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November 10, 2015

National Energy Board
517 Tenth Avenue SW
Calgary, Alberta T2R 0A8

Filed Electronically

Attention: Ms. Sheri Young, Secretary of the Board

Dear Madam:

Re: TransCanada PipeLines Limited (TransCanada)
Section 58 Application for the Vaughan Mainline Expansion Project (Project)

TransCanada applies under section 58 of the *National Energy Board Act* (Act) for approvals to construct and operate the following facilities and for exemption from sections 30(1)(a) and 31 of the Act:

- approximately 11.7 km of 1067 mm (NPS 42) pipeline
- a tie-in into TransCanada's approved 914.4 mm (NPS 36) King's North Connection (KNC) project
- a tie-in into TransCanada's existing Line 200-2, 914.4 mm (NPS 36) pipeline
- a tie-in to TransCanada's existing Line 200-3, 1067 mm (NPS 42) pipeline
- associated facilities

The Project is necessary to meet aggregate service requirements starting November 1, 2017. Therefore, TransCanada must start construction of the Project no later than October 1, 2016 to have the facilities completed and in-service by November 2017. Accordingly, TransCanada requests that the Board issue a decision on the Application by August 2016 to allow sufficient time to prepare for construction and comply with any pre-construction conditions that the Board may order, as well as to construct and place the pipeline into service.

As part of on-going engagement, TransCanada continues to work with landowners to address outstanding concerns regarding the proposed routing and potential impacts of the Project. As a result, TransCanada elected not to utilize the Board's Online Application System for this Application. TransCanada therefore requests that the Board establish a formal written process and schedule for consideration of the Application to provide interested parties an opportunity to make submissions and for TransCanada to respond in order to ensure the Board has the information necessary for adjudication of the Application. TransCanada also respectfully requests that when the Board issues its letter concerning legislated time limit and decision on process, that it also provide its details about the process and timelines.

As noted in the attached Environmental and Socio-Economic Assessment, information with respect to the location of species at risk and species of special conservation concern is being provided under separate cover in order to support protecting information concerning vulnerable and endangered species.

On filing this Application, TransCanada will notify landowners, First Nations and Métis communities and organizations, municipal stakeholders identified in Sections 7, 8 and 9 of this Application, and the Tolls Task Force.

Please direct all communication regarding this Application to:

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Yours truly,
TransCanada PipeLines Limited

Original signed by

Robert Tarvydas
Vice-President, Regulatory Affairs

Enclosures

cc. Distribution List
TransCanada Mainline Tolls Task Force

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ABBREVIATIONS AND ACRONYMS

Act	*National Energy Board Act*
AUT	Automated ultrasonic testing
CEAA 2012	*Canadian Environmental Assessment Act, 2012*
CP	cathodic protection
DBRS	DBRS Limited
EDA	Eastern Distribution Area
Enbridge	Enbridge Gas Distribution
EOC	Emergency Operations Centre
EPP	Environmental Protection Plan
ESA	Environmental and Socio-Economic Assessment
FCAW	flux-cored arc welding
FT	Firm Transportation Service
FT-SN	Firm Transportation Short Notice Service
Gaz Métro	Gaz Métro Limited Partnership
GHG	greenhouse gas
GMAW	gas metal arc welding
GMIT	Gaz Métro’s Eastern Delivery Area
Golder	Golder Associates
GTO	Greater Toronto Area
HDD	horizontal directional drill
HSE MS	Health, Safety and Environment Management System
ILI	in-line inspection

IMP	Integrity Management Program
LMCI	Land Matters Consultation Initiative
LOUR	Land Occupancy and Use Reports
LSA	Local Study Area
MNO	Métis Nation of Ontario
MOP	maximum operating pressure
MTO	Ministry of Transportation of Ontario
NBC 2010	National Building Codes of Canada
NCOS	New Capacity Open Season
NDA	Northern Distribution Area
NDE	Nondestructive Examination
NEB or Board	National Energy Board
New Credit	New Credit First Nation
NGOs/ENGOs	nongovernment organizations/environmental nongovernment organizations
NPS	Nominal pipe size
OD	outside diameter
OEB	Ontario Energy Board
OPR	*Onshore Pipeline Regulations*
PA	Public Awareness
ROW	right-of-way
RSA	Regional Study Area
SAF	Survey Acknowledgement Forms
SCADA	Supervisory Control and Data Acquisition

Six Nations	Six Nations of the Grand River
SMAW	Shielded metal arc welding
SSA	Socio-Economic Study Area
STS	Storage Transportation Service
TBO	Transportation by Others
TOP	TransCanada operating procedures
TransCanada	TransCanada PipeLines Limited
TRCA	Toronto and Region Conservation Authority
TTF	Tolls Task Force
TWS	temporary work space
Union	Union Gas Limited
US	United States

SYMBOLS, WEIGHTS AND MEASURES

$	dollars
%	percent
Bcf/d	billion cubic feet per day
km	kilometre
m	metre
m^3	cubic metres
m^3/d	cubic metres per day
mm	millimetre
Tcf	trillion cubic feet

NATIONAL ENERGY BOARD

IN THE MATTER OF the *National Energy Board Act* (Act), R.S.C. 1985, c. N-7, as amended, and the Regulations enacted thereunder

AND IN THE MATTER OF an Application by TransCanada PipeLines Limited pursuant to section 58 of the Act for approval to construct and operate the Vaughan Mainline Expansion Project and for exemption from sections 30(1)(a) and 31 of the Act

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TRANSCANADA PIPELINES LIMITED

VAUGHAN MAINLINE EXPANSION PROJECT

November 2015

To: The Secretary
National Energy Board
517 Tenth Avenue SW
Calgary, Alberta
T2R 0A8

VAUGHAN MAINLINE EXPANSION PROJECT

TransCanada PipeLines Limited (TransCanada) applies to the National Energy Board (NEB or Board), pursuant to section 58 of the *National Energy Board Act* (Act), for an Order approving the construction and operation of the Vaughan Mainline Expansion Project (the Project), and for exemption from sections 30(1)(a) and 31 of the Act, all as described more particularly in this Application.

Applicant

1. TransCanada is a federally incorporated Canadian corporation and a “company” as that term is defined in the Act.

2. TransCanada owns and operates a high-pressure natural gas transmission system that extends from the Alberta border across Saskatchewan, Manitoba, and Ontario, through a portion of Québec, and connects to various downstream Canadian and international pipelines (Mainline or Mainline System).

3. The Board regulates TransCanada’s Mainline as a Group 1 gas pipeline company.

Vaughan Mainline Expansion Project

4. The Project is located in the City of Vaughan, in the Regional Municipality of York, in southern Ontario, and consists of approximately 11.7 km of 1067 mm (NPS 42) pipeline, valves and associated facilities. The Project will connect into TransCanada’s approved 914.4 mm (NPS 36) King’s North Connection (KNC) project (Board Order XG-T211-027-2015) and the existing TransCanada Line 200-2, 914.4 mm (NPS 36) pipeline northwest of the intersection of Major MacKenzie Drive and Huntington Road. Beginning in the west, the Project will run north and east before heading south to connect into the existing TransCanada Line 200-3, 1067 mm (NPS 42) pipeline near the existing mainline valve (MLV) 201A crossover valve site located southeast of the intersection of Kirby Road and Kipling Avenue. At that location the existing crossover valve MLV 201A and associated crossover piping will be removed. A receiver barrel and associated piping will be installed at the existing TransCanada Maple Compressor Station (Station 130).

5. Overview maps of the Project are provided as Appendix 1-1 to this Application.

6. The Project does not trigger the requirements of the *Canadian Environmental Assessment Act, 2012* (CEAA 2012) because it is not a designated project pursuant to the *Regulations Designating Physical Activities* and is not located on federal lands. Therefore, a federal environmental assessment pursuant to CEAA 2012 is not required.

7. To meet firm service commitments, the Project is required to be in service for November 1, 2017. To meet this in-service date, TransCanada must start construction on the Project no later than October 2016. Accordingly, TransCanada requests that the Board issue a decision on the Application as soon as possible and in any event by August 2016 to allow sufficient time to prepare for construction and comply with any pre-construction conditions that the Board may order, as well as to construct and place the pipeline into service.

8. The estimated cost of the Project is $221 million.

Purpose and Justification

9. The Project is required to transport 425,081 GJ/d of firm 15-year transportation service commitments on the Mainline System starting November 1, 2017.

10. In order to provide the necessary capacity to meet the new service commitments, TransCanada is proposing the Project, in conjunction with a Transportation by Others (TBO) arrangement on Enbridge Gas Distribution's (Enbridge's) Albion pipeline. The Enbridge Albion pipeline has received approval from the Ontario Energy Board (OEB) and includes the Segment A pipeline and the Albion Station expansion. Together, the Project and the TBO act as a partial loop of TransCanada's Mainline facilities between Parkway and Station 130. A schematic of the Project in relation to Enbridge's Segment A pipeline and the Albion Station expansion is provided in Figure 3-2.

11. The Project is consistent with the RH-001-2014 Decision. The applied-for facilities are supported by new long-term service commitments, long-term supply, new and existing upstream pipeline infrastructure and sufficient long-term markets. The Project will provide the market with greater flexibility and greater access to emerging supplies from the Marcellus and Utica shale regions.

Transportation Services and Tolls

12. The impacts on tolls as a result of adding the proposed facilities to the Mainline are outlined in Section 3.1.8 of this Application. TransCanada is not, in this Application, seeking approvals pursuant to Part IV of the Act, relating to the recovery of the costs of the Project through tolls.

Application Content

13. In this Application, TransCanada provides information required for the Board's consideration of the Application pursuant to section 58 of the Act, as outlined in the Board's Filing Manual.

Supporting Material

14. In support of this Application, TransCanada provides and relies on the information attached to this Application and any additional information it might file.

Relief Requested

15. TransCanada applies to the Board for:

    a) an Order pursuant to section 58 of the Act approving the construction and operation of the Project and exempting TransCanada from the provisions of sections 30(1)(a) and 31 of the Act

    b) such other relief that TransCanada might request or that the Board might deem appropriate.

Respectfully Submitted

November 10, 2015
Calgary, Alberta

TransCanada PipeLines Limited

Original signed by

Robert Tarvydas
Vice President, Regulatory Affairs

Please direct all communications relating to this Application to:

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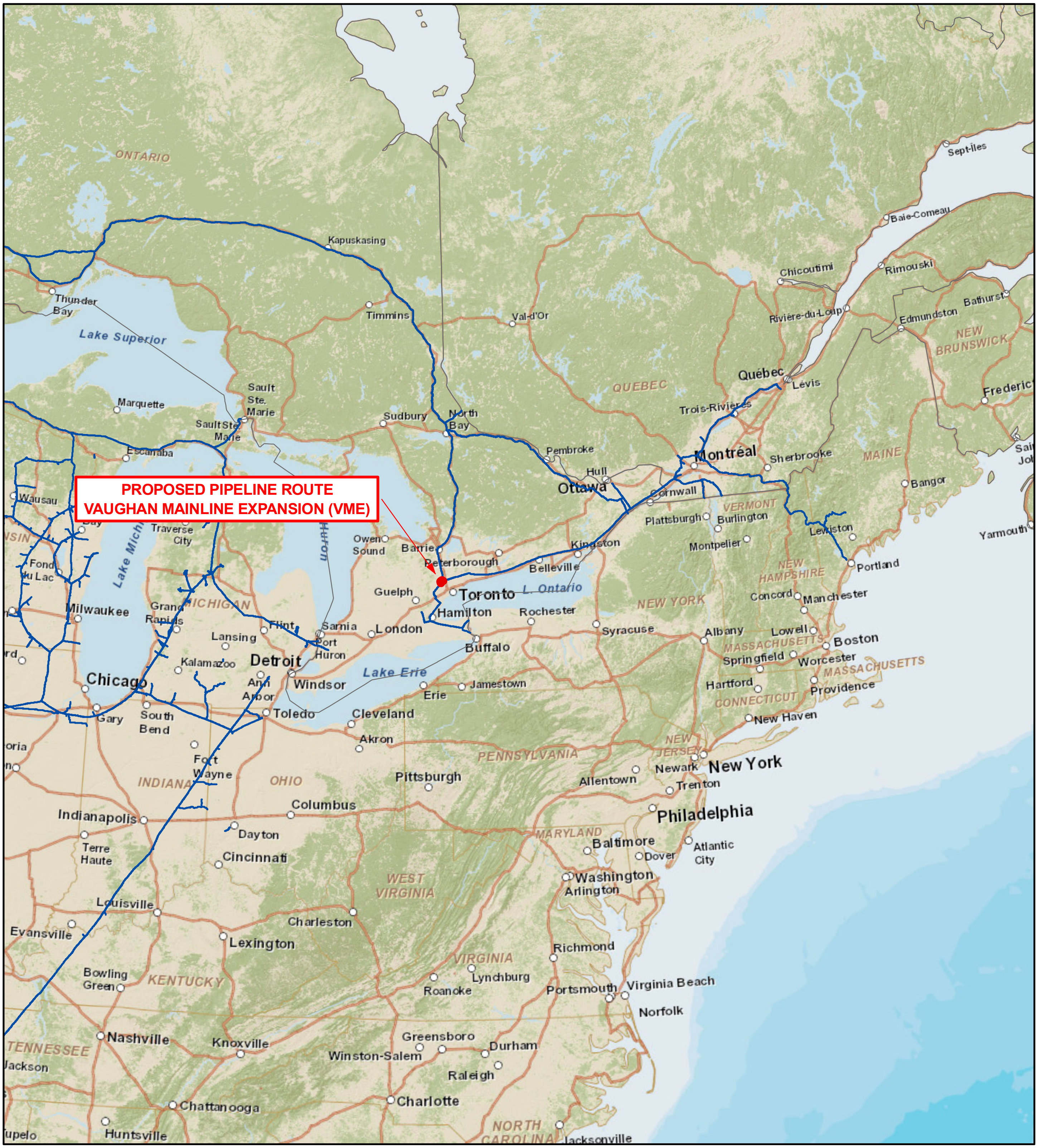
Appendix 1-1

Overview Maps



Legend

Proposed Pipeline Route

Existing TC Pipeline

0 50 100 200 300 400 500
Kilometres

N

PROPOSED PIPELINE ROUTE
VAUGHAN MAINLINE EXPANSION (VME)

FILE	Vaughan_Fig_1_Map_1.mxd	LOCATION	Ontario
SOURCE	ESRI, TCPL	TERMS OF USE: The datasets used to create this map have been gathered from various sources for a specific purpose. TransCanada PipeLines provides no warranty, regarding the accuracy or completeness of the datasets. Unauthorized or improper use of this map, including supporting datasets is strictly prohibited. TransCanada PipeLines Limited accepts no liability whatsoever related to any loss or damages resulting from proper, improper, authorized, or unauthorized use of this map and associated datasets.	
Map 1 (Global)			

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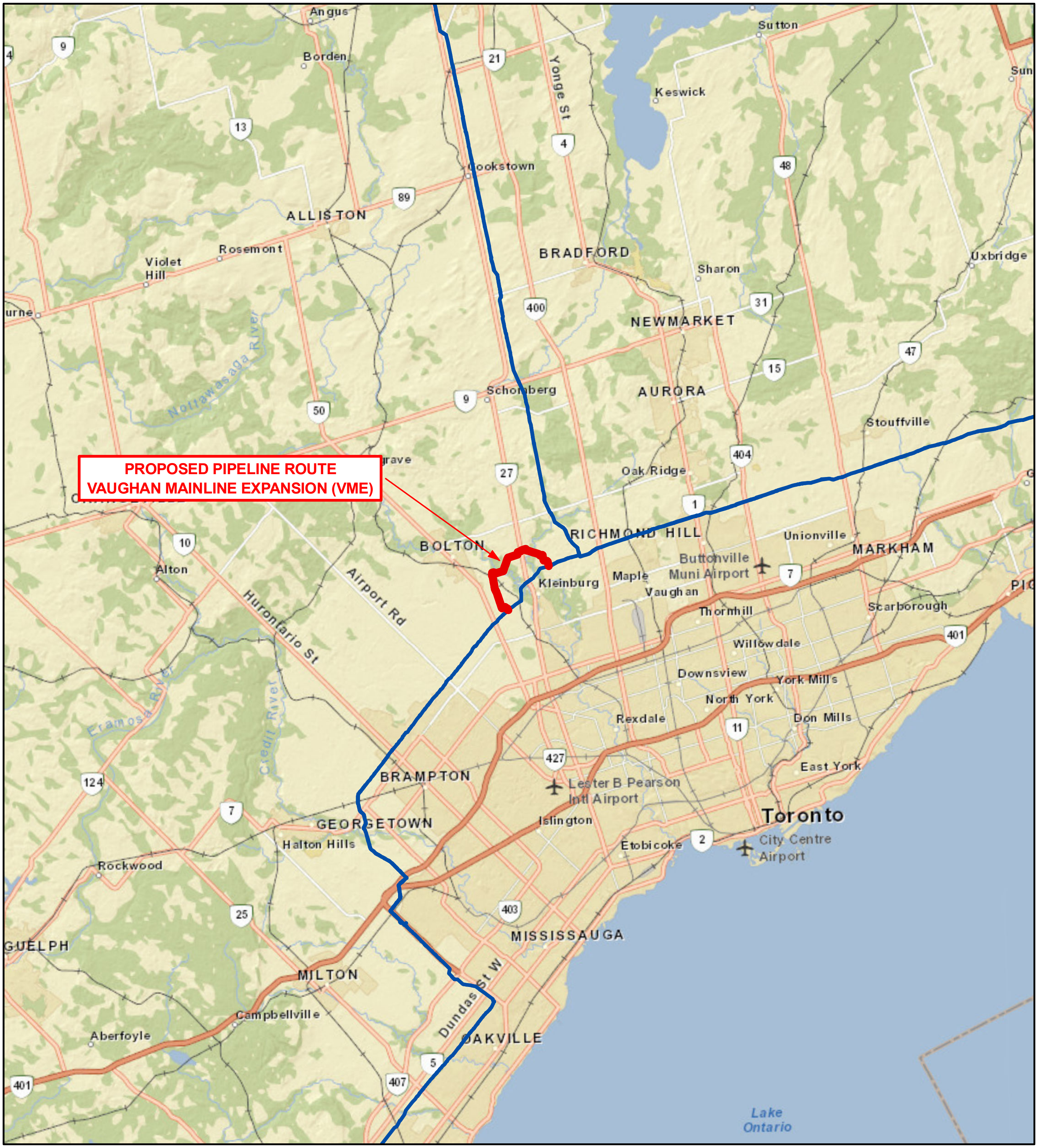
DESIGN	LS	Oct 05 2015



N

Legend

- Proposed Pipeline Route
- Existing TC Pipeline

0 2.5 5 10 15 20 25 30 Kilometres

PROPOSED PIPELINE ROUTE
VAUGHAN MAINLINE EXPANSION (VME)

FILE	Vaughan_Fig_1_Map_2.mxd	LOCATION	Ontario
SOURCE	ESRI, TCPL		
Map 2 (Regional)			

TERMS OF USE: The datasets used to create this map have been gathered from various sources for a specific purpose. TransCanada PipeLines Limited provides no warranty, regarding the accuracy or completeness of the datasets. Unauthorized or improper use of this map, including supporting datasets is strictly prohibited. TransCanada PipeLines Limited accepts no liability whatsoever related to any loss or damages resulting from proper, improper, authorized, or unauthorized use of this map and associated datasets.

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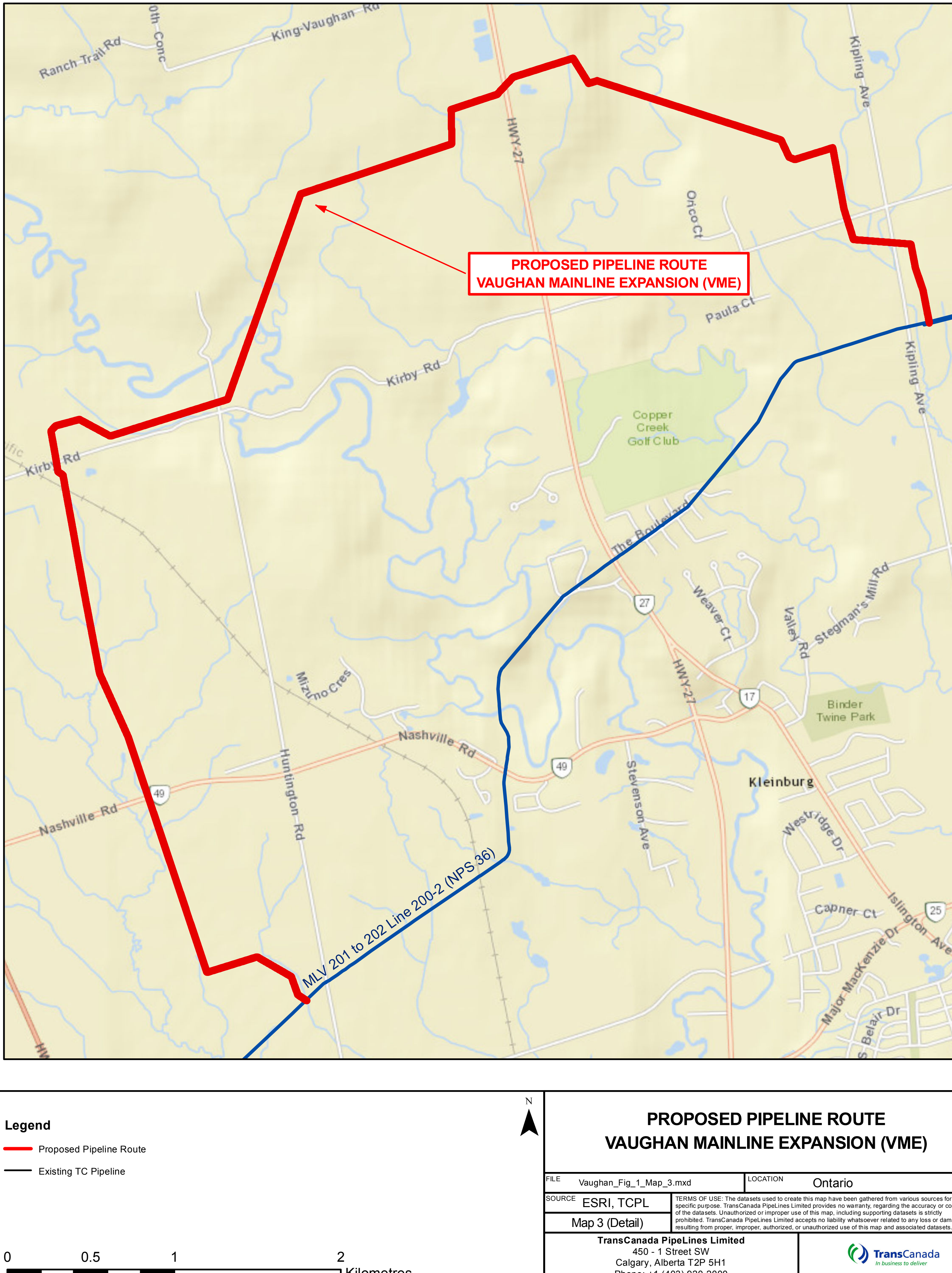
DESIGN	LS	Oct 05 2015



PROPOSED PIPELINE ROUTE
VAUGHAN MAINLINE EXPANSION (VME)

FILE	Vaughan_Fig_1_Map_3.mxd	LOCATION	Ontario
SOURCE	ESRI, TCPL		
Map 3 (Detail)			

TERMS OF USE: The datasets used to create this map have been gathered from various sources for a specific purpose. TransCanada PipeLines Limited provides no warranty, regarding the accuracy or completeness of the datasets. Unauthorized or improper use of this map, including supporting datasets is strictly prohibited. TransCanada PipeLines Limited accepts no liability whatsoever related to any loss or damages resulting from proper, improper, authorized, or unauthorized use of this map and associated datasets.

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DESIGN	LS	Oct 05 2015

2.0 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.	• Section 1	
3.2 Application or Project Purpose			
1.	Purpose of the proposed project.	• Section 1	
3.4 Consultation			
3.4.1 Principles and Goals of Consultation			
1.	The corporate policy or vision.	• Section 8.1	
2.	The principles and goals of consultation for the project.	• Section 8.1	
3.	A copy of the Aboriginal protocol and copies of policies and principles for collecting traditional use information, if available.	• Section 9.1 • Appendix 9-1	
3.4.2 Design of Consultation Program			
1.	The design of the consultation program and the factors that influenced the design.	• Section 8.2	
3.4.3 Implementing a Consultation Program			
1.	The outcomes of the consultation program for the project.	• Section 7.13 • Section 8.5 • Section 8.6 • Table 8-1 •Table 8-2	
3.4.4 Justification for Not Undertaking a Consultation Program			
1.	The application provides justification for why the applicant has determined that a consultation program is not required for the project.		N/A
3.5 Notification of Commercial Third Parties			
1.	Confirm that third parties were notified.	• Section 3.2	
2.	Details regarding the concerns of third parties.	• Sections 3.2	
3.	List the self-identified interested third parties and confirm they have been notified.	• Section 3.2	
4.	If notification of third parties is considered		N/A

Filing #	Filing Requirement	In Application? References	Not in Application? Explanation
	unnecessary, an explanation to this effect.		

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.	• Section 4 • Section 5	
2.	The project location and criteria used to determine the route or site.	• Section 4.1	
3.	How and when the project will be carried out.	• Section 5	
4.	Description of any facilities, to be constructed by others, required to accommodate the proposed facilities.	• Section 3.1.4 • Section 3.3.5 • Section 3.3.6	
5.	An estimate of the total capital costs and incremental operating costs, and changes to abandonment cost estimates.	• Section 3.1.8	
6.	The expected in-service date.	• Section 5.3	
4.2 Economic Feasibility, Alternatives and Justification			
4.2.1 Economic Feasibility			
1.	Description of the economic feasibility of the project.	• Section 3.1	
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.	• Section 3.3.7	
2.	Describe and justify the selection of the proposed route and site including a comparison of the options evaluated using appropriate selection criteria.	• Section 3.3.7 • Section 4.1	
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.	• Section 4.12 • Section 5	
4.2.3 Justification			
1.	Justification for the proposed project.	• Section 3.1	

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.	• Section 4.2	
2.	Line pipe specifications.	• Section 4.3	
3.	Pigging facilities specifications.	• Section 4.3 • Section 4.7	
4.	Compressor or pump facilities specifications.		N/A
5.	Pressure regulating or metering facilities specifications.	• Section 4.4	
6.	Liquid tank specifications or other commodity storage facilities.		N/A
7.	New control system facilities specifications.	• Section 4.5 • Section 6.2	
8.	Gas processing, sulphur or LNG plant facilities specifications.		N/A
9.	Technical description of other facilities not mentioned above.	• Table 4-2	
10.	Building dimensions and uses.		N/A
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
A.1.2 Engineering Design Principles			
1.	Confirmation project activities will follow the requirements of the latest version of CSA Z662.	• Section 4.12	
2.	Provide a statement indicating which Annex is being used and for what purpose.		N/A
3.	Statement confirming compliance with OPR or PPR.	• Section 4.12	
4.	List of all primary codes and standards, including version and date of issue.	• Section 4.12	
5.	Confirmation that the project will comply with company manuals and confirm manuals comply with OPR/PPR and codes and standards.	• Section 4.12	
6.	Any portion of the project a non-hydrocarbon commodity pipeline system? Provide a QA program to ensure the materials are appropriate for their		N/A

Filing #	Filing Requirement	In Application? References	Not in Application? Explanation
	intended service.		
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		N/A
8.	If directional drilling involved: • Preliminary feasibility report • Description of the contingency plan	• Section 4.10 • Appendix 4-5	
9.	If new materials are involved, provide material supply chain information, in tabular format.		N/A
10.	If reuse of materials is involved, provide an engineering assessment in accordance with CSA Z662 that indicates its suitability for the intended service.		N/A
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.	• Section 4.12	
2.	A quality assurance program if project non-routine or incorporates unique challenges due to geographical location.		N/A
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		N/A

Guide A – A.2 Environmental and Socio-Economic Assessment

Filing #	Filing Requirement	In Application? References	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.	• Section 10 • Appendix 10-2	
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.	• Section 10 • Appendix 10-2	
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 on in meeting these information requirements, and the rationale for that extent of reliance.	• Section 10 • Appendix 10-2	
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.	• Section 10 • Appendix 10-2	
5.	Applicants must consult with other expert federal, provincial or territorial departments and other relevant authorities on requirements for baseline information and methods.	• Section 10 • Appendix 10-2	

Guide A – A.2 Environmental and Socio-Economic Assessment

Filing #	Filing Requirement	In Application? References	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.	• Section 10 • Appendix 10-2	
2.	Predict the effects associated with the proposed project, including those that could be caused by construction, operations, decomissioning or abandonment, as well as accidents and malfunctions. Also inlcude effects the environment could have on the project. For those biophysical and socio-economic elemnts or their valued components that require further analysis (see Table A-1), provide the detailed information outlined in Tables A-2 and A-3.	• Section 10 • Appendix 10-2	
Mitigation Measures			
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.	• Appendix 10-2	
2.	Ensure that commitments about mitigative measures will be communicated to field staff for implementation through and Environmental Protection Plan (EP Plan).	• Appendix 10-2	
3.	Describe plans and measures to address potential effects of accidents and malfunctions during construction and operation of the project.	• Appendix 10-2	
Evaluation of Significance			
1.	After taking into account any appropriate mitigation measures, identify any remaining residual effects from the project.	• Appendix 10-2	
2.	Describe the methods and criteria used to determine the significance of adverse effects, including defining the point at which any particular effect on a valued component is considered “significant.”	• Appendix 10-2	
3.	Evaluate the significance of residual adverse environmental and socio-economic effects against the defined criteria.	• Appendix 10-2	

Filing #	Filing Requirement	In Application? References	Not in Application? Explanation
4.	Evaluate the likelihood of significant residual adverse environmental and socio-economic effects occurring and substantiate the conclusions made.	• Section 10 • Appendix 10-2	
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 effects.	• Section 10 • Appendix 10-2	
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.	• Section 10 • Appendix 10-2	
3.	Identify other physical facilities or activities that have been or will be carried out in the identified spatial and temporal boundaries for the cumulative effects assessment.	• Section 10 • Appendix 10-2	
4.	Identify whether the effects of those physical facilities or activities that have been or will be carried out would be likely to produce effects on the valued components in the identified spatial and temporal boundaries.	• Section 10 • Appendix 10-2	
5.	Where other physical facilities 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 facilities or activities. • Provide a description of the extent of the cumulative effects on valued components. • Where professional knowledge or experience is cited, explain the extent to which professional knowledge or experience was relied on and justify how the resulting conclusions or decisions were reached.	• Section 10 • Appendix 10-2	
Mitigation Measures for Cumulative Effects			
1.	Describe the general and specific mitigation measures, beyond project-specific mitigation already	• Appendix 10-2	

Filing #	Filing Requirement	In Application? References	Not in Application? Explanation
	considered, that are technically and economically feasible to address any cumulative effects.		
The Applicant's Evaluation of Significance			
1.	After taking into account any appropriate mitigation measures for cumulative effects, identify any remaining residual cumulative effects.	• Appendix 10-2	
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."	• Appendix 10-2	
3.	Evaluate the significance of adverse residual cumulative effects against the defined criteria.	• Appendix 10-2	
4.	Evaluate the likelihood of significant, residual adverse cumulative environmental and socio-economic effects occurring and substantiate the conclusions made.	• Appendix 10-2	
A.2.8 Inspection, Monitoring, Follow-up and Operation			
1.	Describe inspections plans to ensure compliance with biophysical and socio-economic commitments, consistent with sections 48, 53 and 54 of the OPR.	• Appendix 10-2	
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 OPR.	• Appendix 10-2	
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.	• Appendix 10-2	
4.	For CEAA-designated projects, identify which elements and monitoring procedures would constitute follow-up under CEAA 2012.	• Appendix 10-2	
Table A-1 Circumstances and Interactions Requiring Detailed Biophysical and Socio-Economic Information			
Physical and meteorological environment		• Appendix 10-1 • Appendix 10-2	
Soil and soil productivity		• Appendix 10-1 • Appendix 10-2	
Vegetation		• Appendix 10-1 • Appendix 10-2	
Water quality and quantity		• Appendix 10-1 • Appendix 10-2	

Filing #	Filing Requirement	In Application? References	Not in Application? Explanation
Fish and fish habitat, including any fish habitat compensation required		•Appendix 10-1 •Appendix 10-2	
Wetlands		•Appendix 10-1 •Appendix 10-2	
Wildlife and wildlife habitat		•Appendix 10-1 •Appendix 10-2	
Species at Risk or Species of Special Status and related habitat		•Appendix 10-1 •Appendix 10-2	
Air emissions		•Appendix 10-1 •Appendix 10-2	
Greenhouse gas (GHG) emissions		•Appendix 10-1 •Appendix 10-2	
Acoustic environment		•Appendix 10-1 •Appendix 10-2	
Human occupancy and resource use		•Appendix 10-1 •Appendix 10-2	
Heritage resources		•Appendix 10-1 •Appendix 10-2	
Navigation and navigation safety		•Appendix 10-1 •Appendix 10-2	
Traditional land and resource use		•Appendix 10-1 •Appendix 10-2	
Social and cultural well-being		•Appendix 10-1 •Appendix 10-2	
Human health and aesthetics		•Appendix 10-1 •Appendix 10-2	
Infrastructure and services		•Appendix 10-1 •Appendix 10-2	
Employment and economy		•Appendix 10-1 •Appendix 10-2	

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.	• Section 4.2	
2.	A discussion of all potential supply sources.	• Section 3.1.2	
3.	Forecast of productive capacity over the economic life of the facility.	• Section 3.1.2 • Section 3.1.3	
4.	For pipelines with contracted capacity, a discussion of the contractual arrangements underpinning supply.	• Section 3.1.5	
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	• Section 3.3	
2.	In case of new pipeline, justification that size of expansion is appropriate given available supply.	• Section 3.3	
Throughput			
1.	For pipelines with contracted capacity, information on contractual arrangements.	• Section 3.1.5	
2.	For non-contract carrier pipelines, forecast of annual throughput volumes by commodity type, receipt location and delivery destination over facility life.		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	• Section 3.3.4 • Appendix 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
A.3.3 Markets			
1.	Provide an analysis of the market in which each commodity is expected to be used or	• Section 3.1.3	

Filing #	Filing Requirement	In Application? References	Not in Application? Explanation
	consumed.		
2.	Provide a discussion of the physical capability of downstream facilities to accept the incremental volumes that would be delivered.	• Section 3.1.4 • Section 3.3.6	
A.3.4 Financing			
1.	Evidence that the applicant has the ability to finance the proposed facilities.	• Section 3.4	
2.	Estimated toll impact for the first full year that facilities are expected to be in service.	• Section 3.1.8	
3.	Confirmation that shippers have been apprised of the project and toll impact, their concerns and plans to address them.	• Section 3.2	
4.	Additional toll details for applications with significant toll impacts.		N/A
A.3.5 Non-NEB Regulatory Approvals			
1.	Confirm that all non-NEB regulatory approvals, required to allow the applicant to meet the construction schedule and planned in-service date and to allow the facilities to be used and useful, are or will be in place.	•Appendix 10-2	
2.	If any of the approvals referred to in 1. might be delayed, describe the status of those approval(s) and provide an estimation of when the approval is anticipated.	•Appendix 10-2	All approvals will be in place before start of construction activities.

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	• Section 7.3 • Appendix 7-1	
A.4.2 Land Rights			
1.	The type of lands rights proposed to be acquired for the project.	• Section 7.8	
2.	The relative proportions of land ownership along the route of the project.	• Section 7.2	
3.	Any existing land rights that will be required for the project.		N/A
A.4.3 Lands Acquisition Process			
1.	The process for acquiring lands.	• Section 7.8	
2.	The timing of acquisition and current status.	• Section 7.9	
3.	The status of service of section 87(1) notices.	• Section 7.8 • Section 7.9	
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.		N/A
2.	A sample copy of any proposed fee simple, work space, access or other land agreement.	• Appendix 7-3 • Appendix 7-4	
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.	• Appendix 7-2	
2.	Confirmation that all notices include a copy of *Pipeline Regulation in Canada: A Guide for Landowners and the Public.*	• Section 7.8	
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

3.0 PROJECT JUSTIFICATION

This section provides a justification of the proposed facilities, including a description of the:

- supply and markets served by the Project
- firm service shipper commitments that underpin the Project
- commercial third party notifications
- design of the facilities
- alternatives considered
- financing for the Project

3.1 SUPPLY, MARKETS AND TRANSPORTATION

3.1.1 Introduction

The shipper commitments underpinning the Project have a receipt point of Union Parkway Belt (Parkway), which is a point of interconnection between TransCanada's Mainline system and the Union Gas system. The Union Gas system in turn can receive supply from the Western Canadian Sedimentary Basin (WCSB), and other supply basins such as the Marcellus and Utica basins.

The Union Gas system is interconnected to a number of pipelines at Dawn, including TransCanada, Vector, Panhandle, Blue Lake and MichCon. These pipelines have supply connections from a variety of supply regions including the WCSB, Marcellus and Utica basins.

The recent development of the Marcellus and Utica basins in the US Northeast represent growing supplies of natural gas that are near the eastern Canadian markets. The Project will facilitate greater access to these US sources of supply and will serve existing markets in Ontario and Québec that are expected to grow modestly over time.

Gas from the Marcellus and Utica basins is able to enter the Mainline system at interconnect points such as Niagara and Chippawa. From there gas travels to the Union system, where it can make its way to Parkway. The availability of this US supply is a key factor motivating TransCanada's Mainline shippers to contract short-haul service originating at eastern receipt points.

The following sections describe the recent trends in Marcellus and Utica supply development (see Section 3.1.2), market demand to be served by this gas supply (see Section 3.1.3), upstream pipeline development (see Section 3.1.4), and long-term shipper commitments that underpin the Project (Section 3.1.5).

3.1.2 Gas Supply Assessment

North American shale production continues to be a major source of supply, particularly the Marcellus and Utica shale plays in the US Northeast region. This region is close to markets served by the Mainline, and the Marcellus and Utica shale plays encompass the states of Pennsylvania, West Virginia and Ohio. The Marcellus is estimated to contain 11.3 10^{12} m^3 (400 Tcf)[1] of recoverable resource, while the relatively immature yet emerging[2] Utica play could contain 5.7 to 8.5 10^{12} m^3 (200 to 300 Tcf).

TransCanada forecasts gas production from these plays to grow from approximately 401 10^6m^3/d (14 Bcf/d) in 2014, to approximately 958 10^6m^3/d (34 Bcf/d) in 2025. For TransCanada's forecast of future Marcellus and Utica supply, see Figure 3-1.

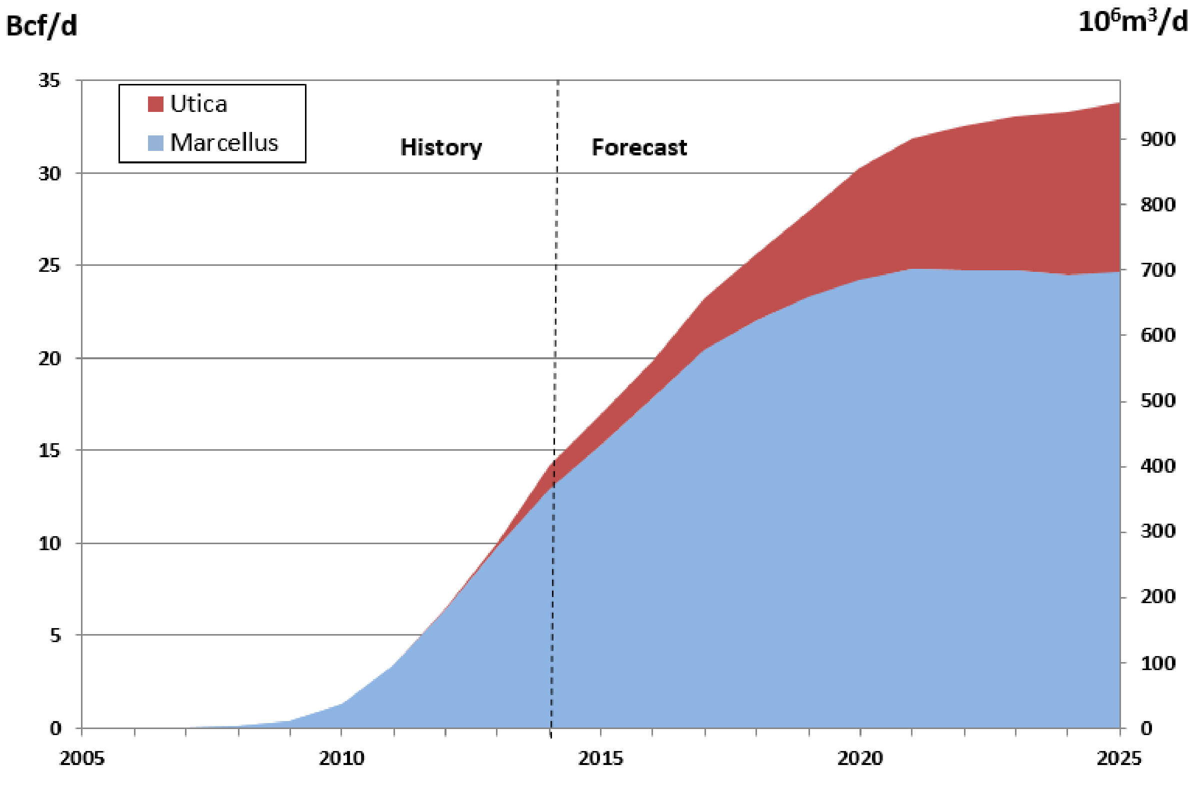


Figure 3-1: Marcellus Region Gas Production Forecast

1 Recovery factor applied to quoted OGIP in "Assessment of Factors Influencing CO_2 Storage Capacity and Injectivity in Eastern U.S. Gas Shales" published by Elsevier Ltd. in Energy Procedia 00 (2013) 000–000.

2 Recovery factor applied to quoted OGIP in "A Geologic Play Book for Utica Shale Appalachian Basin Exploration Final Report" published by Utica Shale Appalachian Basin Exploration Consortium at West Virginia University, July 2015.

Such rapid change is unprecedented in the gas industry, where new sources of gas supply have tended to evolve and mature over decades. In a short period, shale production in North America has changed the dynamics of continental flow away from traditional pipeline transportation routes.

TransCanada's forecast of imports on its system at Niagara and Chippawa is anticipated to increase from 15 to 39 $10^6 m^3/d$ (0.42 and 1.1 Bcf/d) during the next decade. While there will be increased imports to Canada from the US, TransCanada anticipates that supply from the Marcellus and Utica shales will also serve US markets. Given the modest size of the Project, compared with the productive potential of the Marcellus and Utica region, there is more than adequate supply to support the applied-for facilities.

3.1.3 Markets

The Project is driven by incremental market requirements, as well as a desire for supply diversity from existing Eastern markets. The Project will serve existing markets that are expected to grow modestly over time.

Domestic residential, commercial and industrial markets in Ontario and Québec are expected to remain essentially flat, with these sectors forecast to grow from approximately 88.4 $10^6 m^3/d$ (3.1 Bcf/d) in 2014 to approximately 89.8 $10^6 m^3/d$ (3.2 Bcf/d) in 2030. Gas demand in eastern Canada is expected to grow in the power-generation sector. Ontario and Québec gas demand for power is forecast to increase from approximately 9.0 $10^6 m^3/d$ (0.3 Bcf/d) in 2014 to approximately 20.2 $10^6 m^3/d$ (0.7 Bcf/d) in 2030.

As Marcellus and Utica supplies are developed and connected to markets, exports to the US Northeast are forecast to decline from approximately 16.4 $10^6 m^3/d$ (0.58 Bcf/d) in 2014 to approximately 5.2 $10^6 m^3/d$ (0.2 Bcf/d) in 2030.

3.1.4 Upstream Pipeline Development

Union[3] has recently applied to the OEB for a facility expansion on its Dawn Parkway system to be placed in-service for November 2017. Union has stated that its project is necessary for providing greater flexibility, supply diversity and security through increased access to growing US gas supplies from the Marcellus and Utica basins.

The proposed Union 2017 Dawn Parkway Project includes the installation of three new compressor stations. The development of these facilities is anticipated to increase the gas available to the Project and align with the new Parkway receipt requests that underpin the Project.

[3] Union 2017 Dawn Parkway Project (EB-2015-0200).

3.1.5 New Service Requests

TransCanada held a New Capacity Open Season (2017 NCOS) that started on December 12, 2014 and closed on January 30, 2015. It resulted in executed precedent agreements from 12 shippers for a total of 425,081 GJ/d. The precedent agreements include a commitment by TransCanada to provide service subject to certain conditions, such as necessary regulatory approval.

For a summary of the new requests for firm transportation services from these shippers, which are supported by precedent agreements, see Table 3-1. Each new request is for 15 years of Mainline firm transportation services starting November 1, 2017. For a summary of requests for long haul to short haul conversion, see Table 3-2.

Table 3-1: Requests for New Firm Transportation Service

Shipper	Contract Demand (GJ/d)	Service Type	Receipt Point	Delivery Point
1425445 Ontario Limited	3000	FT	Union Parkway Belt	KPUC EDA
Atlantic Power Limited Partnership	6400	FT	Union Parkway Belt	Tunis NDA
Enbridge Gas Distribution Inc.	24484	FT	Union Parkway Belt	Enbridge CDA
Enbridge Gas Distribution Inc.	48737	FT	Union Parkway Belt	Enbridge EDA
Gaz Métro Limited Partnership	11400	FT	Union Parkway Belt	GMIT EDA
GreenField Specialty Alcohols Inc.	1100	FT	Union Parkway Belt	Union EDA
Queen's University at Kingston	1000	FT	Union Parkway Belt	KPUC EDA
St. Lawrence Gas Company, Inc.	10000	FT	Union Parkway Belt	Cornwall
TransCanada Energy Ltd.	42000	FT	Union Parkway Belt	Union EDA
TransCanada Energy Ltd.	100000	FT-SN	Union Parkway Belt	Napanee
Union Gas Limited	5000	FT	Union Parkway Belt	Union EDA
Union Gas Limited	2000	FT	Union Parkway Belt	Union NCDA
Vermont Gas Systems, Inc.	6000	FT	Union Parkway Belt	Philipsburg
Vermont Gas Systems, Inc.	4000	FT	Union Parkway Belt	Philipsburg
Irving Oil Limited	27095	FT	Union Parkway Belt	East Hereford
Northern Utilities, Inc.	6333	FT	Union Parkway Belt	East Hereford
Total	**298549**			

Table 3-1: Requests for New Firm Transportation Service (cont'd)

1 EDA: Eastern Delivery Area
2 CDA: Central Delivery Area
3 NDA: Northern Delivery Area
4 NCDA: North Central Delivery Area
5 FT: Firm Transportation Service
6 FT-SN: Firm Transportation Short Notice Service
7 GMIT EDA: Gaz Métro's Eastern Delivery Area

Table 3-2: Requests for Long Haul to Short Haul Conversion

Shipper	Contract Demand (GJ/d)	Service Type	Receipt Point	Delivery Point
1425445 Ontario Limited	3000	FT	Union Parkway Belt	KPUC EDA
Enbridge Gas Distribution Inc.	8375	FT	Union Parkway Belt	Enbridge CDA
Enbridge Gas Distribution Inc.	15000	FT	Union Parkway Belt	Enbridge CDA
Enbridge Gas Distribution Inc.	40093	FT	Union Parkway Belt	Enbridge CDA
Enbridge Gas Distribution Inc.	7613	FT	Union Parkway Belt	Enbridge EDA
Enbridge Gas Distribution Inc.	26313	FT	Union Parkway Belt	Enbridge EDA
Enbridge Gas Distribution Inc.	451	FT	Union Parkway Belt	Enbridge EDA
Union Gas Limited	887	FT	Union Parkway Belt	Union NCDA
Gaz Métro Limited Partnership	24800	FT	Union Parkway Belt	GMIT EDA
Total	**126532**			

1 EDA: Eastern Delivery Area
2 CDA: Central Delivery Area
3 NCDA: North Central Delivery Area
4 FT: Firm Transportation Service
5 GMIT EDA: Gaz Métro's Eastern Delivery Area

3.1.6 Turnback

To determine the appropriate amount of capacity required to meet the requests for new service, TransCanada held a Capacity Management Open Season (CMOS), which closed on March 13, 2015. TransCanada sought requests for the turnback of Firm Transportation Service (FT), Storage Transportation Service (STS) and Firm Transportation Short Notice Service (FT-SN) that could help reduce or eliminate the incremental facilities otherwise required as a result of the NCOS. TransCanada received 90,000 GJ/d of acceptable turnback bids.

3.1.7 Term Up

In addition to the CMOS referenced above, TransCanada also initiated a Term Up process as approved by the NEB in its RH-001-2014 Decision. To help determine the appropriate amount of capacity required to meet the new service requests, TransCanada submitted Term Up Notices to those customers whose contract paths had an impact on the requirement for the new facilities. The notices were submitted to customers in March 2015. Customers then had in excess of the minimum 60 days to elect to extend the term of their existing contracts for an additional period so that the new termination date of their contracts was no less than five years from the requested in-service date of the new facilities, in this case, November 1, 2017. As a result of this process, some customers elected not to term up their contracts, which reduced the overall contract requirement by an additional 39,414 GJ/d.

3.1.8 Impact on Mainline Tolls

The tolling treatment for the service requested in the 2017 NCOS will be consistent with the NEB's RH-001-2014 Decision, which supports the efficient development of natural gas infrastructure in eastern Canada to serve market demand for supply diversity and market access. Because of the settlement agreement, filed in the RH-001-2014 proceeding (Settlement Agreement) and the resulting Compliance Tolls, it is difficult to determine a specific impact of the Project in isolation.

On average, the 2018–2020 annual cost of service will increase by approximately $23 million with the addition of an annual cost of $22 million for the Project and an estimated annual cost of $0.7 million for the TBO arrangement, subject to the OEB-approved rate methodology.

The overall average annual cost of service impact was calculated using the following assumptions:

- cost of service parameters from the RH-001-2014 proceeding
- capital cost of approximately $221 million for the Project
- associated TBO on the OEB-approved Enbridge Albion Pipeline of approximately $0.7 million per year

The fuel ratio impact as a result of the Project is forecast to be negligible because the Project facilities consist of pipe with no additional compression.

3.1.9 Summary

The Project is consistent with the Settlement Agreement. The applied-for facilities are supported by new long-term service commitments, long-term supply, new and existing upstream pipeline infrastructure and sufficient long-term markets. The Project will provide the market with greater flexibility and greater access to emerging supplies from the Marcellus and Utica shale regions.

3.2 NOTIFICATION OF COMMERCIAL THIRD PARTIES

On September 9, 2015, TransCanada provided a presentation to the Mainline Tolls Task Force (TTF), requesting that the TTF provide any comments or concerns they may have regarding the Project.

In that presentation, TransCanada outlined the firm service shipper commitments that underpin the Project and provided detail on the location and type of expansion required to meet these contractual obligations. In accordance with the confidentiality provisions of the TTF, TransCanada requested that any comments that parties wished to share non-confidentially be provided outside the TTF forum by September 23, 2015. No comments or concerns were received.

3.3 SYSTEM DESIGN

This section summarizes the hydraulic design of the facilities, including capability and alternatives.

3.3.1 Description of the Proposed Facilities

With the new service requests shown in Tables 3-1 and 3-2 starting November 1, 2017, the requirements on the pipeline segments leading out of Parkway and into Station 130 will exceed the capacity provided by the existing facilities. As such, the following facilities are required:

- approximately 11.7 km of 1067 mm (NPS 42) pipeline
- associated valves and fittings, and launcher and receiver facilities

3.3.2 Facility Purpose and Operation

As with the existing lines 200-2 and 200-3, which have the ability to flow bi-directionally, the Project will have the ability to flow bi-directionally as required by market conditions. Depending on area gas demands, the pipelines in the Parkway area are able to both receive gas from and deliver gas to Union Gas. Historically, area demands have resulted in the pipeline system receiving gas from Union Gas for most of the year, with some deliveries to Union Gas during the summer period.

3.3.3 Design Conditions

TransCanada designs its system to meet firm transportation requirements for all days of the year. For the applied-for facilities, the defining design condition is a peak winter day, when flows received at Parkway are at their highest, and with a loss of a critical unit at Station 130.

3.3.4 Capability Impact of the Proposed Facilities

For determination of the facilities' capability with the inclusion of the Project, TransCanada used Station 130 as a measurement point. The new service requests listed in Tables 3-1 and 3-2, in combination with expiring contracts, results in incremental winter 2017/2018 firm requirements of 296 TJ/d, for a total Station 130 throughput requirement of 3165 TJ/d. Without the applied-for facilities, there would be a firm design day shortfall of 362 TJ/d.

Once the Project is constructed, the system capability equals the contractual requirements (see Table 3-3). Appendix 3-1 shows flow schematics for the peak day design cases with the new facilities.

Table 3-3: Capability versus Requirements (TJ/d)

Net Maple (Station 130) Requirements	**3165 (TJ/d)**	1
Without Facilities		
Capability	2803	2
Shortfall (2 minus 1)	(362)	3
With Facilities		
Capability	3165	4
Available (4 minus 1)	0	5

3.3.5 Transportation by Others

To meet the new firm requirements, an additional 105 TJ/d of TBO on the Enbridge Albion Pipeline is required in addition to the proposed facilities, via an Enbridge open season.

3.3.6 Upstream Capacity

This pipeline will be integrated into the TransCanada Mainline system and will be supplied via TransCanada's Line 200-2 and the KNC project, once constructed.

3.3.7 Alternatives Considered

TransCanada evaluated options for transporting the requested volumes and considered the following two alternatives to the Project:

- a facility alternative
- pipe size alternative

3.3.8 Facility Alternative

In order to meet the new service requests, the facility alternative to the Project would be the addition of three new 15 MW units at Station 130. This alternative was eliminated due to higher capital cost, fuel and operating expenses, and operational inefficiencies.

3.3.9 Pipe Size Alternative

As an alternative to the applied-for 1067 mm (NPS 42) pipe for the Project, a 914 mm (NPS 36) pipeline was considered. However, this alternative pipe size would result in an unacceptably large pressure drop that would subsequently reduce the suction pressure at Station 130 to the extent that there would be insufficient power to meet the November 1, 2017 contracted volumes. In addition, using a smaller pipe size would increase the likelihood that the pipeline may need to be looped in the future, thereby increasing land disturbance.

3.4 FINANCING

TransCanada will fund Project construction through cash flow generated from operations and new senior debt. TransCanada will also consider a combination of other funding options, such as subordinated capital in the form of additional preferred shares and hybrid securities, issuance of common shares and portfolio management.

Since 2010, TransCanada and TransCanada Corporation have generated $20 billion from operations and raised $18 billion in the debt and equity capital markets to support a $25 billion capital program and repay $7 billion in debt maturities.

TransCanada's and TransCanada Corporation's liquidity, access to capital markets and strong financial position provide significant financial flexibility. As of September 30, 2015, TransCanada and other subsidiaries of TransCanada Corporation had approximately $750 million cash on hand, $5.6 billion undrawn committed credit facilities and two well-supported commercial paper programs.

As of September 30, 2015, TransCanada Corporation's consolidated capital structure consisted of 35% common equity, 5% preferred shares, 4% junior subordinated notes and 56% debt net of cash.

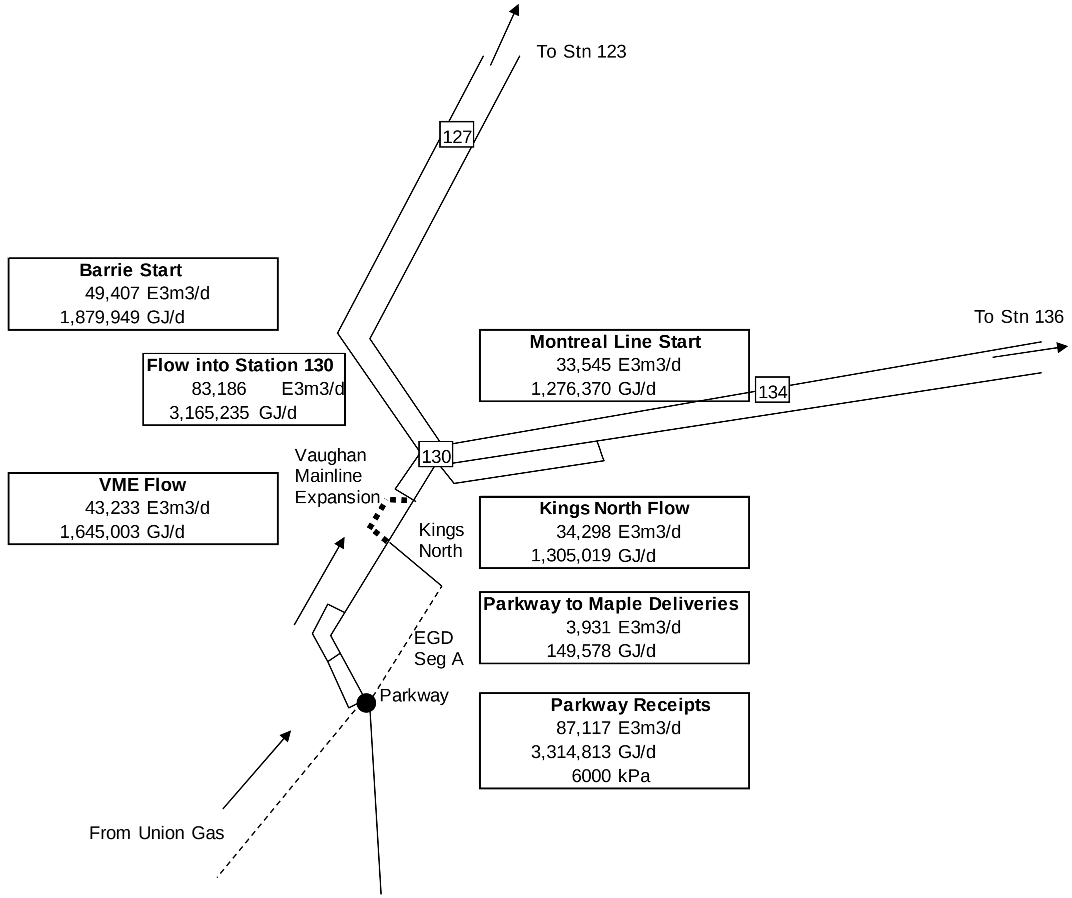
TransCanada and TransCanada Corporation have been assigned “A” level investment grade credit ratings by Moody’s Investor Service, Inc. and Standard and Poor’s in the US, and by DBRS Limited (DBRS) in Canada.

See the following appendices for copies of the recent rating reports issued by the credit agencies:

- Appendix 3-2 – Moody’s Investor Service opinion report on TransCanada PipeLines Limited dated June 8, 2015
- Appendix 3-3 – Dominion Bond Rating Service report on TransCanada PipeLines Limited and TransCanada Corporation dated June 5, 2015
- Appendix 3-4 – Standard and Poor’s Research report on TransCanada Corporation dated September 8, 2015

Appendix 3-1

Schematic



Compressor Station Data in E6m3/d

STN	**127**	**130**	**134**
MWA	29.49	43.68	11.39
MWR	20.61	30.99	8.45
P Suc.	3957	4348	3932
P Dis.	5501	5487	5797
Ratio	1.38	1.26	1.46
Fuel	0.152	0.234	0.000
Flow	43.465	82.952	15.354
TS/TD	23/50	31/50	17/50

TransCanada
In business to deliver

Parkway-Maple Area Flow Schematic

System Capability
Peak Winter Day LOU with Facilities
Operating Year:
2017/18

11/5/2015	Page 1/1

Appendix 3-2

Moody's TCPL Credit Opinion
June 8, 2015

MOODY'S
INVESTORS SERVICE

Credit Opinion: TransCanada PipeLines Limited

Global Credit Research - 08 Jun 2015

Calgary, Alberta, Canada

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	A3
Senior Unsecured	A3
Jr Subordinate	Baa1
Parent: TransCanada Corporation	
Outlook	Stable
Issuer Rating	Baa1
TransCanada Trust	
Outlook	Stable
Bkd Subordinate	Baa2
NOVA Gas Transmission Ltd.	
Outlook	Stable
Senior Unsecured	A3
TC PipeLines, LP	
Outlook	Stable
Senior Unsecured	Baa2
ANR Pipeline Company	
Outlook	Stable
Senior Unsecured	A3

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William L. Hess/New York City	212.553.3837

Key Indicators

[1]**TransCanada PipeLines Limited**

	3/31/2015(L)	12/31/2014	12/31/2013	12/31/2012	12/31/2011
(FFO + Interest) / Interest	**3.7x**	**3.7x**	**3.7x**	**3.3x**	**3.5x**
FFO / Debt	**11.8%**	**13.0%**	**13.5%**	**12.7%**	**13.9%**
(FFO - Dividends) / Debt	**7.0%**	**7.8%**	**8.1%**	**6.8%**	**9.0%**

[1] Based on consolidated financial data of TransCanada Corporation. All ratios are calculated using Moody's Standard Adjustments.

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Scale and portfolio diversification benefits

Stable and growing cash flow

Execution risk surrounding large capital program

Stable credit metrics and credit supportive financial policies

Corporate Profile

TransCanada PipeLines Limited (TCPL: A3 stable) is the principal subsidiary and debt issuer of TransCanada Corporation (TransCanada: Baa1 stable, issuer rating), headquartered in Calgary, Alberta. TransCanada is an energy infrastructure company with three business segments: Natural Gas Pipelines (56% of LTM EBITDA including regulated gas storage of 250 Bcf, 68,000 km), Liquids Pipelines (20% of LTM EBITDA), and Energy (24% of LTM EBITDA including unregulated gas storage of 118 Bcf, 10,900 MW). TCPL is the GP of and owner of a 27.6% interest in TC PipeLines, LP (TCP: Baa2 stable), a publicly traded master limited partnership (MLP) that owns a portfolio of TransCanada's US interstate gas pipelines.

SUMMARY RATING RATIONALE

TCPL's credit quality is driven by its generally predictable and growing cash flow, large size and portfolio diversification benefits. Offsetting these key strengths are the execution risks and pressure on financial metrics that will result from its large capital program, highlighted by the ongoing uncertainty around Keystone XL, and its forecast of ongoing high levels of debt. The long term issuer rating on parent TransCanada is one notch below the consolidated rating of A3 as a result of its structural subordination to TCPL.

DETAILED RATING CONSIDERATIONS

SCALE AND PORTFOLIO DIVERSIFICATION BENEFITS

Substantial financial resources with forecasted 2015 EBITDA of more than C$5bn, economies of scale from its large and diverse asset base of more than C$60 billion and strong market access all support current credit quality. Portfolio diversification by geography, business line and counterparty reduces overall cash flow volatility, a key credit strength. While some assets may have moderate levels of correlation, substantial portions of the portfolio are uncorrelated due to the specific business line fundamentals.

STABLE AND GROWING CASH FLOW

Cash flow that is primarily regulated or contracted provides a greater degree of certainty, a key credit strength. An agreement with Eastern LDC's regarding the "Mainline" was approved by the National Energy Board in November 2014 and we expect the Mainline to continue to earn its allowed ROE. The regulated NGTL system is expected to generate stable returns and we expect cash flow growth will be driven by ongoing rate base investments on the system. US pipelines continue to exhibit volatility as a result of changing gas fundamentals in the US. Some of the pipelines benefit from a mix of contracts and a strong underlying competitive position; however, shifting volume flows driven by the emergence of shale gas has led to increased variability and some declines in this previously stable segment. The company is repurposing its existing infrastructure, managing its cost profile and creating new connections to adapt to the changing landscape. The long term contracts with an average life of 23 years for all of the capacity on the Southeast Main Line portion of the ANR Pipeline system is a good example. The Liquids segment, currently dominated by the Keystone Base system is expected to provide relatively stable cash flow until the end of the 20 year contracts in 2030. Key contract terms that support our assumption of stable cash flow generation are the take or pay nature of the contracts covering 90%, or 530kbpd of the 590kbpd pipeline capacity. TCPL is not exposed to underlying commodity prices and key variable costs including power, property taxes and maintenance are flow through costs to shippers. At the end of the contract term TCPL will have fully recovered the capital costs of its initial investment. The Energy segment includes some of the most variable cash flows in the company, although the sub segments and individual assets have very different profiles. The segment itself is reasonably well diversified by fuel type, geography and facility. Riskier cash flows are exposed to dispatch, price and operating risks, while some contracts provide capacity payments with operating risk as the only meaningful exposure.

EXECUTION RISK SURROUNDING LARGE CAPITAL PROGRAM

The company's capital program will improve the company's business risk profile upon completion but carries material execution risk and will put pressure on key credit metrics during construction, both negatives for credit quality. All of the investments are underpinned by either long term contracts with favorable terms that are expected to generate stable long term cash flow or to a lesser extent are being made into regulated businesses with strong underlying fundamentals. Contract terms would typically include take or pay provisions with minimum volume commitments, no commodity price risk, a long contract tenor with generally creditworthy counterparties and a flow through of variable costs. The total capital program over the period 2015 to 2020 is substantial at about $46 billion, or about 70% of total assets. About $12 billion is planned for a series of smaller to medium sized projects with limited execution risk that are largely expected to be in-service by the end of 2017, with the remainder going into five large projects totaling about $34 billion. These projects are Energy East, two LNG Gas pipelines, Keystone XL and NGTL's Merrick Pipelines ($1.9 billion). These first four projects with total capital spending of $32 billion expose the company to varying degrees of execution risk, including exposure to potential cost overruns (partially mitigated by cost sharing mechanisms with shippers) and delays in project in-service dates. Given the size of these projects, they add a binary component to many aspects of the company's credit profile. Each of these four projects is exposed to varying degrees of uncertainty that affect both the likelihood and timing of the projects moving forward. Execution risks would be exacerbated if the company were to progress with more than one project at a time. The figures above do not include refurbishment of Ontario nuclear reactors.

STABLE CREDIT METRICS AND CREDIT SUPPORTIVE FINANCIAL POLICIES

We expect the company to continue to generate predictable, growing cash flow and maintain stable credit metrics, a key credit strength. We base this on the diversity and underlying quality of cash flows and the company's financial strategies, particularly in light of the company's large capital program. Management has indicated that it intends to maintain its target of 15% reported FFO to debt and we expect adjusted FFO/debt to remain in the range of about 13-15%. While the large capital program could put pressure on the balance sheet management has identified several levers that it intends to utilize to finance its expected capital program. In addition to internally generated cash flow and debt issuance, we expect the company to issue preferred shares and hybrid securities with some equity characteristics and actively manage its portfolio of assets. The company has also publicly announced its intention to sell its remaining US gas pipeline assets to TC Pipelines over the 2015-2017 period to help fund its capital program. The company may also engage in assets sales and take on strategic partners on its largest projects. Depending on the ultimate profile of the capital program and the combination of factors above, management may also issue equity through a dividend reinvestment program or direct equity issuance. Financial metrics, on an LTM basis, are below our expectations, however they are in part somewhat depressed by $C1.8 billion of largely unrestricted cash on hand and the impact of foreign exchange rates. We include hybrid instruments of C$2.5 billion at TransCanada Corporation as part of our consolidated financial analysis of TCPL.

Liquidity Profile

TransCanada currently has an adequate liquidity profile; however, its current committed sources of alternate liquidity are modest relative to its capital program and the company relies in part on short-term facilities that must be renewed annually. These liquidity arrangements are based on the company's continued ability to extend its expiring 364-day facilities and refinance its upcoming debt maturities. TransCanada has extended its existing facilities for another year and has historically not experienced difficulty in obtaining these extensions. We believe the company continues to have strong access to the capital markets.

At the end of March 2015, TransCanada reported cash on hand of C$1.8 billion. For the twelve months ended 31 March 2015, the company had negative free cash flow of C$2.3 billion as a result of CFO of C$3.7 billion, capex of C$4.3 billion, and total dividends of C$1.6 billion (figures Moody's adjusted). TransCanada expects to spend about $12 billion in capital expenditures in 2015-2017 excluding any construction costs associated with its large projects.

The amount of TransCanada's committed credit facilities would not be able to cover the negative free cash flow and near-term debt maturities if it were to move forward with these large projects. We have assumed that the company would likely increase the size of its committed and short-term facilities consistent with final investment decisions on its large capital projects. At 31 March 2015, TransCanada had C$5.5 billion (C$2.7 billion of unused capacity) of committed credit facilities: a C$3 billion revolver at TCPL expiring in December 2019 and two extendible 364-day US$1 billion revolvers at TCPL USA and at TransCanada American Investments Limited (TAIL), both expiring on 6 November 2015. The revolver at TCPL provides for same day funding up to a swingline sub-commitment of C$750 million, and credit facilities at TCPL USA and TAIL each provide for same day funding up to US$1 billion. The facilities at TCPL and TAIL are undrawn backup facilities for commercial paper programs at each of these entities. The facilities do not require the company to represent and warrant as to a material adverse event at each borrowing, which supports liquidity. These facilities include a single financial covenant setting the maximum consolidated debt/capitalization at 75%. TransCanada has ample headroom under that covenant. In the next 12 months TransCanada has about C$2.1 billion of long-term debt due and we expect TransCanada to refinance these debt obligations as they mature.

Rating Outlook

The stable outlook for the company is based on ongoing stable earnings and cash flow. Given the company's funding strategy for its large capital program we do not anticipate any meaningful decline in credit metrics that could lead to a rating action.

What Could Change the Rating - Up

We do not expect a rating upgrade in the near to medium term. The company's leverage is relatively high and the large capital program is unlikely to lead to an improvement in the financial profile for the duration of the period of high capital spending. While we don't expect it, if following the successful completion of the large capital program we forecast FFO/debt in the high teens we could raise the rating.

What Could Change the Rating - Down

A downgrade could occur if the company fails to deliver its capital program on time and budget leading to a sustained forecasted decline in Moody's adjusted credit metrics to about 12% FFO/debt. We could also downgrade the company if the company experiences increased cash flow variability in its core businesses or if the company changes its financial policies.

Rating Factors

TransCanada PipeLines Limited

Natural Gas Pipelines Industry Grid [1]	**Current LTM 3/31/2015**		[2]**Moody's 12-18 Month Forward ViewAs of 6/8/2015**	
Factor 1 : Market Position (15%)	**Measure**	**Score**	**Measure**	**Score**
a) Demand Growth		Aaa		Aaa
b) Competition		A		A
c) Volume Risk & Throughput Trend		A		A
Factor 2 : Quality of Supply Source (10%)				
a) Supply Source		Aaa		Aaa
Factor 3 : Contract Quality (30%)				
a) Firm Revenues		A		A
b) Contract Life		Aa		Aa
c) Shipper Quality / Recontracting Risk		A		A
Factor 4 : Financial Strength (45%)				
a) (FFO + Interest) / Interest	3.7x	Ba	3.5x - 4x	Ba
b) FFO / Debt	11.8%	Ba	13% - 15%	Ba
c) (FFO - Dividends) / Debt	7.0%	Ba	6% - 8%	Ba
Rating:				
a) Indicated Rating from Grid		Baa1		Baa1
b) Actual Rating Assigned		A3		A3

Source: Moody's Financial Metrics

[1] Based on consolidated financial data of TransCanada Corporation. All ratios are calculated using Moody's Standard Adjustments. [2] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the ratings tab on the issuer/entity page on http://www.moodys.com for the most updated credit rating action information and rating history.

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Appendix 3-3

DBRS TransCanada Corp RR Final
June 5, 2015

Rating Report

TransCanada Corporation & TransCanada PipeLines Limited

Insight beyond the rating.

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Ratings

Debt Rated	Issuing Entity	Rating	Rating Action	Trend
Issuer Rating	TransCanada PipeLines Limited	A (low)	Confirmed	Stable
Unsecured Debentures & Notes	TransCanada PipeLines Limited	A (low)	Confirmed	Stable
Junior Subordinated Notes	TransCanada PipeLines Limited	BBB	Confirmed	Stable
Commercial Paper	TransCanada PipeLines Limited	R-1 (low)	Confirmed	Stable
Preferred Shares – Cumulative	TransCanada Corporation	Pfd-2 (low)	Confirmed	Stable

Rating Update

DBRS Limited (DBRS) has confirmed the ratings of TransCanada Corporation (TCC or the Company) and its wholly owned subsidiary, TransCanada PipeLines Limited (TCPL), both with Stable trends. The preferred share rating of TCC, which owns 100% of TCPL and holds no other material assets, is based on the strength of TCPL and the expectation that no debt will be issued at TCC. The ratings primarily reflect (1) expected improvement in TCC's overall business risk profile over the medium term, (2) potential medium-term pressure on its credit metrics and (3) environmental, regulatory and political risks with respect to its natural gas and liquids pipelines segments.

1. TCC's planned $46 billion growth capital expenditures (capex) program ($12 billion of small- to medium-term projects and $34 billion of large-scale, medium- and longer-term projects) would improve TCC's overall business risk profile by expanding its lower-risk liquids pipeline segment and reducing its proportional exposure to the Canadian Mainline natural gas pipeline and to volume and/or commodity price risk within its Energy segment. The growth projects are largely contracted with good counterparties and, if completed, would also reduce the proportion of its EBITDA that is exposed to commodity price risk.

2. DBRS expects TCC's credit metrics to be pressured in the medium term, particularly if some of its large-scale projects are approved in the next few quarters. Key credit metrics targeted by TCC are cash flow-to-debt of at least 15% and cash flow-to-interest of at least 3.0 times (x; 13.8% and 4.0x, respectively, as calculated by DBRS as at March 31, 2015). The negative impacts of the weaker Canadian dollar on outstanding U.S.-dollar debt and pre-funding of near-term spending in Q1 2015 were key factors contributing to artificially weak metrics at the end of Q1 2015. DBRS expects that the length of time of credit metric underperformance would be dependent on the timing of approval and capex spending pattern of the projects that are currently awaiting regulatory approvals and/or final investment decisions.

3. TCC faces environmental, regulatory and political risks with respect to several projects, including Keystone XL, which has been repeatedly delayed due to environmental and political issues. Future project execution could entail longer lead times and higher construction costs than before, potentially affecting Energy East and other large projects. Regulatory risk was highlighted by the National Energy Board's (NEB) March 2013 and November 2014 Canadian Mainline decisions, which eliminated the full throughput protection of the previous tolling methodology and resulted in lower earnings despite higher throughput in Q1 2015 and could potentially lead to lower Canadian Mainline earnings going forward.

Financial Information

(DBRS-adjusted amounts and ratios)	3 mos. ended Mar. 31		12 mos. ended Mar. 31	For the year ended December 31			
(CAD millions, US GAAP in all periods)	**2015**	**2014**	**2015**	**2014**	**2013**	**2012**	**2011**
Net income before extras	488	447	1,855	1,814	1,678	1,407	1,636
Cash flow (before working capital changes)	1,153	1,102	4,319	4,268	3,916	3,284	3,451
Total debt & equivalents/capital	57.7%	54.0%	57.7%	55.3%	53.9%	51.7%	51.0%
Cash flow/total debt & equivalents	14.7%	17.1%	13.8%	15.4%	15.5%	15.1%	16.4%
EBITDA interest coverage [1]	4.08	4.17	3.96	3.98	3.76	3.44	3.67
EBIT interest coverage [1]	2.92	3.03	2.81	2.83	2.63	2.36	2.59
Fixed-charges coverage (EBIT-based) [1]	2.70	2.76	2.57	2.59	2.39	2.18	2.39
Common & pref divs/net income (before extras)	80.3%	81.4%	80.2%	80.4%	83.1%	93.6%	76.8%

1 Includes dividends/distributions received from equity investments in numerator of each ratio.

Rating Considerations

Strengths

1. Growth capex would improve business risk profile.
TCC's planned $46 billion capex program (see Major Capital Projects section) would improve the Company's overall business risk profile by expanding its lower-risk liquids pipeline segment and reducing its proportional exposure to the Canadian Mainline and to volume and/or commodity price risk within its Energy segment. The growth projects are largely contracted with good counterparties and, if completed, would also reduce the proportion of its EBITDA that is exposed to commodity price risk. Ownership of one of the largest integrated natural gas pipeline networks in North America should allow it to adapt to changing supply/demand dynamics over time.

2. Regulatory/contractual framework for pipelines.
Despite challenges in recent years (see below), the Company has benefited from the regulatory and/or contractual framework within its pipeline segments, which have accounted for approximately 75% of its segment EBITDA in recent years. The NEB and the Federal Energy Regulatory Commission (FERC) (although to a lesser extent) have been relatively supportive in providing the regulatory framework necessary for pipelines to have the opportunity to recover their costs and earn an adequate return on equity (ROE) and return of equity over a reasonable time frame.

3. Base-load/long-term contract support in Energy.
TCC's Energy segment benefits from its weighting toward base-load power and long-term contractual arrangements. A substantial proportion of the EBITDA from TCC's Energy segment is supported by long-term power contracts with creditworthy parties (e.g., Ontario Power Authority (OPA) and Hydro-Québec, both rated A (high) by DBRS). In addition, more than 80% of its 2,034 megawatts (MW) of capacity in Alberta is from base-load coal-fired electricity generation under power purchase agreements (PPAs) that expire in 2017 (560 MW) and 2020 (1,109 MW), although low power prices resulted in low returns in 2014 and Q1 2015.

4. Reasonable balance sheet and credit metrics.
The Company's financial profile remains reasonable for its business risk profile as capex has been lower than previously anticipated due to the ongoing Keystone XL delay (see Financial Profile section).

Challenges

1. Uncertainties in natural gas pipeline segment.
TCC faces challenges in its Canadian and U.S. natural gas pipeline segments related to changing gas flows as a result of large-scale shale gas production, particularly in various regions in the United States, which has resulted in depressed continental gas prices. This trend in turn had a disproportionately negative impact on the Canadian Mainline's 2012 and 2013 volumes, thereby driving up tolls under the previous cost-of-service methodology to levels that resulted in lower netbacks for natural gas producers. The NEB's recent decisions (see Regulation – Canadian Mainline and NOVA Gas Transmission Ltd. (NGTL) System section) have resulted in an increase in TCC's business risk by eliminating the full throughput protection of the previous tolling methodology as Canadian Mainline earnings fell in Q1 2015 despite higher throughput. DBRS believes that similar issues could develop with respect to certain TCPL natural gas pipelines in the United States over the medium term.

2. Volume and/or price risk with some assets.
The Company faces volume and/or commodity price risk within some of its assets. For example, its U.S. natural gas pipelines retain some volume risk, although usually limited to certain components of toll revenue. The Canadian Mainline is more exposed to volume risk following recent NEB decisions and the Keystone Pipeline System (Base Keystone) has a relatively small uncontracted component, while Gulf Coast Pipeline's long-term contracts only come into effect when Keystone XL is completed. Energy segment assets have exposure to either one or both of price and volume risk. TCC hedges much of its limited commodity price exposure.

3. Rising environmental regulatory and political risk.
TCC faces environmental, regulatory and political risks with respect to several projects, including Keystone XL, which has been repeatedly delayed due to environmental and political issues. The NEB's recent decisions with respect to the Canadian Mainline provide an example of regulatory risk. These issues raise the possibility that future pipeline project development could entail longer lead times and construction costs than previously experienced, potentially affecting other projects.

4. Potential medium term pressure on credit metrics.
TCC's credit metrics will likely be pressured in the medium term, particularly if some of its large-scale projects are approved in the next few quarters prior to improvement (starting in 2017) as most of the $11.6 billion of small- to medium-sized projects are placed into service and begin to generate cash. Key credit metrics targeted by TCC are cash flow-to-debt of at least 15% and cash flow-to-interest of at least 3.0x. DBRS expects that the length of time of underperformance with respect to these metrics would be dependent on the timing of approval and capex spending pattern of the projects.

Regulation – Canadian Mainline and NGTL System

The Canadian Mainline, NGTL System and the other Canadian natural gas pipelines owned and/or operated by TCPL are regulated by the NEB, which regulates the construction and operation of facilities and the terms and conditions of service (including rates) that are expected to provide TCPL with the opportunity to recover the costs of transporting natural gas, including return of and return on capital.

Canadian Mainline

In March 2013, the NEB released a decision that set Canadian Mainline tolls for 2013 through 2017 at competitive levels, fixing tolls for some services and providing unlimited pricing discretion for others.

- The NEB established an allowed ROE of 11.5% on 40% deemed common equity and included mechanisms to achieve the fixed tolls through the use of a Long Term Adjustment Account (LTAA) as well as a Tolls Stabilization Account (TSA) to capture the surplus (or shortfall) between revenues and cost of service for each year over the five-year term of the decision.
- The decision provided an opportunity to generate incentive earnings by raising revenues and reducing costs.
- The NEB also identified certain circumstances that would require a new tolls application prior to the end of the five-year term. One of those circumstances occurred in 2013 when the TSA balance became positive. In December 2013, TCC filed the 2015-2030 Tolls and Tariff Application that addressed tolls moving forward.

In November 2014, the NEB approved the Canadian Mainline's 2015-2030 Tolls and Tariff Application under which TCC and the three largest Canadian local distribution companies agreed to the following terms:

- New fixed tolls for 2015 to 2020 as well as certain parameters for a toll-setting methodology to 2030.
- Tolls to be calculated on a 10.1% base allowed ROE on 40% deemed common equity.
- Includes an incentive mechanism that requires a $20 million (after-tax) annual contribution by TCC from 2015 to 2020, which could result in a range of ROE outcomes from 8.7% to 11.5%.
- Toll stabilization through continued use of deferral accounts, namely the LTAA and the Bridging Amortization Account, to capture the surplus (or shortfall) between revenues and cost of service for each year over the six-year term of the decision.
- TCC was required to file a compliance filing with the NEB in Q1 2015 (filed March 31, 2015, currently operating under interim tolls) and a toll review for the 2018 to 2020 period prior to December 31, 2017.
- TCC commited to increase pipeline capacity to eastern Canadian markets for supplies from the Dawn and Niagara, Ontario, regions.
- Provides a market driven, stable, long-term accommodation of future demand in the region in combination with the anticipated lower demand for transportation on the Prairies Line and the Northern Ontario Line while providing a reasonable opportunity for TCC to recover related Canadian Mainline costs.
- TCC retains pricing flexibility for discretionary services to implement certain toll changes and new services as required by the terms of the settlement.

NGTL System

In February 2015, the NEB approved the NGTL System's 2015 Revenue Requirement Settlement Application. The Settlement structure is similar to the previous 2013–2014 Settlement with fixed annual operating, maintenance and administration (OM&A) costs, allowed ROE and deemed common equity. Any variance between fixed OM&A costs in the Settlement and actual costs accrue to TCC.

- Allowed ROE was fixed at 10.1% on 40% deemed common equity in 2015 (same as for 2013 and 2014), compared with 9.7% allowed ROE on 40% deemed common equity in 2012.
- Depreciation expense was established at a forecast composite rate of 3.12% in 2015 (same as for 2014), compared with a composite rate of 3.05% for 2013 and 2.71% in 2012.
- OM&A costs for 2015 were fixed at an escalation of 2014 actual costs, with any variances to NGTL's account. All other costs were passed through to the shippers on a flow-through basis.

In April 2015, the NEB recommended that the federal government approve the NGTL System's $1.7 billion North Montney Mainline Project (see Major Capital Projects section) and approved the rolled-in tolling design for the project costs during a transition period, subject to certain conditions that TCC is reviewing. The project remains subject to certain conditions, including a final investment decision on the associated LNG project.

Earnings and Outlook

Income Statement	3 mos. ended Mar. 31		12 mos. ended Mar. 31	For the year ended December 31			
	2015	2014	2015	2014	2013	2012	2011
(CAD millions, US GAAP, DBRS-adjusted)							
Canadian Natural Gas Pipelines	522	566	2,274	2,318	2,107	1,892	1,961
U.S. & International Natural Gas Pipelines	371	291	1,020	941	780	878	966
Business Development Costs	(18)	(9)	(26)	(17)	(35)	(29)	(52)
Natural Gas Pipelines EBITDA before extras	874	848	3,267	3,241	2,853	2,741	2,875
Liquids Pipelines EBITDA before extras	309	241	1,127	1,059	752	698	587
Energy EBITDA before extras	388	345	1,391	1,348	1,362	903	1,168
Segment EBITDA before extras	1,571	1,434	5,785	5,648	4,967	4,342	4,630
Corporate and other	(42)	(3)	(109)	(70)	(100)	22	(108)
EBITDA before extras [1]	1,529	1,431	5,676	5,578	4,867	4,364	4,522
Depreciation & amortization	(434)	(393)	(1,652)	(1,611)	(1,472)	(1,375)	(1,328)
EBIT before extras [1]	1,095	1,038	4,024	3,967	3,395	2,989	3,194
Interest expense, net	(305)	(264)	(1,184)	(1,143)	(1,006)	(969)	(931)
Net income before extras and taxes	790	774	2,840	2,824	2,389	2,020	2,263
Other income (expense)	(55)	(103)	(103)	(151)	(49)	(136)	(33)
Income taxes recovered (paid)	(247)	(224)	(882)	(859)	(662)	(477)	(594)
Net Income before extraordinary items	488	447	1,855	1,814	1,678	1,407	1,636
Extraordinary items	(78)	(10)	(40)	28	128	(31)	(33)
Reported net income	410	437	1,815	1,842	1,806	1,376	1,603
Segment EBITDA Breakdown							
% Canadian Natural Gas Pipelines	33%	39%	39%	41%	42%	44%	42%
% U.S. & International Natural Gas Pipes	24%	20%	18%	17%	16%	20%	21%
% Natural Gas Pipelines	56%	59%	56%	57%	57%	63%	62%
% Liquids Pipelines	20%	17%	19%	19%	15%	16%	13%
% Energy	25%	24%	24%	24%	27%	21%	25%

1 Includes dividends/distributions received from equity investments.

Net income (before extras) rose by $136 million (8%) in 2014 compared with 2013, mainly due to much higher EBITDA from Natural Gas Pipelines and Liquids Pipelines, partly offset by lower Energy EBITDA and higher corporate and income tax expense (see Business Segments section for detailed EBITDA breakdown).

- Canadian Natural Gas Pipelines EBIT and EBITDA rose by 14% and 10%, respectively, largely reflecting higher Canadian Mainline incentive earnings in 2014 (see Regulation – Canadian Mainline section).
- U.S. and International Natural Gas Pipelines EBIT and EBITDA rose by 25% and 21%, respectively, mainly due to higher earnings from the Tamazunchale Extension placed into service in 2014, higher revenue at Great Lakes Gas Transmission Limited Partnership (as a result of increased demand from cold winter weather) and the positive impact of a the stronger U.S. dollar relative to the Canadian dollar.
- Liquids Pipelines EBIT and EBITDA rose by 40% and 41%, respectively, primarily due to incremental earnings from the Keystone Gulf Coast Extension placed into service in January 2014 and the stronger U.S. dollar.
- Energy EBIT and EBITDA fell by 3% and 1%, respectively, due to a number of factors including (a) lower earnings from Western Power due to lower realized prices; (b) higher realized capacity prices in New York and higher realized power prices in New York and New England; (c) incremental Eastern Power earnings from four solar facilities acquired in each of 2013 and 2014; and (d) lower Natural Gas Storage earnings due to lower realized natural gas price spreads.

Net income (before extras) rose by $41 million (9%) in Q1 2015 compared with Q1 2014, mainly due to higher EBITDA from U.S. and International Natural Gas Pipelines (+27%), Liquids Pipelines (+28%) and Energy (+12.5%), partly offset by lower EBITDA from Canadian Natural Gas Pipelines (-8%) and higher depreciation, interest and income tax expenses (see Business Segments section for detailed EBITDA breakdown).

Earnings and Outlook (CONTINUED)

Outlook

DBRS expects lower earnings growth in 2015 as fewer projects come on stream (Houston Lateral and Terminal as well as certain smaller Canadian Mainline and NGTL System projects) compared with 2014.

- Incremental earnings from these new assets, combined with expected higher American Natural Resources (ANR) earnings from new long-term contracts and expected higher net margins and production from U.S. Power assets, could mitigate the potential for low realized power prices and gas storage spreads in Alberta and lower Canadian Mainline earnings.
- Medium-term earnings growth is expected to come from TCC's large organic capex program.

Financial Profile

Consolidated Financial Profile	3 mos. ended Mar. 31		12 mos. ended Mar. 31	For the year ended December 31			
(DBRS-adjusted amounts and ratios)	**2015**	**2014**	**2015**	**2014**	**2013**	**2012**	**2011**
(CAD millions, US GAAP in all periods)							
Net income before extras	488	447	1,855	1,814	1,678	1,407	1,636
Depreciation and amortization	434	393	1,652	1,611	1,472	1,375	1,328
Deferred income taxes, NCI and other	231	262	812	843	766	502	487
Cash Flow from Operations	**1,153**	**1,102**	**4,319**	**4,268**	**3,916**	**3,284**	**3,451**
Capex and equity investments	(1,100)	(937)	(4,776)	(4,613)	(4,915)	(3,250)	(3,146)
Dividends (common, preferred & NCI)	(429)	(403)	(1,696)	(1,670)	(1,602)	(1,474)	(1,413)
Gross free cash flow (before working capital)	(376)	(238)	(2,153)	(2,015)	(2,601)	(1,440)	(1,108)
Changes in non-cash working capital items	(393)	(123)	(459)	(189)	(326)	287	235
Gross Free Cash Flow	**(769)**	**(361)**	**(2,612)**	**(2,204)**	**(2,927)**	**(1,153)**	**(873)**
Business acquisitions, net of cash	0	0	(241)	(241)	(216)	(214)	0
Proceeds on sale of invest. and other	292	80	922	710	123	193	96
Net Free Cash Flow	**(477)**	**(281)**	**(1,931)**	**(1,735)**	**(3,020)**	**(1,174)**	**(777)**
Inc. (dec.) in total debt	1,540	(160)	2,578	878	2,475	960	126
Inc. (dec.) in non-controlling int. financing	4	0	83	79	384	0	321
Inc. (dec.) in preferred shares	243	240	243	240	385	0	0
Inc. (dec.) in common shares	22	23	99	100	152	111	324
Dec. (inc.) in cash balances	(1,332)	178	(1,072)	438	(376)	103	6
Funding Sources	**477**	**281**	**1,931**	**1,735**	**3,020**	**1,174**	**777**
Total debt & equivalents/capital	57.7%	54.0%	57.7%	55.3%	53.9%	51.7%	51.0%
Cash flow/total debt & equivalents	14.7%	17.1%	13.8%	15.4%	15.5%	15.1%	16.4%
Cash flow interest coverage	4.07	4.21	4.01	4.04	4.03	3.59	3.80
EBIT interest coverage [1]	2.92	3.03	2.81	2.83	2.63	2.36	2.59
Fixed-charges coverage (EBIT-based) [1]	2.70	2.76	2.57	2.59	2.39	2.18	2.39
Common & pref divs/net income (before extras)	80.3%	81.4%	80.2%	80.4%	83.1%	93.6%	76.8%

1 Includes dividends/distributions received from equity investments in numerator of each ratio. NCI = Noncontrolling Interests.
Note: Common equity and total capital exclude accumulated other comprehensive income for ratio calculations.

TCC's financial profile remains reasonable for its business risk profile as capex remains lower than previously anticipated, largely due to the Keystone XL delay. In 2014, increased earnings and cash flow as well as preferred and common share issuance supported its key credit ratios despite relatively high capex.

Financial Profile (CONTINUED)

- Cash flow benefited from improved earnings in 2014, attributable to higher results in all segments except Energy (see Earnings and Outlook section) as well as relatively low cash income taxes.
- The increase in the debt-to-capital ratio since YE2012 is attributable to both net debt issuance to fund growth capex and the negative impact of the weaker Canadian dollar on outstanding U.S.-dollar debt.
- TCC's dividend payout ratio remains high (80% of net income before extras in 2014 compared with 94% in 2012) as earnings growth has not kept pace with common and preferred share issuances since 2011.
- Key credit ratios weakened in Q1 2015 despite higher earnings and cash flow as significant debt financing, and new preferred equity were used to build up cash balances (i.e., pre-funding of near-term spending) and fund a higher free cash flow deficit. The negative impact of the weaker Canadian dollar on outstanding U.S.-dollar debt was also a key factor contributing to artificially weak metrics at the end of Q1 2015.
- In 2015, the Company expects capex of $6 billion, mainly related to Natural Gas Pipeline projects including NGTL System and Canadian Mainline expansions; Liquids Pipelines projects including Grand Rapids, Northern Courier, Energy East and Heartland; and Energy projects including Napanee.
- TCC's credit metrics will likely be pressured in the medium term, particularly if Keystone XL is approved in the next few quarters prior to improvement starting in 2017 as most of the $11.6 billion of small- to medium-sized, shorter-term projects are to be placed into service by that year.
- Credit metric weakness would likely be extended beyond 2017 if some or all of the large-scale projects proceed. Key credit metrics targeted by TCC are cash flow-to-debt of at least 15% and cash flow-to-interest of at least 3.0x.
- On April 1, 2015, TCC completed the drop down of its final 30% Gas Transmission Northwest interest to TCP. The pro forma impact on TCC's credit metrics was modest.
- TCC is expected to drop down its remaining U.S. gas pipelines (USD 1 billion per year) by the end of 2017.

Outlook

TCC has a large capex program to be funded with (a) retained cash flow, (b) senior debt and subordinated capital issuance and (c) further asset dropdowns into TC PipeLines, LP (TCP; see NCI financing in the above table).

Bank Lines and Long-Term Debt Maturities

At March 31, 2015, TCPL and its consolidated subsidiaries had the following committed, revolving credit facilities, part of which was allocated to backstop its commercial paper (CP) programs.

- TCPL has a $3.0 billion facility maturing in December 2019 to backstop its $3.0 billion CP program.
- TransCanada American Investments Ltd. has a USD 1.0 billion 364-day (plus one-year term-out) facility, guaranteed by TCPL, maturing in November 2015 to backstop its USD 1.0 billion CP program.
- TransCanada PipeLine USA Ltd. has a USD 1.0 billion 364-day (plus one-year term-out) facility, guaranteed by TCPL, maturing in November 2015.

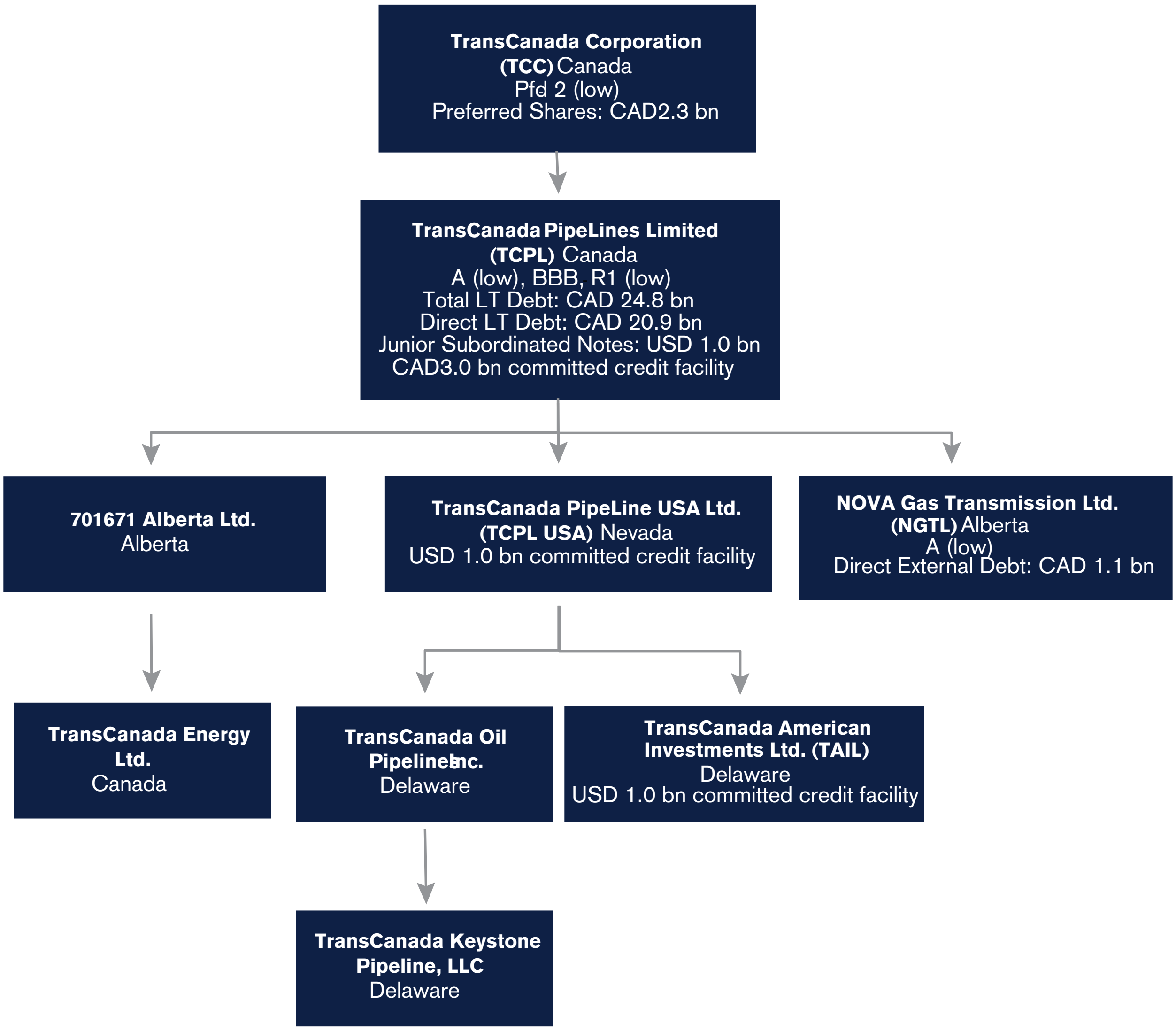
Long-Term Debt Maturities	3 mos. ended Mar. 31		12 mos. ended Mar. 31	For the year ended December 31		
As at December 31, 2014	**2015**	**2016**	**2017**	**2018**	**2019+**	**Total**
Long-term debt maturities (CAD billions)	1.797	2.225	0.846	1.766	18.123	24.757
% of long-term debt	7.3%	9.0%	3.4%	7.1%	73.2%	100.0%

Excludes $2.5 billion of CP backstopped by various credit faciilties.

- Debt maturities are well within the Company's ability to refinance, although significant new issuance is expected over the medium term to fund the large capex program.
- During Q1 2015, TCC issued $250 million of preferred shares and TCPL issued USD 1.5 billion of medium-term notes (MTNs) and repaid USD 800 million of MTNs. TCP also issued USD 350 million of MTNs.
- In Q2 2015, TransCanada Trust (guaranteed by TCPL) issued USD 750 million of subordinated trust notes.

Simplified Corporate Structure

Long-Term Debt As at December 31, 2014



Major Capital Projects

The following table summarizes TCC's small- to medium-sized projects. Capital cost composition of these projects by segment is Liquids Pipelines at 34%, Natural Gas Pipelines at 58% and Energy at 8%. Capital cost composition by project status is Under Construction at 47% and Under Development at 53%.

The Houston Lateral will extend the Keystone Pipeline System to Houston area refineries and the Houston Terminal will have initial storage capacity for 700,000 barrels of crude oil upon completion in Q4 2015.

Consolidated Financial Profile	**Capital Cost**	**Invested to Date**	**Status at Mar. 31, 2015**	**Expected In-Service Date**	**Revenue Stream**
(CAD billions)					
Houston Lateral & Terminal (Liquids Pipe) (USD)	0.6	0.4	Construction	Q4 2015	Contracted / Spot
Topolobampo Pipeline (Mexico) (Gas Pipe) (USD)	1.0	0.7	Construction	mid-to-late 2016	Fully contracted
Mazatlan Pipeline (Mexico) (Gas Pipe) (USD)	0.4	0.2	Construction	mid-to-late 2016	Fully contracted
Grand Rapids Pipeline (50% share) (Liquids Pipe)	1.5	0.3	Construction	2016-2017	Contracted / Spot
Heartland Pipeline & TC Terminals (Liquids Pipe)	0.9	0.2	Development	late 2017	Largely contracted
Northern Courier Pipeline (Alberta) (Liquids Pipe)	1.0	0.3	Construction	2017	Fully contracted
Canadian Mainline - Other (Gas Pipe)	0.4	0.0	Development	2015-2016	Cost of Service
NGTL System - North Montney (Gas Pipe)	1.7	0.1	Development	2016-2017	Cost of Service
NGTL System - 2016/17 Facilities (Gas Pipe)	2.7	0.1	Development	2016-2018	Cost of Service
NGTL System - Other (Gas Pipe)	0.4	0.0	Development	2015-2016	Cost of Service
Napanee Generating Station (Ontario) (Energy)	1.0	0.1	Construction	2017 or 2018	Fully contracted
Small to Medium-Sized, Shorter Term Projects	**11.6**	**2.4**			

The Topolobampo Pipeline is a 30-inch, 530 kilometre (km) or 329 mile natural gas pipeline in Mexico with 670 million cubic feet per day (MMcf/d) of contracted capacity, supported by a 25-year contract with Mexico's state-owned power utility.

The Mazatlan Pipeline is a 24-inch, 413 km or 257 mile natural gas pipeline in Mexico with 200 MMcf/d of contracted capacity, supported by a 25-year contract with Mexico's state-owned power utility.

The Grand Rapids Pipeline includes crude oil and diluent pipelines between the producing area northwest of Fort McMurray, Alberta, and terminals in the Edmonton/Heartland region in Alberta. Grand Rapids is supported by a long-term shipping contract by TCC's 50% partner and is expected to be in service in 2016 or 2017.

The Heartland Pipeline (which is in development) would connect the new TC Terminals facility (which is under construction) in the Edmonton/Heartland crude oil market region to facilities in Hardisty, Alberta. The pipeline could ship up to 900,000 barrels per day (b/d), while the terminal could provide storage for up to 1.9 million barrels.

The Northern Courier Pipeline includes bitumen and diluent pipelines between the Fort Hills mine site and Suncor Energy Inc.'s terminal located north of Fort McMurray and is expected to be in service in 2017.

The Canadian Mainline – Other project refers to new short-haul arrangements, subject to regulatory approval, in the Eastern Triangle portion of the Canadian Mainline that need new facilities or modifications to existing facilities with expected in-service dates between November 2015 and November 2016.

Subject to federal government approval, the NGTL System – North Montney Mainline project would be an extension and expansion of the NGTL System to receive and transport natural gas from the North Montney area of British Columbia and include an interconnection with TCC's proposed Prince Rupert Gas Transmission project (PRGT; see below). Under commercial arrangements, receipt volumes are expected to rise between 2016 and 2019 to a total of about two billion cubic feer per day (bcf/d) and delivery volumes to the PRGT of about 2.1 bcf/d beginning in 2019. In April 2015, the NEB approved the rolled-in tolling design for the project costs during a transition period, subject to certain conditions that TCC is reviewing.

The Napanee Generating Station is a 900 MW natural gas-fired combined-cycle power plant in Eastern Ontario supported by a 20-year contract with the Independent Electricity System Operator with completion expected in late 2017 or early 2018.

The following table summarizes TCC's large-scale projects. The capital cost composition of these projects by segment is Liquids Pipelines at 61% and Natural Gas Pipelines at 39%.

Consolidated Financial Profile	Capital Cost	Invested to Date	Status at Mar. 31, 2015	Expected In-Service Date	Revenue Stream
(CAD billions)					
Upland (Liquids Pipe) (USD)	0.6	0.0	Development	2020	Largely contracted
Keystone XL (Liquids Pipe) (USD)	8.0	2.4	Development	Permit date + 2 yrs	Largely contracted
Keystone Hardisty Terminal (Liquids Pipe)	0.3	0.2	Development	Permit date + 2 yrs	Largely contracted
Energy East (Liquids Pipe)	12.0	0.6	Development	2020	Largely contracted
Eastern Mainline (Gas Pipe)	1.5	0.0	Development	2017	Cost of Service
Coastal GasLink (B.C.) (Gas Pipe)	4.8	0.3	Development	2019+	Fully contracted
Prince Rupert Gas Transmission (B.C.) (Gas Pipe)	5.0	0.3	Development	2019+	Largely contracted
NGTL System- Merrick (Gas Pipe)	1.9	0.0	Development	2020	Largely contracted
Total Large Scale Projects	**34.1**	**3.8**			
Small to Medium-Sized & Large Scale Projects	**45.7**	**6.2**			

The Upland Pipeline would ship crude oil from and between multiple points in North Dakota and interconnect with the Energy East Pipeline at Moosomin, Saskatchewan. Upland is conditional on Energy East proceeding and, subject to regulatory approvals, is expected to be in service in 2020.

The Keystone XL project would ship crude oil from Hardisty to Steele City, Nebraska, to expand the capacity of the Keystone Pipeline System. Timing and approval of Keystone XL remains uncertain. Keystone XL is expected to have an initial capacity of 830,000 b/d with more than 500,000 b/d contracted for an average term of 18 years. These contracts would also apply to the Gulf Coast Pipeline. The combined Keystone system would have an initial capacity of 1.4 million b/d.

The 2.6 million barrel capacity Keystone Hardisty Terminal will be constructed in conjunction with Keystone XL to provide new crude oil batch accumulation tankage and access to the Keystone Pipeline System. The project is secured by binding long-term commitments exceeding 500,000 b/d.

The Energy East Pipeline project involves conversion of 3,000 kms (1,860 miles) of the Canadian Mainline from natural gas to crude oil service and the construction of 1,500 kms (930 miles) of new pipeline. Energy East would have 1.1 million b/d of capacity, with about 1.0 million b/d contracted on a long-term basis. In April 2015, TCC announced that the marine and associated tank terminal in Cacouna, Québec, would not be built. Subject to regulatory approvals, the project is anticipated to be in service in 2020.

The Eastern Mainline project would add 0.6 bcf/d of new capacity in the Eastern Triangle portion of the Canadian Mainline as a result of the proposed transfer of a portion of the existing Canadian Mainline capacity to crude oil from natural gas service as part of the Energy East Pipeline project (see above). The Eastern Mainline project is contingent upon the Energy East project proceeding.

The Coastal GasLink Pipeline project would initially transport up to 1.7 bcf/d of natural gas 670 kms (416 miles) from the North Montney gas-producing region near Dawson Creek, British Columbia, to the proposed LNG Canada liquefied natural gas (LNG) export facility near Kitimat, British Columbia, to be owned by Shell Canada Limited and its partners. The project is subject to regulatory approvals and a final investment decision by LNG Canada (expected in early 2016) to proceed with the export facility.

The Prince Rupert Gas Transmission (PRGT) project would transport natural gas 900 kms (559 miles) from the North Montney gas-producing region near Fort St. John, British Columbia, to a proposed LNG export facility near Prince Rupert, British Columbia, to be owned by a subsidiary of Malaysia's state-owned petroleum company, PETRONAS. The PRGT project is subject to regulatory approvals and a final investment decision by PETRONAS (now expected by end of Q2 2015) to proceed with the export facility.

The NGTL System - Merrick Mainline Pipeline (Merrick) project would be an extension from the existing Groundbirch Mainline section of the NGTL System beginning near Dawson Creek to its endpoint near Summit Lake, British Columbia. NGTL has signed agreements for 1.9 bcf/d of firm service to ship natural gas to the inlet of the proposed Pacific Trail Pipeline terminating near Kitimat. Merrick is dependent on regulatory approval and a positive final investment decision from the Kitimat LNG project.

Business Segments

1. Natural Gas Pipelines (56% of segment EBITDA, 53% of segment EBIT in the last 12 months (LTM) ending March 31, 2015):
TCPL's network of 57,000 kms or 35,500 miles of wholly owned pipelines and 11,000 km (6,600 miles) of partially owned pipelines access virtually all major gas supply basins in North America.

(a) Natural Gas Pipelines – Canada (39% of segment EBITDA, 35% of segment EBIT)

Canadian Mainline (22% of segment EBITDA, 15% of net income before extras)

- The Canadian Mainline extends 14,114 km (8,770 miles) from the Alberta/Saskatchewan border to the Québec/Vermont border and connects with other pipelines in Canada and in the United States.
- Natural gas throughput on the Canadian Mainline rebounded to 4.5 bcf/d in 2014, reversing the previous declining trend (3.7 bcf/d in 2013; 4.2 bcf/d in 2012; 5.2 bcf/d in 2011) as the cold winter combined with the ability to price discretionary services at market services resulted in a significant increase in long-haul firm transportation originating at Empress, Alberta.
- Canadian Mainline net income (before extras) and EBITDA rose by 8% and 19%, respectively, in 2014 compared with 2013 primarily due to higher incentive earnings, partly offset by higher carrying charges owed to shippers on the positive TSA balance and a lower average investment base.
- Canadian Mainline net income (before extras) fell by 28% and EBITDA fell by 16% in Q1 2015 compared with Q1 2014, primarily due to implementation of the 2015 to 2030 Tolls and Tariffs regulatory decision, which resulted in a lower ROE of 10.1% in 2015 compared with 11.5% in 2014 as well as lower incentive earnings and a lower average investment base in Q1 2015.

NGTL System (15% of segment EBITDA, 13% of net income before extras)

- The NGTL System connects the Canadian Mainline and Foothills systems along with third-party natural gas pipelines through 24,525 km (15,239 miles) of pipeline, mostly within Alberta and partly in British Columbia.
- NGTL is well positioned to link Western Canadian Sedimentary Basin (WCSB) supply to proposed west coast of Canada LNG projects.
- Natural gas throughput on the NGTL System continued to rise (field receipts averaged 10.7 bcf/d in 2014 compared with 10.1 bcf/d in 2013 and 10.0 bcf/d in 2012), largely due to rising WCSB shale gas production and completed expansion projects. Volumes fell to 11.8 bcf/d in Q1 2015 from 12.6 bcf/d in Q1 2014, which had risen from 11.0 bcf/d in Q1 2013 largely as a result of colder winter weather.
- NGTL System net income (before extras) and EBITDA were relatively flat in 2014 compared with 2013 as higher OM&A costs were offset by a higher average investment base.
- NGTL System net income (before extras) and EBITDA rose by 1.6% and 1.4%, respectively, in Q1 2015 compared with Q1 2014, primarily due to a higher average investment base.

Foothills System (2% of segment EBITDA, 1% of net income before extras)

- Transporting natural gas from central Alberta to the U.S. border, Foothills consists of a 1,241 km (771 mile) transmission system, which serves markets in the U.S. Midwest, Pacific Northwest, California and Nevada.

(b) Natural Gas Pipelines – United States and International (18% of segment EBITDA, 18% of segment EBIT)

American Natural Resources (4% of segment EBITDA)

- ANR consists of 15,109 km (9,388 miles) of pipeline transporting natural gas primarily from Texas and Oklahoma on its southwest leg and in the Gulf of Mexico on its southeast leg to Wisconsin, Michigan, Illinois, Ohio and Indiana. ANR also connects with other pipelines, providing access to other gas sources.
- ANR owns and operates underground gas storage facilities in Michigan, with 250 bcf of capacity.
- ANR is regulated by the FERC on a complaint basis with an estimated 15% ROE. The last pipeline rate settlement began in 1997. Pipeline services are provided under tariffs that set limits on the rates for services and allow for non-discriminatory negotiations and discounts. The value of ANR's storage services is based on market conditions that could result in reduced rates and terms.
- In 2014, ANR secured almost 2 bcf/d of commitments (23-year average term) on its Southeast Main Line, with 1.25 bcf/d of the new contracts beginning service in late 2014.
- ANR's EBITDA was flat on a USD basis, but rose by 28% on a CAD basis in 2014 compared with 2013 as a result of a stronger U.S. dollar relative to the Canadian dollar.
- ANR's EBITDA rose by 13% on a USD basis (28% on a CAD basis) in Q1 2015 compared with Q1 2014, mainly due to a settlement with a producer for damages to ANR's pipeline and a stronger U.S. dollar.

TransCanada Corporation

Segment EBITDA (CAD millions, US GAAP)	3 mos. ended Mar. 31 2015		3 mos. ended Mar. 31 2014		12 mos. ended Mar. 31 2015		For the year ended December 31 2014		2013		2012	
Natural Gas Pipelines												
Canadian Mainline	266	17%	315	22%	1,285	22%	1,334	24%	1,121	23%	994	23%
NGTL System	222	14%	219	15%	859	15%	856	15%	846	17%	749	17%
Foothills	27	2%	27	2%	106	2%	106	2%	114	2%	120	3%
Trans Quebec & Maritimes (50% owned)	7	0%	5	0%	24	0%	22	0%	26	1%	29	1%
Cdn Gas Pipe EBITDA before extras	**522**	**33%**	**566**	**39%**	**2,274**	**39%**	**2,318**	**41%**	**2,107**	**42%**	**1,892**	**44%**
ANR Pipeline and Storage	110	7%	86	6%	233	4%	209	4%	193	4%	254	6%
Great Lakes (66.7% owned)	25	2%	21	1%	58	1%	54	1%	35	1%	62	1%
TC Pipelines, LP (28.3% owned)	32	2%	29	2%	101	2%	97	2%	74	1%	74	2%
Other (Bison, GTN, Iroquis, Portland)	51	3%	49	3%	148	3%	146	3%	188	4%	223	5%
Mexico (Guadalajara, Tamazunchale)	59	4%	27	2%	208	4%	177	3%	103	2%	99	2%
Other (mostly non-controlling interests)	95	6%	79	6%	271	5%	256	5%	187	4%	166	4%
U.S. & Int. Gas Pipe EBITDA bef. Extras	**371**	**24%**	**291**	**20%**	**1,020**	**18%**	**941**	**17%**	**780**	**16%**	**878**	**20%**
Business Development Costs	(18)	-1%	(9)	-1%	(26)	0%	(17)	0%	(35)	-1%	(29)	-1%
Subtotal (Natural Gas Pipelines)	**875**	**56%**	**848**	**59%**	**3,268**	**56%**	**3,242**	**57%**	**2,852**	**57%**	**2,741**	**63%**
Liquids Pipelines												
Keystone Pipeline System	309	20%	241	17%	1,127	19%	1,059	19%	752	15%	698	16%
Subtotal (Liquids Pipelines)	**309**	**20%**	**241**	**17%**	**1,127**	**19%**	**1,059**	**19%**	**752**	**15%**	**698**	**16%**
Energy												
Western Power	15	1%	72	5%	195	3%	252	4%	355	7%	311	7%
Eastern Power	131	8%	93	6%	388	7%	350	6%	322	6%	321	7%
Bruce Power	79	5%	64	4%	329	6%	314	6%	310	6%	14	0%
Cdn Power EBITDA before extras	225	14%	229	16%	912	16%	916	16%	987	20%	646	15%
U.S. Power EBITDA before extras	163	10%	93	7%	484	8%	414	7%	333	7%	209	5%
Gas Storage EBITDA before extras	3	0%	27	2%	20	0%	44	1%	63	1%	67	2%
Business Development Costs	(4)	0%	(5)	0%	(25)	0%	(26)	0%	(20)	0%	(19)	0%
Subtotal (Energy)	**387**	**25%**	**344**	**24%**	**1,391**	**24%**	**1,348**	**24%**	**1,363**	**27%**	**903**	**21%**
Subtotal of segments	1,571	100%	1,434	100%	5,786	100%	5,648	100%	4,967	100%	4,342	100%
Corporate and Other	(42)		(3)		(110)		(70)		(100)		22	
EBITDA before extras [1]	**1,529**		**1,431**		**5,676**		**5,578**		**4,867**		**4,364**	
Extraordinary items	(78)		(10)		(40)		28		128		(31)	
EBITDA [1]	1,451		1,421		5,636		5,606		4,995		4,333	

1 EBITDA includes dividends/distributions received from equity investments.

Mexican Natural Gas Pipelines (4% of segment EBITDA)

- The 310 km (193 mile) Guadalajara Pipeline transports natural gas from Manzanillo to Guadalajara.
- The 365 km (227 mile) Tamazunchale Pipeline transports natural gas from Naranjos to El Sauz.
- EBITDA growth of USD 60 million (60%) in 2014 and USD 22 million (88%) in Q1 2015 mainly reflect higher earnings from the Tamazunchale Extension placed in service in 2014.

2. Liquids Pipelines (19% of segment EBITDA, 21% of segment EBIT in LTM March 31, 2015)

Keystone Pipeline System (Base Keystone) and Gulf Coast Pipeline

- Phase 1 of Base Keystone, which extends from Hardisty to Wood River and Patoka, Illinois, had an initial nominal capacity of 435,000 b/d and was placed into commercial service on June 30, 2010.
- Phase 2 of Base Keystone, which expanded nominal capacity to 591,000 b/d and extended the pipeline to Cushing, Oklahoma, was placed in commercial service in Q1 2011.
- The Gulf Coast Pipeline, which is an extension of Base Keystone from Cushing to Nederland, Texas, in the U.S. Gulf Coast was placed into service in January 2014 with an initial crude oil capacity of up to 700,000 b/d and an ultimate capacity of 830,000 b/d.
- Construction of the Cushing Marketlink project facilities, which transports crude oil from Cushing to the U.S. Gulf Coast refining market and forms part of Base Keystone, was completed in September 2014.
- The Houston Lateral will extend the Keystone Pipeline System to Houston area refineries and the Houston Terminal will have initial storage capacity for 700,000 barrels of crude oil upon completion in Q4 2015.
- Liquids Pipelines EBIT and EBITDA rose by 40% and 41%, respectively, in 2014 compared with 2013, primarily due to incremental earnings from the Gulf Coast Extension placed into service in January 2014 and the stronger U.S. dollar.
- Liquids Pipelines EBIT and EBITDA each rose by 28% in Q1 2015 compared with Q1 2014, primarily as a result of incremental earnings from the Gulf Coast Extension placed into service in January 2014, higher volumes and the stronger U.S. dollar.

3. Energy (24% of segment EBITDA, 26% of segment EBIT in LTM March 31, 2015)

TCPL's operating power plants have net capacity of approximately 11,800 MW supported by low-cost, base-load generation and long-term contracts with relatively stable earnings and cash flow. In addition, the segment includes 118 bcf of unregulated natural gas storage capacity in Alberta, accounting for about one-third of all storage capacity in the province.

(a) Canadian Power (16% of segment EBITDA)

Bruce Power (Ontario) (6% of segment EBITDA)

- TCC owns 48.9% of Bruce A, which has four reactors with a combined capacity of 3,000 MW. Under a contract, the OPA receives all of Bruce A's output at a fixed price that is adjusted annually for inflation.
- TCC owns 31.6% of Bruce B, which has four operating reactors with a combined capacity of 3,200 MW. All output is sold under contracts to the OPA at a floor price, adjusted annually for inflation.
- The Province of Ontario's 2013 Long-Term Energy Plan included potential refurbishment of six Bruce Power units. The parties have not agreed on terms and there is no assurance of an agreement.
- Bruce Power equity income rose by $4 million (1%) in 2014 compared with 2013, mainly due to higher sales volumes and realized prices, partly offset by a $40 million insurance recovery recognized in 2013.
- Bruce Power equity income rose by $15 million (23%) in Q1 2015 compared with Q1 2014, mainly due to higher volumes resulting from fewer outage days at both Bruce A and Bruce B.

Power Generation Capacity at March 31, 2015

Western Power*	(MW)	Fuel Type	U.S. Power	(MW)	Fuel Type
Sheerness PPA (expires 2020)					
Coolidge (Arizona) (contract to 2031)	756	Coal	Ravenswood	2,480	Natural gas/oil
Sundance A PPA (expires 2017)	575	Natural gas	TC Hydro (13 facilities)	583	Hydro
Sundance B PPA (expires 2020) [1]	560	Coal	Ocean State Power	560	Natural gas
MacKay River	353	Coal	Kibby Wind	132	Wind
Carseland	165	Natural gas	U.S. Power	3,755	
Bear Creek	80	Natural gas	Bruce Power		
Redwater	80	Natural gas	Bruce A [4]	1,467	Nuclear
Western Power	40	Natural gas	Bruce B [4]	1,022	Nuclear
* All Western Power (except Coolidge) is in Alberta	2,609		Bruce Power	2,489	
Eastern Power			Total Power Generation	11,793	
Napanee (20-year contract)**					
Halton Hills (contract to 2030)	900	Natural gas	Natural gas	3,998	33.9%
Bécancour (contract to 2026)	683	Natural gas	Natural gas/oil	2,480	21.0%
Cartier Wind (contracts to 2032) [2]	550	Natural gas	Nuclear	2,489	21.1%
Portlands Energy (contract to 2029) [3]	366	Wind	Coal	1,669	14.2%
Grandview (contract to 2025)	275	Natural gas	Hydro	583	4.9%
Ontario Solar (contracts to 2033)	90	Natural gas	Wind	498	4.2%
Eastern Power	76	Solar	Solar	76	0.6%
** Under construction; contract is from in-service date	2,940		Total Power Generation	11,793	100.0%

1 50% share of total 706 MW capacity
2 62% share of the total 590 MW capacity
3 50% share of the total 550 MW capacity
4 48.9% share of Bruce A and 31.6% of Bruce B

Eastern Power (7% of segment EBITDA)

- All Eastern Power assets are supported by long-term contractual arrangements.
- Eastern Power EBITDA rose by $28 million (9%) in 2014 compared with 2013, mainly as a result of incremental earnings from the four solar facilities acquired in 2013, the additional four facilities acquired in late 2014 and higher contractual earnings at Bécancour Power Plant (Bécancour).
- Eastern Power EBITDA rose by $38 million (41%) in Q1 2015 compared with Q1 2014, largely due to the sale of unused natural gas transportation, higher contractual earnings at Bécancour and incremental earnings from the solar facilities acquired in late 2014.

Western Power (3% of segment EBITDA)

- Most Western Power assets are exposed to the volatility of the Alberta spot power market despite the fact that approximately 75% of sales volumes were sold under contract in 2014 (72% in 2013; 85% in 2012).
- Western Power EBITDA fell by $103 million (-29%) in 2014 compared with 2013, largely due to lower realized power prices as average Alberta spot prices fell 38% to $50 per megawatt hour (MWh) in 2014 from $80/MWh in 2013.
- Western Power EBITDA fell by $57 million (-79%) in Q1 2015 compared with Q1 2014, mainly due to the lower realized power prices as average Alberta spot prices fell 53% to $29/MWh in Q1 2015 from $62/MWh in Q1 2014.

(b) U.S. Power (8% of segment EBITDA)

Ravenswood (New York City)

- Ravenswood is a natural gas and oil-fired generating facility consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology, with the capacity to supply about one-fifth of the overall peak load in New York City. Power output and capacity is sold to the New York Independent System Operator (ISO) market.
- During 2013, FERC addressed complaints with respect to the controversial interpretation of the mitigation exemption test by the New York ISO on new entrants into the market, which effectively lowered capacity payments that Ravenswood received for making its capacity available in 2012.
- Average New York Zone J capacity prices were 27% higher in 2014 than in 2013. The increase in spot prices and the impact of hedging activities resulted in higher realized capacity prices in New York in 2014.

TC Hydro (New Hampshire, Vermont and Massachusetts)

- TC Hydro comprises 13 hydroelectric facilities, including stations and associated dams and reservoirs.

Ocean State Power (OSP) (Rhode Island)

- OSP is a natural gas-fired, combined-cycle facility.
- U.S. Power EBITDA rose by USD 53 million (16%) in 2014 compared with 2013, in large part due to (1) higher realized capacity prices primarily in New York; (2) higher realized power prices for the New England and New York facilities; (3) higher generation volumes primarily at Ravenswood; and (4) higher margins on volumes purchased for resale to wholesale, commercial and residential customers.
- U.S. Power EBITDA rose by USD 47 million (55%) in Q1 2015 compared with Q1 2014, mainly due to (1) higher margins on purchased and resold volumes and (2) lower realized power prices and generation at the New York and New England facilities partially offset by higher margins and sales to wholesale, commercial and industrial customers.

TransCanada Corporation

Balance Sheet

(CAD millions, US GAAP)	Mar. 31 2015	Dec. 31 2014	Dec. 31 2013
Assets			
Cash and equivalents	1,821	489	927
Accounts receivable	1,419	1,313	1,122
Inventories	280	292	251
Other current assets	1,589	1,446	847
Current assets	5,109	3,540	3,147
Property, plant and equip., net	44,211	41,774	37,606
Equity investments	5,735	5,598	5,759
Goodwill	4,410	4,034	3,696
Regulatory assets	1,247	1,297	1,735
Intangibles and other assets	3,104	2,704	1,955
Total	63,816	58,947	53,898

	Mar. 31 2015	Dec. 31 2014	Dec. 31 2013
Liabilities & Equity			
Notes payable	2,818	2,467	1,842
A/P and accrued liab.	3,277	3,320	2,543
L.t. debt due in one year	2,112	1,797	973
Current liabilities	8,207	7,584	5,358
Other long-term liabs.	1,838	1,315	885
Deferred income taxes	5,561	5,275	4,564
Long-term debt	25,733	22,960	21,892
Jnr. subordinated notes	1,268	1,160	1,063
Noncontrolling interests	1,739	1,583	1,417
Preferred shares	2,499	2,255	2,007
Common equity	16,971	16,815	16,712
Total	63,816	58,947	53,898

	3 mos. ended Mar. 31		12 mos. ended Mar. 31	Year ended December 31			
Balance Sheet and Liquidity Ratios	**2015**	**2014**	**2015**	**2014**	**2013**	**2012**	**2011**
Current Ratio	0.62	0.69	0.62	0.47	0.59	0.48	0.56
Net debt & equivalents/capital	56.2%	53.2%	56.2%	54.9%	53.0%	51.0%	50.2%
Total debt & equivalents/capital	57.7%	54.0%	57.7%	55.3%	53.9%	51.7%	51.0%
Adj. Total debt & equivalents/capital*	n/a	n/a	n/a	57.1%	54.5%	52.2%	51.6%
Common equity/capital	33.3%	37.1%	33.3%	35.9%	37.7%	40.8%	41.3%
Cash flow/total debt & equivalents	14.7%	17.1%	13.8%	15.4%	15.5%	15.1%	16.4%
Adj. Cash flow/total debt & equivalents*	n/a	n/a	n/a	14.6%	15.4%	15.1%	16.3%
(Cash flow - total dividends)/capex	0.76	0.87	0.63	0.64	0.53	0.76	0.87
Common divs/net income (before extras)	75.6%	75.8%	74.9%	75.0%	77.5%	88.1%	72.1%
Pref. share divs/net income (before extras)	4.7%	5.6%	5.2%	5.5%	5.6%	5.5%	4.7%
Common & pref divs/net income (before extras)	80.3%	81.4%	80.2%	80.4%	83.1%	93.6%	76.8%
Dividends (common, pref. & NCI)/cash flow	37.2%	36.6%	39.3%	39.1%	40.9%	44.9%	40.9%
Coverage Ratios (times)							
EBIT interest coverage [1]	2.92	3.03	2.81	2.83	2.63	2.36	2.59
EBITDA interest coverage [1]	4.08	4.17	3.96	3.98	3.76	3.44	3.67
Fixed-charges coverage (EBIT-based) [1]	2.70	2.76	2.57	2.59	2.39	2.18	2.39
Cash flow interest coverage	4.07	4.21	4.01	4.04	4.03	3.59	3.80
Adj. EBIT interest coverage [1]*	n/a	n/a	n/a	2.78	2.59	2.33	2.56
Profitability Ratios (before extras.)							
Operating margin	33.4%	30.1%	34.2%	33.3%	31.9%	32.6%	35.7%
Profit margin	17.0%	15.5%	18.2%	17.8%	19.2%	17.6%	20.9%
Return on common equity	11.0%	10.1%	10.4%	10.2%	9.8%	8.5%	10.2%
Return on capital	5.5%	5.5%	5.4%	5.5%	5.5%	5.1%	5.7%
Segmented EBIT (CAD millions)							
Natural Gas Pipelines	595	586	2,187	2,178	1,839	1,808	1,952
Liquids Pipelines	246	192	897	843	603	553	457
Energy	303	268	1,074	1,039	1,069	620	907
Corporate	(49)	(8)	(134)	(93)	(116)	8	(122)
EBIT before extras. [1]	1,095	1,038	4,024	3,967	3,395	2,989	3,194
Selected Operating Statistics							
Cdn. Mainline Average Investment Base	$5,018	$5,706		$5,690	$5,841	$5,737	$6,179
NGTL System Average Investment Base	$6,419	$6,137		$6,236	$5,938	$5,501	$5,074
Canadian Mainline Volumes (Bcf/day)	5.9	5.9		4.5	3.7	4.2	5.2
NGTL System Volumes (Bcf/day)	11.8	12.6		10.7	10.1	10.0	9.6
ANR System Volumes (Bcf/day)	5.7	5.8		4.4	4.3	4.4	4.7
Energy Sales Volumes (GWh)	14,924	13,587		54,372	48,428	43,794	40,709

1 EBIT and EBITDA include dividends/distributions received from equity investments. NCI = Noncontrolling Interests
* Includes operating leases treated as debt. n/a = not available.

Rating History

TransCanada PipeLines Limited	Current	2013-2014	2012	2009-2011	2007-2008	2006
Issuer Rating	A (low)	A (low)	A	NR	NR	NR
Unsecured Debentures & Notes	A (low)	A (low)	A	A	A	A
Junior Subordinated Notes	BBB	BBB	BBB (high)	BBB (high)	BBB (high)	NR
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
TransCanada Corporation						
Preferred Shares – Cumulative	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	NR	NR

Issuer Description

TransCanada PipeLines Limited (TCPL) is a leading integrated energy services company in North America involved in natural gas and liquids transmission as well as electricity generation. TransCanada Corporation (TCC) is TCPL's parent company and holds no material assets other than TCPL's common shares.

Previous Action(s)

- TCPL Preferred Share rating Discontinued -Repaid, May 28, 2015.
- New TCPL Notes issues, March 31, 2015.
- New TCC Preferred shares issue, March 2, 2015.
- New TCPL Notes issues, January 9, 2015.

Related Research

- Trans Quebec & Maritimes Pipeline Inc., Rating Report, November 11, 2014.
- NOVA Gas Transmission Ltd., Rating Report, June 24, 2014.

Authorized Principal CP Limit

- TCPL: $3.0 Billion

Previous Report

- TransCanada Corporation & TransCanada PipeLines Limited, Rating Report, June 5, 2014.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on **www.dbrs.com**.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

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Appendix 3-4

TransCanada Corporation Full Analysis
September 8, 2015

STANDARD & POOR'S
RATINGS SERVICES
McGRAW HILL FINANCIAL

RatingsDirect®

TransCanada Corp.

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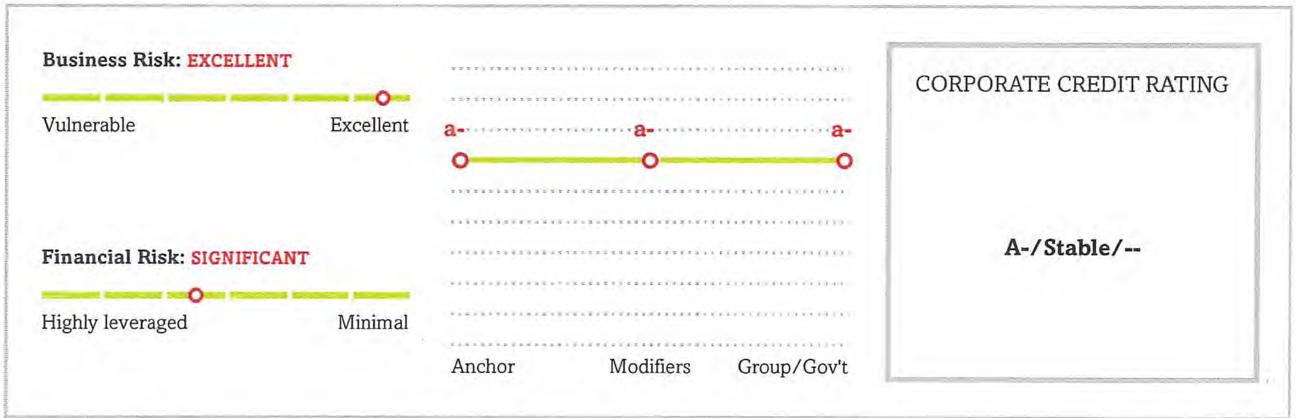

Rationale

Business Risk	Financial Risk
• A diversified asset base in oil and gas pipelines and power generation • A highly stable cash flow profile, with regulated and long-term contracted take-or-pay gas and oil pipelines • Heightened regulatory and permitting risk to pipeline approvals • A higher degree of cash flow volatility with unregulated power than with the midstream business segment	• Weak forecast financial metrics for Standard & Poor's Ratings Services' two-year outlook period • High capital expenditures in the next several years, which will require significant external financing

Outlook

The stable outlook on TransCanada Corp. reflects our expectation that the company's diverse business will continue to generate stable cash flows during its significant capital expansion phase. We expect it will finance capital programs largely through a combination of equity, hybrid securities, and drop downs, with a small proportion of additional debt.

Downside scenario

We would lower the ratings if TransCanada has sustained adjusted funds from operations (AFFO)-to-debt below 13%, which would largely be because of higher debt to finance the 2015-2018 capital program or lower than-forecast cash flows in 2015 and 2016. In addition, cost overruns on its planned major projects could depress metrics and trigger a downgrade.

Upside scenario

Although unlikely during our two-year outlook period given the weak financial metrics, we could raise the ratings if AFFO-to-debt improves to and stays above 20%.

Standard & Poor's Base-Case Scenario

Our base-case assumptions do not include Keystone XL-related capital spending due to the uncertainty surrounding the project. We have also excluded capital costs concerning the Energy East pipeline. It is also facing environmental approval issues and we expect the company to file amendments to the project to the National Energy Board (NEB) by the end of 2015.

Assumptions

- Average Alberta power prices of C$40 per megawatt-hour in 2015 and C$45 in 2016 onward
- Mid-to-high 80% availability at the Bruce nuclear facility in Ontario
- Oil pipeline cash flows will remain stable, while U.S. natural gas pipelines contract profile is improving
- The mainline will earn its revenue requirement, and the NEB will approve negotiated settlement with market-area shippers
- A large capital program of approximately C$4.5 billion in 2015

Key Metrics

	2014A	2015E	2016E
FFO/debt	13.3%	14%-15%	15%-17%
Debt/EBITDA	5.3x	About 5x	4.5x-5x

FFO--Funds from operations. A--Actual. E--Estimate.

Company Description

Calgary, Alta.-based TransCanada develops and operates energy infrastructure in North America. Its pipeline network includes approximately 4,200 kilometers (km) of oil pipeline, plus 57,000 km of wholly owned and 11,000 km of partially owned gas pipeline that connects with virtually all major gas supply basins in North America. The company also owns, or has interests in, approximately 11,800 megawatts of power generation.

Business Risk

We view TransCanada as having an "excellent" business risk profile with an "excellent" competitive position. The company operates several groups of diversified midstream assets that provide stable cash flows, including rate-regulated natural gas pipelines in Canada and highly contracted, investment grade counterparty oil and Mexican natural gas pipelines that account for more than 60% of EBITDA. Natural gas pipelines in the U.S. show higher volatility due to their weaker contract profile and lower level of firm capacity commitments; however, they account for less than 15% of EBITDA. No pipelines have commodity risk.

We have not considered any impact from Keystone XL pipeline, given the uncertainty surrounding the project. However, we believe operations will commence within 24 months following approval. We believe that the final capital cost will likely be near the current C$8 billion estimate (compared with the initial estimate of C$5.4 billion). However, the final amount depends on TransCanada's plans to accelerate the in-service date to the extent it is possible. In addition, there are costs to keep the project active, which our estimates account for.

The company recently announced that it will not build the marine and associated tank terminal in Cacouna, Que. (part of the Energy East Pipeline [EE] project) because of the potential reclassification of beluga whales as an endangered species. We expect TransCanada to file amendments to the project to NEB by end of 2015. This will move the in-service date of the EE pipeline to 2020 from 2018. This means that the overall share of midstream business (which is lower risk than merchant power) will continue to be less than 80% through that period.

Although we view unregulated power as a higher-risk industry than midstream energy, the overall contribution is relatively small, at 20%-25% of EBITDA. In addition, the company has a significant amount of the Canadian portfolio under long-term contracts that limit the pricing variability that can be inherent in the business. It operates what we consider a highly diversified fleet of generation by fuel type, geography, and markets.

S&P Base-Case Operating Scenario

We expect modest EBITDA increases with increased contracts for ANR Pipeline, incremental earnings from solar facilities acquired in 2014, and an increase in the average investment base for the Nova Gas Transmission System in Alberta. However, higher planned maintenance activity at Bruce and lower Alberta power prices could offset this.

Peer comparison

Table 1

TransCanada Corp. -- Peer Comparison				
Industry Sector: Pipeline				
	TransCanada Corp.	**Kinder Morgan Energy Partners L.P.**	**Pembina Pipeline Corp.**	**Enbridge Inc.**
Rating as of Sept. 8, 2015	A-/Stable/--	BBB-/Stable/--	BBB/Stable/--	BBB+/Stable/(A-2)
	--Average of past three fiscal years--			
(Mil. mixed currency)	**C$**	**US$**	**C$**	**C$**
Revenues	8,996.3	9,794.4	4,840.5	31,955.0
EBITDA	5,378.1	4,096.5	842.1	4,783.3
Funds from operations (FFO)	3,739.9	3,308.5	638.0	3,473.7
Net income from contuing operations	1,660.0	2,183.6	319.6	899.7
Cash flow from operations	3,738.4	3,300.1	568.6	2,590.2
Capital expenditures	3,735.8	2,043.3	915.1	7,976.0
Free operating cash flow	2.6	1,256.7	(346.5)	(5,385.8)
Discretionary cash flow	(1,511.4)	(1,414.1)	(565.1)	(6,686.5)
Cash and short-term investments	163.9	110.9	0.0	316.1
Debt	28,388.3	16,625.3	3,364.9	30,241.3
Equity	19,265.3	12,529.0	5,035.7	15,563.2
Adjusted ratios				
EBITDA margin (%)	59.8	41.8	17.4	15.0
Return on capital (%)	7.2	12.2	7.6	8.3
EBITDA interest coverage (x)	3.5	5.6	4.8	3.6
FFO cash inteest coverage (x)	5.1	5.8	5.9	4.1
Debt/EBITDA (x)	5.3	4.1	4.0	6.3
FFO/debt (%)	13.2	19.9	19.0	11.5
Cash flow from operations/debt (%)	13.2	19.8	16.9	8.6
Free operating cash flow/debt (%)	0.0	7.6	(10.3)	(17.8)
Discretionary cash flow/debt (%)	(5.3)	(8.5)	(16.8)	(22.1)

Financial Risk

We view the company's financial risk profile as "significant." TransCanada has limited headroom above our downgrade threshold, which is largely because of the high capital program for 2015-2018. We expect to see modest dividend growth and a financial policy that will maintain credit metrics above our threshold. The timing of approvals will affect the capital program, which will increase the variability of AFFO-to-debt and debt-to-EBITDA metrics in coming years. Once major projects receive approval, the related financing could put pressure on the credit metrics. We continue to forecast AFFO-to-debt in the 13%-16% area in 2015-2017 timeframe, with the approximately C$4.5 billion capital program in 2015.

S&P Base-Case Cash Flow And Capital Structure Scenario

- The company will finance most of its capital requirements with drop-downs to subsidiary TC PipeLines L.P. and the remaining with preferred shares and debt issuances
- Modest dividend growth of approximately 8%-10%
- Credit metrics in the 15% AFFO-to-debt range for the next couple of years

Financial summary

Table 2

TransCanada Corp. -- Financial Summary

Industry Sector: Pipeline

	--Fiscal year ended Dec. 31--				
	2014	**2013**	**2012**	**2011**	**2010**
Rating history	A-/Stable/--	A-/Stable/--	A-/Stable/--	A-/Stable/--	A-/Stable/--
(Mil. C$)					
Revenues	10,185.0	8,797.0	8,007.0	7,839.0	8,064.0
EBITDA	5,932.4	5,434.6	4,767.3	4,898.1	4,342.3
Funds from operations (FFO)	4,168.3	3,933.2	3,118.2	3,252.9	2,906.7
Net income from continuing operations	1,840.0	1,786.0	1,354.0	1,581.0	1,294.0
Cash flow from operations	4,162.2	3,623.2	3,514.2	3,614.9	2,743.7
Capital expenditures	4,330.2	4,385.9	2,491.3	2,394.3	4,612.6
Free operating cash flow	(252.4)	(762.7)	1,022.8	1,220.6	(1,868.8)
Discretionary cash flow	(1,854.9)	(2,280.2)	(399.1)	68.1	(2,755.8)
Cash and short-term investments	122.3	231.8	137.8	163.5	191.0
Debt	31,250.7	28,520.5	25,393.7	24,702.5	24,995.7
Equity	20,105.5	19,664.0	18,026.5	17,960.5	17,280.6
Adjusted ratios					
EBITDA margin (%)	58.2	61.8	59.5	62.5	53.8
Return on capital (%)	7.4	7.4	6.7	7.5	6.5
EBITDA interest coverage (x)	3.7	3.7	3.2	3.4	2.8
FFO cash int. cov. (x)	5.2	5.5	4.7	5.1	6.3
Debt/EBITDA (x)	5.3	5.2	5.3	5.0	5.8
FFO/debt (%)	13.3	13.8	12.3	13.2	11.6
Cash flow from operations/debt (%)	13.0	12.7	13.8	14.6	11.0
Free operating cash flow/debt (%)	(0.8)	(2.7)	4.0	4.9	(7.5)
Discretionary cash flow/debt (%)	(5.9)	(8.0)	(1.6)	0.3	(11.0)

Liquidity

We view TransCanada's liquidity as "adequate." Sources less uses are positive, and sources over uses are greater than 1.2x over the next 12 months. We believe the company will continue to have solid relationships with its banks, a generally high standing in credit markets, and generally prudent risk management.

Principal Liquidity Sources	Principal Liquidity Uses
• FFO of more than C$4.5 billion • Cash and short-term investments of C$590 million as of June 30, 2015 • Credit facility availability of approximately C$6.5 billion (C$4.3 billion to back commercial paper)	• Committed capital expenditures of C$3.6 billion-C$3.8 billion • Dividends of C$1.7 billion–C$1.9 billion • Debt maturities of about C$1.9 billion • Commercial paper outstanding of about C$2.1 billion

Debt maturities

Table 3

Debt Maturities

Due date	Amount
2015	1,797
2016	2,225
2017	846
2018	1,766
2019	1,007
After year 5	20,743
Total	28,384

Other Modifiers

None of the other modifiers had an impact on the rating.

Group Influence

TransCanada PipeLines Ltd. (TCPL) is the ultimate parent to subsidiary TC PipeLines LP. TransCanada Corp. is atop TCPL and we consider it "core" to TCPL, which equalizes the ratings on it to those on TCPL. TransCanada Corp. has no assets and modest hybrid securities. TCPL represents 100% of revenues and cash flows of TransCanada Corp.

Ratings Score Snapshot

Corporate Credit Rating

A-/Stable/--

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Excellent

Financial risk: Significant

- **Cash flow/Leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a-

- **Entity status within group:** Core (no impact)

Reconciliation

Table 4

Reconciliation Of TransCanada Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$)

	--Fiscal year ended Dec. 31, 2014--								
TransCanada Corp. reported amounts									
	Debt	**Shareholders' equity**	**EBITDA**	**Operating income**	**Interest expense**	**EBITDA**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	28,384.0	19,070.0	4,903.0	3,292.0	1,198.0	4,903.0	4,079.0	1,617.0	4,357.0
Standard & Poor's adjustments									
Interest expense (reported)	N/A	N/A	N/A	N/A	N/A	(1,198.0)	N/A	N/A	N/A
Interest income (reported)	N/A	N/A	N/A	N/A	N/A	(4.0)	N/A	N/A	N/A
Current tax expense (reported)	N/A	N/A	N/A	N/A	N/A	(145.0)	N/A	N/A	N/A
Operating leases	569.7	N/A	99.9	38.9	38.9	60.9	60.9	N/A	N/A
Intermediate hybrids reported as debt	(580)	580	N/A	N/A	(32.5)	32.5	32.5	32.5	N/A
Intermediate hybrids reported as equity	1,127.5	(1,127.5)	N/A	N/A	48.5	(48.5)	(47.0)	(47.0)	N/A

Table 4

Reconciliation Of TransCanada Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$) (cont.)

Postretirement benefit obligations/deferred compensation	327.8	N/A	28.0	28.0	19.8	15.1	(20.9)	N/A	N/A
Surplus cash	(366.8)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Capitalized interest	N/A	N/A	N/A	N/A	259.0	(259.0)	(259.0)	N/A	(259.0)
Dividends received from equity investments	N/A	N/A	579.0	N/A	N/A	579.0	N/A	N/A	N/A
Power purchase agreements	1,291.0	N/A	322.6	90.4	90.4	232.2	232.2	N/A	232.2
Asset retirement obligations	73.5	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Non-operating income (expense)	N/A	N/A	N/A	613.0	N/A	N/A	N/A	N/A	N/A
Non-controlling Interest/Minority interest	N/A	1,583.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Debt - Accrued interest not included in reported debt	424.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total adjustments	2,866.7	1,035.5	1,029.4	770.3	424.1	(734.7)	(1.2)	(14.5)	(26.8)

Standard & Poor's adjusted amounts

	Debt	Equity	EBITDA	EBIT	Interest expense	Funds from operations	Cash flow from operations	Dividends paid	Capital expenditures
Adjusted	31,250.7	20,105.5	5,932.4	4,062.3	1,622.1	4,168.3	4,077.8	1,602.5	4,330.2

N/A--Not applicable.

Related Criteria And Research

Related Criteria

- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Key Credit Factors For The Unregulated Power And Gas Industry, March 28, 2014
- Key Credit Factors For The Midstream Energy Industry, Dec. 19, 2013
- Corporate Methodology, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Hybrid Capital Handbook: September 2008 Edition, Sept. 15, 2008

Business And Financial Risk Matrix

Business Risk Profile	Financial Risk Profile					
	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Ratings Detail (As Of September 8, 2015)

TransCanada Corp.	
Corporate Credit Rating	A-/Stable/--
Preferred Stock	
Canada National Scale Preferred Share	P-2
Preferred Stock	BBB
Corporate Credit Ratings History	
30-Sep-2009	A-/Stable/--
Related Entities	
ANR Pipeline Co.	
Issuer Credit Rating	A-/Stable/--
Senior Unsecured	A-
NOVA Gas Transmission Ltd.	
Issuer Credit Rating	A-/Stable/--
Senior Unsecured	A-
TC PipeLines L.P.	
Issuer Credit Rating	BBB-/Stable/--
Senior Unsecured	BBB-
TransCanada PipeLines Ltd.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Foreign Currency	A-2
Junior Subordinated	BBB
Senior Unsecured	A-
TransCanada PipeLine USA Ltd.	
Issuer Credit Rating	A-/Stable/A-2
Tuscarora Gas Transmission Company	
Issuer Credit Rating	BBB-/Stable/--

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

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