyethylene (HDPE) where underground.

Foam System

The foam system will have the following features:

- new centralized foam building complete with a foam concentrate storage tank and injection system;
- foam distribution system serving the new dock complex and shore infrastructure; and
- foam mains constructed of HDPE, where underground.

Storage tanks will be fitted with seal-area foam pourers permanently connected to the fire-water/foam supply. The foam supply to each tank will be activated by automated valves.

3.4.4.9 Nitrogen Purge System

A nitrogen gas generator or a nitrogen storage system will be provided to allow for the purging of the vapor recovery lines.

3.4.4.10 Electrical

The Westridge Marine Terminal will have enough increase in power consumption to require a service upgrade by BC Hydro. Approximately 3 MW of additional power will be required for the VRU system and ancillary devices.

Currently there is a single feed from BC Hydro to a small substation located west of Tank 201. BC Hydro will be performing a study to determine what reinforcements of their electrical system are required to handle the additional load.

A new 12.5 kV to 4,160 V, 3 MVA transformer will be required to service the existing and new loads.

New ESBs, distributed around the site, will be required to house switch-gear, MCCs, and control panels.

A standby generator will be installed to provide emergency power to all MOVs and designated emergency equipment during a power outage. A UPS will be installed to maintain communications and critical information during the transfer from utility power to generator power.

Consideration will be given to the space required on the docks for future shore power transformers and conversion equipment. The power supply upgrade to support the new dock and VRU infrastructure will not be large enough for shore power (which will require up to 20 MW capacity) and will need a further major upgrade should shore power be installed in the future.

Navigation marker lights will be designed in accordance with International Association of Lighthouse Authorities standards. Lights will be mounted on the outer east or west vertical face of the dolphin pile caps where they will be visible from seaward but not interfere with mooring line deployment. The location, color and intensity for these navigation lights will be confirmed with BCCP and Transport Canada.

Area lighting will be directional and targeted to the greatest extent practical to reduce extraneous lighting impact on the adjacent community.

3.4.4.11 Instrumentation

The general scope of the instrumentation will include:

- a radar gauging system on each storage tank, with high level and low level sensing and overfill protection capability;
- a redundant overfill protection system on each storage tank;
- a fire detection system on each storage tank;
- a leak detection system under each storage tank and in the interstitial space of the sump tank(s);
- a hydrocarbon detection system in each storage tank containment areas and selected other containment areas;
- piping pressure and temperature sensors and transmitters for measurement and protection,
- ultrasonic meters;
- densitometer(s), viscometer(s), and automatic sampler(s);
- bi-directional, positive displacement meter prover;
- waste oil sump level and control instrumentation; and
- berthing assistance instrumentation.

The characteristics and features of the instrumentation will be as per Section 3.4.1.10.1, as applicable, except that the tank fire detection system will be other than IR. IR detectors cannot be used on fixed-roof tanks.

3.4.4.11.1 Custody Transfer Metering System

A custody transfer metering system will be installed at the Westridge Marine Terminal.

The metering system will consist of six meter runs, two on each dock delivery line and two spare meter runs. The meters will be ultrasonic.

Measurement accuracy will meet or exceed *Canadian Weights and Measures Regulation Part IV* of +/- 0.25 per cent. The proving method will be a permanent bi-directional, positive displacement meter prover.

The custody transfer metering system will include instrumentation to provide continuous monitoring of fluid characteristics (including temperature, pressure, viscosity, and density), an automatic sampler, and flow computers.

3.4.4.11.2 Berthing Assistance System

A berthing assistance system will be installed on each berth at the Westridge Marine Terminal. The system will measure the speed of approach, distance to berth, and angle of approach for a vessel up to 200 m from the berth.

The berthing assistance system will include the following instruments:

- laser rate-of-approach docking sensors; and
- tide, wind, current, and visibility sensors.

Critical information will be indicated on display boards that can be seen from an approaching vessel's bridge and transmitted to control screens on shore and to the BCCP portable piloting units.

3.4.4.12 Protection Philosophy

3.4.4.12.1 Emergency Shutdown Systems

All equipment added for TMEP will be integrated into the existing Westridge Marine Terminal ESD system, which will be expanded and enhanced as necessary. Additional integration will be developed between the ESD systems at Burnaby and at Westridge Marine Terminal. A standby generator will ensure essential services and ESD functionality during power outages.

Tanker Loading

Emergency shut down buttons will be located near each loading arm and in the new operations building. The activation of any of these ESD buttons will safely stop loading operations and send an alarm to the PCC (or SCC). The ESD condition will cause the booster pumps located at Burnaby Terminal to shut down and may cause other automated devices to activate.

3.4.4.13 Control

The control system for the new facilities will be integrated with the existing Westridge Marine Terminal control system and will comply with existing control philosophies. The Westridge Marine Terminal, including all transitional (start, ramp-up, ramp down, and stop) vessel loading and unloading activities will be controlled and monitored from the new Westridge Marine Terminal control building. The majority of operational functions will also be able to be monitored from the PCC (or SCC) by CCOs using the SCADA system. Steady-state loading operations will be controlled by the CCOs.

New control panels housing remote I/O racks will be provided in each of the new ESBs. The UPS will provide power to the new remote I/O racks. Additional HMIs will be added as required. Upgrading and reconfiguration of the existing HMIs will be performed, as necessary, to incorporate status, analog information, and control of the additional tanks, piping, valves, alarms, equipment, process data, and trends. Where possible, tank and meter display screens will be the same as currently in use.

The metering system will be controlled by flow computers and a PLC, consistent with those currently in service.

Control and shutdown functions for the protection of equipment and systems will be installed at the equipment and will be independent of inputs from the control system. The existing Operating Limits and Protective Device Settings document will be updated to include settings and functionality for all new equipment.

3.4.4.13.1 Communications

The existing wired and fiber optic industrial network will be expanded to provide communications between PLCs and equipment. Communications to the PCC and SCC SCADA systems will be by leased land line. Back-up communications will be provided by satellite.

An additional communications link will be installed between Westridge Marine Terminal and Burnaby Terminal to allow instantaneous response to alarms originating at either location.

3.5 Facilities Design - Other Facilities

3.5.1 Sending and Receiving Traps

3.5.1.1 Overview

New trap facilities will be installed at three pump stations on Line 1 and seven terminal or pump station locations on Line 2. Trap facilities will be deactivated at two Line 1 pump stations. Table 3.5.1 indicates the locations of existing and new traps on all pipelines.

TABLE 3.5.1

NEW AND EXISTING SENDING AND RECEIVING TRAPS

Pump Station	Existing	New
Edmonton	Sending (1)	Sending (2)
Edson	Sending (1) and Receiving (1)	Sending (2) and Receiving (2)
Hinton	Remove Sending (2) Receiving (1)	Sending (1)
Rearguard	-	Sending (1) and Receiving (1) Sending (2) and Receiving (2)
Darfield	Remove Receiving (1) Sending (2)	Receiving (2)
Black Pines	-	Sending (1) and Receiving (1) Sending (2) and Receiving (2)
Kamloops	Sending (1) and Receiving (1)	Sending (2) and Receiving (2)
Sumas	Sending (1) and Receiving (1) Sending (24ST) Provision Only Sending (20ST) Provision Only Sending (24PS)	-
Sumas Terminal	Receiving (24ST) Receiving (20ST)	-
Burnaby Terminal	Receiving (1) Sending (24WMT)	Receiving (2) Sending (30-1WMT) Sending (30-2WMT)
Westridge Marine Terminal	-	Receiving (30-1WMT) Receiving (30-2WMT) Receiving (24WMT)
US Border	-	Sending (20PS) Receiving (24PS)

Notes: (1) Line 1
(2) Line 2
(20ST) NPS 20 Sumas Terminal
(24ST) NPS 24 Sumas Terminal
(20PS) NPS 20 US Puget Sound Line
(24PS) NPS 24 US Puget Sound Line
(24WMT) NPS 24 WMT Existing Delivery Line
(30-1WMT) NPS 30 WMT New Delivery Line 1
(30-2WMT) NPS 30 WMT New Delivery Line 2

Each trap system will include the following features:

- sending and/or receiving barrels, with door assembly;
- isolation and bypass valves piping;
- thermal relief and drain valve(s) and piping;
- containment below the door; and
- instrumentation.

Quick-opening door assemblies will be designed, fabricated, and tested in accordance with CSA Z662 and the American Society of Mechanical Engineers (ASME) *Boiler and Pressure Vessel Code* Section VIII, Division 1. The door design and operation will prohibit opening should any pressure exist within the sending or receiving traps.

All trap facilities with the exception of the border traps will be installed within the fenced area of pump stations and terminals.

The line size transition facility at Hargreaves, BC (Kilometre Post [KP] 468.0) will be decommissioned and removed.

Table 3.5.2 lists the approximate run distances between sending and receiving traps, after completion of TMEP.

TABLE 3.5.2

APPROXIMATE RUN DISTANCES BETWEEN SENDING AND RECEIVING TRAPS

Pipeline Segment	Pipeline OD (mm)	Run Distance* (km)
Line 1		
Edmonton to Edson, AB	609.6	229
Edson to Hinton, AB	762.0	89
Hinton, AB, to Rearguard, BC	609.6	159
Rearguard to Black Pines, BC	609.6	308
Black Pines to Kamloops, BC	762.0	38
Kamloops to Sumas, BC	609.6	259
Sumas to Burnaby, BC	609.6	65
Line 2		
Edmonton to Edson, AB	914.4	247
Edson, AB, to Rearguard, BC	914.4	251
Rearguard to Darfield, BC	914.4	271
Darfield to Black Pines, BC	762.0	43
Black Pines to Kamloops, BC	914.4	39
Kamloops to Burnaby, BC	914.4	329
Other		
Burnaby to Westridge Marine Terminal	609.6	4
Burnaby to Westridge Marine Terminal (2 lines)	762.0	4
Sumas to US Boarder (Puget Sound Line)	609.6	9

Note: *The run distances are unequal between the two pipelines because of routing differences.

The sending and receiving trap system layouts and designs will be integrated with the pump station systems layouts and designs. The details will be developed during the detailed engineering and design phase.

3.5.2 Main Line Block Valves (Locations and Infrastructure)

Line 1

Line 1 will have 24 main line block valves (MLBVs) located at the existing and new pump stations and at the existing terminals. Some of these sites will also have check valves and some MLBVs (*i.e.*, where there are traps) may be combinations of multiple valves. Table 3.5.3 gives the locations of the MLBVs.

TABLE 3.5.3

LINE 1 MLBV LOCATIONS

#	Facility	KP	Valve Type	Current Status
1	Edmonton Terminal	0.00	Automated MLBV	Existing
2	Stony Plain Pump Station	49.49	Automated MLBV	Existing
3	Gainford Pump Station	99.43	Automated MLBV	Existing
4	Chip Pump Station	147.04	Automated MLBV	Existing
5	Niton Pump Station	173.37	Automated MLBV	Existing
6	Edson Pump Station	228.75	Automated MLBV	Existing
7	Hinton Pump Station	317.76	Automated MLBV	Existing
8	Jasper Pump Station	369.53	Automated MLBV	Existing
9	Rearguard Pump Station	476.76	Automated MLBV	Existing
10	Albreda Pump Station	519.13	Automated MLBV	Existing
11	Chappel Pump Station	555.46	Automated MLBV	Existing
12	Finn Pump Station	612.49	Automated MLBV	Existing
13	McMurphy Pump Station	645.01	Automated MLBV	Existing
14	Blackpool Pump Station	710.02	Automated MLBV	Existing
15	Darfield Pump Station	741.98	Automated MLBV	Existing
16	Black Pines Pump Station	785.00	Automated MLBV	New
17	Kamloops Pump Station	822.96	Automated MLBV	Existing
18	Stump Pump Station	862.74	Automated MLBV	Existing
19	Kingsvale Pump Station	924.85	Automated MLBV	Existing
20	Hope Pump Station	1011.81	Automated MLBV	Existing
21	Wahleach Pump Station	1045.92	Automated MLBV	Existing
22	Sumas Pump Station	1082.01	Automated MLBV	Existing
23	Port Kells Pump Station	1124.33	Automated MLBV	Existing
24	Burnaby Terminal	1147.07	Automated MLBV	Existing

In addition to the MLBVs located at pump stations, there will be 64 RMLBVs and 8 check valves located along Line 1, of which 62 RMLBVs and 2 check valves exist. Table 5.1.10 in Appendix D gives the location of the existing RMLBVs and check valves.

It is anticipated that two RMLBVs and six check valves will be added to the Line 1 pipeline sections to be reactivated between Hinton, AB, and Hargreaves, BC, and between Darfield, BC, and Black Pines, BC. In addition, it is anticipated that four of the existing manual RMLBVs will be automated. Table 5.1.11 in Appendix D gives a preliminary list of the RMLBVs in the sections to be reactivated. The numbers and locations will be finalized during the detailed engineering and design phase.

Line 2

There will be 12 MLBVs (11 with associated check valves) located at the new Line 2 pump stations and at the existing terminals. Table 3.5.4 lists the MLBV locations. Some of these MLBVs (*i.e.*, where there are traps) may be combinations of multiple valves. There will also be one MLBV at Burnaby Terminal (with an associated check valve) and one MLBV at Westridge Marine Terminal on each of the Burnaby to Westridge Marine Terminal pipelines.

TABLE 3.5.4

LINE 2 MLBV LOCATIONS

#	Facility Name	RK	Valve Type
1	Edmonton Terminal	0.000	Automated MLBV
2	Gainford Pump Station	117.4	Automated MLBV
3	Wolf Pump Station	206.1	Automated MLBV
4	Edson Pump Station	247.2	Automated MLBV
5	Hinton Pump Station	339.4	Automated MLBV
6	Rearguard Pump Station	498.3	Automated MLBV
7	Blue River Pump Station	614.6	Automated MLBV
8	Blackpool Pump Station	736.9	Automated MLBV
9	Black Pines Pump Station	811.8	Automated MLBV
10	Kamloops Pump Station	850.9	Automated MLBV
11	Kingsvale Pump Station	955.5	Automated MLBV
12	Burnaby Terminal	1179.8	Automated MLBV

In addition to the MLBVs located at the new pump stations and at the terminals, there will be approximately 72 RMLBVs and 21 check valves located along Line 2. Seventy-one of these RMLBVs will be automated. Some of the RMLBVs will be located at Line 1 pump station sites or deactivated pump station sites. Where possible, Line 2 RMLBVs that are not located at pump station sites will be co-located at existing Line 1 RMLBV sites to take advantage of common infrastructure. There will also be 1 RMLBV located on each of the Burnaby-Westridge pipelines. Table 5.1.12 in Appendix D gives a preliminary list of the RMLBVs. The numbers and locations will be finalized during the detailed engineering and design phase.

RMLBV Sites

All RMLBV sites will be located on Line 1 and Line 2 rights-of-way.

Each automated RMLBV site will have, as a minimum, the following components:

- a full-port, through conduit, slab gate valve, complete with bypass piping;
- a motor operator;
- pressure and temperature instrumentation;
- a power, control, and communications, cabinet;

- a UPS;
- a PLC;
- a communications system;
- a power supply; and
- security fencing.

Where utility power cannot be provided, an alternate power source will be provided. Various technologies are commercially available. The final power sources will be determined during the detailed design and engineering phase.

3.5.2.1 Civil and Structural

Once the valve assembly has been installed as part of pipeline construction activity, the general scope of civil work will include the following:

- rough grading;
- piles (likely screw piles) for the cabinet, and fence posts;
- fencing; and
- finish grading.

3.5.2.2 Buildings/Cabinets

The power, control, and communications cabinets will be pre-fabricated and pre-assembled, complete with the equipment they house, off-site.

3.5.2.3 Electrical

Where possible, a 480 or 575 VAC, 100 A three phase power service will be provided at each RMLBV site via overhead power lines. The power will be brought into the site from the service transformer on the last pole via an underground power cable routed to the electrical cabinet. The power cable will be connected to a power meter then to a distribution panel in the electrical cabinet.

Cabinets will be mounted outside of hazardous areas.

The PLC will be connected to the transducers via Teck 90 instrument cable and sealed where required by the Canadian Electrical Code.

3.5.2.4 Control

The control system for the new RMLBVs will be integrated with the existing mainline control system and will comply with existing control philosophies. The majority of operational functions will be able to be controlled from the PCC (or SCC) by CCOs using the SCADA system. The function of the SCADA system for RMLBV sites will be very similar to the function for a pump station. Additional details on the function of the SCADA system are included in Section 3.3.17 and in Volume 4C, Section 7.1.

New control panels housing remote I/O racks will be provided in each of the new cabinets. The UPS will provide power to the new remote I/O racks.

The Operating Limits and Protective Device Settings document will be updated to include settings and functionality for all new equipment.

3.5.2.4.1 Communications

Satellite communication will be installed at each RMLBV site and the PLC will report directly to the SCADA system. There will not be back-up communications systems at RMLBV sites.

3.5.3 Pressure Control Stations

Downstream of the Coquihalla summit in BC, one or more pressure control valves at one or more pressure control stations may be required on each pipeline to eliminate slack flow.

The pressure control station(s) will likely be at the existing Hope pump station but the location(s) and details will be finalized during the detailed engineering and design phase.

3.5.4 Sumas Terminal Line 2 Take-off

This facility will be located approximately 200 m from the Sumas Terminal. This take-off will connect Line 2 to the Sumas Terminal manifold and to the new Tank 100.

This take-off facility may have some of the following components:

- a main line block valve;
- a take-off valve;
- a check valve;
- a control valve;
- a densitometer;
- a power supply;
- a control and communications link; and
- a security fence.

The take-off will be able to deliver the full Line 2 flow to tankage or a slip stream off the main line. Operating parameters will be determined during the detailed engineering and design phase.

3.5.5 Power Supply Requirements

3.5.5.1 Alberta Power Supply Requirements

In Alberta, power infrastructure improvements will be required at Edmonton Terminal, Gainford Pump Station, and Edson Pump Station to support the Line 2 loads. Applications have been submitted to the AESO. Fortis Alberta and AltaLink have been tasked by the AESO to make a recommendation on the type of service (transmission or distribution) and infrastructure improvements required. The design and construction of all improvements, including substations, interconnection (customer) power lines, and deep system infrastructure improvements will be managed by either of Fortis or AltaLink, as determine by the AESO.

New substations will be required at Edmonton Terminal and Edson Pump Station. A substation upgrade will be required at Gainford Pump Station.

Preliminary indications are that there are only small power line infrastructure upgrades required, but this will depend on the determination of the AESO. For power line additions or upgrades, Fortis or AltaLink will be responsible for public consultation, environmental studies, and other regulatory compliance requirements.

Fortis or AltaLink will maintain both the sub-stations and the power lines.

Table 3.5.5 indicates the preliminary scope of the Alberta power interconnection and substation requirements.

TABLE 3.5.5

ALBERTA POWER INTERCONNECTION AND SUBSTATION REQUIREMENTS

Location	Voltage (kV)	New Power Line Required?	New Power Line Length (km)	Sub-station* Changes	Notes
Edmonton	138	Y	100 m	N	Existing Substation remains in service, add new 25 MVA substation for new loads
Stony Plain	138	N	NA	NC	
Gainford	138	N	NA	U	New 25 MVA transformer within Company property
Chip Lake	138	N	NA	NC	
Niton	25	N	NA	NC	
Wolf Lake	25	N	NA	NC	
Edson	25 or 138	Y	40 or 4	N	Option 1 - 25 kV is being studied and would require an ~ 40 km power line. Option 2 - 138 kV is being studied and would require an ~4 km power line.
Hinton	138	N	NA	NC	
Jasper	25	N	NA	NC	

Notes: * NC - No Changes

N - New

U - Upgrade

3.5.5.2 British Columbia Power Requirements

In BC, it is anticipated that deep system power infrastructure improvements will be required in the North Thompson region to support the Line 2 loads. Applications have been submitted to BC Hydro who will determine the deep system infrastructure improvements required. The design and construction of sub-stations and interconnection (customer) power lines will be managed by Trans Mountain. The design and construction of deep system infrastructure improvements will be managed by BC Hydro.

New substations will be required at Black Pines, Kamloops, and Kingsvale pump stations, and at Burnaby and Westridge terminals. Substation upgrades will be required at Blackpool and Sumas Pump Stations.

A new 138 kV transmission power line, approximately 4 km in length, will be required to supply Black Pines Pump Station. A new 138 kV transmission power line, approximately 24 km in length, will be required to supply Kingsvale Pump Station. New 25 kV distribution power lines, approximately 11 km and 5 km in length, respectively, will be required to supply Burnaby and Westridge Marine Terminal.

New power lines will be wooden pole construction, either single pole with a cross arm or double wooden pole in an H configuration, designed to BC Hydro specifications.

Ownership of the power lines will transfer to BC Hydro after construction. BC Hydro will maintain the power lines. Trans Mountain will maintain the substations.

Table 3.5.6 indicates the preliminary scope of the BC power interconnection and substation requirements.

TABLE 3.5.6

BRITISH COLUMBIA POWER INTERCONNECTION AND SUBSTATION REQUIREMENTS

Location	Voltage (kV)	New Power Line Required?	New Power Line Length (km)	Sub-station* Changes	Notes
Rearguard	132	N	NA	NC	
Albreda	132	N	NA	NC	
Chappel	132	N	NA	NC	
Blue River	132	N	NA	NC	
Finn Creek	132	N	NA	NC	
McMurphy	132	N	NA	NC	
Black Pool	132	N	NA	U	New 25 MVA transformer within Company property
Darfield	132	N	NA	NC	
Black Pines	132	Y	4	N	New 15 MVA sub-station within existing Company property
Kamloops	132	N	NA	N	Existing 10 MVA substation remains in service. Add new 25 MVA sub-station within existing Company property
Stump Lake	132	N	NA	NC	
Kingsvale	132	Y	24	N	New 15 MVA sub-station within existing Company property
Hope	69	N	NA	NC	
Wahleach	69	N	NA	NC	
Sumas	69	N	NA	U	New 10 MVA transformer and breaker within existing substation
Sumas Terminal	12.5	N	NA	NC	
Port Kells	69	N	NA	NC	
Burnaby Terminal	12.5	Y	11	U	New 7.5 MVA sub-station within existing Company property, reconductor ~11 km power line
Westridge Marine Terminal	12.5	Y	5	U	New 7.5 MVA sub-station owithin existing Company property, reconductor ~5 km power line

Notes: * NC - No Changes
N - New
U - Upgrade

3.6 Reactivation of NPS 24 Segments (Hinton to Hargreaves and Darfield to Black Pines)

3.6.1 Background

Trans Mountain plans to reactivate two deactivated segments of the existing NPS 24 pipeline as part of TMEP. Reactivation will be undertaken in accordance with the NEB OPR and CSA Z662, Oil and Gas Pipeline Systems. The segments proposed for reactivation are:

- Hinton, AB to Hargreaves, BC – approximately 150 km in length, which was in continuous operation from 1953 to 2008; and
- Darfield, BC to Black Pines, BC – approximately 43 km in length, which was in continuous operation from 1953 to 2004.

3.6.1.1 Hinton to Hargreaves

The Hinton to Hargreaves segment was deactivated in 2008 under NEB Certificate OC-49 following completion of the TMX Anchor Loop Expansion Project (TMX-Anchor Loop). In anticipation of future growth, measures were taken to promote the long-term integrity of the deactivated segment to maintain the potential for its future reactivation.

3.6.1.2 Darfield to Black Pines

The Darfield to Black Pines NPS 24 pipeline segment was deactivated in 2004 under NEB Order XO-T099-05-2004 when the parallel NPS 30 segment was reactivated as part of the Capacity Upgrade Project. In anticipation of future growth, measures were taken to promote the long-term integrity of the deactivated segment to maintain the potential for its future reactivation.

The measures taken to ensure the long-term integrity of the deactivated pipeline segments included:

- removing the oil through the use of bi-directional pigs and a nitrogen purge;
- isolating the pipeline through the installation of weld caps;
- maintaining nitrogen in the pipeline (verified by pressure monitoring) to prevent internal corrosion;
- maintaining the cathodic protection (CP) system to prevent external corrosion:
- maintaining the Pipeline Protection Management System which includes One-Call and aerial patrol; and
- implementing the Trans Mountain Natural Hazards Program.

3.6.2 Regulatory Requirement

A preliminary engineering assessment has been completed as a first step in satisfying the requirements of the *OPR* for reactivation. The assessment details “the measures to be employed for the reactivation” and generally satisfies the intent of CSA Z662, Section 10.15.2 to “conduct an engineering assessment” and if the engineering assessment finds that the pipe is not suitable for service, to detail “the corrective measures necessary to make it suitable before reactivating." The preliminary engineering assessment will be updated to a final engineering assessment during the detailed engineering and design phase.

3.6.3 Engineering Assessment

3.6.3.1 Objective

The purpose of the preliminary engineering assessment is to document the integrity management status of the segments to be reactivated and the measures that Trans Mountain will employ to verify their integrity prior to reactivation.

3.6.3.2 Scope

The preliminary engineering assessment examines the integrity history and condition of the deactivated pipeline segments and identifies the measures required to ensure fitness for service. The general approach to reactivation includes inspection, repair, and hydrostatic testing, similar to the approach that was employed for the reactivation of the NPS 30 Darfield to Kamloops segment in 2004. Elements of the preliminary engineering assessment are discussed in the following sections.

3.6.3.3 Pipe Description

Construction of the NPS 24 pipeline was completed in 1953 using double submerged arc welded pipe manufactured by Kaiser Steel Corporation and Consolidated Western Steel and flash welded pipe manufactured by A.O. Smith. The pipeline was coated in the field with coal tar enamel. A breakdown of the pipe manufacturers for the deactivated segments is provided in the Tables 3.6.1 and 3.6.2.

TABLE 3.6.1

PIPE MANUFACTURERS – HINTON TO HARGREAVES

Hinton to Hargreaves							
Manufacturer	**NPS**	**Specification**	**Grade**	**W.T. (mm)**	**Year**	**Seam Type**	**km of Pipe**
A.O. Smith	24	API 5L	290	12.7	1953	FW	2.1
A.O. Smith	24	API 5L	359	7.9	1953	FW	20.1
Consolidated Western Steel	24	API 5L	318	12.7	1953	DSAW	0.2
Consolidated Western Steel	24	API 5L	359	7.9	1953	DSAW	102.0
Kaiser Steel Corp.	24	API 5L	318	12.7	1953	DSAW	0.9
Kaiser Steel Corp.	24	API 5L	359	7.9	1953	DSAW	17.8
Kaiser Steel Corp.	24	API 5L	359	6.4	1953	DSAW	7.6
Consolidated Western Steel	24	API 5L	359	7.9	1953	DSAW	33.8
Consolidated Western Steel	24	API 5L	359	8.7	1953	DSAW	3.6
Kaiser Steel Corp.	24	API 5L	359	7.9	1953	DSAW	5.5

3.6.3.4 Service

Upon completion of TMEP, the reactivated segments will form part of Line 1. The products transported will be similar to those which are currently transported in the TMPL system with the exception that very little heavy crude will be transported. Heavy crude will be largely transported in Line 2. The reactivated segments are expected to operate at pressures and flow rates that are consistent with historical operating pressures and flow rates.

3.6.3.5 Hydrostatic Testing

The initial post-construction hydrostatic test for the Hinton to Hargreaves segment took place in 1953 (Figure 3.6.1). This segment was initially tested in three sections. The test pressures ranged from 83 to 91.5 per cent of the SMYS at the low points. No failures occurred as a result of these initial tests. Additional hydrostatic testing of the pipeline occurred in eight sections between 1964 through 1998 with a test pressure ranging between 88 and 101.8 per cent of the SMYS. Three failures occurred in the 1965 hydrostatic test to 100 per cent of the SMYS. No failures occurred in the other seven tests.

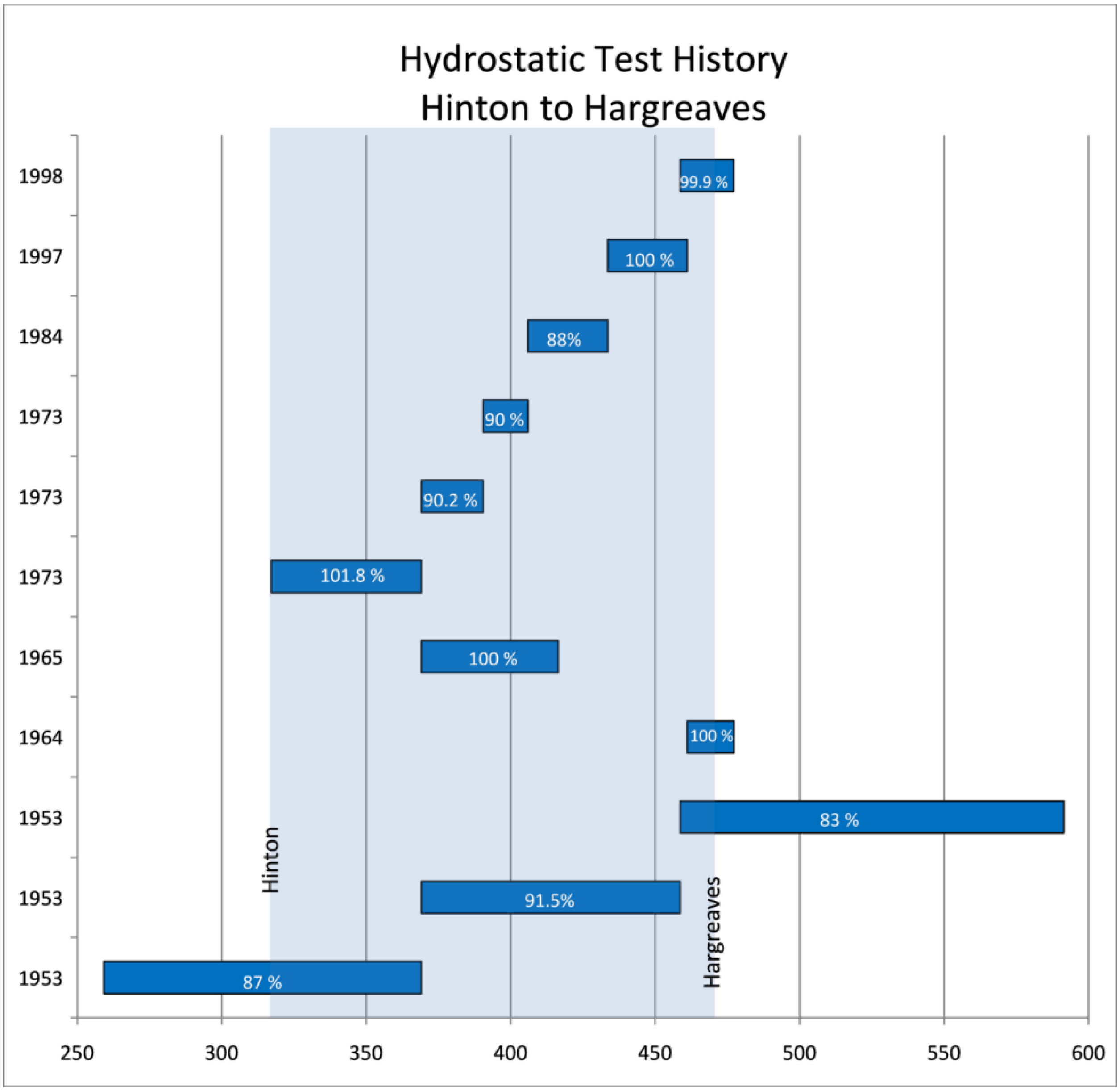


Figure 3.6.1 Hydrostatic Test History – Hinton to Hargreaves

The initial post-construction hydrostatic test for the Darfield to Black Pines segment took place in 1953 (see Figure 3.6.2). The pipeline was initially tested in one section. The test pressure was 83 per cent of the SMYS at the low point. The segment was retested in two sections in 1978. The test pressure achieved was 100 per cent of the SMYS at the low point of the two test sections. No failures occurred in either of the test sections.

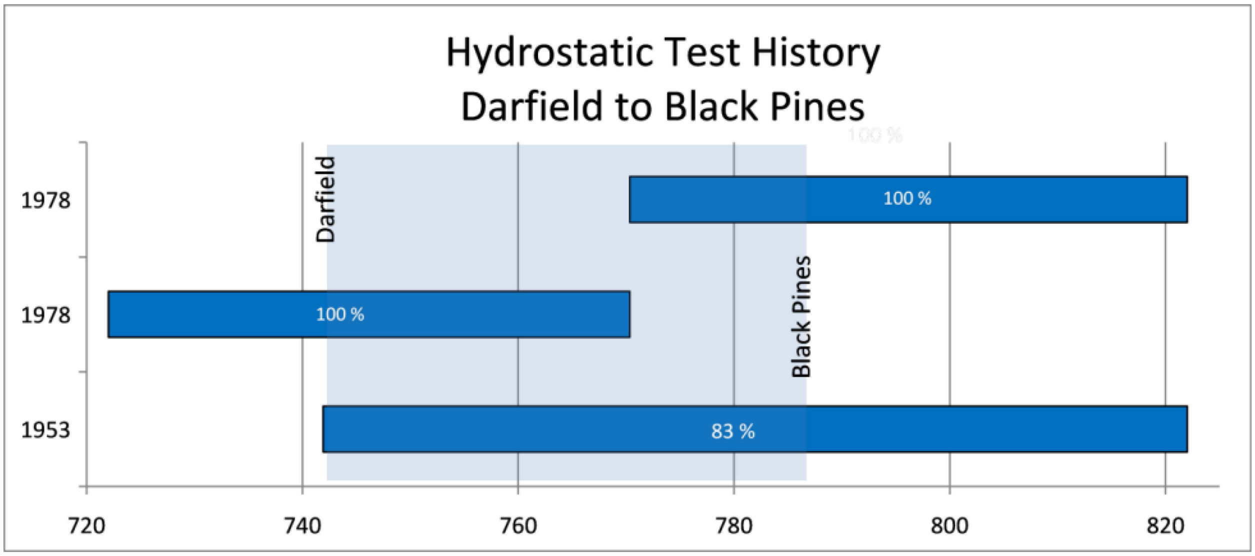


Figure 3.6.2 Hydrostatic Test History – Darfield to Black Pines

3.6.3.6 In-line Inspection

In-line Inspection (ILI) programs began on the TMPL system in the 1970s when ILI tools first became available. High resolution ILI tools became available in the 1990s. Since then, Trans Mountain has been inspecting the pipeline system using high resolution tools.

The Hinton to Hargreaves segment has been inspected with the following high resolution ILI tools:

- 1998 – Pipetronix WM Ultrasonic Metal Loss;
- 2001 – BJ GEOPIG (High Resolution Geometry);
- 2007 – BJ Vectra (High Resolution Metal Loss); and
- 2007 – GE UltraScan Crack Detection (USCD) (High Resolution Crack Detection).

The Darfield to Black Pines segment has been inspected with the following ILI tools:

- 1995 – Tuboscope MFL Metal Loss (Low Resolution Metal Loss); and
- 2003 – BJ GEOPIG (High Resolution Geometry).

Results of the ILIs are discussed in the following sections.

Prior to hydrostatic testing, Trans Mountain will complete ILIs of the deactivated segments using a high resolution metal loss tool, a high resolution axial flaw detection tool, and a high resolution geometry tool. These inspections will be completed by pushing the tools through the deactivated segments using nitrogen or compressed air. The tool configurations and methods of moving the tools will be determined during the detailed engineering and design phase.

Trans Mountain will also inspect the reactivated segments, within the first two years of operation, with a specialized high-resolution ultrasonic tool, to verify that no detrimental crack defects were initiated and/or grew as a result of the hydrostatic testing. Ultrasonic tools require the pipe to be liquid filled and cannot be run prior to reactivation.

3.6.3.7 Corrosion

The NPS 24 mainline, including the active segments and the currently inactive segments, has a very good performance history with respect to corrosion defects. To date there have been no documented spills that have been attributed to internal or external corrosion.

The good performance of the mainline can be attributed to good adhesion of the coal tar enamel coating, maintenance, monitoring and upgrading of the CP system, turbulent flow rates in the pipeline (that minimize the likelihood of water and sediment gathering on the internal surface of the pipe), and a batch lineup that includes products such as gasoline (which assist in keeping the inside of the pipe clean).

In addition, the deactivated sections were filled with nitrogen to provide an inert atmosphere.

3.6.3.7.1 External Corrosion

Following the 1998 Pipetronix and the 2001 GEOPIG ILIs, 179 pipeline excavations were completed along the Hinton to Hargreaves section of pipeline. Ninety-four per cent of the excavations indicated that the adhesion of the coating was good.

CP has been maintained since the pipeline segments were deactivated. To maintain effective CP of the pipeline system, Trans Mountain targets a minimum value of -850 mV off-potential. This is consistent with the National Association of Corrosion Engineers (NACE) recommended practices for protection of pipelines from external corrosion and with Canadian Energy Pipeline Association published recommendations for protection of the pipeline from initiation and growth of stress corrosion cracking.

Off-potentials along the Hinton to Hargreaves segments are generally good with test station readings showing that the minimum target of -850 mV is being maintained with the exception of a few locations. Test station readings in 2012 showed that low readings occurred between KP 370 and KP 380, between KP 407 and KP 408, and between KP 455 and KP 465. As part of Trans Mountain’s CP maintenance program, Trans Mountain is reviewing the protection at these locations to determine whether adjustments or modifications to the CP system are required.

The 2007 BJ MFL ILI indicated that there were five joints of pipe that had anomalies and clusters that were predicted to have a rupture pressure of less than 1.0. A rupture pressure of 1.0 is the pressure at which the pipeline would be expected to fail at its SMYS. The inspection tool also identified 11 pipe joints that had external anomalies predicted to be deeper than 50 per cent of the pipe wall thickness. Some of these features are located within the anomalies and clusters that were reported to have a rupture pressure ratio of less than 1.0.

No excavations have been completed to further assess these anomalies as the segment was deactivated shortly after the inspection was completed. Prior to reactivation, a high resolution MFL metal loss ILI tool will be run and repairs will be completed to remove anomalies that would otherwise have the potential to fail during hydrostatic testing.

Off-potentials on the Darfield to Black Pines segment are good, with all test station readings showing that the minimum target of -850 mV is being maintained. No high resolution metal loss ILIs have been completed on this segment. Prior to reactivation, a high resolution MFL metal loss ILI tool will be run and repairs will be completed to remove anomalies that would otherwise have the potential to fail during hydrostatic testing.

3.6.3.7.2 Internal Corrosion

The deactivated sections have been purged with nitrogen and the integrity of the nitrogen blankets have been verified by pressure monitoring. Nitrogen provides an inert atmosphere that inhibits corrosion from occurring on the internal surface of the pipeline.

The 2007 BJ MFL ILI on the Hinton to Hargreaves segment indicated that there were no joints of pipe that had internal anomalies that were predicted to have a rupture pressure of less than 1.0. The ILI tool identified three pipe joints that had internal anomalies that were predicted to be deeper than 50 per cent of the pipe wall thickness.

No excavations have been completed to assess these anomalies as the segment was deactivated shortly after the inspection was completed.

No high resolution metal loss ILIs have been completed on the Darfield to Black Pines segment of the pipeline.

The plan for the detection and removal of internal corrosion defects will be the same as for external corrosion defects as described in 3.6.3.7.1.

3.6.3.8 Cracking

3.6.3.8.1 Seam and Body Cracking

A USCD tool was run in the Hinton to Hargreaves segment in 2007. The USCD report indicated that there were approximately 21 crack-like anomalies in the pipeline. Sixteen of these anomalies were predicted to be between 1 mm and 2 mm deep (approximately 12 to 25 per cent of the pipe wall thickness). The remaining five indications were predicted to be between 2 mm and 3 mm deep (approximately 25 to 40 per cent of the pipe wall thickness).

Four of the locations where 2 mm to 3 mm deep features were identified by the USCD tool were excavated and further assessed. No indications were found at two of these locations. The other two sites found linear indications that had depths of less than 10 per cent of the pipe wall thickness.

The USCD tool also identified one notch-like indication with a depth range of 2 mm to 3 mm. This feature was excavated and further assessed and was determined to be caused by grinder marks on both sides of the longitudinal weld.

One indeterminate feature was identified by the tool and was excavated and assessed. The feature was determined to be an irregular weld with a small, visible, pin hole.

Eighteen weld anomalies were also identified by the USCD tool. None of these features were field assessed.

No crack inspections have been completed on the Darfield to Black Pines segment.

Prior to reactivating the pipeline segments, Trans Mountain will run an axial flaw detection (AFD) ILI tool that is able to identify axially oriented features such as corrosion grooves, gouges and open cracks.

Trans Mountain will also inspect the reactivated segments, within the first two years of operation, with a specialized high-resolution ultrasonic tool, to verify that no detrimental crack defects were initiated and/or grew as a result of the hydrostatic testing.

3.6.3.8.2 Stress Corrosion Cracking

Stress Corrosion Cracking (SCC) is a form of cracking that can occur beneath coatings that have disbonded from the pipe surface where there is an absence of adequate CP or when the disbonded coating shields the pipe from the cathodic current. It is possible for SCC to occur on coal tar enamel coated pipelines. Trans Mountain has confirmed a few existences of SCC on the NPS 24 pipeline.

Trans Mountain has confirmed indications of SCC on the Hinton to Hargreaves segment at KP 407 and KP 407.3. No SCC has been found in the Darfield to Black Pines segment. Repairs consisted of cutting the affected pipe out of the pipeline and replacing it.

The SCC at KP 407 consisted of three colonies with a maximum crack length of 3 mm and a maximum depth of less than 10 per cent of the pipe wall thickness. The cracks were oriented longitudinally. The pipe was located in a muskeg area with moist soil conditions.

The SCC at KP 407.3 consisted of one colony with a maximum crack length of 5 mm and a maximum depth of less than 10 per cent of the pipe wall thickness. The cracks were oriented longitudinally. The pipe was located in a rock/clay/sand mix soil with wet soil conditions.

Both SCC features appear in a section of pipeline where the 2012 test station readings showed low off-potentials (below -850 mV). As noted, Trans Mountain is reviewing the CP in these areas to determine if adjustments or modifications are required.

A USCD tool was run in the Hinton to Blue River section of the pipeline (which includes the Hinton to Hargreaves segment) in 2007. One crack field anomaly was identified. The feature was predicted to be approximately 1 mm to 2 mm (12 to 25 per cent) of the pipe wall thickness. The feature has not been assessed in the field.

Prior to reactivating the pipeline segments, Trans Mountain will run an AFD ILI tool that is able to identify axially oriented features such as cracks.

Trans Mountain will also inspect the reactivated segments, within the first two years of operation, with a specialized high-resolution ultrasonic tool, to verify that no detrimental crack defects were initiated and/or grew as a result of the hydrostatic testing.

3.6.3.9 Dents

Dents may exist in pipelines as a result of the pipelines settling over rocks, from rock impingement due to soil movements (*e.g.*, freeze/thaw cycles), or from third-party damage. A high resolution GEOPIG ILI was completed in 2001 on the Hinton to Hargreaves segment and in 2003 on the Darfield to Black Pines segment.

The 2001 GEOPIG ILI identified 14 top side dents with a depth greater than 2 per cent of the pipe diameter. The largest top side dent identified was a 3 per cent dent. Bottom side dents were more frequent and are typical of construction through the rocky terrain of the mountains. One bottom side dent had a predicted depth of 6 per cent of the pipe diameter. Three bottom side dents had predicted depths of between 5 and 6 per cent. Four dents were identified with predicted depths between 4 and 5 per cent and 25 dents had predicted depths between 3 and 4 per cent.

Excavations were completed at 54 locations along the Hinton to Hargreaves segment. Dents were identified at 49 of the sites. At two of the sites, corrosion was found in the dents. In both cases, the dent/corrosion was not severe, the corrosion features were ground out, and the pipes were recoated. Gouges were found in dents at two locations. One was in a top side dent at approximately the one o'clock position and one was in a bottom side dent at approximately the six o'clock position. In both cases, the features were non-deleterious, the gouges were ground out and the pipes were recoated. Nine dents were found to contain scratches. Scratches are small surface level indications that do not have measurable depth. Eight of these defects were ground out and one was repaired with an epoxy filled sleeve. Four of these defects were located on the top side of the pipe and five were located on the bottom side of the pipe. The largest dent depth that was recorded as a result of the excavations was 2.15 per cent of the pipe diameter. This was likely due to rebounding of the dents once the indentors were removed rather than overestimation of the sizing of the features by the GEOPIG.

On the Darfield to Black Pines segment, nine dents with a predicted depth greater than 2 per cent of the pipe diameter were identified by the 2003 GEOPIG inspection. All of the dents were located on the bottom of the pipe. The largest dent identified was predicted to have a depth of 4.6 per cent. Two dents were predicted to have depths between 3 and 4 per cent. The remaining dents were all predicted to have depths between 2 and 3 per cent. No excavations were completed on the dents identified in the Darfield to Black Pines segment.

The low number and low severity of top side dents is an indicator that the public awareness program, the One-Call systems and aerial and ground monitoring programs are effective at limiting unauthorized activities around the pipeline. Also, there is relatively little construction activity that occurs in the vicinity of the Hinton to Hargreaves segment in Jasper National Park and Mount Robson Provincial Park.

Prior to reactivation, Trans Mountain will complete additional high resolution geometry ILIs in these segments to identify additional potential dent, wrinkle, or buckle defects that may exist. This will also allow overlapping of the previous GEOPIG inspections to detect any ground movements.

3.6.3.10 Third-party Activity

Trans Mountain has a public awareness program, signage along the rights-of-way, aerial patrols and ground patrols, and participates in the Alberta and BC One-Call systems. Trans Mountain has maintained these programs on the deactivated segments.

Trans Mountain's Public Awareness Program ensures that landowners adjacent to the rights-of-way, contractors using excavating equipment, emergency response agencies and the general public are made aware of the need to protect the operating pipeline from damage.

Signage is used to identify the pipeline rights-of-way at regular intervals and at all road and utility crossings. Besides serving to prevent damage to the pipelines from accidental interference, the signage includes an emergency contact number for the public to call if they spot unusual activity.

Right-of-way surveillance is conducted via aerial patrols. Aerial patrols help to prevent incidents by reporting unauthorized ground disturbance activities. The frequency of aerial patrol for the two segments to be reactivated is provided in Table 3.6.3.

TABLE 3.6.3

AERIAL PATROL FREQUENCY

TMPL Line/Segment	Summer (May to October)	Winter (November to April)
Edmonton to Barrier, BC	2/month (12)	1/month (6)

Field operations personnel also conduct day-to-day surveillance of the rights-of-way during the performance of their regular duties and report potential or existing encroachments.

3.6.3.11 Natural Hazards

The natural hazards program is designed to detect, monitor, and remediate sites which are deemed to present a risk of damage to or failure of the pipeline due to geotechnical or hydrotechnical hazards. Trans Mountain has conducted natural hazards monitoring on the pipeline system since the early days of operation; however, a formal program to assess and monitor natural hazards was implemented in 1998.

The program has identified nine areas for potential mitigation prior to reactivation of the Hinton to Hargreaves segment (Table 3.6.4). There are no areas of mitigation required in the Darfield to Black Pines segment. If additional natural hazard sites are identified prior to reactivation, these will be added to the list for potential mitigation.

TABLE 3.6.4

NATURAL HAZARDS MITIGATION PRIORITY LIST (HINTON TO HARGREAVES)

Priority	KP	Creek Name	Depth of Cover (m)	Comments
1	452.72	Unnamed Creek Debris Flow	0	Pipe is exposed for 5 m in 2012 and is partly suspended in the channel.
1	461.18	Fraser River 7	0	Pipe exposure was noted in 2013 but the exact length of the section is unknown
1	411.57	Rockingham Creek	0	1 m of exposed pipe discovered in 2013
2	360.18	Snaring River	0	Pipe is exposed for 10 m in 2012.
2	374.97	Cottonwood Creek	0	Pipe is exposed for 0.5 m since 2008.
2	389.91	Minaga Creek	0	Pipe is exposed for 2 m. Mitigated in 2001 but exposed again in 2008.
2	403.99	Miette 5	0	Pipe is exposed for 3 m in 2012.
3	341.66	Unnamed Creek	0	Depth of cover was 0.05 m in 2012, near exposure.
3	385.97	Muhigan Creek	0	Pipe is exposed for 2.9 m in 2012.

The nine areas identified are stream crossings where there is insufficient depth of cover or exposure. Mitigation measures will be developed in the detailed engineering and design phase. Options will include armouring of the crossings with additional fill or other protective measures (rock blanket, concrete matting) or replacement of the pipe in the crossings with added depth of cover. Where a pipe replacement option is necessary, trenchless, isolated open cut, and open cut methods will be considered after an assessment of the hydrological and aquatic conditions and other technical and environmental factors. The results of the assessments will be filed with the NEB prior to reactivation, if required.

In addition to the mitigation measures at the known priority sites, Trans Mountain will run a high resolution geometry ILI tool prior to reactivation. The geometry tool data will be integrated with the data from the GEOPIG inspections completed in 2001 and 2003 to identify pipe movements that may have been caused by slope instability, river scour, or other geological, geotechnical, or hydrologic phenomena.

3.6.3.12 Consequence Reduction

Trans Mountain is currently assessing consequence reduction options on the Hinton to Hargreaves and Darfield to Black Pines segments. These studies will be completed in conjunction with risk studies, environmental sensitivity studies, and the engagement of Parks Canada and BC Parks. The studies are expected to be complete in Q2, 2014 and will be included in an updated engineering assessment.

Consequence reduction will generally consist of automating some existing RMLBVs and/or installing new automated RMLBVs or check valves at locations that are most advantageous in reducing the impact of a pipeline rupture. The valve automation/placement studies assume a worst case rupture (*i.e.*, a complete break). The calculated escaped volume is based on the maximum flow rate of the pipeline, the time required for the leak detection system to generate an alarm, and the time required for the pipeline operator to shut down the pipeline and close the RMLBVs. See Section 3.5.2 for the proposed location of RMLBVs in the reactivation segments.

An ancillary benefit to additional RMLBVs will be pressure monitoring at more locations. Additional pressure monitoring is expected to improve leak detection capabilities.

3.6.4 Risk Assessment

Trans Mountain is currently undertaking a risk assessment for the reactivation segments. The risk assessment is expected to be complete in Q2 of 2014. The updated engineering assessment report will include the results of the risk assessment.

3.6.5 Reactivation Steps

The various steps to prepare for and achieve reactivation are discussed in the following sections. A preliminary schedule for these activities is included in Volume 4B, Section 3.2 along with the preliminary pipeline construction schedule.

3.6.5.1 Initial In-Line Inspections and Repairs

As discussed in the previous sections, Trans Mountain will run three ILI tools, along with an initial gauging tool in the segments to be reactivated, prior to hydrostatic testing. The tools will identify metal loss, mechanical damage, and axially oriented cracks.

Once the ILI results are received, Trans Mountain will do a number of digs to verify the tools' sizing accuracy and to assess any anomalies. Since the pipeline is inactive and has been purged with nitrogen, any required repairs will be completed as cut-outs (*i.e.*, replacements of the damaged sections of pipe with new pipe).

3.6.5.2 Natural Hazards Mitigation

After the initial ILI program, Trans Mountain will mitigate the stream crossing hazards already identified and any other hazards identified during ongoing assessments.

3.6.5.3 Remote Main Line Block Valve Automation and Installation

In conjunction with the natural hazards mitigation program, Trans Mountain will complete the automation of existing RMLBVs and the installation of new RMLBVs that are identified during the ongoing study work.

Existing access roads and power lines will be utilized to the extent possible and any new infrastructure required to automate existing RMLBVs or install additional RMLBVs will be vetted with local Aboriginal groups and stakeholders.

Remote main line block valves will also include pressure monitoring devices that will communicate with the SCADA/Leak Detection system.

3.6.5.4 Additional Maintenance Activities

In conjunction with the RMLBV automations and installations, the existing RMLBVs will be inspected and refurbished, if necessary. Existing pipeline fittings will also be inspected and replaced if necessary and unnecessary small bore valves and piping will be removed.

3.6.5.5 Additional Construction Activities

As part of previous deactivation work, and in order to isolate the deactivated pipeline segments from the active pipeline segments, some fittings and piping that connected the pipelines to pump stations were removed. Modifications to piping were also made at other locations to allow the active NPS 24 pipeline segments and the larger diameter loops to form a continuous pipeline system. To allow for ILI work to proceed, the following activities will be required:

- From Hinton to Hargreaves:
  - installation of a temporary sending trap at the former Hinton trap site;
  - installation of approximately 250 m of NPS 24 pipe between the station isolation valves at Jasper Pump Station;
  - installation of approximately 200 m of NPS 24 pipe at the former Yellowhead Pump Station site; and
  - installation of a temporary receiving trap at the Hargreaves trap site.
- From Darfield to Black Pines:
  - assessment and possible upgrade of the existing sending trap at Darfield Pump Station; and
  - installation of a temporary receiving trap at the Black Pines RMLBV site.

These temporary installations and modifications will be coordinated with the permanent modification work required at some of these sites as discussed in Sections 3.3 and 3.5.

3.6.5.6 Hydrostatic Test

The final step in the reactivation process will be hydrostatic testing of the pipeline segments to qualify them to at least their former MOPs. Where possible, portions of the segments will be tested to 100 per cent of the SMYS. Hydrostatic testing will be conducted in accordance with CSA Z662, Oil and Gas Pipeline System requirements and KMC Standard MP4121, Main Line Hydrostatic Testing. Hydrostatic testing will ensure that a 1.25 safety factor is established prior to the segments returning to operation. The operating conditions of the reactivated pipeline are expected be similar to what they were prior to deactivation.

3.6.5.7 Final In-Line Inspection

As discussed in previous sections, Trans Mountain will conduct an ILI of the reactivated segments within the first two years of operation with a specialized high-resolution ultrasonic tool to verify that no detrimental crack defects were initiated and/or grew as a result of the hydrostatic testing. Any defects identified will be assessed and a repair program will be initiated, as necessary.

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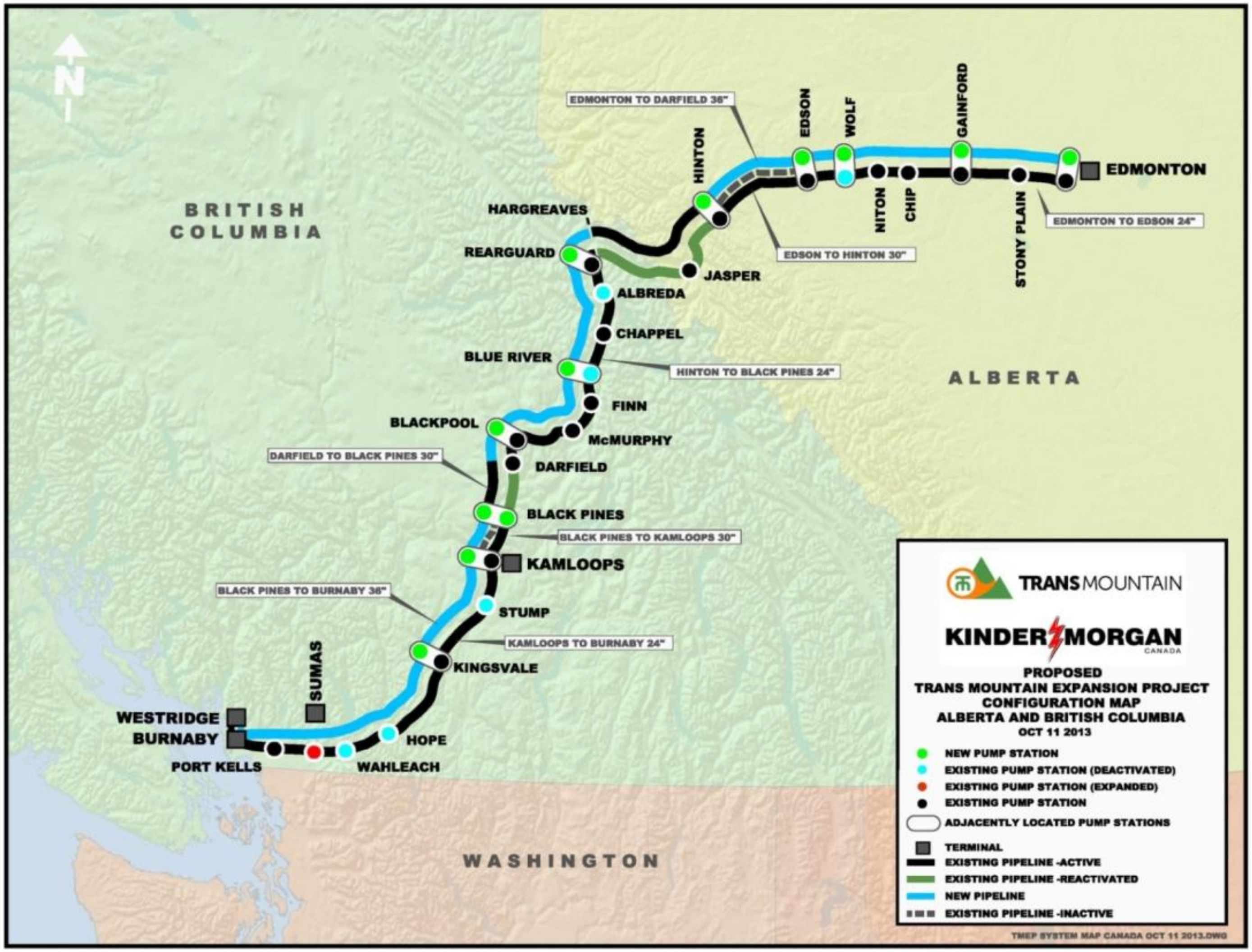
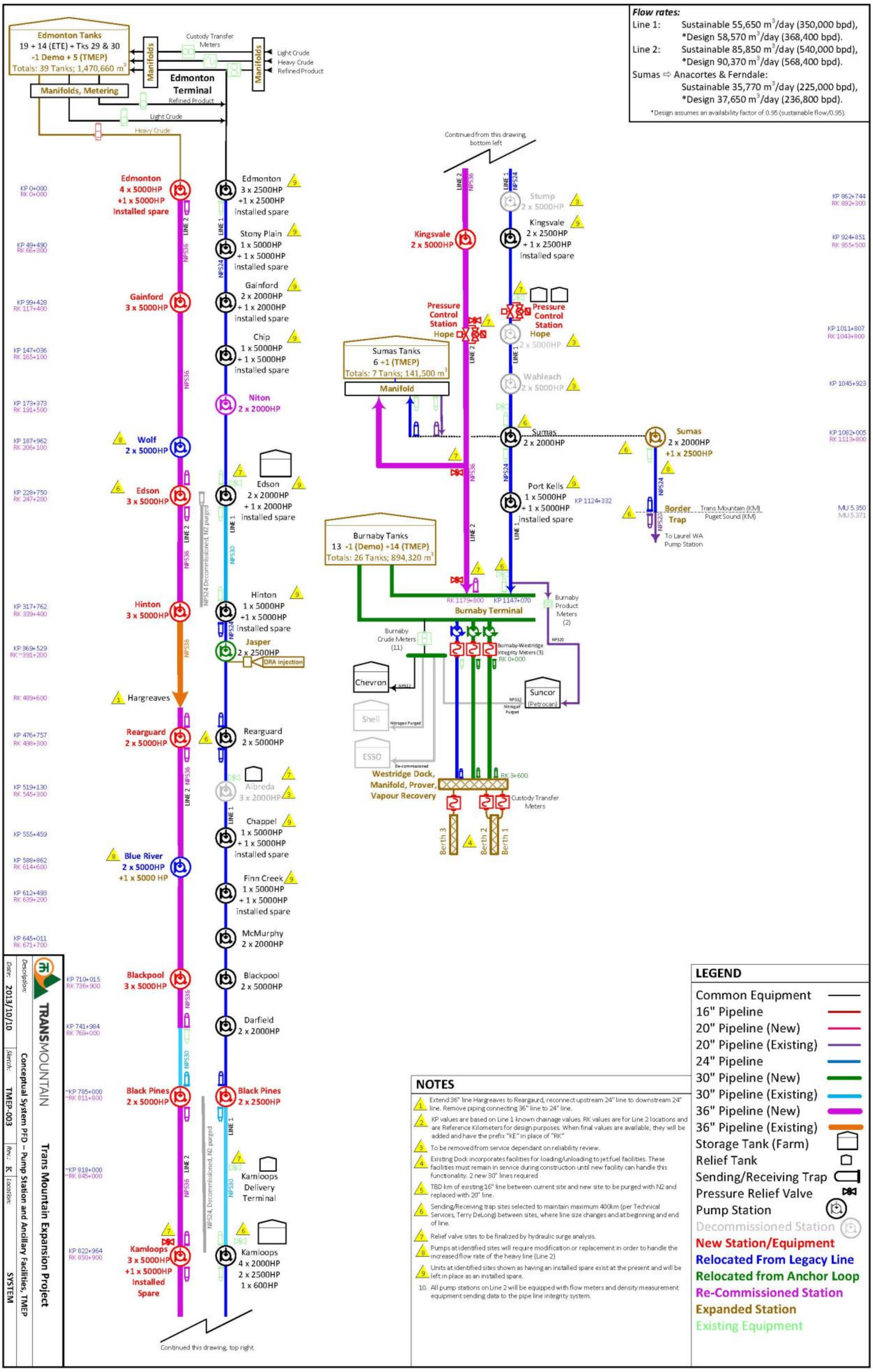
5.0 APPENDICES

Appendix A Configuration Map and Schematics

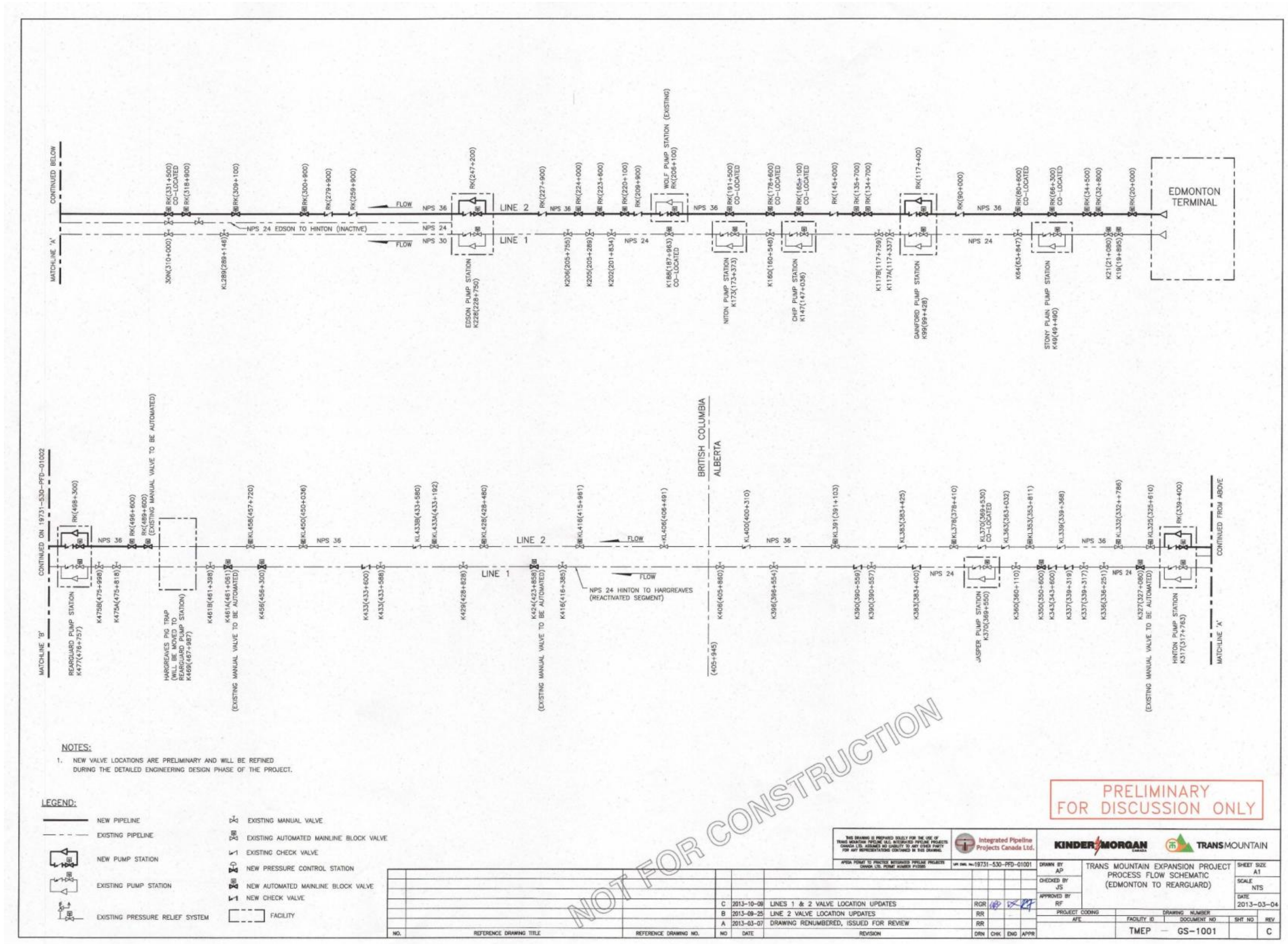


Map 5.1.1 Project Configuration Map and System Schematics

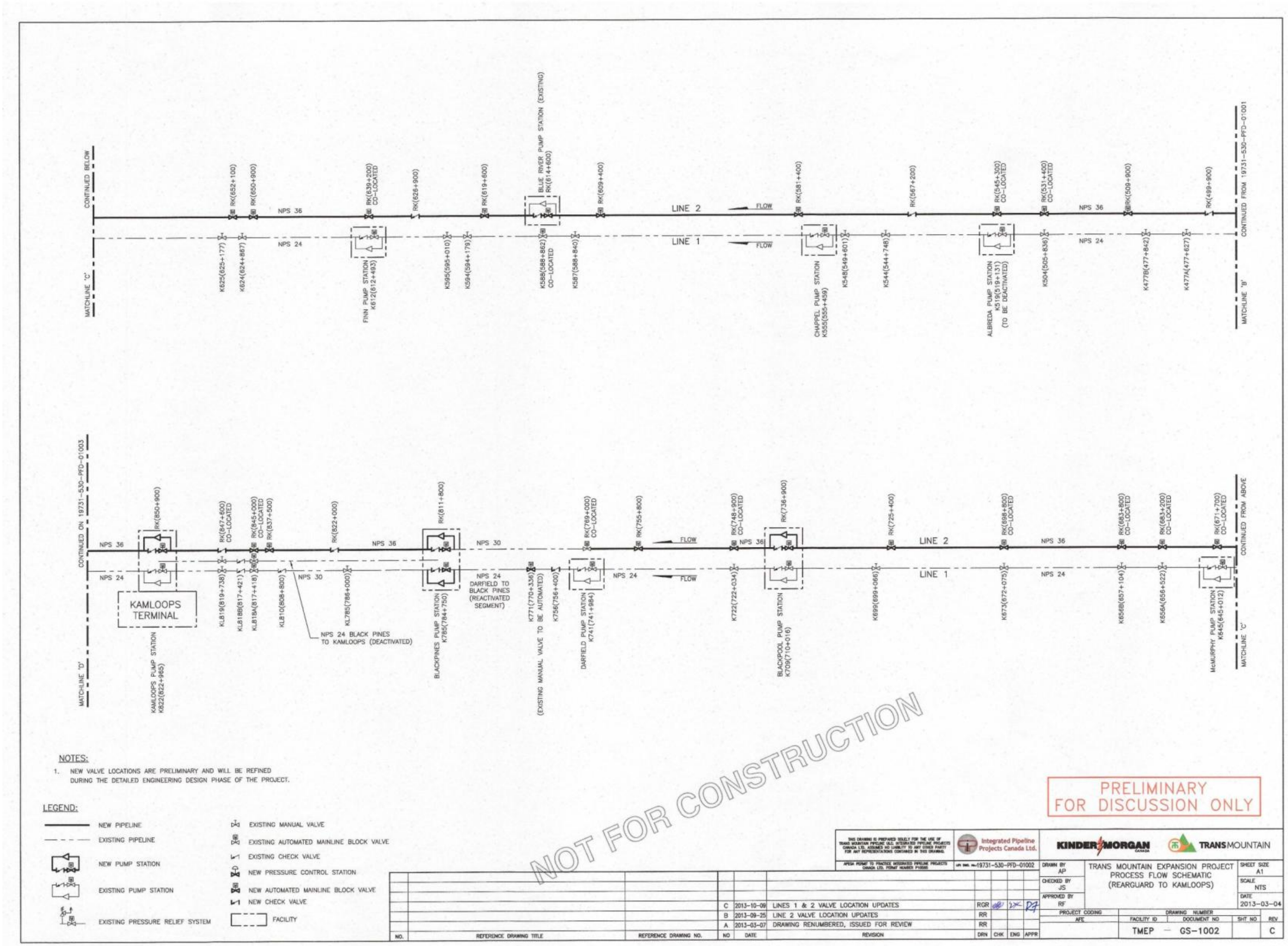
Conceptual System Process Flow Diagrams



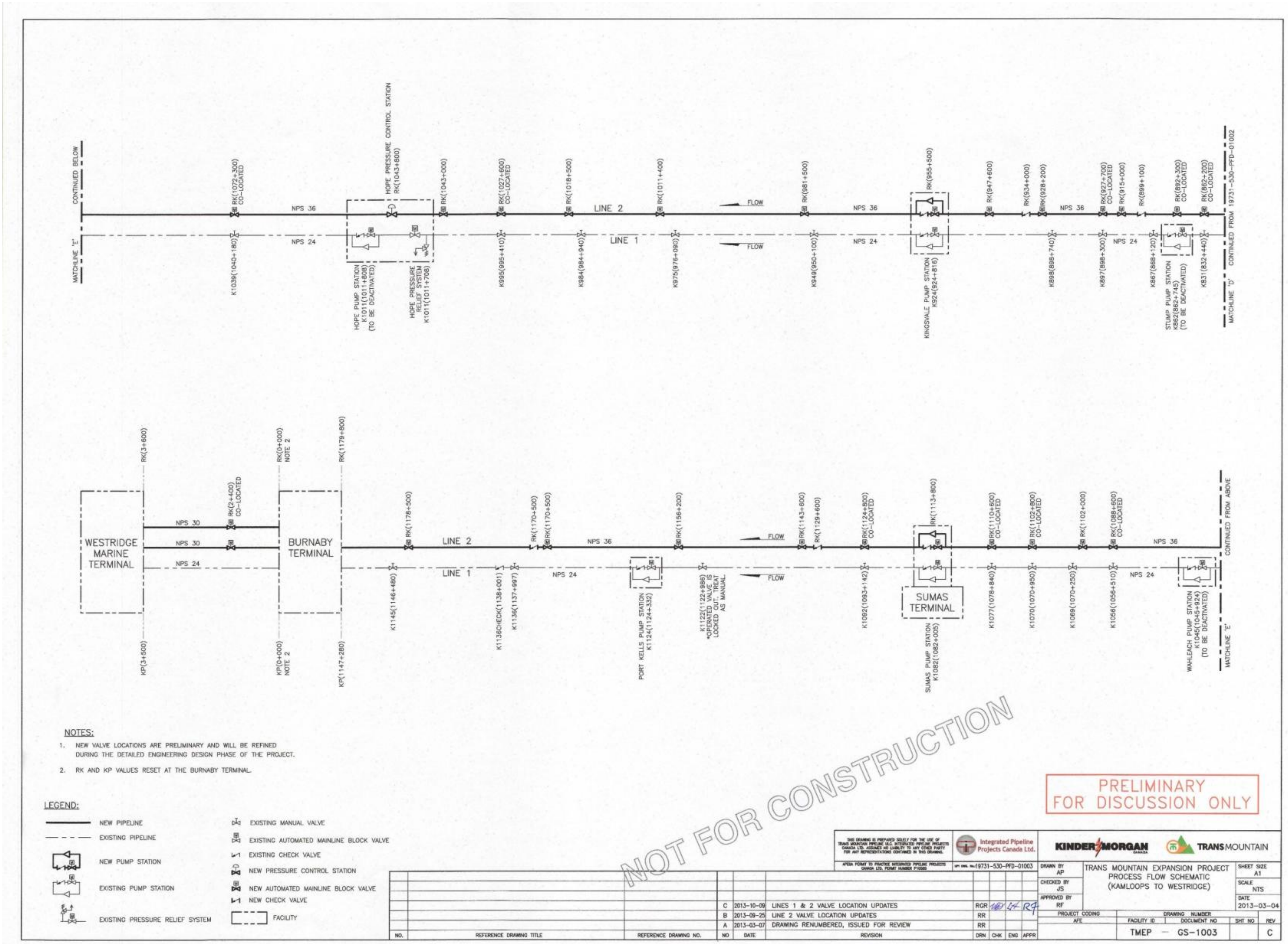
Map 5.1.2 Pump Station and Ancillary Facilities



Map 5.1.3 Pipeline Process Flow Schematic – Edmonton to Rearguard



Map 5.1.4 Pipeline Process Flow Schematic – Rearguard to Kamloops



Map 5.1.5 Pipeline Process Flow Schematic – Kamloops to Westridge

Appendix B Figures

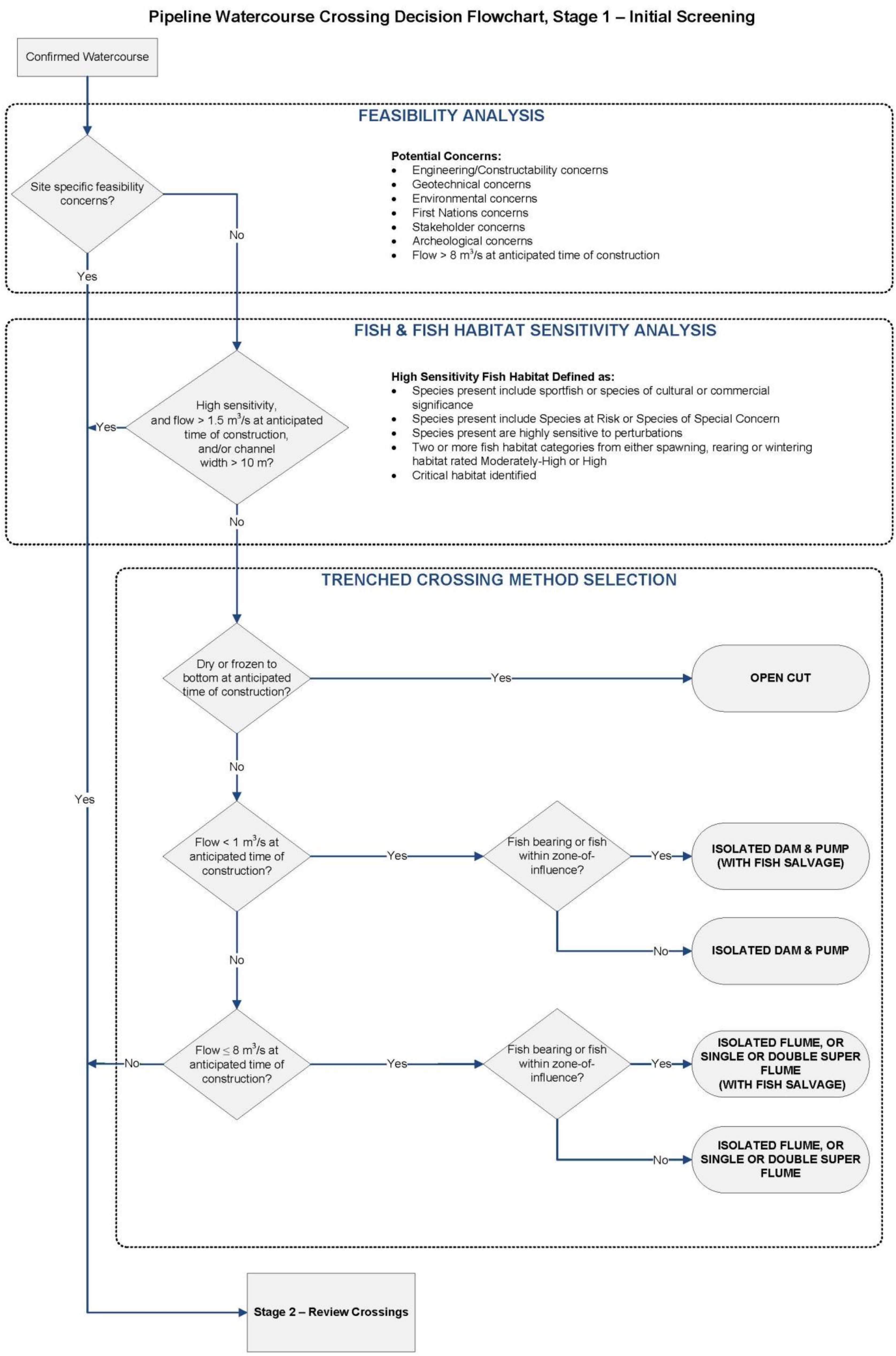


Figure 5.1.1 Pipeline Watercourse Crossing Decision Flowchart, Stage 1 – Initial Screening

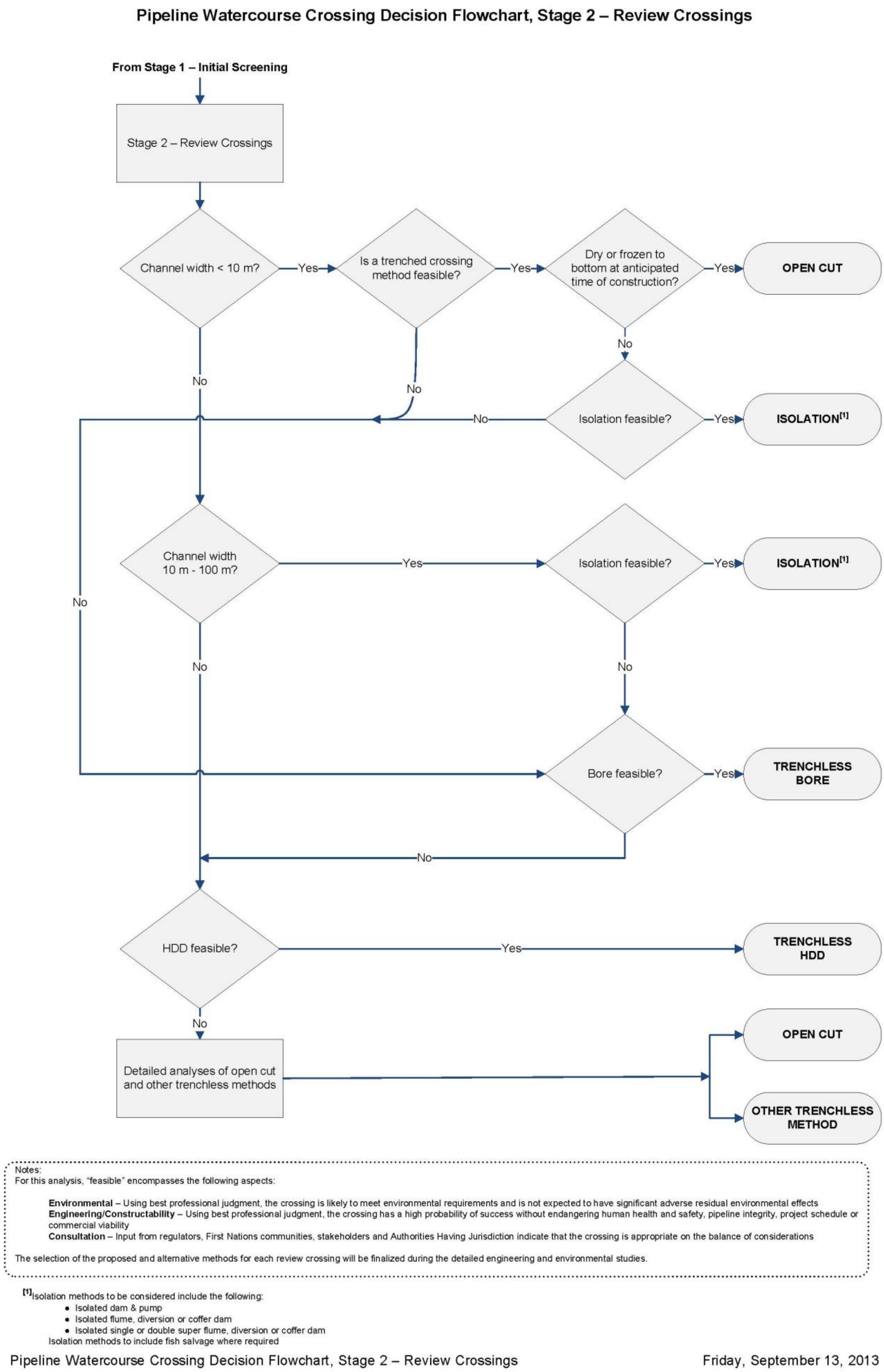
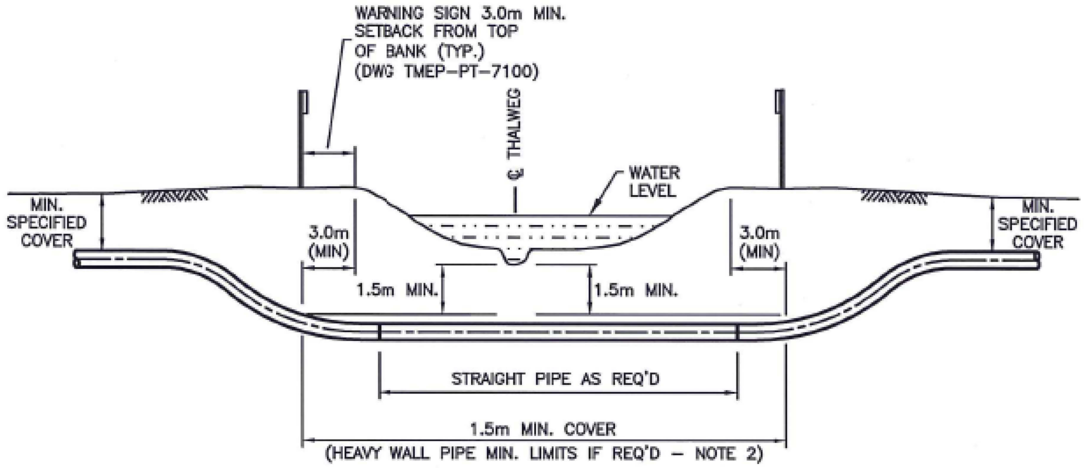


Figure 5.1.2 Pipeline Watercourse Crossing Decision Flowchart, Stage 2 – Review Crossings

Appendix C Drawings

- TMEP - PT-6101 – Double Sag Water Crossing
- TMEP - PT-6200 – Foreign Pipeline Crossing
- TMEP - PT-6300 – Buried Cable Crossing
- TMEP - PT-6401 – Municipal Road Crossing (Alberta)
- TMEP - PT-6403 – Municipal Road Crossing (British Columbia)
- TMEP - PT-6404 – Highway Crossing Trenchless: Bore Method
- TMEP - PT-6702 – Foreign Crossing Protective Concrete Slab
- TMEP - PT-6500 – Uncased Railway Crossing

ALIGNMENT SHEET CODE: L



CROSS SECTION OF WATER CROSSING

NOTES:

1. USE OF DOUBLE SAG CROSSING REQUIRED WHERE WIDTH OF DRAINAGE DOES NOT PERMIT USE OF SINGLE SAG.
2. FOR HEAVYWALL PIPE AND/OR ADDITIONAL COVER REQUIREMENTS REFER TO ALIGNMENT SHEETS.
3. CONSTRUCT TO THE LATEST EDITION OF CSA Z662, IN ACCORDANCE WITH THE INSTRUCTIONS PUBLISHED BY AUTHORITIES HAVING JURISDICTION, AND THE CONTRACT SPECIFICATIONS.

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UPI DWG. No.: 19731–505–TYP–06101

KINDER MORGAN CANADA — TRANS MOUNTAIN

DRAWN BY | CHECKED BY | APPROVED BY

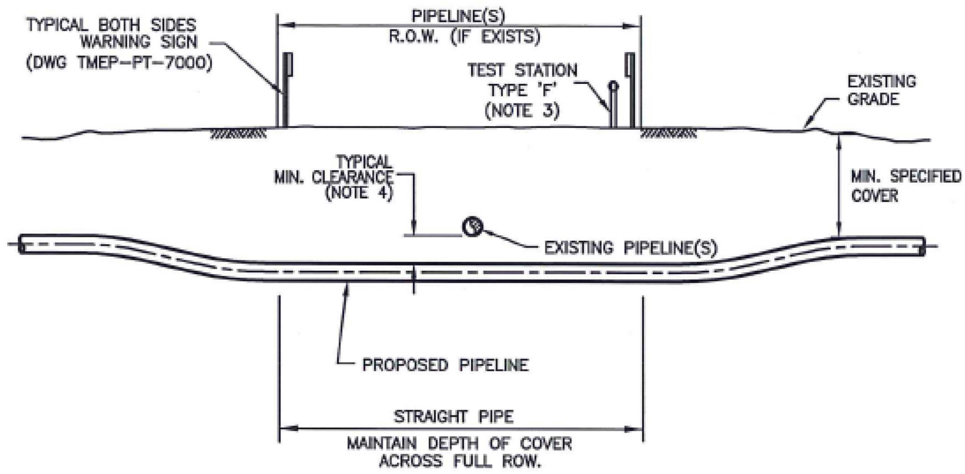
TRANS MOUNTAIN EXPANSION PROJECT
TYPICAL DRAWING
DOUBLE SAG WATER CROSSING

SHEET SIZE: 8.5x11
SCALE: NTS
DATE: 2012–11–05

NO.	DATE	REVISION	DRN	CHK	ENG	APPR
A	2012–11–05	ISSUED FOR REVIEW	RMR			

PROJECT CODING AFE	FACILITY ID	DOCUMENT NO	SHT NO	REV
	TMEP	PT–6101	1	A

ALIGNMENT SHEET CODE: 0



CROSS SECTION OF FOREIGN PIPELINE(S) R.O.W.

NOTES:

1. EXISTING PIPELINE LOCATIONS & DEPTHS TO BE CONFIRMED BY HAND–DIGGING OR "HYDRO–VAC".
2. OWNER(S) OF EXISTING PIPELINE(S) SHALL BE NOTIFIED AT LEAST 72 HOURS IN ADVANCE OF EXCAVATION OF CROSSING, OR AS REQUIRED BY THE CROSSING AGREEMENT. THE OWNER OR HIS REPRESENTATIVE SHALL BE PRESENT ON SITE WHEN THE CROSSING OPERATION TAKES PLACE UNLESS OTHERWISE APPROVED BY THE EXISTING PIPELINE OWNER.
3. WHERE EXISTING STEEL PIPELINE(S) ARE CROSSED, A TYPE 'F' TEST STATION SHALL BE INSTALLED AS REQUIRED AND LOCATED WHERE PRACTICAL UNLESS OTHERWISE SPECIFIED IN THE CROSSING AGREEMENT OR BY EXISTING PIPELINE OWNER. REFER TO TYPICAL TEST STATION DWG TMEP–PT–4002.
4. MINIMUM CLEARANCE SHALL BE AS LISTED BELOW OR AS INDICATED ON THE CROSSING AGREEMENT. PIPE SHALL BE STRAIGHT WITH DEPTH OF COVER MAINTAINED FOR THE FULL ANGULAR WIDTH OF EXISTING PIPELINE R.O.W.

CROSSING TYPE	FOREIGN PIPELINE MATERIAL	MIN. CLEARANCE
OPEN CUT–PRIVATE LANDS	STEEL	0.6
	PLASTIC	0.3
OPEN CUT–CROWN LAND	ALL	0.3
BORE	ALL	1.0
HDD	ALL	2.0

5. PLASTIC PIPELINE SHALL BE SUPPORTED. AS A MINIMUM, UNLESS EXISTING LINE OWNER HAS MORE STRINGENT SPECIFIC REQUIREMENTS, ANGLE IRON OF MINIMUM DIMENSIONS 75mm x 75mm x 6mm SHALL BE USED.
6. ALL BACKFILL WITHIN 3m OF A PIPELINE CROSSING TO BE DEPOSITED IN 150mm LIFTS AND COMPACTED TO 85% STANDARD PROCTOR DENSITY, OR THE SATISFACTION OF THE MANAGER.
7. TEMPORARY RAMP SHALL BE CONSTRUCTED FOR ACCESS OVER ALL PIPELINES. SEE DWG TMEP–PT–1000 OR TMEP–PT–1001.
8. CONSTRUCT TO THE LATEST EDITION OF CSA Z662 IN ACCORDANCE WITH THE INSTRUCTIONS PUBLISHED BY AUTHORITIES HAVING JURISDICTION, AND THE CONSTRUCTION SPECIFICATIONS.
9. ALL DIMENSIONS ARE IN METRES UNLESS NOTED OTHERWISE.
10. ALL REQUIREMENTS OF CROSSING PERMIT MUST BE MET AND A COPY MUST BE AVAILABLE ON SITE.

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UPI DWG. No.: 19731–505–TYP–06200

KINDER MORGAN CANADA — TRANS MOUNTAIN

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CHECKED BY
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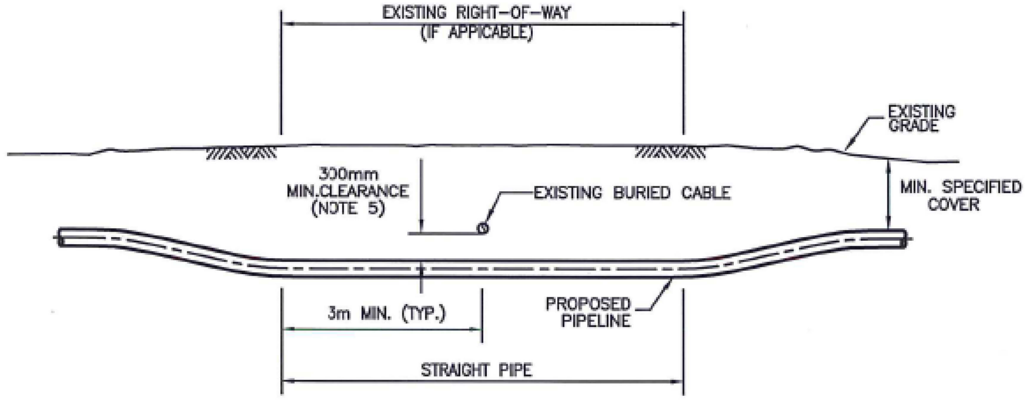
TRANS MOUNTAIN EXPANSION PROJECT
TYPICAL DRAWING
FOREIGN PIPELINE CROSSING

SHEET SIZE 8.5x11
SCALE NTS
DATE 2012–11–05

NO.	DATE	REVISION	DRN	CHK	ENG	APPR
A	2012–11–05	ISSUED FOR REVIEW	RMR			

PROJECT CODING AFE	FACILITY ID		DOCUMENT NO	SHT NO	REV
	TMEP	—	PT–6200	1	A

ALIGNMENT SHEET CODE: M



CROSS SECTION

NOTES:

1. BURIED CABLE LOCATION AND DEPTH TO BE CONFIRMED BY HAND-DIGGING OR "HYDRO-VAC" ON DITCH CENTRELINE AND BOTH SIDES OF THE RIGHT-OF-WAY TO VERIFY ANGLE OF CROSSING IN ADVANCE OF PIPELINE CONSTRUCTION.
2. OWNER OF BURIED CABLE(S) SHALL BE NOTIFIED AT LEAST 72 HOURS IN ADVANCE OF EXCAVATION OF CROSSING, OR AS REQUIRED BY THE CROSSING AGREEMENT.
3. CONTRACTOR SHALL SUPPORT CABLE AS REQUIRED BY CABLE OWNER. IF CABLE OWNER HAS NO SPECIFIC REQUIREMENTS, ANGLE IRON 75mm x 75mm x 6mm SHALL BE USED.
4. ALL BACKFILL WITHIN 3m OF A CABLE CROSSING TO BE DEPOSITED IN 150mm LIFTS, AND MECHANICALLY COMPACTED TO 85% STANDARD PROCTOR.
5. MINIMUM CLEARANCE SHALL BE 300 mm IF OPEN-CUT AND 600mm IF BORED OR AS REQUIRED BY THE CROSSING AGREEMENT. PIPELINE DEPTH OF COVER SHALL BE MAINTAINED FOR THE FULL ANGULAR WIDTH OF THE EXISTING CABLE RIGHT-OF-WAY.
6. ALL REQUIREMENTS OF CROSSING PERMIT MUST BE MET AND A COPY MUST BE AVAILABLE ONSITE.

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UPI DWG. No.: 19731-505-TYP-06300

KINDER MORGAN CANADA

TRANS MOUNTAIN

DRAWN BY	TRANS MOUNTAIN EXPANSION PROJECT TYPICAL DRAWING BURIED CABLE CROSSING	SHEET SIZE 8.5x11
CHECKED BY		SCALE NTS
APPROVED BY		DATE 2012-11-05

NO.	DATE	REVISION	DRN	CHK	ENG	APPR
A	2012-11-05	ISSUED FOR REVIEW	RMR			

PROJECT CODING AFE	DRAWING NUMBER FACILITY ID	DOCUMENT NO	SHT NO	REV
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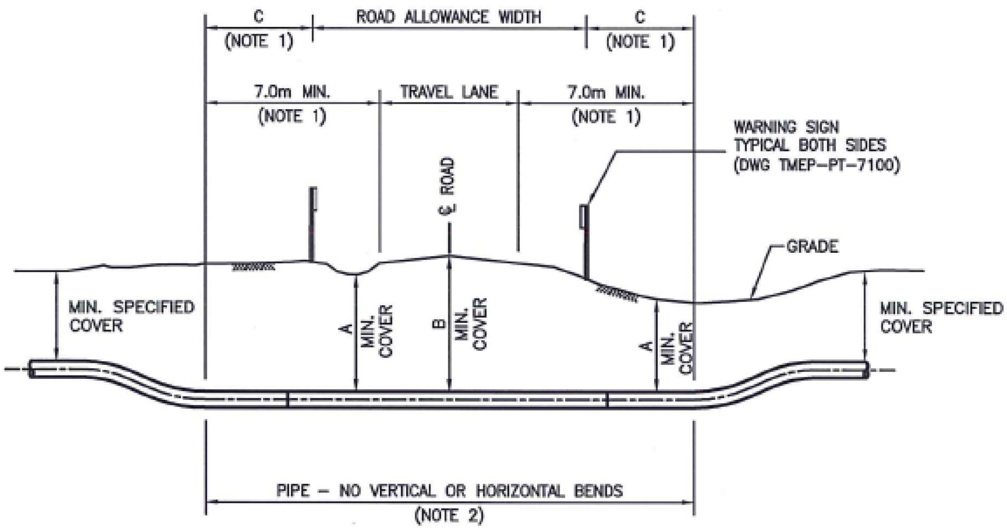
ALIGNMENT SHEET CODE: H



SECTION

COUNTY	MINIMUM COVER (m)		FUTURE WIDENING LIMIT (m)
	DITCH BOTTOM "A"	ROAD CROWN "B"	"C"
STRATHCONA COUNTY/ SHERWOOD PARK	1.8	1.8	30m FROM ℄ FOR CLASS I, II; 20m FROM ℄ FOR CLASS III, IV
PARKLAND COUNTY	2.0	2.0	15m FROM ℄
YELLOWHEAD COUNTY	2.0	3.0	7.6m FROM RA BOUNDARY (IF 20m RA TREAT AS 30m RA THEN ADD 7.6m TO EITHER SIDE)

NOTES:

1. DIMENSION SHOWN IS MEASURED PERPENDICULAR TO ROAD ALLOWANCE BOUNDARY.
2. HEAVY WALL PIPE REQUIRED IF SPECIFIED OR BORED. REFER TO ALIGNMENT SHEET FOR DETAILS.
3. BACKFILL AND MECHANICALLY COMPACT AS PER PROJECT CONSTRUCTION SPECIFICATIONS OR AS SPECIFIED IN CROSSING AGREEMENT.
4. IDENTIFICATION TAPE SHALL BE INSTALLED 0.6m ABOVE PIPE TOP CUT.
5. ALL DIMENSIONS ARE IN METERS UNLESS NOTED OTHERWISE.
6. ALL REQUIREMENTS OF CROSSING PERMIT MUST BE MET AND A COPY MUST BE AVAILABLE ON SITE.

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UPI DWG. No.: 19731–505–TYP–06401

KINDER MORGAN CANADA — TRANS MOUNTAIN

DRAWN BY	TRANS MOUNTAIN EXPANSION PROJECT TYPICAL DRAWING MUNICIPAL ROAD CROSSING (ALBERTA)	SHEET SIZE 8.5x11
CHECKED BY		SCALE NTS
APPROVED BY		DATE 2012–11–05

NO.	DATE	REVISION	DRN	CHK	ENG	APPR
A	2012–11–05	ISSUED FOR REVIEW	RMR			

PROJECT CODING AFE	FACILITY ID	DOCUMENT NO	SHT NO	REV
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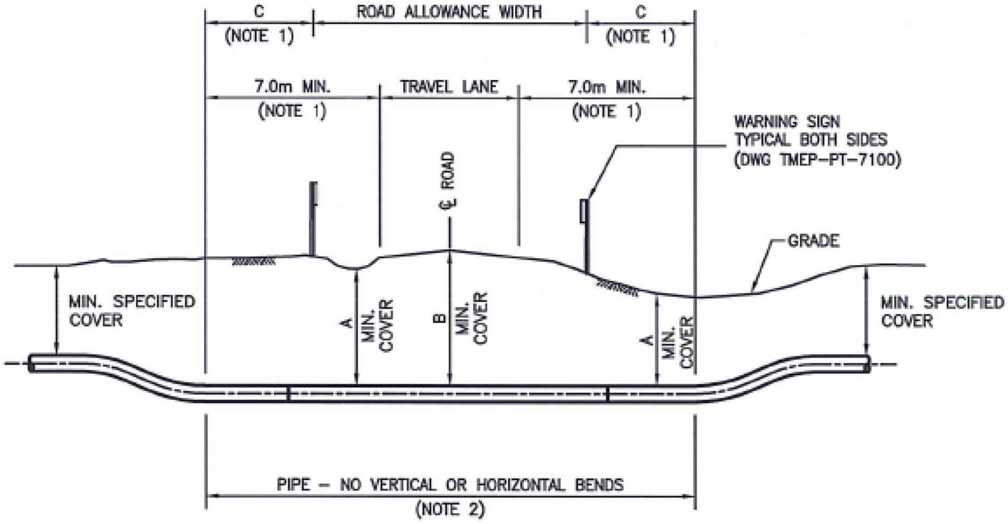
ALIGNMENT SHEET CODE: H



SECTION

NOTES:

1. DIMENSION SHOWN IS MEASURED PERPENDICULAR TO ROAD ALLOWANCE BOUNDARY.
2. HEAVY WALL PIPE REQUIRED IF SPECIFIED OR BORED. REFER TO ALIGNMENT SHEET FOR DETAILS.
3. BACKFILL AND MECHANICALLY COMPACT AS PER PROJECT CONSTRUCTION SPECIFICATIONS OR AS SPECIFIED IN CROSSING AGREEMENT.
4. IDENTIFICATION TAPE SHALL BE INSTALLED 0.6m ABOVE PIPE TOP CUT.
5. ALL DIMENSIONS ARE IN METERS UNLESS NOTED OTHERWISE.
6. ALL REQUIREMENTS OF CROSSING PERMIT MUST BE MET AND A COPY MUST BE AVAILABLE ON SITE.
7. THE B.C. MINISTRY OF TRANSPORTATION AND INFRASTRUCTURE (MOTI), SPECIFIES A MINIMUM DEPTH OF COVER OF 1.2m OR AS SPECIFIED IN THE CROSSING AGREEMENT, WHICHEVER IS GREATER.

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UPI DWG. No.: 19731–505–TYP–06403

KINDER MORGAN CANADA — TRANS MOUNTAIN

NO.	DATE	REVISION	DRN	CHK	ENG	APPR
A	2012-11-05	ISSUED FOR REVIEW	RMR			

DRAWN BY	TRANS MOUNTAIN EXPANSION PROJECT TYPICAL DRAWING MUNICIPAL ROAD CROSSING (BRITISH COLUMBIA)	SHEET SIZE 8.5x11
CHECKED BY		SCALE NTS
APPROVED BY		DATE 2012–11–05

PROJECT CODING AFE	DRAWING NUMBER FACILITY ID	DOCUMENT NO	SHT NO	REV
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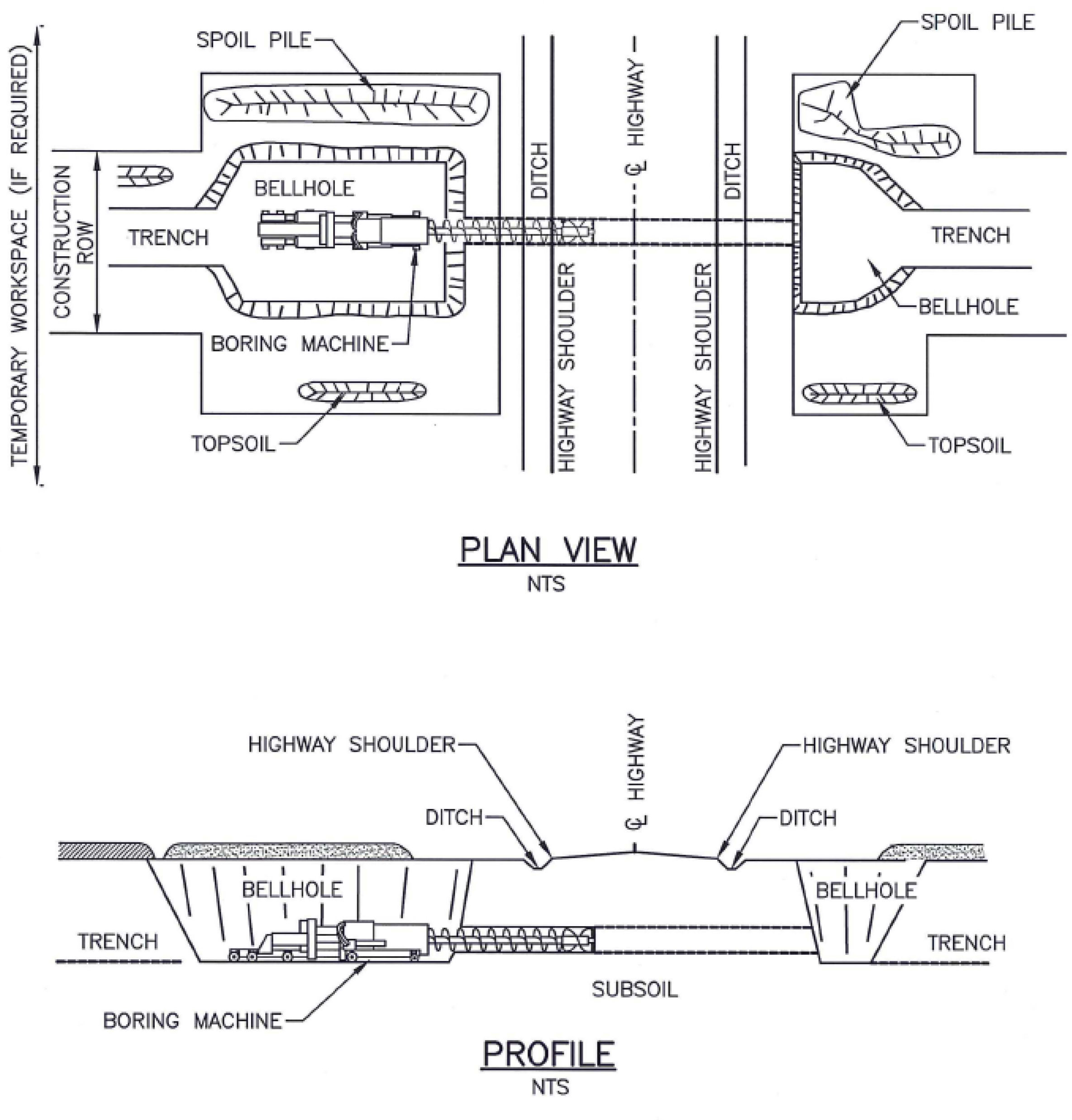

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UPI DWG. No.: 19731-505-TYP-06404

KINDER MORGAN CANADA — TRANSMOUNTAIN

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TRANS MOUNTAIN EXPANSION PROJECT
TYPICAL DRAWING
HIGHWAY CROSSING
TRENCHLESS: BORE METHOD

SHEET SIZE 8.5x11
SCALE NTS
DATE 2013-06-26

PROJECT CODING AFE	DRAWING NUMBER FACILITY ID	DOCUMENT NO	SHT NO	REV
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NO.	DATE	REVISION	DRN	CHK	ENG	APPR
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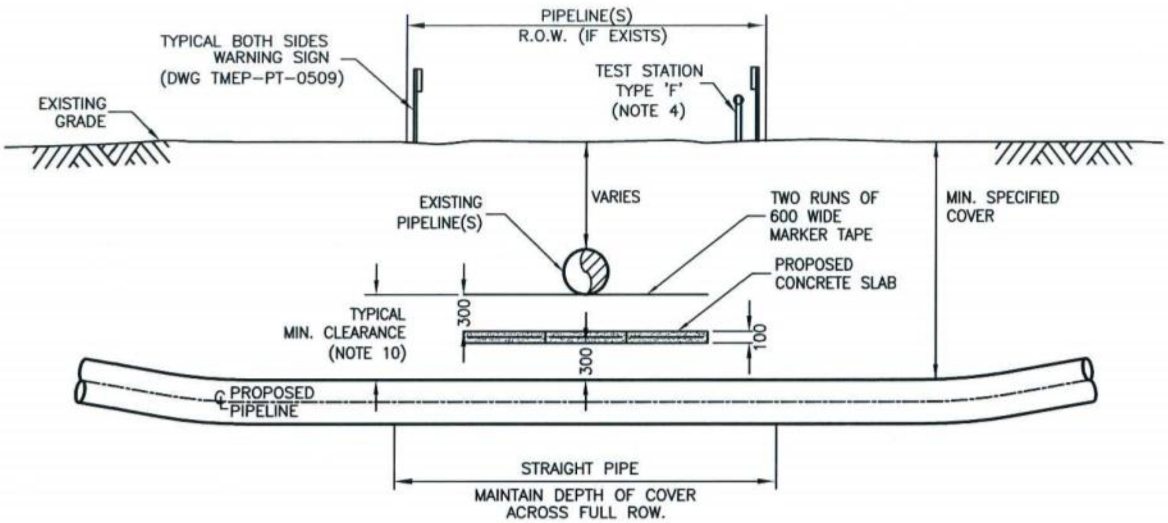

CROSS SECTION OF FOREIGN PIPELINE(S) R.O.W.

NOTES:

1. ALL DIMENSIONS ARE IN MILLIMETRES UNLESS OTHERWISE SPECIFIED.
2. EXISTING PIPELINE LOCATIONS & DEPTHS TO BE CONFIRMED BY HAND-DIGGING OR "HYDRO-VAC".
3. OWNER(S) OF EXISTING PIPELINE(S) SHALL BE NOTIFIED AT LEAST 72 HOURS IN ADVANCE OF EXCAVATION OF CROSSING, OR AS REQUIRED BY THE CROSSING AGREEMENT. THE OWNER OR HIS REPRESENTATIVE SHALL BE PRESENT ON SITE WHEN THE CROSSING OPERATION TAKES PLACE UNLESS OTHERWISE APPROVED BY THE EXISTING PIPELINE OWNER.
4. WHERE EXISTING STEEL PIPELINE(S) ARE CROSSED, A TYPE 'F' TEST STATION SHALL BE INSTALLED AS REQUIRED AND LOCATED WHERE PRACTICAL UNLESS OTHERWISE SPECIFIED IN THE CROSSING AGREEMENT OR BY EXISTING PIPELINE OWNER. REFER TO TYPICAL TEST STATION DWG TMEP-PT-4002.
5. PLASTIC PIPELINE SHALL BE SUPPORTED, AS A MINIMUM BY ANGLE IRON OF MINIMUM DIMENSIONS 75mm x 75mm x 6mm, UNLESS EXISTING LINE OWNER HAS MORE STRINGENT SPECIFIC REQUIREMENTS.
6. ALL BACKFILL WITHIN 3m OF A PIPELINE CROSSING TO BE DEPOSITED IN 150mm LIFTS AND COMPACTED TO 85% STANDARD PROCTOR DENSITY, OR TO THE SATISFACTION OF THE MANAGER.
7. TEMPORARY RAMP SHALL BE CONSTRUCTED FOR ACCESS OVER ALL PIPELINES. SEE DWG TMEP-PT-1000 OR TMEP-PT-1001.
8. CONSTRUCT TO THE LATEST EDITION OF CSA Z662 IN ACCORDANCE WITH THE INSTRUCTIONS PUBLISHED BY THE AUTHORITIES HAVING JURISDICTION, AND THE CONSTRUCTION SPECIFICATIONS.
9. ALL REQUIREMENTS OF THE CROSSING PERMIT SHALL BE MET AND A COPY SHALL BE AVAILABLE ON SITE.
10. MINIMUM CLEARANCE SHALL BE AS LISTED BELOW OR AS INDICATED ON THE CROSSING AGREEMENT. PIPE SHALL BE STRAIGHT WITH DEPTH OF COVER MAINTAINED FOR THE FULL ANGULAR WIDTH OF THE EXISTING FOREIGN R.O.W.

CROSSING TYPE	FOREIGN PIPELINE MATERIAL	MIN. CLEARANCE
OPEN CUT-PRIVATE LANDS	STEEL	0.7 m
	PLASTIC	0.7 m
OPEN CUT-CROWN LAND	ALL	0.7 m
BORE	ALL	1.0 m
HDD	ALL	2.0 m

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UPI DWG. No.: 19731-505-TYP-06702

KINDER MORGAN CANADA — TRANS MOUNTAIN

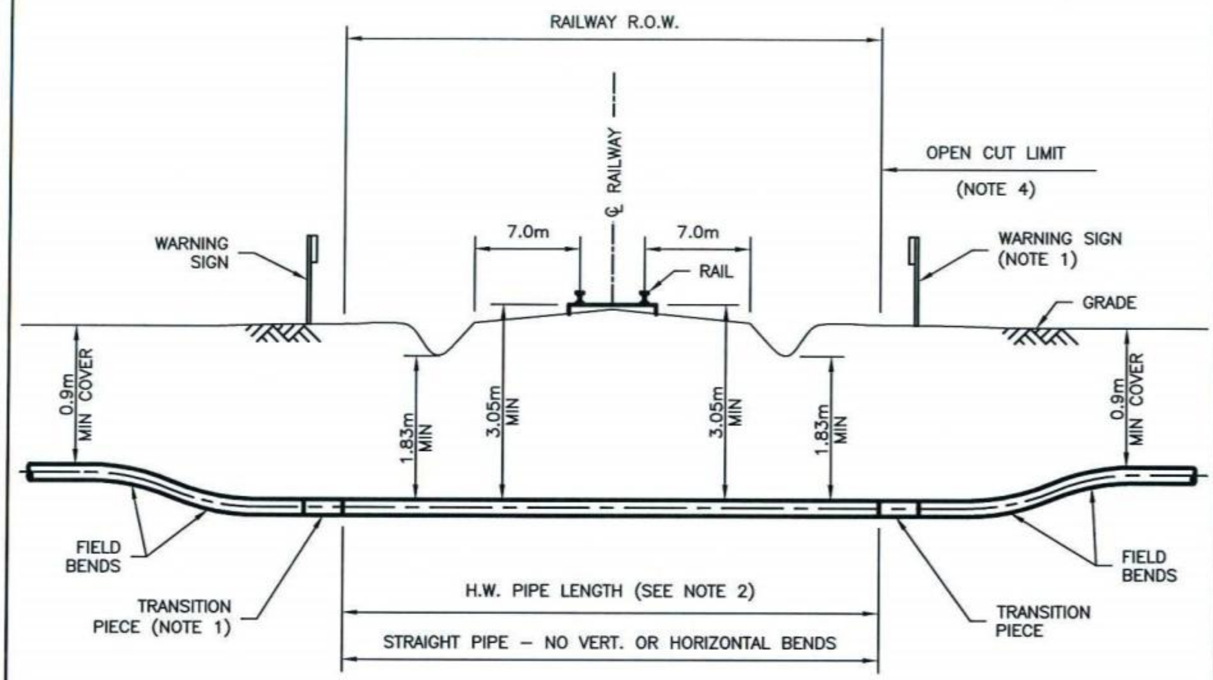
DRAWN BY	MPL
CHECKED BY	
APPROVED BY	

TRANS MOUNTAIN EXPANSION PROJECT
TYPICAL DRAWING
FOREIGN PIPELINE CROSSING WITH PROTECTIVE CONCRETE SLAB

SHEET SIZE 8.5x11
SCALE NTS
DATE 2012-11-19

PROJECT CODING AFE	FACILITY ID	DOCUMENT NO	SHT NO	REV
	TMEP	PT-6702		A

NO.	DATE	REVISION	DRN	CHK	ENG	APPR
A	2012-11-19	ISSUED FOR REVIEW	MPL	[illegible]	[illegible]	[illegible]



SECTION

NOTES:

1. REFER TO SPECIFIC TYPICAL DRAWING FOR WARNING SIGN DETAILS, TEST LEAD STN. AND TRANSITION DETAIL.
2. REFER TO "SITE SPECIFIC" CROSSING DWG. OR CONSTRUCTION ALIGNMENT SHT. FOR LENGTH OF H.W. PIPE REQUIRED.
3. ALL CROSSINGS SHALL BE BORED.
4. OPEN CUTTING TO BORE FACE SHALL BE LIMITED TO THE AREA OUTSIDE OF THE RAILWAY R.O.W. BOUNDARIES OR AS REQUIRED BY THE CROSSING AGREEMENT.
5. CONSTRUCT TO THE LATEST EDITION OF CSA Z662 AND IN ACCORDANCE WITH THE REQUIREMENTS OF THE AUTHORITIES HAVING JURISDICTION.

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UPI DWG. No.: 19731–505–TYP–06500

KINDER MORGAN CANADA — TRANS MOUNTAIN

DRAWN BY	RGR
CHECKED BY	
APPROVED BY	

TRANS MOUNTAIN EXPANSION PROJECT
TYPICAL DRAWING
UNCASED RAILWAY CROSSING

SHEET SIZE	8.5x11
SCALE	NTS
DATE	2013–11–19

PROJECT CODING AFE	FACILITY ID	DOCUMENT NO	SHT NO	REV
	TMEP	PT–6500		A

NO.	DATE	REVISION	DRN	CHK	ENG	APPR
A	2013–11–19	ISSUED FOR REVIEW	RGR			

Appendix D Tables

TABLE 5.1.1

INDUSTRY CODES, STANDARDS, SPECIFICATIONS AND RECOMMENDED PRACTICES

Document No.	Title
API 5L	Specification for Line Pipe
API 6D	Specification for Pipeline Valves
API RP 505	Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1 and Zone 2
API 510	Pressure Vessel Inspection Code: Maintenance Inspection, Rating, Repair and Alteration
API 521	Guide for Pressure-Relieving and Depressuring Systems
API 541	Form-Wound Squirrel-Cage Induction Motors 500 Horsepower and Larger
API 598	Valve Inspection and Testing
API 602	Steel Gate, Globe, and Check Valves for Sizes DN 100 and Smaller for the Petroleum and Natural Gas Industries
API 607	Fire Test for Quarter-Turn Valves and Valves Equipped with Non-Metallic Seats
API 610	Centrifugal Pumps for Petroleum, Petrochemical and Natural Gas Industries
API 614	Lubrication, Shaft-Sealing, and Control-Oil Systems and Auxiliaries for Petroleum, Chemical and Gas Industry Services
API 650	Welded Tanks for Oil Storage
API 653	Tank Inspection, Repair, Alteration and Reconstruction
API RP 686	Machinery Installation and Installation Design
ASME	Boiler and Pressure Vessel Code, Section VIII, Rules for Construction of Pressure Vessels
ASME	Boiler and Pressure Vessel Code, Section IX, Welding and Brazing Qualifications
ASTM A36	Standard Specification for Carbon Structural Steel
ASTM A53	Standard Specifications for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless
ASTM A105	Standard Specification for Carbon Steel Forgings and Piping Applications
ASTM A106	Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service
ASTM A193	Standard Specification for Alloy-Steel and Stainless Steel Bolting for High Temperature or High Pressure Service and Other Special Purpose Applications
ASTM A194	Standard Specification for Carbon and Alloy Steel Nuts for Bolts for High Pressure or High Temperature Service
ASTM A234	Standard Specification for Piping Fittings of Wrought Carbon Steel and Alloy Steel for Moderate and High Temperature Service
ASTM A307	Standard Specification for Carbon Steel Bolts, Studs and Threaded Rod (60,000 PSI Tensile Strength)
ASME B16.5	Pipe Flanges and Flanged Fittings
ASME B16.9	Factory-Made Wrought Buttwelding Fittings
ASME B16.11	Forged Fittings, Socket-Welding and Threaded
ASME B16.20	Metallic Gaskets for Pipe Flanges: Ring-Joint, Spiral-Wound and Jacketed
ASTM E18	Standard Test Methods for Rockwell Hardness of Metallic Materials
ASTM E138	Method for Wet Magnetic Particle Inspection
ASTM E165	Standard Practice for Liquid Penetrant Examination for General Industry
ASTM F436	Standard Specification for Hardened Steel Washers
ASTM E709	Standard Guide for Magnetic Particle Testing
CSA A23.1/A23.2	Concrete Materials and Methods of Concrete Construction/Test Methods and Standard Practices for Concrete
CSA A23.3	Design of Concrete Structures
CSA A23.4	Precast Concrete - Materials and Construction

TABLE 5.1.1

INDUSTRY CODES, STANDARDS, SPECIFICATIONS AND RECOMMENDED PRACTICES (continued)

Document No.	Title
CSA C22	Canadian Electrical Code, Parts 1 and 2
CSA-C22.3 No. 6-13	Principles and Practices of Electrical Coordination Between Pipelines and Electric Supply Lines
CSA C88	Power Transformers and Reactors
CSA C60044	Instrument Transformers (Parts 1 to 8)
CSA G30.18	Carbon Steel Bars for Concrete Reinforcement
CSA/CAN S16	Design of Steel Structures
CSA S136	North American Specification for the Design of Cold-Formed Steel Structural Members
CSA W59	Welded Steel Construction
CSA W186	Welding of Reinforcing Bars in Reinforced Concrete Construction
CSA Z245.1	Steel Pipe
CSA Z245.11	Steel Fittings
CSA Z245.12	Steel Flanges
CSA Z245.15	Steel Valves
CSA Z245.20 Series-10	Plant-Applied External Coatings for Steel Pipe
CSA Z460	Control of Hazardous Energy - Lockout and Other Methods
CSA Z462	Workplace Electrical Safety
CSA Z662	Oil and Gas Pipeline Systems
IEEE 85	Test Procedure for Airborne Sound Measurements on Rotating Electric Machinery
IEEE 112	Standard Test Procedure for Polyphase Induction Motors and Generators
IEEE 519	Recommended Practices and Requirements for Harmonic Control in Electric Power Systems
NEMA ICS 1	Industrial Control and Systems: General Requirements
NEMA ICS 2	Industrial Control and Systems Controllers, Contactors and Overload Relays Rated 600 Volts
NEMA ICS 2 Part 9	AC Vacuum-Breaker Magnetic Controllers Rated 1500 Volts AC
NEMA ICS 18	Industrial Control and Systems: Motor Control Centers
NEMA MG-1	Motors and Generators
NEMA MG-2	Safety Standard and Guide for Selection, Installation and Use of Electric Motors and Generators
NFPA 30	Flammable and Combustible Liquids Code
SSPC-PA 1	Shop, Field and Maintenance Painting of Steel
SSPC-SP 6	Commercial Blast Cleaning
SSPC-SP 10	Near-White Blast Cleaning

TABLE 5.1.2

KMC STANDARDS, SPECIFICATIONS, MANUALS AND RECOMMENDED PRACTICES

Document No.	Title
EE1100	Low Voltage Motor Control Centre Standard
EE1101	Low Voltage Electric Motors
EI2020	Valve Motor Operator
EI2510	Control Panels
GC1000	Coating Selection and Specification
GC3101	External Coating of Piping, Components and Structural Steel
GC3102	External Coating of Buried Piping
GC3103	External Coating of Girth Welds on Buried Pipe
GC3105	External Fusion Bond Epoxy Coating
GC3202	Two Layer Polypropylene Coating of Line Pipe
GC3401	External Coating of Oil Storage Tanks
GC3503	Epoxy Phenolic Lining for Welded Steel Tanks and Vessels
MP1100	Pipe Selection and Specification
MP1110	Station and Terminal Piping Design
MP1110A	Standard Piping Classes
MP1110B	General Piping Details
MP1110C	Anchor Block Calculations
MP1110D	Pipe Support Design
MP1110E	Environmental Design Data
MP1200	Fitting Selection and Specification
MP1300	Valve Selection and Specification
MP2110	Station Pipe Material Requirements
MP2120	Main Line Pipe Material Requirements (Mill Run Quantities)
MP2121	Main Line Pipe Material Requirements
MP2210	Blind Flanges and Steel Line Blanks
MP2211	Wrought Steel Butt-Welding Fittings
MP2212	Forged Steel Flanges
MP2213	Forged Steel Socket-Welding and Threaded Fittings
MP2214	Forged Steel Branch Outlet Fittings
MP2215	Scraper Tee Fittings
MP2216	Forged Steel Anchor Forgings
MP2217	Induction Pipe Bending
MP2219	Full-Encirclement Saddles
MP2300	Pipeline Valves
MP2301	Small Pipeline Valves
MP2410	Bi-direction Pipe Provers
MP2411	Custody Transfer Positive Displacement Meters
MP2413	In-Line Basket Strainers
MP2414	Wedge Flow Elements
MP2415	In-Line Static Mixers
MP3101	General Piping Fabrication Requirements
MP3102	Piping Insulation Requirements
MP3110	Station Piping Fabrication
MP3110A	Standard References

TABLE 5.1.2

KMC STANDARDS, SPECIFICATIONS, MANUALS AND RECOMMENDED PRACTICES (continued)

Document No.	Title
MP3120	Pipeline Construction
MP3120B	Environmental Guidelines
MP3120C	Blasting Guidelines
MP3120D	Standards for Materials Selection and Placement for Road Crossings
MP3210	Bolted Flange Joint Assembly Standard
MP4111	Station Hydrostatic Test Standard
MP4121	Main Line Hydrostatic Test Standard
MP4121A	Pressure and Volume Calculations
MP4301	Valve Pressure Test Procedure
MP4401	Fabricated Assembly Test Standard
MT2321	Mechanical Shoe Seals for Floating Roofs
MT2322	Plate Wiper Seals for Floating Roofs
MT3000	Above Ground Storage Tanks Cleaning
PM1101	Stage/Gate Project Review Process (Draft)
PM3101	Project Organization and Accountability
PM3201	Construction Health and Safety Management (Draft)
PM3501	Materials and Equipment Quality Assurance
PM3511	Construction Quality Assurance (Draft)
PM3611	Commissioning of Pipeline Facilities
PM4701	Document Control
S-10-NT5	Below Ground Butt Weld (≤ Grade 359, NPS 2 to 12, 1.5 to 12.9 mm WT)
S-11-NT5	Below Ground Butt Weld (≤ Grade 386, ≥ NPS 8, 1.5 to 14.3 mm WT)
S-12-NT5	Below Ground Butt Weld (≤ Grade 414, ≥ NPS 8, 1.5 to 9.5 mm WT)
S-13-NT5	Below Ground Butt Weld (≤ Grade 483, ≥ NPS 16, 1.5 to 14.3 mm WT)
S-14-NT5	Below Ground Butt Weld (≤ Grade 483, ≥ NPS 16, 4.0 to 23.9 mm WT)
S-15-NT5	Butt Weld Thru Wall Repair Procedure
S-16-NT5	Butt Weld Back-Weld Repair Procedure
S-20-LT	Above Ground Butt Weld - Fabrication Welding Procedure (P1, Groups 2 and 3)
TD-S-03LT	Above Ground Butt Weld - Fabrication Welding Procedure (P1, Groups 1 and 2)
	Health and Safety Standards Manual
	Integrity Management Procedures
	Mechanical Maintenance Procedures
	Pipeline Maintenance Procedures

TABLE 5.1.3

CORRIDOR ASSESSMENT CLASSIFICATION

Assessment Classification	Assessment Criteria
1 (Green)	· room for full width work space (> 25 m) · light to moderate grading · sufficient room for extra work space · no access restrictions · suitable for mechanized welding
2 (Yellow)	· reduced work space, restricted access, loss of travel lane (25 to 12 m) · moderate to heavy grading · rock, blasting, grade or ditch · steep grades · swampy, low ground requiring rip rap or padding · restrictions on extra work space placement, some hauling required · complicated crossings, *e.g.,* limited space, poor ground conditions, · restricted access · more difficult, but not enough to suggest a reroute · constructible, but with restrictions, tie-ins, poor boy
3 (Orange)	· severely reduced work space (< 12 m) · unconventional construction techniques required, *e.g.,* stove piping · reroutes should be considered, but not mandatory · extreme grading · jump offs, tunnelling · blasting required in close proximity to existing lines · very difficult crossings which may require minor reroute · no room for extra work space · severe access restrictions · residential area, backyards
4 (Red)	· reroute required · no room for construction · no access · safety concerns · environmental restrictions · significant geotechnical issues

TABLE 5.1.4

PRIMARY TERRAIN STABILITY CONSIDERATIONS AND STANDARD MITIGATION MEASURES

Primary Terrain Stability Considerations	Standard Mitigation Measures
Deep seated slides	· locate pipelines and facilities to avoid deep seated slides · install ground and surface water control · install berm and rip rap toe reinforcements · site monitoring
Shallow to moderately deep slides	· locate pipelines and facilities to avoid slides · install ground and surface water control · design cuts and fills to minimize instability · install anchors, shotcrete or mechanical stabilized earth
Rock fall and rock toppling	· locate pipelines and facilities to avoid rock falls · design rock cuts to minimize instability · install stabilization measures, including scaling, anchoring, shotcrete, and mesh · install rock fall protection measures, including berms, catchment areas, and ditches · install reinforced concrete slabs over pipelines in selected areas · remove potential problem boulders on slopes
Debris flows	· locate pipelines and facilities to avoid debris flows · locate above ground structures away from alluvial fans and streams subject to debris flow · install pipelines at a deeper depth in selected areas · install concrete coated pipe in selected areas · install debris flow berms · monitor weather and snow melt conditions during construction in areas subject to debris flows, and remove personnel and equipment if necessary · set temporary bridges to appropriate elevations on debris flow streams during construction
Avalanches	· locate pipelines and facilities to avoid avalanches · consider avalanche issues when locating key facilities such as tunnel portals that will require year-round construction · conduct avalanche monitoring and control during construction · conduct avalanche monitoring and control where required during operations · install pipeline at a deeper depth or install a concrete coated pipe in locations prone to avalanche cause avulsion
Sedimentation and erosion	· design cuts and fills to minimize sedimentation and erosion · install ground and surface water control · avoid diversion of surface water flows along the pipeline · install silt fencing and temporary water control, re-vegetate disturbed areas · install sedimentation ponds, sediment collection berms and filtration berms in selected areas
Karst	· locate pipelines and facilities to avoid karst formations
Acid rock drainage (ARD)	· locate pipelines and facilities to avoid ARD · conduct visual assessment followed by sampling and analysis, when required, during construction · implement mitigation measures, including disposal, in designated areas where oxidation will be avoided (capped or under water), mixing with buffer material and shotcreting of bedrock surfaces · ARD mitigation protocols will conform with Guidelines for Metal Leaching and Acid Rock Drainage at Mine Sites in British Columbia

TABLE 5.1.4

PRIMARY TERRAIN STABILITY CONSIDERATIONS AND STANDARD MITIGATION MEASURES (continued)

Primary Terrain Stability Considerations	Standard Mitigation Measures
Seismicity	· locate pipelines and facilities away from areas of potential liquefaction · design pipelines and facilities to current seismic standards
Marine clays	· locate the pipelines and facilities away from areas of potential sensitive marine clays · conduct detailed stability analysis during detailed engineering
Tsunamis	· locate facilities away from areas of high tsunami risk · design facilities to limit potential tsunami impacts

TABLE 5.1.5

PRELIMINARY WATERCOURSE STAGE 2 REVIEW CROSSINGS

Reference Kilometre (RK)	Watercourse Name	Primary Crossing Method (Construction Timing)
24.2	Blackmud Creek	Isolation (Inside Least Risk Biological Window)
28.1	Whitemud Creek	Isolation (Inside Least Risk Biological Window)
33.5	North Saskatchewan River	HDD
36.9	Unnamed Creek (Wedgewood Creek)	Isolation (Inside Least Risk Biological Window)
135.0	Pembina River	HDD
173.7	Little Brule Creek	HDD or Isolation (Inside Least Risk Biological Window)
193.1	Carrot Creek	Isolation (Inside Least Risk Biological Window)
220.6	Wolf Creek	HDD
223.9	McLeod River	HDD
327.6	Maskuta Creek	Isolation (Inside Least Risk Biological Window)
491.6	Marathon Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
495.8	Terry Fox Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
496.8	Fraser River (East to West) [1,2]	Open Cut (Inside Least Risk Biological Window, If Flows Allow) or Open Cut (During Low Flow Period)
499.7	Fraser River (West to East) [1,2]	Open Cut (Inside Least Risk Biological Window, If Flows Allow) or Open Cut (During Low Flow Period)
522.5	Swift Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
531.3	Canoe River	Isolation (During Low Flow Period)
534.5	Camp Creek	Isolation (During Low Flow Period)
545.9	Camp Creek	Isolation (During Low Flow Period)
547.6	Camp Creek	Isolation (During Low Flow Period)
552.1	Albreda River	Isolation (Inside Least Risk Biological Window, If Flows Allow)
556.5	Unnamed Drainage (Wetland) [3]	Isolation (Inside Least Risk Biological Window, If Flows Allow)
559.0	Clemina Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)

TABLE 5.1.5

PRELIMINARY WATERCOURSE STAGE 2 REVIEW CROSSINGS (continued)

Reference Kilometre (RK)	Watercourse Name	Primary Crossing Method (Construction Timing)
559.4	Dora Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
561.2	Albreda River	Isolation (During Low Flow Period)
563.6	Albreda River	Isolation (During Low Flow Period)
567.6	Dominion Creek	Isolation (During Low Flow Period)
571.9	Moonbeam Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
580.4	Serpentine Creek	Isolation (During Low Flow Period)
581.2	North Thompson River	HDD
582.0	Chappell Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
592.9	Miledge Creek	Isolation (During Low Flow Period)
600.2	Thunder River	Isolation (During Low Flow Period)
605.2	Whitewater Creek	Isolation (During Low Flow Period)
613.8	Blue River	HDD
616.9	Goose Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
619.9	North Thompson River	HDD
626.6	Froth Creek	Isolation (During Low Flow Period)
638.8	Finn Creek [2]	Isolation (Inside Least Risk Biological Window, If Flows Allow)
648.9	Tumtum Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
651.6	North Thompson River	HDD
683.4	Mad River	Isolation (Inside Least Risk Biological Window, If Flows Allow)
717.7	Raft River	HDD
725.5	Clearwater River	HDD
735.0	Mann Creek	HDD
749.3	Lemieux Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
752.3	Eakin Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
768.2	Darlington Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
768.5	Lindquist Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
846.8	Thompson River	HDD

TABLE 5.1.5

PRELIMINARY WATERCOURSE STAGE 2 REVIEW CROSSINGS (continued)

Reference Kilometre (RK)	Watercourse Name	Primary Crossing Method (Construction Timing)
865.2	Anderson Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
892.8	Moore Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
915.9	Clapperton Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
928.0	Nicola River	HDD
957.9	Coldwater River	HDD
970.3	Coldwater River	HDD
980.0	Coldwater River	HDD
980.8	Juliet Creek	Isolation (Inside Least Risk Biological Window)
990.0	Coldwater River	HDD
1020.3	Ladner Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
1021.8	Coquihalla River	Isolation (Inside Least Risk Biological Window, If Flows Allow)
1022.9	Dewdney Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
1026.5	Coquihalla River	Isolation (Inside Least Risk Biological Window, If Flows Allow)
1028.6	Coquihalla River	Isolation (During Low Flow Period)
1032.6	Coquihalla River	Isolation (During Low Flow Period)
1043.2	Coquihalla River	HDD
1047.2	Silverhope Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
1051.5	Chawuthen Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
1055.5	Hunter Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
1060.9	Lorenzetta Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
1061.5	Wahleach Creek (Jones Creek)	Isolation (During Low Flow Period)
1071.4	Unnamed Channel	Isolation (Inside Least Risk Biological Window, If Flows Allow)
1072.3	Unnamed Channel	Isolation (Inside Least Risk Biological Window, If Flows Allow)
1094.0	Chilliwack Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
1102.3	Chilliwack/Vedder River	HDD
1102.7	Unnamed Channel	Isolation (Inside Least Risk Biological Window, If Flows Allow)

TABLE 5.1.5

PRELIMINARY WATERCOURSE STAGE 2 REVIEW CROSSINGS (continued)

Reference Kilometre (RK)	Watercourse Name	Primary Crossing Method (Construction Timing)
1110.7	Sumas Lake Canal	Isolation (Inside Least Risk Biological Window, If Flows Allow)
1114.6	Sumas River	HDD
1118.8	Unnamed Creek (Ledgeview Creek)	Isolation (If Water Present)
1127.8	McLennan Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
1138.0	Nathan Creek	Isolation (Inside Least Risk Biological Window, If Flows Allow)
1147.4	Salmon River	Isolation (Inside Least Risk Biological Window, If Flows Allow)
1168.9	Fraser River	HDD
1171.1	Como Creek	TBD
1176.5	Stoney Creek	Isolation (Inside Least Risk Biological Window)

Notes:

1. These Fraser River crossings are at the same geographic location.
2. An HDD crossing method was originally considered for this crossing, but investigations determined that an HDD is likely not feasible.
3. Seasonal off-channel fish habitat with culverts connecting to Albreda River.

TABLE 5.1.6

PRELIMINARY HDD WATERCOURSE CROSSINGS

Reference Kilometre (RK)	Watercourse Name	Alternative Crossing Method (Construction Timing)
33.5	North Saskatchewan River	Open Cut (Inside Least Risk Biological Window)
135.0	Pembina River	Isolation (Outside Least Risk Biological Window) or Open Cut (Inside Least Risk Biological Window)
220.6	Wolf Creek	Isolation (Outside Least Risk Biological Window)
223.9	McLeod River	Isolate (Outside Least Risk Biological Window) or Open Cut (Inside Least Risk Biological Window)
581.2	North Thompson River	Open Cut (Inside Least Risk Biological Window)
613.8	Blue River	Isolation (During Low Flow Period) or Open Cut (Inside Least Risk Biological Window)
619.9	North Thompson River	Open Cut (Inside Least Risk Biological Window)
651.6	North Thompson River	Open Cut (Inside Least Risk Biological Window)
717.7	Raft River	Isolation (During Low Flow Period) or Open Cut (Inside Least Risk Biological Window)
725.5	Clearwater River	Open Cut (Inside Least Risk Biological Window)
735.0	Mann Creek	Isolation (During Low Flow Period)
846.8	Thompson River	Open Cut (Inside Least Risk Biological Window)
928.0	Nicola River	Isolation (During Low Flow Period) or Open Cut (Inside Least Risk Biological Window)
957.9	Coldwater River	Isolation (During Low Flow Period)
970.3	Coldwater River	Isolation (During Low Flow Period)

TABLE 5.1.6

PRELIMINARY HDD WATERCOURSE CROSSINGS (continued)

Reference Kilometre (RK)	Watercourse Name	Alternative Crossing Method (Construction Timing)
980.0	Coldwater River	Isolation (During Low Flow Period)
990.0	Coldwater River	Isolation (During Low Flow Period)
1,043.2	Coquihalla River	Isolation (During Low Flow Period) or Open Cut (Inside Least Risk Biological Window)
1102.3	Chilliwack/Vedder River	Open Cut (Inside Least Risk Biological Window)
1114.6	Sumas River	Other Trenchless
1168.9	Fraser River	Other Trenchless

TABLE 5.1.7

REPRESENTATIVE PROPERTIES OF CRUDE OILS

Crude Comparison - From September 1, 2011 to September 1, 2013

Basic Analysis	Light Sour	Light Sweet	Synthetic	High TAN Dilbit	Dilbit	Synbit	Dilsynbit
Density (kg/m^3)	829.5 ± 6.8	828.7 ± 3.9	844.9 ± 18.4	874.2 ± 48.4	928.0 ± 5.2	931.9 ± 6.1	933.2 ± 6.8
Gravity (deg. API)	39.0 ± 1.4	39.1 ± 0.8	35.9 ± 3.6	30.7 ± 9.0	20.9 ± 0.9	20.2 ± 1.0	20.0 ± 1.1
Viscosity cSt) @ 5°C	10.6	12.1	10.7	Blended to meet < 350 cSt at Reference Temperature			
Viscosity cSt) @ 10°C	8.0	8.0	8.9				
Viscosity cSt) @ 15°C	6.9	6.4	7.5				
Reid Vapour Pressure (kPa)	68.9	74.9	31.7	62.9	51.7	20	62.7
Sulphur (wt%)	0.69 ± 0.18	0.42 ± 0.07	0.29 ± 0.12	2.08 ± 1.78	3.78 ± 0.08	3.42 ± 0.38	3.11 ± 0.70
Hydrogen Sulphide (ppm)	< 250	< 10	< 1	< 10	< 10	< 10	< 10
MCR (wt%)	2.13 ± 0.44	1.92 ± 0.18	0.94 ± 0.89	6.06 ± 4.55	10.42 ± 0.30	8.93 ± 1.55	11.50 ± 1.47
Sediment (ppmw)	-	-	-	136 ± 113	123 ± 92	92 ± 38	378 ± 341
TAN (mgKOH/g)	-	-	-	1.72 ± 0.09	0.98 ± 0.08	1.20 ± 0.24	0.75 ± 0.27
Salt (ptb)	-	-	-	6.2 ± 1.7	10.4 ± 2.3	7.5 ± 3.2	10.7 ± 1.9
Nickel (mg/L)	5.6 ± 2.6	4.2 ± 0.7	1.4 ± 2.9	48.0 ± 33.5	65.8 ± 3.6	59.2 ± 7.4	54.7 ± 12.4
Vanadium (mg/L)	14.9 ± 7.9	8.3 ± 2.4	2.7 ± 6.3	129.1 ± 92.3	172.0 ± 12.8	159.5 ± 15.8	129.6 ± 45.5
Olefins (wt%)	-	ND	ND	ND	ND	ND	ND
Light Ends (vol%)							
Butanes	4.07 ± 1.10	3.98 ± 0.68	3.13 ± 1.09	2.38 ± 1.78	0.91 ± 0.27	0.73 ± 0.27	1.16 ± 0.46
Pentanes	2.80 ± 0.45	3.16 ± 0.70	2.93 ± 0.81	5.81 ± 2.86	6.19 ± 1.10	3.75 ± 2.65	5.82 ± 1.09
Hexanes	5.70 ± 0.38	5.43 ± 0.53	4.75 ± 1.02	6.18 ± 0.89	5.46 ± 0.50	3.67 ± 1.91	5.48 ± 0.48
Heptanes	7.72 ± 0.50	6.87 ± 0.55	5.32 ± 1.77	5.66 ± 1.49	3.51 ± 0.50	2.64 ± 0.89	3.62 ± 0.60
Octanes	7.68 ± 0.84	6.93 ± 0.74	5.60 ± 1.58	4.77 ± 2.41	2.29 ± 0.55	2.33 ± 0.51	2.74 ± 0.86
Nonanes	6.04 ± 0.89	5.46 ± 0.62	4.38 ± 1.21	3.33 ± 2.20	1.42 ± 0.42	1.85 ± 0.66	1.78 ± 0.69
Decanes	3.00 ± 0.54	2.54 ± 0.34	2.12 ± 0.51	1.55 ± 1.03	0.70 ± 0.22	0.99 ± 0.39	0.86 ± 0.32
BTEX (vol%)							
Benzene	0.36 ± 0.07	0.24 ± 0.03	0.22 ± 0.04	0.27 ± 0.05	0.24 ± 0.03	0.15 ± 0.10	0.20 ± 0.06
Toluene	1.10 ± 0.15	0.74 ± 0.11	0.63 ± 0.17	0.64 ± 0.16	0.42 ± 0.09	0.29 ± 0.15	0.37 ± 0.10
Ethyl Benzene	0.26 ± 0.03	0.24 ± 0.02	0.21 ± 0.04	0.15 ± 0.09	0.06 ± 0.02	0.07 ± 0.03	0.08 ± 0.04
Xylenes	1.43 ± 0.22	1.00 ± 0.13	0.82 ± 0.22	0.70 ± 0.34	0.35 ± 0.10	0.33 ± 0.10	0.35 ± 0.11
Distillation (°C)							
5% Mass Recovered	52.2 ± 13.78	45.9 ± 15.30	79.0 ± 29.07	43.0 ± 9.85	46.9 ± 10.56	83.6 ± 41.61	46.1 ± 9.46
10% Mass Recovered	85.5 ± 9.09	88.1 ± 8.70	121.9 ± 27.54	80.2 ± 16.19	91.2 ± 18.39	135.2 ± 51.87	93.4 ± 23.50
20% Mass Recovered	125.0 ± 14.82	129.9 ± 8.45	176.5 ± 39.25	184.1 ± 58.65	244.4 ± 19.80	247.6 ± 14.75	243.6 ± 40.89
30% Mass Recovered	172.1 ± 13.87	183.1 ± 11.36	225.1 ± 34.23	286.8 ± 78.88	334.0 ± 13.44	317.7 ± 18.06	356.3 ± 29.83
40% Mass Recovered	223.4 ± 13.64	241.7 ± 13.77	270.7 ± 23.81	359.1 ± 86.29	407.1 ± 12.95	377.1 ± 31.17	421.5 ± 19.49
50% Mass Recovered	278.5 ± 11.80	298.1 ± 15.66	313.1 ± 15.50	426.2 ± 93.01	475.1 ± 14.85	435.9 ± 41.16	478.4 ± 15.05
60% Mass Recovered	334.7 ± 11.27	355.7 ± 20.66	356.7 ± 17.47	502.0 ± 103.98	551.4 ± 19.04	503.1 ± 52.22	538.5 ± 21.26
70% Mass Recovered	398.7 ± 10.90	419.3 ± 25.15	402.9 ± 29.16	580.2 ± 112.62	633.2 ± 20.38	586.1 ± 58.31	605.3 ± 33.58
80% Mass Recovered	468.4 ± 12.20	492.8 ± 41.00	455.9 ± 53.70	599.0 ± 114.00	700.3 ± 16.47	662.3 ± 41.15	667.8 ± 33.97
90% Mass Recovered	567.3 ± 23.96	564.4 ± 20.77	488.1 ± 44.43	562.8 ± 34.51	-	705.1 ± 9.13	703.2 ± 19.40
95% Mass Recovered	628.8 ± 14.41	638.1 ± 32.27	529.9 ± 62.41	635.9 ± 45.89	-	-	-
99% Mass Recovered	699.0 ± 8.66	704.4 ± 15.20	567.1 ± 8.88	-	-	-	-

Source: Crudemonitor.ca and KMC Annual Crude Properties

Note: Format is: Average ± std. dev.

TABLE 5.1.8

PRELIMINARY PIPE WALL THICKNESSES

Pipe	Application	Preliminary Pipe Wall Thickness (mm)
Edmonton to Burnaby (914 mm OD)		
Line pipe	Mainline Pipeline	11.8
Heavy wall pipe	Road Crossings and Watercourse Crossings	14.7
Extra heavy wall pipe	HDD Crossings and Uncased Railway Crossings	19.0
Burnaby to Westridge (Two Lines – 762 mm OD)		
Line pipe	Mainline Pipeline	9.8
Heavy wall pipe	Road Crossings and Watercourse Crossings	12.3
Extra heavy wall pipe	HDD Crossings and Uncased Railway Crossings	15.8

TABLE 5.1.9

ESTIMATED PIPE LENGTHS

Pipe Wall Thickness (mm)	Estimated Pipe Length (m)	Percentage of Total Pipeline Length Constructed (%)
Edmonton to Burnaby (914 mm OD)		
Line pipe (11.8 mm)	868,189	87.98
Heavy wall pipe (14.7 mm)	60,154	6.10
Extra heavy wall pipe (19.0 mm)	58,416	5.92
Total	986,759	100.00
Burnaby to Westridge (Two Lines – 762 mm OD)		
Line pipe (9.8 mm)	2,222	30.65
Heavy wall pipe (12.3 mm)	5,028	69.35
Extra heavy wall pipe (15.8 mm)	0	0
Total	7,250	100.00

TABLE 5.1.10

LINE 1 VALVE LOCATIONS

#	Valve Name or Location	KP	Valve Type
Edmonton to Stony Plain			
1	K19 U/S N. Saskatchewan River	19.90	Automated RMLBV
2	K21 D/S N. Saskatchewan River	21.08	Automated RMLBV
Stony Plain to Gainford			
3	K64 Secondary Hwy. 770 (Carvel Corner)	63.85	Manual RMLBV
Gainford to Chip			
4	K117A U/S Pembina River	117.34	Manual RMLBV
5	K117B D/S Pembina River	117.76	Manual RMLBV
Chip to Niton			
6	K160 Brule Creek	160.55	Manual RMLBV
Niton to Wolf			
No existing mainline block valves.			
Wolf to Edson			
7	K202 Wolf Creek	201.83	Manual RMLBV
8	K205 U/S McLeod River	205.29	Manual RMLBV
9	K206 D/S McLeod River	205.76	Manual RMLBV
Edson to Hinton			
10	KL289 Trail Creek (Athabasca Jump-Off)	289.15	Manual RMLBV
11	KL310 Old Hinton Trap Site	310.00	Manual RMLBV
Hinton to Jasper			
12	K327 Fiddle River	327.22	Manual RMLBV
13	K336 Pocahontas	336.41	Manual RMLBV
14	K337 Celestine Lake Road	339.49	Manual RMLBV
15	K360 Snaring River	360.39	Manual RMLBV
Jasper to Rearguard			
16	K390 Miette River No. 3 (Geike)	390.84	Manual RMLBV
17	K396 Miette River No. 5 (Decoigne)	396.84	Manual RMLBV
18	K406 Yellowhead	406.17	Manual RMLBV
19	K416 Yellowhead River (Baxter)	416.70	Manual RMLBV
20	K424 Fraser River No. 2	424.22	Manual RMLBV
21	K429 Grant Brook	429.20	Manual RMLBV
22	K433 Moose River	433.97	Manual RMLBV
23	K461A Fraser River No. 7A	461.53	Manual RMLBV
24	K461B Fraser River No. 7B	461.87	Manual RMLBV
25	K475A Fraser River No. 8A	475.82	Manual RMLBV
26	K475B Fraser River No. 8B	476.00	Manual RMLBV
Rearguard to Albreda			
27	K477A Fraser River No. 9A	477.63	Manual RMLBV
28	K477B Fraser River No. 9B	477.84	Manual RMLBV
29	K504 Canoe River	505.84	Manual RMLBV

TABLE 5.1.10

LINE 1 VALVE LOCATIONS (continued)

#	Valve Name or Location	KP	Valve Type
Albreda to Chappel			
30	K544 Gosnel	544.75	Manual RMLBV
31	K548 Lempriere	549.60	Manual RMLBV
Chappel to Blue River			
32	K587 Blue River Airport	588.84	Manual RMLBV
Blue River to Finn Creek			
33	K594 U/S N. Thompson River	594.18	Manual RMLBV
34	K595 D/S N. Thompson River	595.01	Manual RMLBV
Finn Creek to McMurphy			
35	K624 U/S N. Thompson River at Avola	624.87	Manual RMLBV
36	K625 D/S N. Thompson River at Avola	625.18	Manual RMLBV
McMurphy to Blackpool			
37	K656A U/S Mad River	656.52	Manual RMLBV
38	K656B D/S Mad River	657.10	Manual RMLBV
39	K673 Vavenby	672.08	Manual RMLBV
40	K699 Clearwater River	699.07	Manual RMLBV
Blackpool to Darfield			
41	K722 Lemieux Creek	722.03	Manual RMLBV
Darfield to Kamloops			
42	K771 Whitewood Creek	770.34	Manual RMLBV
43	KL785 Black Pines	786.00	Manual RMLBV
44	KL810 Dohm Road	810.00	Check
45	KL819 S. Thompson River (Mission Flats)	819.74	Manual RMLBV
Kamloops to Stump			
46	K831 Goose Lake (George Little Ranch)	832.44	Manual RMLBV
Stump to Kingsvale			
47	K867 Guichon Ranch	868.12	Manual RMLBV
48	K897 U/S Nicola River	898.30	Manual RMLBV
49	K898 D/S Nicola River	898.74	Manual RMLBV
Kingsvale to Hope			
50	K949 Juliet Creek	950.10	Manual RMLBV
51	K966 Thar	966.00	Manual RMLBV
52	K975 Coquihalla River No. 9	976.09	Manual RMLBV
53	K981 Powder Shack	981.00	Manual RMLBV
54	K984 Boston Bar Creek	984.94	Manual RMLBV
55	K995 Deneau Creek	995.41	Manual RMLBV
Hope to Wahleach			
56	K1039 Hwy. 1 (Wahleach Power House)	1040.18	Manual RMLBV

TABLE 5.1.10

LINE 1 VALVE LOCATIONS (continued)

#	Valve Name or Location	KP	Valve Type
Wahleach to Sumas			
57	K1056 Hwy. 1 (Upper Sumas Prairie)	1056.51	Manual RMLBV
58	K1069 U/S Vedder River	1070.25	Manual RMLBV
59	K1070 D/S Vedder River	1070.95	Manual RMLBV
60	K1077 Sumas Canal	1078.84	Manual RMLBV
Sumas to Port Kells			
61	K1092 Downess Creek (Townshipline Road)	1093.14	Manual RMLBV
62	K1122 Port Kells (195th Street)	1122.99	Automated RMLBV
Port Kells to Burnaby			
63A	K1136 Fraser River	1138.00	Manual RMLBV
63B	K1136 Fraser River	1138.00	Check
64	K1145 Burnaby Terminal Fence	1146.48	Manual RMLBV

TABLE 5.1.11

PRELIMINARY VALVE LOCATIONS – TMPL LINE 1 REACTIVATED PIPELINE SEGMENTS

Kilometre Post	Status	Name or Location	Valve Type
Hinton to Hargreaves			
KP 327.2	Existing	Fiddle River (existing manual valve to be automated)	Automated MLBV
KP 336.4	Existing	Pocahontas	Manual MLBV
KP 339.5	Existing	Celestine Lake Road	Manual MLBV
KP 339.5	New	Celestine Lake Road (co-located with existing manual valve)	Check Valve
KP 343.6	New	North Jasper Lake	Check Valve
KP 350.6	New	South Jasper Lake	Automated MLBV
KP 360.4	Existing	Snaring River	Manual MLBV
KP 383.4	New	Downstream Miette River	Check Valve
KP 390.8	Existing	Miette River No. 3	Manual MLBV
KP 390.8	New	Miette River No. 3 (co-located with existing manual valve)	Check Valve
KP 396.8	Existing	Miette River No. 5 (Decoigne)	Manual MLBV
KP 406.2	Existing	Yellowhead	Manual MLBV
KP 416.7	Existing	Yellowhead River (Baxter)	Manual MLBV
KP 424.2	Existing	Fraser River No. 2 (existing manual valve to be automated)	Automated MLBV
KP 429.2	Existing	Grant Brook	Manual MLBV
KP 434.0	Existing	Moose River	Manual MLBV
KP 434.0	New	Moose River (co-located with existing manual valve)	Check Valve
KP 456.3	New	Yellowhead	Automated MLBV
KP 461.5	Existing	Fraser River No. 7A (existing manual valve to be automated)	Automated MLBV
KP 461.9	Existing	Fraser River No. 7B	Manual MLBV
Darfield to Black Pines			
KP 756.4	New	Downstream Peterson Creek	Check Valve
KP 770.3	Existing	Whitewood Creek (existing manual valve to be automated)	Automated MLBV

TABLE 5.1.12

PRELIMINARY VALVE LOCATIONS – TMPL LINE 2

Reference Kilometre	Status	Name or Location	Valve Type
Edmonton to Gainford			
RK 20.0	New	91 Street Northwest	Automated MLBV
RK 32.8	New	Upstream North Saskatchewan River	Automated MLBV
RK 34.5	New	Downstream North Saskatchewan River	Automated MLBV
RK 66.3	New	Stony Plain Pump Station (co-located with existing valve)	Automated MLBV
RK 80.6	New	Secondary Highway 770, Carvel Corner (co-located with existing valve)	Automated MLBV
RK 90.0	New	Smithfield	Check Valve
Gainford to Wolf			
RK 134.7	New	Upstream Pembina River	Automated MLBV
RK 135.7	New	Downstream Pembina River	Automated MLBV
RK 145.0	New	Range Road 85	Check Valve
RK 165.1	New	Chip Pump Station (co-located with existing valve)	Automated MLBV
RK 178.6	New	Brule Creek (co-located with existing valve)	Automated MLBV
RK 191.5	New	Niton Pump Station (co-located with existing valve)	Automated MLBV
Wolf to Edson			
RK 209.9	New	Range Road 152	Check Valve
RK 220.1	New	Upstream Wolf Creek	Automated MLBV
RK 223.6	New	Upstream McLeod River	Automated MLBV
RK 224.0	New	Downstream McLeod River	Automated MLBV
RK 227.9	New	Downstream Bench Creek	Check Valve
Edson to Hinton			
RK 259.9	New	Range Road 200	Check Valve
RK 279.9	New	Hargwen	Check Valve
RK 300.9	New	Upstream Sandstone Creek	Automated MLBV
RK 309.1	New	Upstream Trail Creek	Automated MLBV
RK 318.9	New	Upstream Hardisty Creek	Automated MLBV
RK 331.5	New	Old Hinton Trap Site (co-located with existing valve)	Automated MLBV
Hinton to Hargreaves (Existing NPS 36 Pipeline)			
KL 325.6	Existing	Upstream Fiddle River	Automated MLBV
KL 332.8	Existing	Pocahontas	Automated MLBV
KL 339.4	Existing	Downstream Athabasca River	Check Valve
KL 353.8	Existing	Upstream Snaring River	Automated MLBV
KL 363.0	Existing	Downstream Snaring River	Check Valve
KL 369.5	Existing	Jasper Pump Station	Check Valve
KL378.4	Existing	West Jasper	Automated MLBV
KL 383.4	Existing	Downstream Miette River	Check Valve
KL 391.1	Existing	Downstream Meadow Creek	Automated MLBV
KL 400.3	Existing	Downstream Derr Creek	Check Valve
KL 406.5	Existing	Jasper Park Boundary	Manual MLBV
KL 416.0	Existing	West Yellowhead Lake	Automated MLBV
KL 428.5	Existing	Grant Brook	Automated MLBV
KL 433.2	Existing	Upstream Moose River	Automated MLBV
KL 433.6	Existing	Downstream Moose River	Check Valve
KL 450.0	Existing	Red Pass	Automated MLBV

TABLE 5.1.12

PRELIMINARY VALVE LOCATIONS – TMPL LINE 2 (continued)

Reference Kilometre	Status	Name or Location	Valve Type
Hinton to Hargreaves (Existing NPS 36 Pipeline) (continued)			
KL 457.7	Existing	Upstream Fraser River	Automated MLBV
Hargreaves to Rearguard			
RK 489.6	Existing	Hargreaves Trap Site (existing manual valve to be automated)	Automated MLBV
RK 496.6	New	Upstream Fraser River	Automated MLBV
Rearguard to Blue River			
RK 499.9	New	Downstream Fraser River	Check Valve
RK 509.9	New	Jackman Flats	Automated MLBV
RK 531.4	New	Canoe River (co-located with existing valve)	Automated MLBV
RK 545.3	New	Albreda Pump Station (co-located with existing valve)	Automated MLBV
RK 567.2	New	Gosnel	Check Valve
RK 581.4	New	Upstream Chappel Creek	Automated MLBV
RK 609.4	New	Cook Creek	Automated MLBV
Blue River to Blackpool			
RK 619.6	New	Upstream North Thompson River	Automated MLBV
RK 626.9	New	Downstream Froth Creek	Check Valve
RK 639.2	New	Finn Creek Pump Station (co-located with existing valve)	Automated MLBV
RK 650.9	New	Upstream North Thompson River	Automated MLBV
RK 652.1	New	Downstream North Thompson River	Automated MLBV
RK 671.7	New	McMurphy Pump Station (co-located with existing valve)	Automated MLBV
RK 683.2	New	Upstream Mad River (co-located with existing valve)	Automated MLBV
RK 683.8	New	Downstream Mad River (co-located with existing valve)	Automated MLBV
RK 698.8	New	Vavenby (co-located with existing valve)	Automated MLBV
RK 725.4	New	Upstream Clearwater River	Automated MLBV
Blackpool to Darfield			
RK 748.9	New	Lemieux Creek (co-located with existing valve)	Automated MLBV
RK 755.8	New	Downstream Spokane Creek	Automated MLBV
Darfield to Black Pines (Existing NPS 30 Pipeline)			
RK 769.0	Existing	Darfield Pump Station	Automated MLBV
Black Pines to Kamloops			
RK 822.0	New	Downstream Jamieson Creek	Check Valve
RK 837.5	New	Westsyde	Automated MLBV
RK 845.0	New	PetroCanada Take-Off (co-located with existing valve)	Automated MLBV
RK 847.6	New	S. Thompson River, Mission Flats (co-located with existing valve)	Check Valve
Kamloops to Kingsvale			
RK 862.2	New	Goose Lake, George Little Ranch (co-located with existing valve site)	Automated MLBV
RK 892.3	New	Stump Pump Station (co-located with existing valve)	Automated MLBV
RK 899.1	New	Guichon Ranch	Check Valve
RK 915.0	New	Upstream Clapperton Creek	Automated MLBV
RK 927.7	New	Upstream Nicola River (co-located with existing valve)	Automated MLBV
RK 928.2	New	Downstream Nicola River	Automated MLBV
RK 934.0	New	Downstream Spanish Creek	Check Valve
RK 947.6	New	Upstream Salem Creek	Automated MLBV

TABLE 5.1.12

PRELIMINARY VALVE LOCATIONS – TMPL LINE 2 (continued)

Reference Kilometre	Status	Name or Location	Valve Type
Kingsvale to Burnaby			
RK 981.5	New	Downstream Juliet Creek	Automated MLBV
RK 1011.4	New	Downstream Boston Bar Creek	Automated MLBV
RK 1018.5	New	Shylock Road	Automated MLBV
RK 1027.6	New	Deneau Creek (co-located with existing valve)	Automated MLBV
RK 1043.0	New	Upstream Hope, Coquihalla River	Automated MLBV
RK 1043.8	New	Hope Pressure Control Station (co-located with existing valve)	Automated MLBV
RK 1072.3	New	Highway 1, Wahleach Power House (co-located with existing valve)	Automated MLBV
RK 1088.6	New	Highway 1, Upper Sumas Prairie (co-located with existing valve)	Automated MLBV
RK 1102.0	New	Upstream Vedder River	Automated MLBV
RK 1102.8	New	Downstream Vedder River (co-located with existing valve)	Automated MLBV
RK 1110.6	New	Sumas Lake Canal (co-located with existing valve)	Automated MLBV
RK 1113.8	New	Sumas Pump Station (co-located with existing valve)	Automated MLBV
RK 1124.8	New	Upstream Downes Creek (co-located with existing valve site)	Automated MLBV
RK 1129.6	New	Downstream McLennan Creek	Check Valve
RK 1143.6	New	Downstream West Creek	Automated MLBV
RK 1156.2	New	Upstream Fraser River	Automated MLBV
RK 1170.5	New	Downstream Fraser River	Automated MLBV
RK 1170.5	New	Downstream Fraser River	Check Valve
RK 1178.5	New	Eastlake Drive	Automated MLBV
Burnaby to Westridge (RK values reset)			
RK 2.4	New x2	Cliff Avenue	Automated MLBV

TABLE 5.1.13

MINIMUM DEPTHS OF COVER

Location	Minimum Depth of Cover (m)
Pipeline Trench in Mineral Soil	0.9
Pipeline Trench in Rock	0.6
Roads Primary (Cased/Uncased)	
Travel Surface	1.5
Ditches	1.2
Roads Secondary (Cased/Uncased)	
Travel Surface	1.5
Ditches	1.2
Railway (Uncased) per Standard TC-E10	
Below Base of Rail	3.05
Below Ditch or Grade	1.83
Pipeline within Rail Rights-of-Way	1.52
Railway (Cased) per Standard TC-E10	
Below Base of Rail	1.68
Below Ditch or Grade	0.91
Pipeline within Rail Rights-of-Way	1.52
Watercourse Crossings	1.2
Facility Sites	1.5
Below Grade Main Line Block Valve	1.2

TABLE 5.1.14

PRELIMINARY HIGHWAY, ROAD AND RAILWAY CROSSINGS

Reference Kilometre (RK)	Name	Description
Road and Highway Crossings (Edmonton to Burnaby)		
0.045	101A Avenue	Local/Street
0.109	Baseline Road	Collector
2.283	Highway 216	Expressway/Highway
2.318	Unnamed Road Crossing	Ramp
5.187	Fir Street	Local/Street
5.368	Wye Road	Expressway/Highway
5.701	23349 Wye Road	Local/Street
7.156	Township Road 523	Local/Street
8.623	Highway 628	Arterial
11.793	Range Road 234	Collector
11.936	Highway 14	Expressway/Highway
12.111	Anthony Henday Drive Northwest	Expressway/Highway
14.404	17 Street Northwest	Collector
14.431	Unnamed Road Crossing	Ramp
14.451	Unnamed Road Crossing	Ramp
14.462	Unnamed Road Crossing	Ramp
14.630	Unnamed Road Crossing	Ramp
14.676	Unnamed Road Crossing	Ramp
16.163	34 Street Northwest	Collector
17.503	Unnamed Road Crossing	Ramp
17.552	Unnamed Road Crossing	Ramp
17.729	Unnamed Road Crossing	Ramp
17.750	50 Street Northwest	Collector
17.803	Unnamed Road Crossing	Ramp
19.267	66 Street Northwest	Collector
20.801	Unnamed Road Crossing	Ramp
20.830	Unnamed Road Crossing	Ramp
20.978	Unnamed Road Crossing	Ramp
21.007	91 Street Northwest	Collector
21.373	Anthony Henday Drive Northwest	Expressway/Highway
21.438	Unnamed Road Crossing	Ramp
22.293	Parsons Road Northwest	Collector
22.806	Unnamed Road Crossing	Ramp
22.834	Gateway Boulevard Northwest	Expressway/Highway
22.896	Calgary Trail Northwest	Expressway/Highway
22.951	Unnamed Road Crossing	Ramp
23.011	Unnamed Road Crossing	Ramp
23.038	Unnamed Road Crossing	Ramp
24.737	111 Street Southwest	Collector
26.240	127 Street Southwest	Local/Street
27.660	Anthony Henday Drive Northwest	Expressway/Highway
29.187	Rabbit Hill Road Northwest	Local/Street
30.133	156 Street Northwest	Local/Street

TABLE 5.1.14

PRELIMINARY HIGHWAY, ROAD AND RAILWAY CROSSINGS (continued)

Reference Kilometre (RK)	Name	Description
Road and Highway Crossings (Edmonton to Burnaby)		
31.352	Terwillegar Drive Northwest	Collector
34.478 34.629	Anthony Henday Drive Northwest Anthony Henday Drive Northwest	Ramp Expressway/Highway
35.409 35.433 35.442	Anthony Henday Drive Northwest Anthony Henday Drive Northwest Anthony Henday Drive Northwest	Ramp Ramp Ramp
35.777	184 Street Northwest	Collector
38.011 38.025	Anthony Henday Drive Northwest Lessard Road Northwest	Ramp Collector
38.557	45 Avenue Northwest	Local/Street
39.804	62 Avenue Northwest	Local/Street
42.673 42.683	Unnamed Road Crossing Guardian Road Northwest	Ramp Local/Street
43.460	Winterburn Road Northwest	Collector
45.093	231 Street Northwest	Collector
47.134	Range Road 262	Collector
48.831	Highway 60	Expressway/Highway
50.520	Range Road 264	Collector
52.196	Range Road 265	Collector
53.852	Range Road 270	Collector
55.500	Range Road 271	Collector
57.148	Century Road	Collector
58.801	Golden Spike Road South	Collector
59.797	Madison Crescent	Local/Street
60.447	Campsite Road South	Collector
62.159	Highway 16A	Expressway/Highway
62.610	Range Road 275	Collector
64.716	Range Road 280	Collector
65.930	48th Street	Arterial
67.577	Glory Hills Road	Collector
69.236	Range Road 12	Collector
70.873	Range Road 13	Collector
72.514	Range Road 14	Collector
73.766	53105 Range Road 15	Local/Street
74.178	Range Road 15	Collector
74.501	Highway 16A	Expressway/Highway
75.819	Range Road 20	Collector
76.497	53112 Range Road 20	Local/Street
76.816	53123 Range Road 21	Local/Street
77.178	53111 Range Road 21	Local/Street
77.448	Range Road 21	Local/Street
78.645	53111 Range Road 22	Local/Street

TABLE 5.1.14

PRELIMINARY HIGHWAY, ROAD AND RAILWAY CROSSINGS (continued)

Reference Kilometre (RK)	Name	Description
Road and Highway Crossings (Edmonton to Burnaby)		
79.097	Range Road 22	Collector
80.730	Highway 770	Arterial
84.009	Range Road 25	Collector
85.610 85.679	Parkland Drive Range Road 30	Collector Local/Street
87.308	Range Road 31	Collector
88.965	Range Road 32	Collector
90.601	Range Road 33	Collector
92.238	Range Road 34	Collector
93.556	Highway 16	Expressway/Highway
94.162 94.239	Range Road 35 Unnamed Road Crossing	Collector Collector
95.829	Range Road 40	Collector
96.545	Range Road 40A	Collector
97.101 97.229	Unnamed Road Crossing Range Road 41	Collector Collector
99.271	Highway 16	Expressway/Highway
101.572	Range Road 43	Collector
103.716	Range Road 44	Collector
109.076	Range Road 51	Collector
109.881	Unnamed Road Crossing	Resource/Recreation
110.704	Range Road 52	Collector
112.339	Range Road 53	Collector
113.967	Range Road 54	Collector
115.599	Range Road 55	Collector
117.212	Highway 31	Arterial
118.926	Range Road 61	Collector
120.550	Range Road 62	Collector
125.471	Range Road 65	Collector
127.125	Range Road 70	Collector
128.767	Range Road 71	Collector
130.399	Range Road 72	Collector
132.030	Range Road 73	Collector
133.725	Highway 22	Arterial
134.337	49 Street	Collector
134.919	Range Road 74A	Local/Street
136.295	Range Road 75A	Collector
137.157	Range Road 80	Collector
140.447	Range Road 82	Collector
142.087	Range Road 83	Collector
143.719	Range Road 84	Collector
145.371	Range Road 85	Collector

TABLE 5.1.14

PRELIMINARY HIGHWAY, ROAD AND RAILWAY CROSSINGS (continued)

Reference Kilometre (RK)	Name	Description
Road and Highway Crossings (Edmonton to Burnaby)		
147.010	Range Road 90	Collector
148.646	Range Road 91	Collector
150.277	Range Road 92	Collector
151.912	Range Road 93	Collector
153.577	Range Road 94	Collector
155.230	Range Road 95	Collector
158.518	Range Road 101	Collector
160.166	Range Road 102	Collector
161.816	Range Road 103	Collector
163.467	Highway 753	Arterial
163.803	Township Road 534	Collector
165.198	Range Road 105	Collector
166.833	Range Road 110	Collector
168.482	Range Road 111	Collector
170.110	Range Road 112	Collector
171.740	Range Road 113	Collector
173.407	Range Road 114	Collector
174.246	Unnamed Road Crossing	Collector
176.663	Range Road 120	Collector
178.298	Range Road 121	Collector
184.852	Range Road 125	Collector
186.553	Range Road 130	Collector
187.129	Highway 16	Expressway/Highway
188.298	Range Road 131	Collector
191.559	Range Road 133	Collector
193.185	Range Road 134	Collector
196.448	Range Road 140	Collector
198.156	Range Road 141	Collector
200.066	Highway 32	Arterial
205.128	Range Road 145	Collector
206.763	Range Road 150	Collector
208.099	Township Road 534	Collector
208.548	Range Road 151	Collector
210.180	Range Road 152	Collector
211.835	Range Road 153	Collector
213.477	Range Road 154	Collector
214.432	53407 Range Road 155	Local/Street
215.111	Range Road 155	Collector
216.749	Range Road 160	Collector
217.575	Unnamed Road Crossing	Resource/Recreation
218.183	Township Road 534	Collector
218.622	Range Road 161	Collector

TABLE 5.1.14

PRELIMINARY HIGHWAY, ROAD AND RAILWAY CROSSINGS (continued)

Reference Kilometre (RK)	Name	Description
Road and Highway Crossings (Edmonton to Burnaby)		
223.580	Range Road 164	Collector
224.488	Township Road 534	Collector
225.509	Range Road 165	Collector
228.838	25 Street	Arterial
230.500	40 Street	Collector
232.139	Edson Drive	Collector
233.786	63 Street	Local/Street
234.132	66 Street	Local/Street
237.270	Range Road 180	Collector
240.679	Range Road 182	Collector
242.601	Unnamed Road Crossing	Collector
246.018	Range Road 185	Collector
247.817 248.109 248.226	Range Road 185A Township Road 532B Highway 16	Collector Collector Expressway/Highway
252.300	Township Road 530A	Collector
256.536	Range Road 194	Collector
258.991	Range Road 195A	Collector
259.845	Highway 16	Expressway/Highway
260.942	Unnamed Road Crossing	Resource/Recreation
266.740	Unnamed Road Crossing	Collector
270.951	Range Road 210A	Collector
275.244	Unnamed Road Crossing	Resource/Recreation
278.246	Highway 16	Expressway/Highway
278.517	Unnamed Road Crossing	Collector
281.961	Unnamed Road Crossing	Collector
292.575	Highway 16	Expressway/Highway
298.935	Unnamed Road Crossing	Collector
303.061	23518 Highway 16 West	Collector
307.527	Range Road 242	Collector
309.044	East River Road	Collector
309.435	East River Road	Collector
312.405	Highway 16	Expressway/Highway
320.733	Unnamed Road Crossing	Collector
321.827	Robb Road	Collector
326.284	Highway 40	Arterial
328.332	50511 Highway 16 East	Collector
328.975	Highway 16	Expressway/Highway
333.955	Airport Road	Collector
339.144	Unnamed Road Crossing	Collector
516.475	Tinsley Pit Road	Local
518.976	Loseth Road	Local

TABLE 5.1.14

PRELIMINARY HIGHWAY, ROAD AND RAILWAY CROSSINGS (continued)

Reference Kilometre (RK)	Name	Description
Road and Highway Crossings (Edmonton to Burnaby)		
521.941	Highway 5 North	Highway
523.152	Pine Road	Local
523.873	Cranberry Lake Road	Local
526.899	Cranberry Lake Road	Local
528.021	Westridge FSR	Resource
529.667	Highway 5 South	Highway
531.862	Sunnyview Road	Local
539.527	unsigned FSR	Resource
545.632	Highway 5 South	Highway
552.318	Yellowhead South Highway No 5	Highway
582.652	Yellowhead South Highway No 5	Highway
600.189	Mtn Saint Annes FSR	Resource
608.067	Yellowhead South Highway No 5	Highway
611.747	Mud Lake FSR	Resource
614.284	Harwood Drive	Collector
614.740	Cedar Street	Local
614.827	Angus Horne Street	Collector
615.682	Stewart Street	Collector
616.269	Cedar Street	Local
616.490	Dairy Road	Local
625.488	Smoke Creek FSR	Resource
625.602 625.631	Smoke Creek FSR Yellowhead South Highway No 5	Resource Highway
626.886	Yellowhead South Highway No 5	Highway
639.465	Finn Creek FSR	Resource
650.985	Yellowhead South Highway No 5	Highway
652.869	Messiter Station Road	Local
655.503 655.526 655.536	Yellowhead South Highway No 5 Avola East Frtg Diamond Drive	Arterial Restricted Local
655.782	Avola Village Road	Local
655.867	Brazier Road	Local
658.390	unsigned	Local
660.920	Yellowhead South Highway No 5	Highway
675.772	Skinner Road	Local
677.206	Skinner Road	Local
678.107	East Mad FSR	Resource
686.599	Yellowhead South Highway No 5	Highway
688.160	Yellowhead South Highway No 5	Highway
689.001	Yellowhead South Highway No 5	Highway
691.234	Hoirup Road	Local
691.810	Hoirup Road	Local

TABLE 5.1.14

PRELIMINARY HIGHWAY, ROAD AND RAILWAY CROSSINGS (continued)

Reference Kilometre (RK)	Name	Description
Road and Highway Crossings (Edmonton to Burnaby)		
692.525	Yellowhead South Highway No 5	Highway
694.971	Yellowhead South Highway No 5	Highway
695.486	Allingham Way	Local
697.846 697.851 697.856	turning lane Vavenby Bridge Road turning lane	Ramp Collector Ramp
699.773	Harmon Road	Local
704.089	Yellowhead South Highway No 5	Highway
705.574	Lloyd Road	Local
707.583	McCorvie Lakes FSR	Resource
708.077	Yellowhead South Highway No 5	Highway
709.960	Yellowhead South Highway No 5	Highway
710.651	dumproad	Service
714.084 714.088	Yellowhead South Highway No 5 Norris Road	Highway Local
716.496	Deeg Road	Local
717.107 717.191	Yellowhead South Highway No 5 Bain Road	Highway Local
718.084	Raft River FSR	Resource
718.856 718.910	Yellowhead South Highway No 5 Raft River Road	Highway Local
720.373	Candle Creek Road	Collector
720.842	Norfolk Road	Local
722.377	Park Drive	Local
722.893	Murtle Road	Collector
723.187	Clearwater Village Road	Collector
725.455	Swanson Road	Local
726.387	Yellowhead South Highway No 5	Highway
727.642	Yellowhead South Highway No 5	Highway
728.579	Ray Road	Local
729.502	Jenkins Road	Local
730.398	Johnston Road	Local
731.308	Ferry Road	Local
731.592	Old North Thompson Highway	Collector
732.978	Old North Thompson Highway	Collector
734.028	Mann Road	Local
737.027	Yellowhead South Highway No 5	Highway
748.954	Lemieux Creek Road	Local
752.310	93 Mile-Little Fort Highway No 24	Highway
755.441	Lawrence Road	Local
757.975	Yellowhead South Highway No 5	Highway
760.087	Yellowhead South Highway No 5	Highway

TABLE 5.1.14

PRELIMINARY HIGHWAY, ROAD AND RAILWAY CROSSINGS (continued)

Reference Kilometre (RK)	Name	Description
Road and Highway Crossings (Edmonton to Burnaby)		
760.911	Yellowhead South Highway No 5	Highway
761.960	Yellowhead South Highway No 5	Highway
762.786	Yellowhead South Highway No 5	Highway
763.629	Yellowhead South Highway No 5	Highway
766.035	Allen Meeker Road	Local
767.486	Bowden Road	Local
767.709	Yellowhead South Highway No 5	Highway
812.004	Westsyde Road	Local
812.355	Westsyde Road	Local
813.213	Westsyde Road	Local
818.001	Westsyde Road	Local
818.763	Westsyde Road	Local
819.884	Westsyde Road	Local
820.467	Jamieson Creek FSR	Resource
823.874	O'Conner Lake Road	Local
824.447	Inskip Road	Local
824.780	Inskip Road	Local
825.316	Inskip Road	Local
827.002	Noble Lake FSR	Resource
841.498	Lac Du Bois Road	Resource
844.749	Ord Road	Collector
845.332	Tranquille Road	Arterial
845.428	Airport Road	Local
846.183	access road	Service
846.509	Aviation Way	Local
847.442	Mission Flats Road	Collector
850.478 850.522 850.539 850.556	Hillside Drive W Trans-Canada Highway brakecheck W Trans-Canada Highway Frtg	Local Freeway Service Local
863.250	Goose Lake Road	Local
915.768	Coyote Valley Road	Local
916.033	Coyote Valley Road	Local
917.464	unsigned	Local
926.514	Kamloops-Merritt Highway No 5A	Highway
929.667	Coquihalla Highway No 5	Freeway
930.755	Merritt-Princeton Highway No 8 97C	Arterial
931.648	Coldwater Road	Collector
932.804	Coldwater Road	Collector
936.002	Veale Road	Local
938.481	Veale Road	Local
938.682	Coquihalla Highway No 5	Freeway

TABLE 5.1.14

PRELIMINARY HIGHWAY, ROAD AND RAILWAY CROSSINGS (continued)

Reference Kilometre (RK)	Name	Description
Road and Highway Crossings (Edmonton to Burnaby)		
940.035	Veale Road	Local
940.084	Coquihalla Highway No 5	Freeway
941.056	Comstock Road	Local
947.044	Coldwater Road South	Collector
948.358	Coldwater Road South	Collector
951.109	Suttie Road	Local
956.765	Coldwater Road South	Collector
966.470	Coquihalla Highway No 5	Freeway
980.180	Juliet Road	Local
980.469 980.487	Juliet Road Offramp Coquihalla Highway No 5	Ramp Freeway
980.761	Juliet Road	Local
986.242	Mine Creek Pit Road	Local
987.108	Mine Creek FSR	Resource
989.982	Upper Coldwater Road	Local
997.395	park access road	Recreation
1000.720 1000.736 1000.757	highway ramp Highway 5 highway ramp	Ramp Freeway Ramp
1010.801	Highway 5	Freeway
1018.454	Highway 5	Freeway
1021.065	Carolin Mine Road	Restricted
1021.082	Carolin Mine Road	Restricted
1021.455	Carolin Mine Road	Restricted
1021.486	Carolin Mine Road	Restricted
1021.723	Carolin Mine Road	Restricted
1026.870	Highway 5	Freeway
1028.286	Highway 5	Freeway
1032.876 1032.897	unsigned Highway 5	Local Freeway
1034.645	Othello Road	Local
1034.914	Othello Road	Local
1034.940	Othello Road Offramp	Ramp
1035.141	Othello Road	Local
1039.437	Othello Road	Local
1042.321	Kettle Valley Road	Local
1042.408	Birchtrees Drive	Local
1042.713	Mount Hope Road	Local
1042.855	Acacia Drive	Local
1043.409	Old Hope Princeton Way	Collector
1044.286	Highway 3	Freeway
1045.070	Flood Hope Road	Arterial

TABLE 5.1.14

PRELIMINARY HIGHWAY, ROAD AND RAILWAY CROSSINGS (continued)

Reference Kilometre (RK)	Name	Description
Road and Highway Crossings (Edmonton to Burnaby)		
1045.268	Flood Hope Road Offramp	Ramp
1046.530	Trans-Canada Highway	Freeway
1047.489	Elder Road	Local
1048.089	Tobina Road	Local
1048.249	Klassen Road	Local
1048.432	Flood Hope Road	Collector
1050.447	Floods Road	Local
1050.861	Estell Road	Local
1051.111 1051.203 1051.246 1051.299	Flood Road Overpass Flood Road Offramp Trans-Canada Highway Flood Road Offramp	Collector Ramp Freeway Ramp
1054.535	Trans-Canada Highway	Freeway
1059.611	Laidlaw Road	Local
1060.075	McKay Road	Local
1062.166	Laidlaw Road	Local
1062.453 1062.544	Laidlaw Road Offramp Trans-Canada Highway	Ramp Freeway
1064.446 1064.494	Trans-Canada Highway Peters Road Onramp	Freeway Ramp
1064.722	Peters Road	Local
1077.724	Bridal Falls Road	Local
1078.678	Bridal Falls FSR	Resource
1078.780 1078.805 1078.836 1078.870	Popkum Road South Bridal Falls Road Trans-Canada Highway Yale Road E	Local Local Freeway Local
1080.287	Yale Road E	Local
1081.018 1081.029	Highway 9 Highway 9 Onramp	Arterial Ramp
1081.595	Llanberis Way	Local
1081.858	Thompson Road	Local
1083.028	Nevin Road	Local
1083.908	McElwee Road	Local
1084.833	Ford Road	Local
1086.573 1086.580	Chilliwack Central Road Annis Road	Local Local
1088.442	Trans-Canada Highway	Freeway
1090.162 1090.230	Gibson Road Prairie Central Road	Local Local
1092.149	Banford Road	Local
1092.935	McGuire Road	Local
1094.028	Prest Road	Local

TABLE 5.1.14

PRELIMINARY HIGHWAY, ROAD AND RAILWAY CROSSINGS (continued)

Reference Kilometre (RK)	Name	Description
Road and Highway Crossings (Edmonton to Burnaby)		
1095.521	Chilliwack River Road	Collector
1097.180	Vedder Road	Arterial
1098.287	Arlington Drive	Local
1098.604	Tyson Road	Collector
1099.303	Watson Road	Local
1099.482	Canterbury Drive	Local
1100.331	Unsworth Road	Local
1101.047 1101.129	Lickman Road Keith Wilson Road	Local Collector
1102.778	unsigned	Local
1103.462	Lumsden Road	Local
1104.037	Simmons Road	Local
1104.619	Vedder Mountain Road	Collector
1105.389	Wilson Road	Local
1106.188	Eckert Street	Local
1106.999	Stewart Road	Local
1107.959	Boundary Road	Local
1109.037	Tolmie Road	Local
1110.115	Interprovincial Highway	Local
1111.245	Dixon Road	Local
1112.303	Marion Road	Local
1113.891	McDermott Road	Local
1114.016 1114.078 1114.134	South Parallel Road Trans-Canada Highway North Parallel Road	Local Freeway Local
1114.701	Eldridge Road	Local
1116.477	Ward Road	Local
1117.003	Sumas Mountain Road	Collector
1118.493	McKee Road	Collector
1118.946	Golf Course Drive	Strata
1120.359 1120.648 1120.722 1120.895	Caves Court Belanger Drive Poplar Court Old Clayburn Road	Local Local Local Collector
1121.747	Wright Street	Collector
1122.714	Clayburn Road	Collector
1123.758 1123.840	Highway 11 Riverside Street	Arterial Local
1124.947	Townshipline Road	Local
1126.136	Gladwin Road	Collector
1127.340	Hallert Road	Local
1127.856	Glenmore Road	Local

TABLE 5.1.14

PRELIMINARY HIGHWAY, ROAD AND RAILWAY CROSSINGS (continued)

Reference Kilometre (RK)	Name	Description
Road and Highway Crossings (Edmonton to Burnaby)		
1129.116	Bates Road	Local
1129.261	Harris Road	Collector
1131.295	Mt Lehman Road	Local
1131.970	Burgess Avenue	Local
1133.013	Ross Road	Local
1134.767	Bradner Road	Collector
1136.515	Lefeuvre Road	Local
1137.112	Joanita Place	Local
1138.379	272 Street	Collector
1139.389	267 Street	Local
1139.905	264 Street	Collector
1141.176	258 Street	Local
1144.309	Telegraph Trail	Local
1144.928	240 Street	Collector
1146.552	232 Street	Arterial
1147.423	Glover Road	Arterial
1147.671	golf course access road	Recreation
1149.031	88 Avenue	Collector
1150.668	222 Street	Local
1151.371	96 Avenue	Arterial
1151.965	216 Street	Collector
1153.652	208 Street	Collector
1154.983	201 Street	Local
1155.051	201 Street Onramp	Ramp
1155.182	Golden Ears Way	Arterial
1155.260	199A Street Offramp	Ramp
1155.590	99A Avenue	Local
1155.917	197 Street	Local
1156.864	98A Avenue	Collector
1156.883	192 Street	Local
1157.110	191 Street	Restricted
1157.347	98A Avenue	Local
1157.443	98A Avenue	Local
1158.915	182A Street	Local
1159.625	179 Street	Local
1160.156	177A Street	Local
1160.450 1160.472	Daly Road 104 Avenue	Local Local
1166.924	Port Mann Bridge	Freeway
1169.688	Fawcett Road	Local
1170.117	Hartley Avenue	Local
1170.325	United Boulevard	Collector

TABLE 5.1.14

PRELIMINARY HIGHWAY, ROAD AND RAILWAY CROSSINGS (continued)

Reference Kilometre (RK)	Name	Description
Road and Highway Crossings (Edmonton to Burnaby)		
1170.345	Schooner Street	Local
1170.970	United Boulevard	Collector
1170.991	Brigantine Drive	Local
1170.998	United Boulevard	Collector
1171.285	Clipper Street	Local
1171.456	United Boulevard	Collector
1171.860	United Boulevard	Collector
1171.983	King Edward Street	Local
1172.181	United Boulevard	Local
1173.053	Trans-Canada Highway	Freeway
1173.196	Tupper Avenue	Local
1173.428 1173.433	Brunette Avenue Bernatchey Street	Arterial Arterial
1173.618	Henderson Avenue	Local
1173.708	Bernatchey Street	Arterial
1174.084	Alderson Avenue	Local
1175.136	North Road	Arterial
1175.604	Government Street	Collector
1175.751	Lougheed Highway	Arterial
1176.085	Lougheed Highway	Arterial
1176.128	Lougheed Highway	Arterial
1176.170	Lougheed Highway	Arterial
1176.745 1176.783	turning lane Gaglardi Way	Ramp Arterial
1176.829	Lougheed Highway	Arterial
1177.265	Brighton Avenue	Collector
1177.697	Lougheed Highway	Arterial
1177.834	Lougheed Highway	Arterial
1178.250	Underhill Avenue	Local
1178.820	Broadway	Collector
1179.516	Shellmont Street	Collector
Road and Highway Crossings (Burnaby to Westridge)		
0.708	Burnaby Mountain Parkway	Arterial
0.884	Centennial Way	Local
1.931	feeder	Ramp
1.951	Hastings Street	Local
2.180	Duthie Avenue	Collector
2.432	Barnet Road	Local
2.554 2.567	turning lane Inlet Drive	Ramp Arterial
2.648	Cliff Avenue	Collector

TABLE 5.1.14

PRELIMINARY HIGHWAY, ROAD AND RAILWAY CROSSINGS (continued)

Reference Kilometre (RK)	Name	Description
Road and Highway Crossings (Burnaby to Westridge)		
12.013	Canadian National (CN)	Mainline
22.969 22.983	side track Canadian Pacific Railway (CPR)	Spur Mainline
61.453	CN	Mainline
118.530	CN	Mainline
123.569	CN	Mainline
228.145	CN	Mainline
252.906	CN	Mainline
259.666	CN	Mainline
279.580	CN	Mainline
303.739	CN	Mainline
311.840	CN	Mainline
500.397	CN	Mainline
501.303	CN	Mainline
506.714	CN	Mainline
516.238	CN	Mainline
518.893	CN	Mainline
529.500	CN	Mainline
545.747	CN	Mainline
547.722	CN	Mainline
552.202	CN	Mainline
558.611	CN	Mainline
567.247	CN	Mainline
580.917	CN	Mainline
617.485	CN	Mainline
653.643	CN	Mainline
657.269	CN	Mainline
658.588	CN	Mainline
844.869	CN	TBD
845.138	CN	TBD
847.506	CPR	TBD
1062.880	CN	Mainline
1064.392	CN	Mainline
1104.801	Southern Railway of British Columbia (SRY)	Mainline
1123.822	CPR	Mainline
1126.569	SRY	Mainline
1131.375	SRY	Mainline
1145.722	CN	Mainline
1151.240	CN	Mainline
1154.197	side track	Spur
1158.591	CN	Mainline
1160.470	CN	Mainline

TABLE 5.1.14

PRELIMINARY HIGHWAY, ROAD AND RAILWAY CROSSINGS (continued)

Reference Kilometre (RK)	Name	Description
Railway Crossings (Edmonton to Westridge)		
1163.734	CN	Mainline
1168.484	CN	Mainline
1172.219	CPR	Mainline
1172.999 1173.003	CPR CN	Mainline TBD
1175.168	TransLink SkyTrain (TLST)	Light Rail
1176.575	CN	Mainline
1177.856	TLST	Light Rail

TABLE 5.1.15

PRELIMINARY FOREIGN PIPELINE CROSSINGS

Reference Kilometre (RK)	Owner	Product Type	Product	Status
Edmonton to Burnaby				
0.054	ATCO Ltd.	Gas	Natural Gas	Operating
0.060	Keyera Energy Facilities Limited	LVP	Crude Oil	Abandoned
0.066	Plains Marketing Canada, L.P.	LVP	Crude Oil	Discontinued
0.070	Pembina Pipeline Corporation	LVP	Crude Oil	Operating
0.213	ExxonMobil Resources Ltd.	LVP	Crude Oil	Operating
0.216	Plains Marketing Canada, L.P.	LVP	Crude Oil	Operating
0.220	Pembina Pipeline Corporation	LVP	Crude Oil	Operating
0.288	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
0.837	ExxonMobil Resources Ltd.	LVP	LVP Products	Abandoned
0.842	Pembina Pipeline Corporation	LVP	Crude Oil	Operating
0.847	Pembina Pipeline Corporation	LVP	Crude Oil	Operating
0.851	Pembina Pipeline Corporation	LVP	Crude Oil	Discontinued
0.859	Air Liquide Canada Inc.	Gas	Miscellaneous Gases	Operating
0.863	ExxonMobil Resources Ltd.	LVP	LVP Products	Abandoned
0.867	NOVA Chemicals Corporation	HVP	HVP Products	Operating
1.343	Keyera Energy Facilities Limited	HVP	HVP Products	Operating
1.346	Air Liquide Canada Inc.	Gas	Miscellaneous Gases	Operating
1.350	Keyera Energy Facilities Limited	HVP	HVP Products	Operating
1.354	Keyera Energy Facilities Limited	HVP	HVP Products	Operating
1.357	Keyera Energy Facilities Limited	HVP	HVP Products	Operating
1.364	NOVA Chemicals Corporation	HVP	HVP Products	Operating
1.368	Plains Marketing Canada, L.P.	HVP	HVP Products	Operating
1.377	Plains Marketing Canada, L.P.	HVP	HVP Products	Operating
1.387	Pembina Pipeline Corporation	LVP	Crude Oil	Operating
1.391	Pembina Pipeline Corporation	LVP	Crude Oil	Discontinued
1.399	Keyera Energy Facilities Limited	HVP	HVP Products	Operating
1.402	Shell Canada Limited	LVP	LVP Products	Operating
1.406	Shell Canada Limited	LVP	LVP Products	Operating
1.410	Shell Canada Limited	LVP	LVP Products	Operating
1.461	Praxair Canada Inc.	Gas	Miscellaneous Gases	Operating
1.468	ATCO Ltd.	Gas	Natural Gas	Operating
1.766	Plains Marketing Canada, L.P.	LVP	Crude Oil	Operating
1.771	Enbridge Pipelines Inc.	LVP	Crude Oil	Operating
1.775	Pipeline Management Inc.	LVP	Crude Oil	Operating
1.779	Enbridge Pipelines Inc.	LVP	Crude Oil	Operating
1.783	Enbridge Pipelines Inc.	LVP	Crude Oil	Abandoned
1.788	Enbridge Pipelines Inc.	LVP	Crude Oil	Operating
1.792	Enbridge Pipelines Inc.	LVP	Crude Oil	Operating
1.937	ATCO Ltd.	Gas	Natural Gas	Operating
2.666	Alberta Products Pipe Line Ltd	LVP	LVP Products	Operating
2.684	ATCO Ltd.	Gas	Natural Gas	Operating

TABLE 5.1.15

PRELIMINARY FOREIGN PIPELINE CROSSINGS (continued)

Reference Kilometre (RK)	Owner	Product Type	Product	Status
Edmonton to Burnaby				
2.781	NOVA Chemicals Corporation	HVP	HVP Products	Operating
2.804	ATCO Ltd.	Gas	Natural Gas	Operating
3.393	Shell Canada Limited	LVP	LVP Products	Operating
3.400	Shell Canada Limited	LVP	LVP Products	Operating
4.118	NOVA Chemicals Corporation	HVP	HVP Products	Operating
4.621	NOVA Chemicals Corporation	HVP	HVP Products	Operating
5.281	Enbridge Pipelines Inc.	LVP	Crude Oil	Operating
5.319	Pipeline Management Inc.	LVP	Crude Oil	Operating
5.350	Enbridge Pipelines Inc.	LVP	Crude Oil	Operating
5.364	NOVA Chemicals Corporation	HVP	HVP Products	Operating
5.378	Plains Marketing Canada, L.P.	LVP	Crude Oil	Operating
5.379	ATCO Ltd.	Gas	Natural Gas	Operating
5.391	ATCO Ltd.	Gas	Natural Gas	Abandoned
5.399	ATCO Ltd.	Gas	Natural Gas	Abandoned
5.406	ATCO Ltd.	Gas	Natural Gas	Abandoned
5.413	ATCO Ltd.	Gas	Natural Gas	Operating
5.423	ATCO Ltd.	Gas	Natural Gas	Operating
5.791	Alberta Ethane Development Company Ltd.	HVP	HVP Products	Operating
5.813	Alberta Ethane Development Company Ltd.	HVP	HVP Products	Operating
7.051	NOVA Chemicals Corporation	HVP	HVP Products	Operating
7.564	NOVA Chemicals Corporation	HVP	HVP Products	Operating
7.798	NOVA Chemicals Corporation	HVP	HVP Products	Operating
8.438	NOVA Chemicals Corporation	HVP	HVP Products	Operating
8.453	ATCO Ltd.	Gas	Natural Gas	Operating
12.087	Alberta Ethane Development Company Ltd.	HVP	HVP Products	Operating
13.625	Alberta Ethane Development Company Ltd.	HVP	HVP Products	Operating
17.011	Keyera Energy Facilities Limited	HVP	HVP Products	Operating
17.026	Alberta Products Pipe Line Ltd	LVP	LVP Products	Operating
21.933	ATCO Ltd.	Gas	Natural Gas	Operating
21.934	Pembina Pipeline Corporation	LVP	Crude Oil	Operating
21.996	Pembina Pipeline Corporation	LVP	Crude Oil	Discontinued
22.009	Plains Marketing Canada, L.P.	LVP	Crude Oil	Operating
22.019	Keyera Energy Facilities Limited	LVP	Crude Oil	Discontinued
22.033	Keyera Energy Facilities Limited	LVP	Crude Oil	Discontinued
22.043	Keyera Energy Facilities Limited	LVP	Crude Oil	Discontinued
22.079	ATCO Ltd.	Gas	Natural Gas	Operating
22.096	Keyera Energy Facilities Limited	HVP	HVP Products	Discontinued
22.107	Alberta Ethane Development Company Ltd.	HVP	HVP Products	Operating
22.116	AltaGas Ltd.	Gas	Natural Gas	Discontinued
23.897	ATCO Ltd.	Gas	Natural Gas	Operating
23.908	Pembina Pipeline Corporation	LVP	Crude Oil	Operating
25.233	ATCO Ltd.	Gas	Natural Gas	Operating
25.240	ATCO Ltd.	Gas	Natural Gas	Operating

TABLE 5.1.15

PRELIMINARY FOREIGN PIPELINE CROSSINGS (continued)

Reference Kilometre (RK)	Owner	Product Type	Product	Status
Edmonton to Burnaby				
25.258	ATCO Ltd.	Gas	Natural Gas	Operating
25.270	Keyera Energy Facilities Limited	HVP	HVP Products	Discontinued
25.280	Keyera Energy Facilities Limited	LVP	LVP Products	Abandoned
25.292	Keyera Energy Facilities Limited	LVP	LVP Products	Abandoned
25.304	Keyera Energy Facilities Limited	HVP	HVP Products	Abandoned
25.315	Plains Marketing Canada, L.P.	HVP	HVP Products	Operating
25.327	Plains Marketing Canada, L.P.	HVP	HVP Products	Operating
32.385	ATCO Ltd.	Gas	Natural Gas	Abandoned
37.556	ATCO Ltd.	Gas	Natural Gas	Operating
40.183	Penn West Petroleum Ltd.	Water	Fresh Water	Discontinued
40.201	Penn West Petroleum Ltd.	Water	Fresh Water	Discontinued
40.264	ATCO Ltd.	Gas	Natural Gas	Operating
42.024	Leddy Exploration Limited	Gas	Natural Gas	Abandoned
42.406	Leddy Exploration Limited	LVP	Oil Well Effluent	Abandoned
42.421	Leddy Exploration Limited	LVP	Oil Well Effluent	Abandoned
42.437	Leddy Exploration Limited	LVP	Oil Well Effluent	Operating
42.453	Leddy Exploration Limited	LVP	Oil Well Effluent	Operating
42.687	ATCO Ltd.	Gas	Natural Gas	Abandoned
42.703	ATCO Ltd.	Gas	Natural Gas	Operating
43.322	Penn West Petroleum Ltd.	Water	Fresh Water	Discontinued
43.334	Penn West Petroleum Ltd.	Water	Fresh Water	Discontinued
43.567	ATCO Ltd.	Gas	Natural Gas	Abandoned
44.180	Penn West Petroleum Ltd.	Gas	Natural Gas	Abandoned
46.031	Penn West Petroleum Ltd.	LVP	Oil Well Effluent	Abandoned
46.039	Penn West Petroleum Ltd.	LVP	Oil Well Effluent	Abandoned
46.306	Penn West Petroleum Ltd.	LVP	Oil Well Effluent	Operating
46.307	Kingsmere Resources Ltd.	Gas	Natural Gas	Abandoned
46.311	Penn West Petroleum Ltd.	LVP	Oil Well Effluent	Operating
46.322	Kingsmere Resources Ltd.	Gas	Natural Gas	Abandoned
46.535	Penn West Petroleum Ltd.	LVP	Oil Well Effluent	Abandoned
46.793	Penn West Petroleum Ltd.	Gas	Natural Gas	Operating
46.810	Penn West Petroleum Ltd.	LVP	Oil Well Effluent	Discontinued
46.890	Penn West Petroleum Ltd.	Gas	Natural Gas	Operating
47.085	Penn West Petroleum Ltd.	Gas	Natural Gas	Operating
47.093	Penn West Petroleum Ltd.	Gas	Natural Gas	Operating
47.100	Penn West Petroleum Ltd.	LVP	Oil Well Effluent	Operating
47.115	Kingsmere Resources Ltd.	Gas	Natural Gas	Operating
47.126	Kingsmere Resources Ltd.	Gas	Natural Gas	Operating
47.403	Penn West Petroleum Ltd.	LVP	Oil Well Effluent	Operating
47.656	Penn West Petroleum Ltd.	LVP	Oil Well Effluent	Operating
48.096	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
48.122	Penn West Petroleum Ltd.	LVP	Oil Well Effluent	Discontinued
48.140	Penn West Petroleum Ltd.	Gas	Natural Gas	Operating

TABLE 5.1.15

PRELIMINARY FOREIGN PIPELINE CROSSINGS (continued)

Reference Kilometre (RK)	Owner	Product Type	Product	Status
Edmonton to Burnaby				
48.425	Leddy Exploration Limited	Water	Salt Water	Abandoned
48.903	ATCO Ltd.	Gas	Natural Gas	Operating
48.946	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
50.451	Pembina Pipeline Corporation	HVP	HVP Products	Operating
52.126	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
54.672	Penn West Petroleum Ltd.	LVP	Oil Well Effluent	Operating
54.686	ATCO Ltd.	Gas	Natural Gas	Operating
56.996	ATCO Ltd.	Gas	Natural Gas	Operating
58.734	ATCO Ltd.	Gas	Natural Gas	Operating
60.332	ATCO Ltd.	Gas	Natural Gas	Operating
65.522	ATCO Ltd.	Gas	Natural Gas	Operating
68.401	West Parkland Gas Co-Op Ltd.	Gas	Natural Gas	Operating
69.822	Keyera Energy Facilities Limited	HVP	HVP Products	Operating
69.836	Keyera Energy Facilities Limited	HVP	HVP Products	Discontinued
75.777	West Parkland Gas Co-Op Ltd.	Gas	Natural Gas	Operating
75.797	West Parkland Gas Co-Op Ltd.	Gas	Natural Gas	Abandoned
83.357	TAQA North Ltd.	Gas	Natural Gas	Discontinued
85.466	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
85.945	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
96.680	West Parkland Gas Co-Op Ltd.	Gas	Natural Gas	Operating
97.132	ATCO Ltd.	Gas	Natural Gas	Operating
97.171	ATCO Ltd.	Gas	Natural Gas	Operating
117.269	ATCO Ltd.	Gas	Natural Gas	Operating
120.317	West Parkland Gas Co-Op Ltd.	Gas	Natural Gas	Operating
121.733	ATCO Ltd.	Gas	Natural Gas	Operating
127.092	Ste Anne Natural Gas Co-Op Limited	Gas	Natural Gas	Operating
133.994	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
134.007	ATCO Ltd.	Gas	Natural Gas	Operating
135.587	ATCO Ltd.	Gas	Natural Gas	Operating
135.690	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
136.096	ATCO Ltd.	Gas	Natural Gas	Operating
136.124	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
137.240	TRL Gas Co-op Ltd.	Gas	Natural Gas	Operating
151.065	Dewpoint Resources Ltd.	Gas	Natural Gas	Operating
151.562	ATCO Ltd.	Gas	Natural Gas	Operating
151.592	Online Energy Inc.	Gas	Natural Gas	Operating
157.749	Daylight Energy Ltd.	Gas	Natural Gas	Operating
160.987	Daylight Energy Ltd.	Gas	Natural Gas	Operating
163.148	Longview Oil Corp.	Gas	Natural Gas	Operating
165.009	ATCO Ltd.	Gas	Natural Gas	Abandoned
165.567	Nuvista Energy Ltd.	Gas	Natural Gas	Operating
178.336	ATCO Ltd.	Gas	Natural Gas	Operating
182.378	Pembina Pipeline Corporation	LVP	Crude Oil	Operating

TABLE 5.1.15

PRELIMINARY FOREIGN PIPELINE CROSSINGS (continued)

Reference Kilometre (RK)	Owner	Product Type	Product	Status
Edmonton to Burnaby				
183.268	Plains Marketing Canada, L.P.	HVP	HVP Products	Operating
192.470	Direct Energy Marketing Limited	Gas	Natural Gas	Operating
193.769	TransCanada Pipelines Limited	Gas	Natural Gas	Operating
193.811	ATCO Ltd.	Gas	Natural Gas	Operating
195.608	Direct Energy Marketing Limited	Gas	Natural Gas	Operating
197.807	Compton Oil & Gas Corporation	Gas	Natural Gas	Operating
198.390	Signalta Resources Limited	Gas	Natural Gas	Operating
199.344	Direct Energy Marketing Limited	Gas	Natural Gas	Operating
202.383	Compton Oil & Gas Corporation	Gas	Natural Gas	Operating
203.023	Compton Oil & Gas Corporation	Gas	Natural Gas	Operating
203.821	Compton Oil & Gas Corporation	Gas	Natural Gas	Operating
205.862	Compton Oil & Gas Corporation	Gas	Natural Gas	Operating
207.351	Angle Energy Inc.	Gas	Natural Gas	Operating
207.361	Bonavista Petroleum Ltd.	Gas	Natural Gas	Operating
207.955	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
207.968	ATCO Ltd.	Gas	Natural Gas	Operating
208.818	Perpetual Energy Operating Corp.	Gas	Sour Natural Gas	Operating
208.863	Angle Energy Inc.	Gas	Natural Gas	Operating
209.535	Angle Energy Inc.	Gas	Natural Gas	To Be Constructed
210.720	ATCO Ltd.	Gas	Natural Gas	Operating
210.735	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
211.099	Velvet Energy Ltd.	Gas	Natural Gas	Operating
213.385	ConocoPhillips Canada Resources Corp.	Gas	Natural Gas	Operating
213.645	Angle Energy Inc.	Gas	Natural Gas	Operating
215.663	Angle Energy Inc.	Gas	Natural Gas	Operating
215.670	Angle Energy Inc.	Gas	Natural Gas	Operating
219.810	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
219.838	TransCanada Pipelines Limited	Gas	Natural Gas	Operating
221.320	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
222.852	Angle Energy Inc.	Gas	Natural Gas	Operating
226.731	Yellowhead Gas Co-Op Ltd.	Gas	Natural Gas	Operating
227.299	Bridges Energy Inc.	Water	Fresh Water	Abandoned
227.972	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
228.020	ATCO Ltd.	Gas	Natural Gas	Operating
229.313	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
229.859	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
230.548	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
231.353	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
232.171	ATCO Ltd.	Gas	Natural Gas	Operating
233.695	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
234.194	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
234.624	Conserve Oil Corporation	Gas	Natural Gas	Operating

TABLE 5.1.15

PRELIMINARY FOREIGN PIPELINE CROSSINGS (continued)

Reference Kilometre (RK)	Owner	Product Type	Product	Status
Edmonton to Burnaby				
234.771	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
235.061	TransCanada Pipelines Limited	Gas	Natural Gas	Operating
236.616	TransCanada Pipelines Limited	Gas	Natural Gas	Operating
236.641	TransCanada Pipelines Limited	Gas	Natural Gas	Operating
237.956	Talisman Energy Inc.	LVP	Fuel Gas	Operating
237.983	Talisman Energy Inc.	Gas	Sour Natural Gas	Operating
238.009	Talisman Energy Inc.	Water	Salt Water	Operating
238.047	EOG Resources Canada Inc.	Gas	Natural Gas	Operating
240.097	Talisman Energy Inc.	LVP	Fuel Gas	Operating
240.114	Talisman Energy Inc.	Gas	Sour Natural Gas	Operating
240.412	Crocotta Energy Inc.	LVP	Oil Well Effluent	Operating
240.447	Talisman Energy Inc.	Gas	Sour Natural Gas	Operating
240.776	Crocotta Energy Inc.	Gas	Natural Gas	Operating
240.793	TransCanada Pipelines Limited	Gas	Natural Gas	Abandoned
241.163	Crocotta Energy Inc.	Gas	Natural Gas	Operating
241.743	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
242.072	Alliance Pipeline Ltd	Gas	Natural Gas	Operating
242.095	TransCanada Pipelines Limited	Gas	Natural Gas	Operating
242.116	TransCanada Pipelines Limited	Gas	Natural Gas	Operating
242.141	Talisman Energy Inc.	Gas	Sour Natural Gas	Operating
242.636	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
243.038	Talisman Energy Inc.	Gas	Natural Gas	Discontinued
243.052	Talisman Energy Inc.	Gas	Natural Gas	Operating
243.065	Talisman Energy Inc.	Gas	Sour Natural Gas	Operating
244.757	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
246.540	Pembina Pipeline Corporation	LVP	LVP Products	Operating
246.549	Talisman Energy Inc.	Gas	Natural Gas	Operating
246.558	Talisman Energy Inc.	Gas	Natural Gas	Operating
246.567	Talisman Energy Inc.	Gas	Natural Gas	Operating
246.854	Tervita Corporation	Water	Salt Water	Operating
246.901	Pembina Pipeline Corporation	LVP	Crude Oil	Discontinued
247.624	Yellowhead Gas Co-op Ltd.	Gas	Natural Gas	Operating
247.636	Talisman Energy Inc.	Gas	Natural Gas	Operating
247.696	Bonavista Petroleum Ltd.	Gas	Natural Gas	Operating
247.712	Talisman Energy Inc.	Gas	Natural Gas	Operating
247.961	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
248.140	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
248.345	ATCO Ltd.	Gas	Natural Gas	Operating
249.275	ATCO Ltd.	Gas	Natural Gas	Operating
249.287	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
249.313	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
251.309	TAQA North Ltd.	LVP	Oil Well Effluent	Operating
251.328	Talisman Energy Inc.	Gas	Natural Gas	Operating

TABLE 5.1.15

PRELIMINARY FOREIGN PIPELINE CROSSINGS (continued)

Reference Kilometre (RK)	Owner	Product Type	Product	Status
Edmonton to Burnaby				
253.661	Plains Marketing Canada, L.P.	HVP	HVP Products	Operating
253.677	ATCO Ltd.	Gas	Natural Gas	Operating
253.697	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
253.715	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
253.730	ATCO Ltd.	Gas	Natural Gas	Operating
255.426	TransCanada Pipelines Limited	Gas	Natural Gas	Operating
255.442	TransCanada Pipelines Limited	Gas	Natural Gas	Operating
255.636	Talisman Energy Inc.	Gas	Natural Gas	Operating
255.656	TransCanada Pipelines Limited	Gas	Natural Gas	Operating
255.680	TransCanada Pipelines Limited	Gas	Natural Gas	Operating
256.048	Plains Marketing Canada, L.P.	HVP	HVP Products	Operating
256.056	ATCO Ltd.	Gas	Natural Gas	Operating
256.072	ATCO Ltd.	Gas	Natural Gas	Operating
256.088	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
256.106	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
256.487	Canadian Natural Resources Limited	Gas	Natural Gas	Discontinued
260.201	Pengrowth Energy Corporation	Gas	Natural Gas	Operating
260.757	Canadian Natural Resources Limited	Gas	Natural Gas	Operating
260.957	Plains Marketing Canada, L.P.	HVP	HVP Products	Operating
261.986	Canadian Natural Resources Limited	Gas	Natural Gas	Operating
261.998	Canadian Natural Resources Limited	Gas	Natural Gas	Operating
262.013	ATCO Ltd.	Gas	Natural Gas	Operating
263.297	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
263.322	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
266.450	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
266.478	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
266.715	Open Range Energy Corp.	Gas	Natural Gas	Operating
266.724	Canadian Natural Resources Limited	Gas	Natural Gas	Operating
267.537	Talisman Energy Inc.	Gas	Natural Gas	Operating
271.286	Enerplus Corporation	Gas	Natural Gas	Operating
271.327	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
271.333	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
275.274	Talisman Energy Inc.	Gas	Natural Gas	Operating
275.286	Talisman Energy Inc.	Gas	Natural Gas	Operating
276.201	ATCO Ltd.	Gas	Natural Gas	Operating
276.393	Talisman Energy Inc.	Gas	Natural Gas	Abandoned
276.410	Canadian Natural Resources Limited	Gas	Natural Gas	Operating
276.424	Talisman Energy Inc.	Gas	Natural Gas	Operating
276.521	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
278.354	Talisman Energy Inc.	Gas	Natural Gas	Operating
279.268	Daylight Energy Ltd.	Gas	Natural Gas	Operating
279.747	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
280.180	Canadian Natural Resources Limited	Gas	Natural Gas	Operating

TABLE 5.1.15

PRELIMINARY FOREIGN PIPELINE CROSSINGS (continued)

Reference Kilometre (RK)	Owner	Product Type	Product	Status
Edmonton to Burnaby				
280.483	ATCO Ltd.	Gas	Natural Gas	Operating
280.500	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
280.524	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
280.753	Talisman Energy Inc.	LVP	Fuel Gas	Operating
280.766	Talisman Energy Inc.	Gas	Sour Natural Gas	Operating
283.777	Talisman Energy Inc.	Gas	Natural Gas	Operating
284.324	Talisman Energy Inc.	Gas	Natural Gas	Operating
284.977	Canadian Natural Resources Limited	Gas	Natural Gas	Discontinued
288.293	Canadian Natural Resources Limited	Gas	Natural Gas	Operating
288.317	Shell Canada Limited	Gas	Natural Gas	Operating
288.328	Shell Canada Limited	Gas	Natural Gas	Operating
288.694	ATCO Ltd.	Gas	Natural Gas	Operating
290.890	Canadian Natural Resources Limited	Gas	Natural Gas	Operating
294.442	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
294.456	ATCO Ltd.	Gas	Natural Gas	Operating
294.480	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
294.493	Canadian Natural Resources Limited	Gas	Natural Gas	Operating
298.712	Canadian Natural Resources Limited	Gas	Natural Gas	Operating
298.722	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
298.812	ATCO Ltd.	Gas	Natural Gas	Operating
298.831	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
298.917	Coal Valley Resources Inc.	Gas	Natural Gas	Operating
298.968	ATCO Ltd.	Gas	Natural Gas	Operating
302.241	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
302.255	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
303.204	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
303.225	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
304.090	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
304.093	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
304.112	ATCO Ltd.	Gas	Natural Gas	Operating
305.534	ATCO Ltd.	Gas	Natural Gas	Operating
305.557	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
305.977	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
311.192	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
311.203	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
311.223	ATCO Ltd.	Gas	Natural Gas	Operating
327.223	ATCO Ltd.	Gas	Natural Gas	Operating
327.236	ATCO Ltd.	Gas	Natural Gas	Operating
327.241	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
327.253	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
329.884	ATCO Ltd.	Gas	Natural Gas	Operating
329.898	ATCO Ltd.	Gas	Natural Gas	Operating
330.055	ATCO Ltd.	Gas	Natural Gas	Operating

TABLE 5.1.15

PRELIMINARY FOREIGN PIPELINE CROSSINGS (continued)

Reference Kilometre (RK)	Owner	Product Type	Product	Status
Edmonton to Burnaby				
331.327	ATCO Ltd.	Gas	Natural Gas	Operating
339.218	ATCO Ltd.	Gas	Natural Gas	Operating
495.254	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
495.814	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
500.340	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
506.893	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
508.467	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
521.481	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
538.687	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
544.291	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
562.894	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
563.946	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
620.588	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
625.417	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
638.561	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
640.678	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
646.924	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
649.325	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
652.038	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
670.778	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
674.537	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
677.180	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
682.092	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
683.267	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
683.758	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
690.150	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
703.855	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
704.440	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
709.610	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
710.442	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
711.627	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
712.539	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
718.689	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
718.691	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
719.735	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
725.459	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
725.931	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
736.943	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
749.337	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
754.403	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
757.110	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
757.321	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
757.971	Kinder Morgan Canada Inc.	LVP	LVP Products	Active

TABLE 5.1.15

PRELIMINARY FOREIGN PIPELINE CROSSINGS (continued)

Reference Kilometre (RK)	Owner	Product Type	Product	Status
Edmonton to Burnaby				
760.007	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
760.942	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
761.930	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
762.754	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
764.569	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
765.953	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
766.428	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
836.879	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
836.889	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
841.128	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
841.139	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
842.343	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
842.357	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
843.333	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
843.341	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
843.750	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
843.758	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
844.511	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
844.777	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
844.886	FortisBC Energy Inc. (FEI)	Gas		Existing
845.231	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
845.234	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
845.337	FEI	Gas		Existing
845.405	FEI	Gas		Existing
846.460	FEI	Gas		Existing
847.573	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
847.583	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
850.357	FortisBC	Gas		Existing
850.569	FEI	Gas		Existing
850.865	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
897.404	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
899.263	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
930.381	FEI	Gas		Existing
931.663	FEI	Gas		Existing
931.665	FEI	Gas		Existing
932.056	FEI	Gas		Existing
932.742	FEI	Gas		Existing
932.744	FEI	Gas		Existing
937.003	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
946.346	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
947.864	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
948.797	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
950.215	Spectra Energy Transmission	Gas		Existing

TABLE 5.1.15

PRELIMINARY FOREIGN PIPELINE CROSSINGS (continued)

Reference Kilometre (RK)	Owner	Product Type	Product	Status
Edmonton to Burnaby				
950.230	Spectra Energy Transmission	Gas		Existing
954.127	Spectra Energy Transmission	Gas		Existing
954.151	Spectra Energy Transmission	Gas		Existing
955.172	FortisBC	Gas		Existing
955.784	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
956.756	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
958.729	Spectra Energy Transmission	Gas		Existing
958.739	Spectra Energy Transmission	Gas		Existing
964.404	Spectra Energy Transmission	Gas		Existing
964.413	Spectra Energy Transmission	Gas		Existing
966.574	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
968.573	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
969.774	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
971.934	Spectra Energy Transmission	Gas		Existing
971.955	Spectra Energy Transmission	Gas		Existing
974.396	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
974.610	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
975.661	Spectra Energy Transmission	Gas		Existing
975.668	Spectra Energy Transmission	Gas		Existing
980.273	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
981.146	Spectra Energy Transmission	Gas		Existing
981.162	Spectra Energy Transmission	Gas		Existing
982.379	Spectra Energy Transmission	Gas		Existing
983.133	Spectra Energy Transmission	Gas		Existing
988.966	Spectra Energy Transmission	Gas		Existing
988.977	Spectra Energy Transmission	Gas		Existing
1,010.717	Spectra Energy Transmission	Gas		Existing
1,010.734	Spectra Energy Transmission	Gas		Existing
1,021.060	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,021.930	Spectra Energy Transmission	Gas		Existing
1,021.935	Spectra Energy Transmission	Gas		Existing
1,026.697	Spectra Energy Transmission	Gas		Existing
1,026.712	Spectra Energy Transmission	Gas		Existing
1,026.938	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,028.228	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,028.890	Spectra Energy Transmission	Gas		Existing
1,028.902	Spectra Energy Transmission	Gas		Existing
1,029.352	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,029.459	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,031.214	Spectra Energy Transmission	Gas		Existing
1,031.226	Spectra Energy Transmission	Gas		Existing
1,031.470	Spectra Energy Transmission	Gas		Existing
1,031.523	Spectra Energy Transmission	Gas		Existing

TABLE 5.1.15

PRELIMINARY FOREIGN PIPELINE CROSSINGS (continued)

Reference Kilometre (RK)	Owner	Product Type	Product	Status
Edmonton to Burnaby				
1,032.724	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,033.355	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,035.064	Spectra Energy Transmission	Gas		Existing
1,035.109	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,038.140	Spectra Energy Transmission	Gas		Existing
1,039.378	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,042.349	FEI	Gas		Existing
1,042.446	FEI	Gas		Existing
1,042.713	FEI	Gas		Existing
1,042.733	FEI	Gas		Existing
1,042.865	FEI	Gas		Existing
1,042.984	FEI	Gas		Proposed
1,042.999	FEI	Gas		Proposed
1,043.023	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,043.500	FEI	Gas		Existing
1,043.622	Spectra Energy Transmission	Gas		Existing
1,043.628	Spectra Energy Transmission	Gas		Existing
1,043.638	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,045.001	FEI	Gas		Existing
1,045.862	Spectra Energy Transmission	Gas		Existing
1,045.916	Spectra Energy Transmission	Gas		Existing
1,047.750	FEI	Gas		Existing
1,048.055	FEI	Gas		Existing
1,048.473	FEI	Gas		Existing
1,048.506	FEI	Gas		Existing
1,049.155	FEI	Gas		Existing
1,049.289	FEI	Gas		Existing
1,050.501	FEI	Gas		Existing
1,050.660	FEI	Gas		Existing
1,050.720	FEI	Gas		Existing
1,050.724	FEI	Gas		Existing
1,050.906	FEI	Gas		Existing
1,055.163	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,055.574	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,067.080	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,069.192	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,069.659	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,071.252	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,072.009	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,075.099	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,078.592	FEI	Gas		Existing
1,080.408	FEI	Gas		Existing
1,081.209	Kinder Morgan Canada Inc.	LVP	LVP Products	Active

TABLE 5.1.15

PRELIMINARY FOREIGN PIPELINE CROSSINGS (continued)

Reference Kilometre (RK)	Owner	Product Type	Product	Status
Edmonton to Burnaby				
1,081.538	FEI	Gas		Existing
1,081.555	FEI	Gas		Existing
1,081.809	FEI	Gas		Existing
1,083.000	FEI	Gas		Existing
1,084.782	FEI	Gas		Existing
1,086.507	FEI	Gas		Existing
1,086.513	FEI	Gas		Existing
1,088.273	FEI	Gas		Existing
1,090.108	FEI	Gas		Existing
1,090.221	FEI	Gas		Existing
1,092.093	FEI	Gas		Existing
1,092.926	FEI	Gas		Existing
1,093.994	FEI	Gas		Existing
1,095.492	FEI	Gas		Existing
1,096.916	FEI	Gas		Proposed
1,096.922	FEI	Gas		Proposed
1,097.148	FEI	Gas		Existing
1,098.050	FEI	Gas		Existing
1,098.236	FEI	Gas		Existing
1,098.562	FEI	Gas		Existing
1,099.357	FEI	Gas		Existing
1,099.386	FEI	Gas		Existing
1,099.427	FEI	Gas		Existing
1,099.446	FEI	Gas		Existing
1,099.527	FEI	Gas		Existing
1,099.594	FEI	Gas		Existing
1,100.289	FEI	Gas		Dead
1,100.291	FEI	Gas		Existing
1,100.996	FEI	Gas		Existing
1,101.164	FEI	Gas		Existing
1,103.494	FEI	Gas		Existing
1,103.963	FEI	Gas		Existing
1,104.659	FEI	Gas		Existing
1,105.325	FEI	Gas		Existing
1,106.105	FEI	Gas		Existing
1,106.919	FEI	Gas		Existing
1,107.866	FEI	Gas		Existing
1,108.047	FEI	Gas		Existing
1,108.880	FEI	Gas		Existing
1,110.348	Spectra Energy Transmission	Gas		Existing
1,110.355	Spectra Energy Transmission	Gas		Existing
1,111.129	FEI	Gas		Existing
1,113.807	FEI	Gas		Existing

TABLE 5.1.15

PRELIMINARY FOREIGN PIPELINE CROSSINGS (continued)

Reference Kilometre (RK)	Owner	Product Type	Product	Status
Edmonton to Burnaby				
1,113.820	FEI	Gas		Existing
1,113.821	IHS	LVP	LVP Products	Operating
1,113.840	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,113.918	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,113.935	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,114.077	FEI	Gas		Existing
1,115.867	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,115.872	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,116.395	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,116.421	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,118.451	FEI	Gas		Existing
1,118.916	FEI	Gas		Existing
1,118.930	FEI	Gas		Existing
1,118.981	FEI	Gas		Existing
1,120.360	FEI	Gas		Existing
1,120.645	FEI	Gas		Existing
1,120.659	FEI	Gas		Existing
1,120.718	FEI	Gas		Existing
1,120.732	FEI	Gas		Existing
1,120.888	FEI	Gas		Existing
1,121.010	FEI	Gas		Existing
1,121.114	FEI	Gas		Existing
1,121.744	FEI	Gas		Existing
1,122.744	FEI	Gas		Existing
1,124.389	FEI	Gas		Existing
1,124.390	FEI	Gas		Existing
1,124.392	FEI	Gas		Proposed
1,124.968	FEI	Gas		Existing
1,127.862	FEI	Gas		Existing
1,131.286	FEI	Gas		Existing
1,131.979	FEI	Gas		Existing
1,133.024	FEI	Gas		Existing
1,134.743	FEI	Gas		Existing
1,136.497	FEI	Gas		Existing
1,137.098	FEI	Gas		Existing
1,138.370	FEI	Gas		Existing
1,139.892	FEI	Gas		Existing
1,141.164	FEI	Gas		Existing
1,144.305	FEI	Gas		Existing
1,144.931	FEI	Gas		Existing
1,146.398	FortisBC	Gas		Existing
1,146.402	FortisBC	Gas		Existing
1,146.554	FEI	Gas		Existing

TABLE 5.1.15

PRELIMINARY FOREIGN PIPELINE CROSSINGS (continued)

Reference Kilometre (RK)	Owner	Product Type	Product	Status
Edmonton to Burnaby				
1,146.818	FEI	Gas		Proposed
1,147.948	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,150.658	FEI	Gas		Existing
1,150.693	FortisBC	Gas		Existing
1,151.407	FEI	Gas		Existing
1,151.956	FEI	Gas		Existing
1,153.655	FEI	Gas		Existing
1,154.973	FEI	Gas		Existing
1,155.948	FEI	Gas		Existing
1,156.542	FEI	Gas		Existing
1,156.628	FEI	Gas		Existing
1,156.713	FEI	Gas		Existing
1,156.721	FEI	Gas		Existing
1,157.094	FEI	Gas		Existing
1,157.488	FEI	Gas		Existing
1,159.623	FEI	Gas		Existing
1,159.624	FEI	Gas		Dead
1,160.452	FEI	Gas		Dead
1,167.558	FEI	Gas		Dead
1,167.696	FEI	Gas		Dead
1,167.916	FEI	Gas		Dead
1,167.926	FortisBC	Gas		Dead
1,167.978	FortisBC	Gas		Existing
1,169.679	FEI	Gas		Existing
1,169.825	FEI	Gas		Existing
1,169.887	FEI	Gas		Existing
1,170.128	FEI	Gas		Existing
1,170.318	FEI	Gas		Existing
1,170.347	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
1,170.572	Kinder Morgan Canada Inc.	LVP	LVP Products	Inactive
1,171.514	FEI	Gas		Existing
1,171.981	FEI	Gas		Dead
1,171.988	FEI	Gas		Existing
1,172.157	FEI	Gas		Existing
1,173.198	FEI	Gas		Existing
1,173.383	FEI	Gas		Dead
1,173.430	FEI	Gas		Existing
1,173.436	FEI	Gas		Dead
1,173.444	FEI	Gas		Existing
1,173.612	FEI	Gas		Existing
1,174.091	FEI	Gas		Existing
1,175.145	FEI	Gas		Existing
1,175.539	FEI	Gas		Existing

TABLE 5.1.15

PRELIMINARY FOREIGN PIPELINE CROSSINGS (continued)

Reference Kilometre (RK)	Owner	Product Type	Product	Status
Edmonton to Burnaby				
1,176.309	FEI	Gas		Existing
1,177.280	FEI	Gas		Existing
1,177.964	FEI	Gas		Existing
1,178.074	FEI	Gas		Existing
1,178.194	FEI	Gas		Existing
1,178.242	FEI	Gas		Existing
1,178.813	FEI	Gas		Existing
Burnaby to Westridge (RK values reset)				
0.698	FEI	Gas		Existing
1.955	FEI	Gas		Existing
2.184	Kinder Morgan Canada Inc.	LVP	LVP Products	Active
2.187	FEI	Gas		Existing
2.413	FEI	Gas		Existing

TABLE 5.1.16

PRELIMINARY OVERHEAD POWER LINES

Reference Kilometre (RK)	Owner	Voltage (kV)
Edmonton to Burnaby		
11.026		
15.312		
33.512		
90.533		230
96.676		240
99.845		240
124.670		240
131.654		240
145.353		138
163.816		138
248.506		138
249.233		138
255.416		138
256.015		138
259.456		138
263.107		138
265.807		138
267.459		138
271.260		138
275.263		138
294.761		138
295.952		138
298.125		138
298.671		138
312.465		138
321.879		25
535.606	BC Hydro	130
606.495	BC Hydro	130
625.194	BC Hydro	130
633.355	BC Hydro	130
634.466	BC Hydro	130
636.687	BC Hydro	130
663.021	BC Hydro	130
663.570	BC Hydro	130
671.609	BC Hydro Distribution	
685.073	BC Hydro	130
685.988	BC Hydro	130
846.342	BC Hydro Distribution	
850.172	BC Hydro	130
850.196	BC Hydro	130
850.588	BC Hydro	138

TABLE 5.1.16

PRELIMINARY OVERHEAD POWER LINES (continued)

Reference Kilometre (RK)	Owner	Voltage (kV)
Edmonton to Burnaby		
892.907	BC Hydro	500
899.515	BC Hydro	130
955.981	BC Hydro	500
956.042	BC Hydro	500
978.412	BC Hydro Distribution	
1028.291	BC Hydro Distribution	
1042.864	BC Hydro Distribution	
1044.138	BC Hydro	69
1045.992	BC Hydro	69
1047.440	BC Hydro	69
1047.714	BC Hydro	69
1048.366	BC Hydro	69
1049.191	BC Hydro Distribution	
1062.641	BC Hydro Distribution	
1064.767	BC Hydro	69
1067.129	BC Hydro	69
1067.154	BC Hydro	69
1067.263	BC Hydro	69
1067.305	BC Hydro	69
1068.264	BC Hydro	69
1068.314	BC Hydro	69
1069.150	BC Hydro	69
1069.172	BC Hydro	69
1069.710	BC Hydro	69
1069.729	BC Hydro	69
1071.142	BC Hydro	69
1071.164	BC Hydro	69
1071.777	BC Hydro	69
1071.789	BC Hydro	69
1071.822	BC Hydro	69
1071.856	BC Hydro	360
1075.777	BC Hydro	360
1075.833	BC Hydro	69
1078.971	BC Hydro	69
1079.007	BC Hydro	360
1081.539	BC Hydro Distribution	
1082.211	BC Hydro	69
1082.246	BC Hydro	300
1082.257	BC Hydro	500
1082.320	BC Hydro	500
1088.490	BC Hydro	69

TABLE 5.1.16

PRELIMINARY OVERHEAD POWER LINES (continued)

Reference Kilometre (RK)	Owner	Voltage (kV)
Edmonton to Burnaby		
1096.913	BC Hydro Distribution	
1096.930	BC Hydro Distribution	
1096.931	BC Hydro Distribution	
1097.771	BC Hydro	500
1097.859	BC Hydro	500
1097.955	BC Hydro	230
1098.051	BC Hydro Distribution	
1098.059	BC Hydro Distribution	
1099.431	BC Hydro Distribution	
1099.434	BC Hydro Distribution	
1099.441	BC Hydro Distribution	
1099.444	BC Hydro Distribution	
1099.521	BC Hydro Distribution	
1099.525	BC Hydro Distribution	
1099.530	BC Hydro Distribution	
1099.550	BC Hydro Distribution	
1104.794	BC Hydro	69
1104.802	BC Hydro	69
1112.764	BC Hydro	230
1112.872	BC Hydro	500
1112.975	BC Hydro	500
1118.491	BC Hydro Distribution	
1118.496	BC Hydro Distribution	
1118.913	BC Hydro Distribution	
1118.917	BC Hydro Distribution	
1120.378	BC Hydro Distribution	
1120.379	BC Hydro Distribution	
1120.512	BC Hydro Distribution	
1120.655	BC Hydro Distribution	
1120.657	BC Hydro Distribution	
1120.717	BC Hydro Distribution	
1120.731	BC Hydro Distribution	
1121.008	BC Hydro Distribution	
1121.106	BC Hydro Distribution	
1145.698	BC Hydro	69
1145.735	BC Hydro	69
1146.805	BC Hydro Distribution	
1150.374	BC Hydro	69
1150.387	BC Hydro	69
1151.537	BC Hydro Distribution	
1155.985	BC Hydro Distribution	

TABLE 5.1.16

PRELIMINARY OVERHEAD POWER LINES (continued)

Reference Kilometre (RK)	Owner	Voltage (kV)
Edmonton to Burnaby		
1157.709	BC Hydro Distribution	
1167.958	BC Hydro	500
1168.081	BC Hydro	230
1169.623	BC Hydro Distribution	
1169.701	BC Hydro Distribution	
1169.770	BC Hydro Distribution	
1169.776	BC Hydro Distribution	
1169.877	BC Hydro Distribution	
1169.891	BC Hydro Distribution	
1169.977	BC Hydro Distribution	
1170.049	BC Hydro Distribution	
1170.064	BC Hydro Distribution	
1170.180	BC Hydro Distribution	
1170.332	BC Hydro Distribution	
1170.337	BC Hydro Distribution	
1170.345	BC Hydro Distribution	
1170.382	BC Hydro Distribution	
1170.392	BC Hydro Distribution	
1170.419	BC Hydro Distribution	
1170.422	BC Hydro Distribution	
1170.424	BC Hydro Distribution	
1170.453	BC Hydro Distribution	
1170.510	BC Hydro Distribution	
1170.531	BC Hydro Distribution	
1170.532	BC Hydro Distribution	
1170.604	BC Hydro Distribution	
1170.724	BC Hydro Distribution	
1170.729	BC Hydro Distribution	
1170.757	BC Hydro Distribution	
1170.839	BC Hydro Distribution	
1170.919	BC Hydro Distribution	
1171.007	BC Hydro Distribution	
1171.072	BC Hydro Distribution	
1171.267	BC Hydro Distribution	
1171.271	BC Hydro Distribution	
1171.374	BC Hydro Distribution	
1171.380	BC Hydro Distribution	
1171.551	BC Hydro Distribution	
1171.697	BC Hydro Distribution	
1171.990	BC Hydro Distribution	
1172.177	BC Hydro	69

TABLE 5.1.16

PRELIMINARY OVERHEAD POWER LINES (continued)

Reference Kilometre (RK)	Owner	Voltage (kV)
Edmonton to Burnaby		
1172.205	BC Hydro Distribution	
1172.969	BC Hydro	230
1172.981	BC Hydro	69
1173.139	BC Hydro Distribution	
1173.249	BC Hydro Distribution	
1175.155	BC Hydro Distribution	
1175.197	BC Hydro Distribution	
1175.309	BC Hydro Distribution	
1175.310	BC Hydro Distribution	
1175.365	BC Hydro Distribution	
1175.463	BC Hydro Distribution	
1175.466	BC Hydro Distribution	
1175.469	BC Hydro Distribution	
1176.048	BC Hydro Distribution	
1176.055	BC Hydro Distribution	
1176.165	BC Hydro Distribution	
1176.166	BC Hydro Distribution	
1176.167	BC Hydro Distribution	
1176.169	BC Hydro Distribution	
1176.301	BC Hydro Distribution	
1176.405	BC Hydro	69
1176.414	BC Hydro	230
1176.414	BC Hydro	230
1176.419	BC Hydro	69
1176.433	BC Hydro Distribution	
1176.905	BC Hydro Distribution	
1177.273	BC Hydro Distribution	
1177.845	BC Hydro Distribution	
1178.142	BC Hydro Distribution	
1178.160	BC Hydro Distribution	
1178.245	BC Hydro Distribution	
1178.245	BC Hydro Distribution	
1178.245	BC Hydro Distribution	
1178.651	BC Hydro	69
1178.663	BC Hydro	69
1178.815	BC Hydro	230
Burnaby to Westridge (RK values reset)		
0.588	BC Hydro Distribution	
2.215	BC Hydro Distribution	
2.526	BC Hydro Distribution	
2.596	BC Hydro Distribution	
3.387	BC Hydro	69

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
0.037	Telus	communication cable (COMM)
1.352	Telus	COMM
11.756	Telus	COMM
11.832	Telus	COMM
12.128	Telus	COMM
12.239	Telus	COMM
12.244	Telus	COMM
14.408	Telus	COMM
16.110	Telus	COMM
16.112	Telus	COMM
17.780	Telus	COMM
19.600	Telus	COMM
21.054	Telus	COMM
21.077	Telus	COMM
22.922	Telus	COMM
23.902	Telus	COMM
31.318	Telus	COMM
32.470	Telus	COMM
32.471	Telus	COMM
35.788	Telus	COMM
38.544	Telus	COMM
38.546	Telus	COMM
38.565	Telus	COMM
38.566	Telus	COMM
43.012	Telus	COMM
43.426	Telus	COMM
43.448	Telus	COMM
43.451	Telus	COMM
43.469	Telus	COMM
45.102	Telus	COMM
47.144	Telus	COMM
48.869	Telus	COMM
50.527	Telus	COMM
52.205	Telus	COMM
53.032	Telus	COMM
55.507	Telus	COMM
57.157	Telus	COMM
58.807	Telus	COMM
60.180	Telus	COMM
60.254	Telus	COMM
60.455	Telus	COMM

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
61.453	Telus	COMM
62.136	Telus	COMM
62.153	Telus	COMM
62.592	Telus	COMM
62.626	Telus	COMM
64.625	Telus	COMM
64.625	Telus	COMM
64.721	Telus	COMM
65.911	Telus	COMM
65.949	Telus	COMM
66.186	Telus	COMM
67.584	Telus	COMM
69.242	Telus	COMM
70.881	Telus	COMM
72.523	Telus	COMM
73.753	Telus	COMM
74.182	Telus	COMM
74.561	Telus	COMM
75.802	Telus	COMM
75.824	Telus	COMM
76.483	Telus	COMM
76.827	Telus	COMM
77.190	Telus	COMM
78.270	Telus	COMM
78.624	Telus	COMM
80.742	Telus	COMM
83.999	Telus	COMM
85.621	Telus	COMM
85.686	Telus	COMM
87.329	Telus	COMM
88.974	Telus	COMM
90.610	Telus	COMM
92.246	Telus	COMM
93.504	Telus	COMM
94.254	Telus	COMM
95.835	Telus	COMM
96.546	Telus	COMM
97.125	Telus	COMM
97.201	Telus	COMM
99.339	Telus	COMM
101.578	Telus	COMM

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
103.725	Telus	COMM
110.716	Telus	COMM
112.804	Telus	COMM
113.659	Telus	COMM
113.977	Telus	COMM
115.608	Telus	COMM
117.227	Telus	COMM
118.587	Telus	COMM
118.916	Telus	COMM
118.933	Telus	COMM
118.944	Telus	COMM
120.560	Telus	COMM
125.480	Telus	COMM
127.137	Telus	COMM
130.408	Telus	COMM
132.003	Telus	COMM
132.843	Telus	COMM
133.670	Telus	COMM
133.685	Telus	COMM
134.926	Telus	COMM
136.275	Telus	COMM
136.279	Telus	COMM
136.296	Telus	COMM
137.165	Telus	COMM
143.727	Telus	COMM
145.375	Telus	COMM
147.017	Telus	COMM
148.653	Telus	COMM
149.466	Telus	COMM
150.285	Telus	COMM
151.099	Telus	COMM
151.918	Telus	COMM
153.585	Telus	COMM
155.166	Telus	COMM
155.237	Telus	COMM
155.291	Telus	COMM
158.529	Telus	COMM
160.181	Telus	COMM
161.830	Telus	COMM
163.477	Telus	COMM
165.213	Telus	COMM

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
166.842	Telus	COMM
168.487	Telus	COMM
170.118	Telus	COMM
173.394	Telus	COMM
174.237	Telus	COMM
176.671	Telus	COMM
178.308	Telus	COMM
184.840	Telus	COMM
184.860	Telus	COMM
187.074	Telus	COMM
187.180	Telus	COMM
188.309	Telus	COMM
191.570	Telus	COMM
193.196	Telus	COMM
196.454	Telus	COMM
198.159	Telus	COMM
200.033	Telus	COMM
200.096	Telus	COMM
207.158	Telus	COMM
208.082	Telus	COMM
208.555	Telus	COMM
210.185	Telus	COMM
211.847	Telus	COMM
213.493	Telus	COMM
214.417	Telus	COMM
214.444	Telus	COMM
215.121	Telus	COMM
216.676	Telus	COMM
216.756	Telus	COMM
218.202	Telus	COMM
218.632	Telus	COMM
223.662	Telus	COMM
224.466	Telus	COMM
225.559	Telus	COMM
228.127	Telus	COMM
228.837	Telus	COMM
229.159	Telus	COMM
232.148	Telus	COMM
233.779	Telus	COMM
237.250	Telus	COMM
237.277	Telus	COMM

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
240.704	Telus	COMM
244.961	Telus	COMM
246.008	Telus	COMM
246.025	Telus	COMM
246.979	Telus	COMM
247.826	Telus	COMM
248.137	Telus	COMM
248.274	Telus	COMM
252.315	Telus	COMM
252.958	Telus	COMM
256.542	Telus	COMM
258.998	Telus	COMM
259.662	Telus	COMM
259.852	Telus	COMM
259.895	Telus	COMM
262.018	Telus	COMM
262.234	Telus	COMM
263.714	Telus	COMM
270.565	Telus	COMM
275.145	Telus	COMM
278.217	Telus	COMM
278.295	Telus	COMM
279.549	Telus	COMM
281.773	Telus	COMM
292.523	Telus	COMM
303.713	Telus	COMM
306.088	Telus	COMM
307.378	Telus	COMM
311.853	Telus	COMM
312.354	Telus	COMM
321.829	Telus	COMM
326.250	Telus	COMM
326.286	Telus	COMM
328.343	Telus	COMM
328.931	Telus	COMM
333.919	Telus	COMM
493.302	Telus	COMM
494.352	Telus	Fibre Optic Transmission System (FOTS)
494.540	Telus	FOTS
494.828	Telus	COMM
495.225	Telus	COMM

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
495.236	Telus	FOTS
495.806	Telus	FOTS
496.247	Telus	COMM
500.247	Telus	COMM
500.343	Telus	FOTS
504.783	Telus	COMM
504.836	Telus	COMM
506.907	Telus	COMM
507.163	Telus	FOTS
508.429	Telus	COMM
508.461	Telus	FOTS
508.532	Telus	COMM
513.390	Telus	FOTS
513.488	Telus	COMM
516.249	Telus	COMM
516.264	Telus	FOTS
518.208	Telus	FOTS
518.460	Telus	FOTS
518.884	Telus	FOTS
518.899	Telus	COMM
519.240	Telus	FOTS
519.316	Telus	COMM
521.911	Telus	COMM
521.970	Telus	FOTS
522.001	Telus	COMM
523.172	Telus	COMM
523.172	Telus	COMM
525.740	Telus	COMM
526.043	Telus	FOTS
526.126	Telus	COMM
526.164	Telus	FOTS
529.314	Telus	FOTS
529.368	Telus	FOTS
529.369	Telus	COMM
529.392	Telus	COMM
529.638	Telus	FOTS
529.643	Telus	COMM
529.693	Telus	COMM
531.391	Telus	COMM
532.014	Telus	FOTS
532.040	Telus	COMM

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
532.785	Telus	COMM
534.041	Telus	COMM
534.681	Telus	COMM
535.896	Telus	COMM
538.822	Telus	COMM
538.828	Telus	FOTS
539.417	Telus	COMM
539.434	Telus	COMM
545.593	Telus	COMM
545.622	Telus	FOTS
552.346	Telus	FOTS
552.654	Telus	FOTS
558.756	Telus	FOTS
582.514	Telus	COMM
582.514	Telus	COMM
582.547	Telus	FOTS
582.617	Telus	COMM
582.618	Telus	COMM
582.649	Telus	COMM
582.649	Telus	COMM
608.029	Telus	COMM
608.029	Telus	COMM
608.048	Telus	FOTS
611.744	Telus	COMM
625.768	Telus	COMM
625.768	Telus	COMM
625.797	Telus	FOTS
627.523	Telus	COMM
627.523	Telus	COMM
628.397	Telus	FOTS
628.714	Telus	FOTS
629.003	Telus	FOTS
632.052	Telus	FOTS
632.123	Telus	COMM
632.123	Telus	COMM
632.879	Telus	COMM
632.879	Telus	COMM
633.125	Telus	FOTS
635.668	Telus	FOTS
635.695	Telus	COMM
635.695	Telus	COMM

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
636.625	Telus	COMM
636.625	Telus	COMM
636.710	Telus	FOTS
636.717	Telus	FOTS
636.819	Telus	FOTS
636.904	Telus	FOTS
636.905	Telus	FOTS
636.965	Telus	FOTS
637.015	Telus	FOTS
637.022	Telus	COMM
637.022	Telus	COMM
637.049	Telus	COMM
637.049	Telus	COMM
637.233	Telus	FOTS
637.318	Telus	FOTS
637.629	Telus	FOTS
637.637	Telus	FOTS
637.643	Telus	COMM
637.643	Telus	COMM
637.662	Telus	COMM
637.663	Telus	COMM
651.006	Telus	COMM
651.011	Telus	COMM
651.017	Telus	FOTS
652.096	Telus	FOTS
652.110	Telus	COMM
652.110	Telus	COMM
652.238	Telus	COMM
652.238	Telus	COMM
652.243	Telus	FOTS
655.529	Telus	COMM
655.533	Telus	COMM
655.535	Telus	FOTS
658.652	Telus	COMM
658.679	Telus	COMM
660.869	Telus	COMM
662.917	Telus	COMM
662.922	Telus	COMM
662.922	Telus	FOTS
664.073	Telus	COMM
664.076	Telus	COMM

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
664.080	Telus	FOTS
664.882	Telus	FOTS
664.886	Telus	COMM
664.886	Telus	COMM
669.119	Telus	COMM
669.740	Telus	COMM
669.794	Telus	COMM
669.897	Telus	COMM
669.908	Telus	FOTS
671.490	Telus	COMM
671.582	Telus	COMM
678.102	Telus	FOTS
678.113	Telus	COMM
678.113	Telus	COMM
679.031	Telus	COMM
679.031	Telus	COMM
679.043	Telus	COMM
679.043	Telus	COMM
679.273	Telus	COMM
679.273	Telus	COMM
679.554	Telus	COMM
679.554	Telus	COMM
680.906	Telus	COMM
680.906	Telus	COMM
680.949	Telus	COMM
680.949	Telus	COMM
681.321	Telus	COMM
681.321	Telus	COMM
681.571	Telus	COMM
681.571	Telus	COMM
681.933	Telus	COMM
681.933	Telus	COMM
681.981	Telus	COMM
681.981	Telus	COMM
682.059	Telus	COMM
682.059	Telus	COMM
682.062	Telus	COMM
682.062	Telus	COMM
682.087	Telus	COMM
682.087	Telus	COMM
683.272	Telus	COMM

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
683.272	Telus	COMM
683.759	Telus	COMM
683.759	Telus	COMM
684.063	Telus	COMM
684.063	Telus	COMM
684.189	Telus	FOTS
684.207	Telus	COMM
684.207	Telus	COMM
686.578	Telus	COMM
688.195	Telus	COMM
688.991	Telus	COMM
691.799	Telus	COMM
692.530	Telus	COMM
694.996	Telus	COMM
697.831	Telus	COMM
697.863	Telus	COMM
697.869	Telus	COMM
697.878	Telus	COMM
698.077	Telus	FOTS
698.091	Telus	FOTS
704.074	Telus	COMM
707.619	Telus	FOTS
707.621	Telus	COMM
707.621	Telus	COMM
708.098	Telus	COMM
709.940	Telus	COMM
712.972	Telus	FOTS
712.981	Telus	COMM
712.981	Telus	COMM
717.073	Telus	COMM
717.118	Telus	FOTS
717.131	Telus	COMM
717.131	Telus	COMM
723.172	Telus	COMM
723.173	Telus	COMM
725.413	Telus	COMM
725.413	Telus	COMM
725.428	Telus	FOTS
725.946	Telus	COMM
725.946	Telus	COMM
725.964	Telus	FOTS

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
726.375	Telus	COMM
728.104	Telus	FOTS
728.169	Telus	COMM
728.177	Telus	COMM
729.656	Telus	COMM
729.675	Telus	COMM
736.846	Telus	COMM
737.243	Telus	FOTS
737.276	Telus	FOTS
737.326	Telus	FOTS
737.442	Telus	FOTS
739.711	Telus	COMM
740.390	Telus	COMM
740.601	Telus	COMM
740.625	Telus	COMM
741.885	Telus	COMM
741.994	Telus	COMM
742.895	Telus	FOTS
742.918	Telus	COMM
743.237	Telus	FOTS
743.265	Telus	COMM
749.006	Telus	COMM
749.260	Telus	FOTS
749.295	Telus	COMM
749.338	Telus	COMM
749.345	Telus	FOTS
749.607	Telus	COMM
749.767	Telus	COMM
750.300	Telus	FOTS
750.750	Telus	COMM
750.769	Telus	COMM
750.895	Telus	COMM
750.941	Telus	COMM
750.955	Telus	FOTS
751.196	Telus	FOTS
751.767	Telus	FOTS
756.259	Telus	COMM
756.259	Telus	COMM
756.259	Telus	COMM
756.299	Telus	FOTS
757.531	Telus	FOTS

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
757.559	Telus	FOTS
757.940	Telus	COMM
757.981	Telus	COMM
757.984	Telus	COMM
757.993	Telus	FOTS
758.035	Telus	FOTS
758.045	Telus	COMM
758.047	Telus	COMM
758.630	Telus	COMM
758.641	Telus	COMM
759.803	Telus	COMM
759.806	Telus	COMM
760.124	Telus	COMM
760.871	Telus	COMM
761.979	Telus	COMM
762.771	Telus	COMM
763.132	Telus	COMM
763.156	Telus	COMM
763.161	Telus	FOTS
763.173	Telus	FOTS
766.015	Telus	COMM
766.044	Telus	COMM
769.030	Telus	COMM
769.030	Telus	COMM
812.036	Telus	COMM
812.346	Telus	COMM
813.576	Telus	COMM
817.983	Telus	COMM
818.769	Telus	FOTS
818.839	Telus	COMM
819.805	Telus	FOTS
819.866	Telus	COMM
820.185	Telus	COMM
820.189	Telus	COMM
820.244	Telus	FOTS
820.330	Telus	FOTS
820.451	Telus	FOTS
820.473	Telus	FOTS
820.838	Telus	FOTS
820.845	Telus	FOTS
820.862	Telus	FOTS

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
820.862	Telus	FOTS
826.075	Telus	FOTS
826.219	Telus	COMM
826.219	Telus	COMM
826.855	Telus	FOTS
827.084	Telus	FOTS
827.654	Telus	COMM
827.654	Telus	COMM
827.657	Telus	FOTS
827.743	Telus	FOTS
827.747	Telus	COMM
827.747	Telus	COMM
827.835	Telus	FOTS
828.269	Telus	FOTS
828.414	Telus	FOTS
828.420	Telus	FOTS
828.426	Telus	FOTS
828.506	Telus	FOTS
828.603	Telus	FOTS
828.724	Telus	COMM
828.725	Telus	COMM
841.440	Telus	FOTS
842.329	Telus	COMM
842.331	Telus	FOTS
844.759	City of Kamloops	Water
845.213	Telus	COMM
845.213	Telus	COMM
845.217	Telus	FOTS
845.326	City of Kamloops	Water
845.339	Telus	COMM
845.356	City of Kamloops	Sewer
845.424	Telus	COMM
845.431	Telus	COMM
846.088	City of Kamloops	Sewer
846.118	Telus	COMM
846.126	City of Kamloops	Water
846.192	Telus	COMM
846.192	Telus	COMM
846.192	Telus	COMM
846.192	Telus	COMM
846.198	City of Kamloops	Water

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
846.204	City of Kamloops	Water
846.214	Telus	COMM
846.342	City of Kamloops	Sewer
846.349	City of Kamloops	Water
846.490	Telus	COMM
846.501	Telus	COMM
846.501	Telus	COMM
847.437	City of Kamloops	Sewer
847.447	Telus	COMM
848.085	Telus	FOTS
848.086	Telus	COMM
848.087	Telus	COMM
850.466	Telus	COMM
850.526	Telus	COMM
850.549	Telus	COMM
850.565	City of Kamloops	Water
850.735	Telus	COMM
863.254	Telus	COMM
929.712	Telus	FOTS
929.715	Telus	COMM
929.715	Telus	COMM
931.664	Telus	COMM
933.121	Telus	COMM
933.127	Telus	COMM
933.137	Telus	FOTS
935.994	Telus	COMM
955.849	Telus	COMM
955.856	Telus	COMM
956.075	Telus	FOTS
956.742	Telus	COMM
956.745	Telus	COMM
959.899	Telus	COMM
959.904	Telus	COMM
960.440	Telus	FOTS
960.932	Telus	FOTS
961.606	Telus	FOTS
962.304	Telus	FOTS
962.349	Telus	COMM
962.354	Telus	COMM
964.519	Telus	FOTS
964.531	Telus	FOTS

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
964.544	Telus	COMM
964.548	Telus	COMM
974.847	Telus	FOTS
974.899	Telus	COMM
974.904	Telus	COMM
975.627	Telus	COMM
975.631	Telus	COMM
975.711	Telus	COMM
975.715	Telus	COMM
976.623	Telus	COMM
976.635	Telus	COMM
976.648	Telus	FOTS
976.869	Telus	COMM
976.883	Telus	COMM
976.944	Telus	COMM
976.958	Telus	COMM
980.255	Telus	COMM
980.255	Telus	COMM
980.456	Telus	FOTS
983.955	Telus	FOTS
984.712	Telus	COMM
984.712	Telus	COMM
984.869	Telus	COMM
984.869	Telus	COMM
985.678	Telus	COMM
985.678	Telus	COMM
985.946	Telus	COMM
985.947	Telus	COMM
986.404	Telus	COMM
986.404	Telus	COMM
986.980	Telus	COMM
986.980	Telus	COMM
986.989	Telus	FOTS
987.145	Telus	FOTS
987.302	Telus	FOTS
987.454	Telus	FOTS
987.658	Telus	FOTS
987.999	Telus	FOTS
988.058	Telus	FOTS
988.088	Telus	FOTS
988.941	Telus	FOTS

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
988.954	Telus	FOTS
988.966	Telus	COMM
988.966	Telus	COMM
988.982	Telus	FOTS
988.986	Telus	COMM
988.986	Telus	COMM
992.186	Telus	FOTS
995.700	Telus	FOTS
996.467	Telus	FOTS
998.188	Telus	FOTS
998.264	Telus	FOTS
998.563	Telus	FOTS
998.904	Telus	FOTS
999.409	Telus	FOTS
1000.957	Telus	FOTS
1001.753	Telus	FOTS
1002.518	Telus	FOTS
1002.747	Telus	FOTS
1002.869	Telus	FOTS
1004.231	Telus	FOTS
1004.260	Telus	FOTS
1005.600	Telus	COMM
1005.603	Telus	COMM
1005.938	Telus	FOTS
1006.207	Telus	FOTS
1006.368	Telus	FOTS
1006.555	Telus	FOTS
1006.920	Telus	FOTS
1007.131	Telus	FOTS
1007.137	Telus	FOTS
1007.145	Telus	FOTS
1007.228	Telus	FOTS
1007.454	Telus	FOTS
1008.215	Telus	FOTS
1009.249	Telus	FOTS
1009.530	Telus	FOTS
1009.701	Telus	FOTS
1009.880	Telus	FOTS
1010.129	Telus	FOTS
1010.300	Telus	COMM
1010.300	Telus	COMM

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
1010.301	Telus	FOTS
1010.664	Telus	FOTS
1010.672	Telus	COMM
1010.672	Telus	COMM
1010.834	Telus	COMM
1010.834	Telus	COMM
1010.853	Telus	FOTS
1016.021	Telus	COMM
1016.021	Telus	COMM
1016.743	Telus	COMM
1016.743	Telus	COMM
1017.653	Telus	FOTS
1017.653	Telus	FOTS
1018.346	Telus	COMM
1018.346	Telus	COMM
1018.356	Telus	FOTS
1019.176	Telus	FOTS
1019.257	Telus	COMM
1019.257	Telus	COMM
1021.891	Telus	FOTS
1021.902	Telus	COMM
1021.902	Telus	COMM
1024.418	Telus	COMM
1024.418	Telus	COMM
1024.849	Telus	COMM
1024.849	Telus	COMM
1025.118	Telus	COMM
1025.118	Telus	COMM
1026.384	Telus	COMM
1026.384	Telus	COMM
1026.489	Telus	COMM
1026.489	Telus	COMM
1026.566	Telus	COMM
1026.566	Telus	COMM
1026.695	Telus	COMM
1026.695	Telus	COMM
1026.920	Telus	FOTS
1028.250	Telus	FOTS
1028.361	Telus	COMM
1028.363	Telus	COMM
1028.374	Telus	COMM

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
1028.376	Telus	COMM
1028.400	Telus	FOTS
1029.113	Telus	FOTS
1029.155	Telus	COMM
1029.155	Telus	COMM
1029.171	Telus	COMM
1029.171	Telus	COMM
1030.120	Telus	COMM
1030.120	Telus	COMM
1030.700	Telus	COMM
1030.700	Telus	COMM
1030.741	Telus	COMM
1030.741	Telus	COMM
1030.982	Telus	COMM
1030.982	Telus	COMM
1031.008	Telus	COMM
1031.008	Telus	COMM
1031.012	Telus	COMM
1031.189	Telus	COMM
1031.189	Telus	COMM
1031.512	Telus	FOTS
1031.517	Telus	COMM
1031.517	Telus	COMM
1031.578	Telus	FOTS
1031.588	Telus	COMM
1031.588	Telus	COMM
1032.954	Telus	COMM
1032.954	Telus	COMM
1032.961	Telus	FOTS
1034.833	Telus	COMM
1034.833	Telus	COMM
1034.909	Telus	FOTS
1035.179	Telus	COMM
1035.179	Telus	COMM
1035.182	Telus	FOTS
1035.397	Telus	COMM
1035.397	Telus	COMM
1035.690	Telus	FOTS
1038.203	Telus	COMM
1038.203	Telus	COMM
1038.771	Telus	FOTS

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
1039.489	Telus	COMM
1042.311	Telus	COMM
1042.400	Telus	COMM
1042.400	Telus	COMM
1042.855	Shaw	COMM
1042.880	Telus	COMM
1042.880	Telus	COMM
1043.018	Telus	COMM
1043.018	Telus	COMM
1043.683	Telus	COMM
1043.899	Telus	COMM
1044.416	Telus	FOTS
1044.417	Telus	COMM
1044.417	Telus	COMM
1046.496	Telus	COMM
1046.496	Telus	COMM
1046.501	Telus	FOTS
1047.759	Telus	COMM
1048.393	Telus	COMM
1048.400	Telus	COMM
1048.412	Telus	COMM
1049.137	Shaw	COMM
1049.167	Telus	COMM
1049.167	Telus	COMM
1051.262	Telus	FOTS
1051.324	Shaw	COMM
1051.400	Telus	COMM
1051.409	Telus	COMM
1051.420	Telus	COMM
1051.428	Telus	COMM
1052.454	Telus	COMM
1052.454	Telus	COMM
1054.458	Telus	FOTS
1054.505	Telus	COMM
1054.505	Telus	COMM
1054.597	Telus	COMM
1054.597	Telus	COMM
1054.642	Telus	FOTS
1060.071	Telus	COMM
1060.083	Telus	COMM
1062.247	Telus	COMM

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
1062.247	Telus	COMM
1062.310	Telus	COMM
1062.310	Telus	COMM
1062.549	Telus	FOTS
1062.706	Telus	COMM
1064.455	Telus	COMM
1064.455	Telus	COMM
1064.626	Telus	FOTS
1067.987	Telus	COMM
1067.987	Telus	COMM
1068.195	Telus	COMM
1068.195	Telus	COMM
1078.810	Telus	COMM
1078.810	Telus	COMM
1078.863	Telus	FOTS
1081.575	Shaw	COMM
1081.614	Telus	COMM
1081.614	Telus	COMM
1081.901	Telus	COMM
1083.069	Telus	COMM
1083.913	Telus	COMM
1088.466	Telus	COMM
1088.466	Telus	COMM
1088.472	Telus	FOTS
1090.157	Telus	COMM
1092.157	Telus	COMM
1097.171	Telus	COMM
1099.486	Telus	COMM
1099.486	Telus	COMM
1099.494	Shaw	COMM
1101.057	Telus	COMM
1104.031	Telus	COMM
1104.643	Shaw	COMM
1106.184	Telus	COMM
1109.041	Abbotsford	Water
1109.042	Abbotsford	Water
1109.044	Telus	COMM
1110.108	Abbotsford	Water
1110.120	Telus	COMM
1111.236	Telus	COMM
1111.252	Abbotsford	Water

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
1112.307	Abbotsford	Water
1112.308	Abbotsford	Water
1113.889	Abbotsford	Water
1113.911	Telus	COMM
1114.030	Telus	COMM
1114.043	Telus	FOTS
1114.054	Telus	COMM
1114.054	Telus	COMM
1114.120	Telus	COMM
1114.703	Telus	COMM
1118.462	Telus	COMM
1118.466	Abbotsford	Water
1118.480	Abbotsford	Sewer
1118.483	Abbotsford	Drainage
1118.904	Telus	COMM
1118.904	Telus	COMM
1118.916	Abbotsford	Water
1118.916	Shaw	COMM
1118.918	Abbotsford	Sewer
1118.975	Abbotsford	Water
1120.254	Abbotsford	Sewer
1120.290	Abbotsford	Drainage
1120.291	Abbotsford	Sewer
1120.356	Abbotsford	Water
1120.359	Abbotsford	Drainage
1120.359	Telus	COMM
1120.360	Abbotsford	Sewer
1120.507	Telus	COMM
1120.507	Telus	COMM
1120.507	Telus	COMM
1120.644	Abbotsford	Water
1120.650	Telus	COMM
1120.650	Telus	COMM
1120.655	Shaw	COMM
1120.709	Telus	COMM
1120.709	Telus	COMM
1120.713	Shaw	COMM
1120.714	Telus	COMM
1120.714	Telus	COMM
1120.717	Abbotsford	Water
1120.720	Abbotsford	Drainage

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
1120.722	Abbotsford	Sewer
1120.723	Telus	COMM
1120.723	Telus	COMM
1120.735	Shaw	COMM
1120.876	Telus	COMM
1120.880	Telus	COMM
1120.887	Abbotsford	Water
1120.895	Abbotsford	Sewer
1120.896	Abbotsford	Drainage
1120.899	Abbotsford	Water
1120.997	Shaw	COMM
1120.998	Telus	COMM
1120.998	Telus	COMM
1121.004	Abbotsford	Water
1121.070	Telus	COMM
1121.070	Telus	COMM
1121.089	Abbotsford	Water
1121.117	Shaw	COMM
1121.133	Abbotsford	Drainage
1121.136	Abbotsford	Sewer
1121.148	Abbotsford	Drainage
1121.192	Abbotsford	Drainage
1122.705	Abbotsford	Water
1122.715	Abbotsford	Sewer
1122.717	Abbotsford	Sewer
1122.720	Abbotsford	Sewer
1123.774	Abbotsford	Water
1123.781	Telus	COMM
1123.784	Abbotsford	Water
1123.850	Abbotsford	Water
1124.958	Abbotsford	Water
1124.967	Abbotsford	Water
1126.131	Abbotsford	Water
1126.133	Abbotsford	Water
1126.137	Abbotsford	Sewer
1126.139	Abbotsford	Water
1126.139	Abbotsford	Water
1126.537	Abbotsford	Drainage
1126.541	Abbotsford	Sewer
1126.544	Abbotsford	Drainage
1127.850	Abbotsford	Water

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
1129.258	Abbotsford	Sewer
1129.266	Abbotsford	Water
1130.440	Abbotsford	Sewer
1131.299	Abbotsford	Water
1131.978	Abbotsford	Water
1133.008	Telus	COMM
1133.022	Abbotsford	Water
1134.761	Abbotsford	Water
1136.507	Abbotsford	Water
1137.105	Abbotsford	Water
1138.585	Township of Langley	Sewer
1139.397	Township of Langley	Drainage
1139.915	Telus	COMM
1141.162	Telus	COMM
1144.914	Telus	COMM
1146.556	Township of Langley	Water
1146.813	Telus	COMM
1146.816	Township of Langley	Water
1146.979	Township of Langley	Water
1147.405	Telus	COMM
1149.037	Township of Langley	Water
1149.038	Telus	COMM
1151.352	Township of Langley	Sewer
1151.360	Township of Langley	Sewer
1151.389	Township of Langley	Water
1151.955	Township of Langley	Water
1151.968	Township of Langley	Water
1152.356	Telus	COMM
1154.975	Telus	COMM
1154.975	Telus	COMM
1154.979	Metro Vancouver	Water
1154.979	Township of Langley	Sewer
1154.981	Township of Langley	Water
1154.986	Telus	COMM
1154.988	Shaw	COMM
1154.990	Township of Langley	Water
1154.990	Shaw	COMM
1155.346	Township of Langley	Water
1155.351	Township of Langley	Sewer
1155.578	Township of Langley	Sewer
1155.581	Telus	COMM

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
1155.593	Township of Langley	Water
1155.601	Township of Langley	Water
1155.674	Township of Langley	Water
1155.708	Township of Langley	Sewer
1155.726	Township of Langley	Water
1155.878	Township of Langley	Water
1155.905	Township of Langley	Water
1155.914	Township of Langley	Sewer
1155.919	Township of Langley	Drainage
1156.227	Telus	COMM
1156.227	Telus	COMM
1156.294	Surrey	Drainage
1156.453	Telus	COMM
1156.542	Surrey	Water
1156.546	Surrey	Drainage
1156.558	Surrey	Water
1156.591	Surrey	Water
1156.691	Surrey	Sewer
1156.730	Surrey	Water
1156.731	Telus	COMM
1156.871	Surrey	Drainage
1156.892	Surrey	Water
1156.946	Surrey	Water
1157.097	Surrey	Drainage
1157.498	Surrey	Water
1157.668	Surrey	Water
1157.669	Surrey	Water
1158.069	Surrey	Drainage
1158.156	Surrey	Drainage
1159.623	Surrey	Water
1159.626	Surrey	Drainage
1160.143	Surrey	Drainage
1160.432	Surrey	Sewer
1160.437	Surrey	Sewer
1160.444	Surrey	Drainage
1160.450	Surrey	Water
1162.981	Surrey	Sewer
1163.713	Surrey	Sewer
1163.925	Surrey	Sewer
1164.536	Surrey	Sewer
1164.549	Surrey	Sewer

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
1164.618	Surrey	Sewer
1164.978	Surrey	Sewer
1167.284	Metro Vancouver	Water
1167.414	Surrey	Water
1167.462	Metro Vancouver	Water
1167.996	Surrey	Sewer
1168.145	Surrey	Sewer
1169.499	Telus	COMM
1169.562	Coquitlam	Water
1169.572	Coquitlam	Water
1169.612	Telus	COMM
1169.614	Coquitlam	Sewer
1169.638	Telus	COMM
1169.646	Coquitlam	Water
1169.686	Coquitlam	Drainage
1169.687	Coquitlam	Sewer
1169.690	Coquitlam	Water
1169.694	Shaw	COMM
1169.695	Shaw	COMM
1169.696	Shaw	COMM
1169.706	Telus	COMM
1169.706	Telus	COMM
1169.706	Telus	COMM
1169.706	Telus	COMM
1169.727	Coquitlam	Water
1169.751	Telus	COMM
1169.751	Telus	COMM
1169.761	Coquitlam	Sewer
1169.764	Coquitlam	Sewer
1169.787	Telus	COMM
1169.793	Coquitlam	Water
1169.821	Coquitlam	Water
1169.850	Coquitlam	Water
1169.876	Coquitlam	Water
1169.895	Coquitlam	Water
1169.913	Coquitlam	Sewer
1169.913	Coquitlam	Water
1169.959	Coquitlam	Sewer
1169.961	Coquitlam	Water
1169.985	Coquitlam	Water
1170.015	Coquitlam	Water

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
1170.026	Coquitlam	Sewer
1170.103	Telus	COMM
1170.103	Telus	COMM
1170.103	Telus	COMM
1170.103	Telus	COMM
1170.103	Telus	COMM
1170.110	Shaw	COMM
1170.110	Shaw	COMM
1170.119	Coquitlam	Drainage
1170.120	Coquitlam	Sewer
1170.122	Coquitlam	Water
1170.128	Shaw	COMM
1170.138	Shaw	COMM
1170.143	Shaw	COMM
1170.145	Coquitlam	Water
1170.145	Shaw	COMM
1170.177	Coquitlam	Sewer
1170.189	Shaw	COMM
1170.213	Coquitlam	Sewer
1170.216	Coquitlam	Water
1170.233	Coquitlam	Water
1170.244	Coquitlam	Water
1170.249	Coquitlam	Water
1170.253	Telus	COMM
1170.254	Coquitlam	Water
1170.259	Telus	COMM
1170.259	Telus	COMM
1170.302	Coquitlam	Sewer
1170.323	Coquitlam	Water
1170.325	Telus	COMM
1170.325	Telus	COMM
1170.331	Coquitlam	Sewer
1170.332	Coquitlam	Drainage
1170.344	Coquitlam	Sewer
1170.368	Coquitlam	Water
1170.379	Coquitlam	Water
1170.419	Coquitlam	Water
1170.454	Coquitlam	Water
1170.470	Coquitlam	Sewer
1170.507	Coquitlam	Water
1170.523	Coquitlam	Water

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
1170.558	Coquitlam	Sewer
1170.562	Coquitlam	Water
1170.587	Coquitlam	Water
1170.601	Coquitlam	Water
1170.644	Coquitlam	Sewer
1170.698	Telus	COMM
1170.698	Telus	COMM
1170.724	Coquitlam	Water
1170.724	Coquitlam	Water
1170.731	Coquitlam	Sewer
1170.771	Coquitlam	Water
1170.795	Coquitlam	Water
1170.815	Telus	COMM
1170.815	Telus	COMM
1170.855	Coquitlam	Water
1170.856	Telus	COMM
1170.856	Telus	COMM
1170.890	Coquitlam	Sewer
1170.892	Coquitlam	Water
1170.944	Coquitlam	Water
1170.973	Coquitlam	Water
1170.991	Coquitlam	Sewer
1170.999	Shaw	COMM
1171.015	Telus	COMM
1171.068	Coquitlam	Water
1171.088	Telus	COMM
1171.088	Telus	COMM
1171.119	Coquitlam	Water
1171.172	Coquitlam	Water
1171.206	Coquitlam	Water
1171.214	Coquitlam	Water
1171.276	Shaw	COMM
1171.278	Telus	COMM
1171.278	Telus	COMM
1171.278	Telus	COMM
1171.286	Coquitlam	Sewer
1171.330	Coquitlam	Water
1171.331	Coquitlam	Water
1171.373	Coquitlam	Water
1171.378	Telus	COMM
1171.378	Telus	COMM

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
1171.382	Telus	COMM
1171.417	Coquitlam	Water
1171.417	Coquitlam	Water
1171.440	Coquitlam	Water
1171.441	Coquitlam	Water
1171.451	Coquitlam	Sewer
1171.490	Coquitlam	Water
1171.499	Coquitlam	Water
1171.550	Coquitlam	Sewer
1171.552	Coquitlam	Water
1171.554	Coquitlam	Water
1171.561	Telus	COMM
1171.561	Telus	COMM
1171.619	Telus	COMM
1171.653	Coquitlam	Water
1171.666	Coquitlam	Water
1171.694	Coquitlam	Water
1171.738	Telus	COMM
1171.738	Telus	COMM
1171.751	Coquitlam	Drainage
1171.758	Coquitlam	Drainage
1171.780	Coquitlam	Sewer
1171.797	Coquitlam	Water
1171.856	Coquitlam	Water
1171.869	Coquitlam	Water
1171.870	Coquitlam	Drainage
1171.874	Coquitlam	Sewer
1171.885	Telus	COMM
1171.885	Telus	COMM
1171.899	Coquitlam	Sewer
1171.905	Telus	COMM
1171.905	Telus	COMM
1172.001	Telus	COMM
1172.163	Coquitlam	Water
1172.169	Coquitlam	Water
1172.177	Coquitlam	Drainage
1172.196	Telus	COMM
1172.196	Telus	COMM
1172.201	Telus	COMM
1172.201	Telus	COMM
1172.201	Telus	COMM

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
1172.924	Coquitlam	Sewer
1173.093	Coquitlam	Water
1173.127	Coquitlam	Water
1173.140	Coquitlam	Sewer
1173.146	Telus	COMM
1173.173	Coquitlam	Sewer
1173.182	Telus	COMM
1173.182	Telus	COMM
1173.183	Telus	COMM
1173.187	Coquitlam	Water
1173.198	Coquitlam	Sewer
1173.202	Coquitlam	Water
1173.383	Coquitlam	Water
1173.423	Coquitlam	Water
1173.423	Metro Vancouver	Water
1173.427	Coquitlam	Drainage
1173.427	Coquitlam	Water
1173.442	Coquitlam	Drainage
1173.443	Coquitlam	Sewer
1173.446	Shaw	COMM
1173.464	Coquitlam	Water
1173.470	Coquitlam	Water
1173.487	Telus	COMM
1173.489	Coquitlam	Water
1173.491	Coquitlam	Sewer
1173.496	Coquitlam	Drainage
1173.497	Coquitlam	Water
1173.498	Coquitlam	Drainage
1173.506	Coquitlam	Water
1173.519	Coquitlam	Water
1173.522	Coquitlam	Sewer
1173.522	Coquitlam	Water
1173.536	Coquitlam	Water
1173.539	Coquitlam	Water
1173.544	Coquitlam	Water
1173.552	Coquitlam	Sewer
1173.566	Coquitlam	Water
1173.572	Coquitlam	Water
1173.573	Coquitlam	Sewer
1173.606	Coquitlam	Water
1173.633	Coquitlam	Water

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
1173.634	Coquitlam	Sewer
1173.645	Coquitlam	Water
1173.647	Coquitlam	Water
1173.671	Coquitlam	Water
1173.681	Coquitlam	Sewer
1173.682	Coquitlam	Water
1173.717	Coquitlam	Water
1173.766	Metro Vancouver	Water
1173.775	Coquitlam	Water
1173.800	Coquitlam	Sewer
1173.849	Coquitlam	Drainage
1174.099	Telus	COMM
1174.107	Coquitlam	Water
1174.109	Shaw	COMM
1174.110	Coquitlam	Sewer
1174.110	Shaw	COMM
1174.167	Coquitlam	Drainage
1174.610	Coquitlam	Water
1175.018	Coquitlam	Drainage
1175.019	Metro Vancouver	Drainage
1175.063	Telus	COMM
1175.075	Shaw	COMM
1175.077	Shaw	COMM
1175.104	Coquitlam	Sewer
1175.127	Burnaby	Drainage
1175.128	Coquitlam	Drainage
1175.128	Coquitlam	Water
1175.130	Coquitlam	Water
1175.134	Metro Vancouver	Water
1175.135	Coquitlam	Water
1175.142	Burnaby	Water
1175.144	Burnaby	Water
1175.151	Coquitlam	Sewer
1175.177	Metro Vancouver	Drainage
1175.189	Coquitlam	Drainage
1175.191	Burnaby	Drainage
1175.216	Burnaby	Drainage
1175.313	Shaw	COMM
1175.316	Telus	COMM
1175.417	Telus	COMM
1175.427	Shaw	COMM

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Edmonton to Burnaby		
1175.519	Burnaby	Water
1175.528	Burnaby	Water
1175.599	Burnaby	Drainage
1175.745	Metro Vancouver	Drainage
1175.746	Burnaby	Drainage
1175.755	Burnaby	Sewer
1175.792	Burnaby	Drainage
1176.177	Burnaby	Water
1176.310	Burnaby	Water
1176.547	Metro Vancouver	Drainage
1177.180	Burnaby	Drainage
1177.217	Burnaby	Sewer
1177.229	Metro Vancouver	Drainage
1177.252	Shaw	COMM
1177.256	Telus	COMM
1177.847	Metro Vancouver	Water
1177.850	Telus	COMM
1177.853	Burnaby	Water
1177.860	Burnaby	Sewer
1178.240	Telus	COMM
1178.240	Telus	COMM
1178.240	Telus	COMM
1178.240	Shaw	COMM
1178.244	Burnaby	Water
1178.254	Metro Vancouver	Water
1178.257	Burnaby	Drainage
1178.259	Burnaby	Sewer
1178.810	Telus	COMM
1178.810	Shaw	COMM
1178.818	Burnaby	Water
1179.520	Metro Vancouver	Water
Burnaby to Westridge (RK values reset)		
0.982	Telus	COMM
0.986	Shaw	COMM
1.041	Burnaby	Water
1.602	Burnaby	Water
1.946	Burnaby	Drainage
1.947	Burnaby	Sewer
1.953	Burnaby	Water
2.136	Burnaby	Sewer
2.137	Burnaby	Drainage

TABLE 5.1.17

PRELIMINARY BURIED CABLES AND UTILITIES (continued)

Reference Kilometre (RK)	Owner	Type
Burnaby to Westridge (RK values reset)		
2.177	Burnaby	Drainage
2.182	Burnaby	Water
2.207	Telus	COMM
2.209	Telus	COMM
2.22	Shaw	COMM
2.452	Burnaby	Water
2.468	Shaw	COMM
2.504	Burnaby	Water
2.52	Telus	COMM
2.522	Telus	COMM
2.523	Shaw	COMM
2.555	Burnaby	Water
2.631	Shaw	COMM
2.633	Telus	COMM
2.633	Telus	COMM
2.637	Burnaby	Drainage
3.438	Burnaby	Sewer

TABLE 5.1.18

ESTIMATED PIPE COATINGS ALONG PIPELINE

Spread			Coating Requirement (m)	
Name	**Start (RK)**	**End (RK)**	**FBE**	**ARO**
Edmonton to Burnaby				
A1	0.0	49.0	40,758	8,242
A2	49.0	339.4	269,258	21,186
BC1	489.6	769.0	260,250	19,140
BC2	811.8	1018.0	197,353	8,802
BC3	1018.0	1078.1	49,732	10,368
BC4	1078.1	1148.0	62,406	7,494
BC5*	1148.0	1168.4	11,852	8,496
	1169.5	1179.7	8,306	1,964
T1	1168.4	1169.5	48	1,104
Burnaby to Westridge				
BC5*	0.0	3.6	6,890	360
Total			906,853	87,156

Note: * BC5 includes:

- Belmont Golf Course to Fraser River (RK 1148.0 to RK 1168.4)
- Fraser River to Burnaby Terminal (RK 1169.5 to RK 1179.7)
- Burnaby Terminal to Westridge Marine Terminal (RK 0.0 to RK 3.6)