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June 5, 2015

VIA RESS, EMAIL and COURIER

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, ON M4P 1E4

Dear Ms Walli:

Re: EB-2015-0175: Enbridge Gas Distribution Inc. ("Enbridge")
Pre-Approval of a Long-Term Natural Gas Transportation Contract

The Ontario Energy Board's (the "Board", or the "OEB") Filing Guidelines for the Pre-Approval of Natural Gas Supply and / or Upstream Transportation Contracts from the EB-2008-0280 proceeding (the "Guidelines") entitle Enbridge to apply for pre-approval of the cost consequences of a long-term natural gas transportation contract that supports the development of new infrastructure.

Enclosed is Enbridge's Application and supporting evidence seeking pre-approval of the cost consequences of a new long-term natural gas transportation contract that supports the development of new natural gas infrastructure.

Enbridge has entered into a Precedent Agreement with the lead developers of the NEXUS Gas Transmission pipeline ("NEXUS") for natural gas transportation service for a fifteen-year term commencing November 1, 2017. NEXUS will provide transportation service from Kensington, Ohio to the Dawn Hub in Ontario. This transportation path will allow Enbridge to obtain gas supply directly from within the Appalachian Basin in the Northeast United States. NEXUS will require the construction of a new greenfield natural gas transmission pipeline and associated facilities for most of this transportation path. In addition, this transportation path will utilize existing infrastructure from eastern Michigan to transport natural gas supply to the Dawn Hub. The Precedent Agreement is subject to several conditions precedent, including OEB pre-approval of the cost consequences of the transportation agreement. Under the terms of the Precedent Agreement, the condition precedent of OEB pre-approval must be obtained or waived by October 1, 2015. If OEB pre-approval is obtained and other conditions precedent are satisfied, then Enbridge plans to execute a transportation contract with NEXUS on terms that are consistent with the Precedent Agreement.

Enbridge's supporting evidence, which is attached to the Application, addresses the requirements set out in the Guidelines and explains the benefits that the contract with NEXUS would provide to the Enbridge gas supply plan, and therefore Enbridge's customers, through improved reliability, diversity, and flexibility. The cost consequences of the long-term transportation contract are prudent and competitive when compared to other supply and transportation alternatives. Enbridge's participation in the project supports the development of new natural gas transmission infrastructure and allows direct access to new sources of gas supply. As such, this is an appropriate case for pre-approval under the Guidelines.

Enbridge respectfully requests that the Board establish an expedited process, in writing (or an oral hearing process if deemed appropriate by the Board), to consider the pre-approval of the cost consequences of Enbridge's contract with NEXUS, so that the Board's decision may be issued by September 24, 2015. This timing will provide Enbridge with sufficient lead-time to fully consider the implications of the Board's decision in advance of Enbridge's October 1, 2015 deadline to satisfy or waive the pre-approval condition precedent set out in the Precedent Agreement.

In order to expedite matters, Enbridge is serving this Application and all supporting evidence on those parties whom the Company believes may have interest in the proceeding. This includes all participants from Enbridge's most recent full rates proceeding (EB-2012-0459) as well as all participants in Enbridge's recent Dawn Access Consultative (EB-2014-0323), which set out the terms on which customers of Enbridge will be given access to service at the Dawn Hub.

Please contact me at if you have any questions or wish to discuss this submission in more detail.

Yours truly,

(Original Signed)

Andrew Mandyam
Director Regulatory Affairs & Financial Performance

cc: D. Stevens, Aird & Berlis LLP (via email and courier)
EB-2012-0459 Intervenors (via email only)
EB-2014-0323 Intervenors (via email only)

EXHIBIT LIST

A – APPLICATION AND EVIDENCE

Exhibit	Tab	Schedule	Contents	Witness(es)
A	1	1	Exhibit List	J. Denomy
	2	1	Application	J. Denomy
	3	1	Evidence in Support of the Application for Pre-Approval of the Cost Consequences of the NEXUS Contract	J. LeBlanc A. Welburn
		2	Sussex Study: NEXUS Gas Transmission Market Study	J. Stephens
		3	2014-2015 Gas Supply Plan Memorandum	A. Welburn
	4	1	Curricula Vitae of Company Witnesses	J. Denomy
		2	Curricula Vitae of James M. Stephens (Sussex Economic Advisors, LLC)	J. Denomy

EB-2015-0175

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, Sched. B, as amended;

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an Order or Orders Pre-Approving the Cost Consequences associated with a Long-Term Natural Gas Transportation Contract.

APPLICATION

1. The Applicant, Enbridge Gas Distribution Inc. ("Enbridge" or the "Company"), is an Ontario corporation with its head office in the City of Toronto. It carries on the business of selling, distributing, transmitting and storing natural gas within Ontario.

2. In the EB-2008-0280 proceeding, the Ontario Energy Board (the "OEB" or the "Board") indicated that it would consider Applications for the pre-approval of the cost consequences of long-term natural gas supply and / or transportation contracts that support the development of new natural gas infrastructure. The Board issued Filing Guidelines for the Pre-Approval of Natural Gas Supply and / or Upstream Transportation Contracts (the "Guidelines") setting out the items to be included in any such Application.

3. Enbridge hereby applies to the Board, pursuant to the Guidelines and section 36 of the *Ontario Energy Board Act*, *1998* as amended (the "Act"), for an Order or Orders pre-approving the cost consequences associated with a long-term (15 year) gas transportation contract for service on the NEXUS Gas Transmission ("NEXUS") pipeline, commencing November 1, 2017.

4. NEXUS is a proposed pipeline that will provide natural gas markets in Ohio, Michigan, Chicago, and the Dawn Hub in Ontario with a direct link to the vast natural gas resources located within the Appalachian Basin (Marcellus and Utica shale gas supply). NEXUS requires the construction of approximately 250 miles of new greenfield pipeline and associated facilities and includes the efficient use of existing and expanded transportation pipelines.

5. Enbridge has entered into a Precedent Agreement with the developers of the NEXUS pipeline to enter into a contract (the "NEXUS contract") to receive firm transportation service for a term of 15 years commencing on November 1, 2017.

6. Under the terms of the Precedent Agreement, Enbridge must receive OEB pre-approval of the cost consequences of the NEXUS contract by October 1, 2015. If that approval is not received, then Enbridge has the right to terminate the Precedent Agreement without penalty. If OEB pre-approval is received, and other conditions precedent are satisfied, then Enbridge plans to enter into a gas transportation contract with NEXUS that will reflect the terms of the Precedent Agreement.

7. The NEXUS contract will allow Enbridge to obtain a direct supply of gas from the Marcellus and Utica basins to the Dawn Hub. This will allow Enbridge to diversify its gas supply portfolio and increase its security of supply.

8. The NEXUS contract is for 110,000 Dth per day of firm transportation capacity starting in 2017, with an annual cost of around $28 million (US) in transportation charges (a total cost of around $420 million (US) over the 15 year term). The average landed gas supply cost of the NEXUS contract is competitive with costs for Enbridge's other transportation and supply contracts and other alternatives.

9. Enbridge’s evidence addresses all of the items required by the Guidelines. Attached as Appendix A to this Application is a table in the form prescribed by the Guidelines setting out the location of each required item within Enbridge’s evidence.

10. Enbridge therefore applies to the Board for such final and interim Orders as may be necessary to pre-approve the cost consequences associated with the NEXUS contract over its 15 year term. The Company further applies to the Board pursuant to the provisions of the Act and the Board's *Rules of Practice and Procedure* for such final and interim Orders and directions as may be necessary in relation to the Application and the proper conduct of this proceeding.

11. It is not clear to Enbridge that an oral hearing is required. The Company requests that the Board establish a process to determine the Application in writing (or through an oral hearing if necessary) that allows for a decision to be rendered on or before September 24, 2015.

12. The persons affected by this Application are the customers of Enbridge. It is impractical to set out the names and addresses of the customers because they are too numerous.

13. Enbridge requests that a copy of all documents filed with the Board by each party to this proceeding be served on the Applicant and the Applicant's counsel as follows:

The Applicant:

Mr. Andrew Mandyam
Director, Regulatory Affairs and Financial Performance
Enbridge Gas Distribution Inc.

Address for personal service:	500 Consumers Road Willowdale, Ontario M2J 1P8
Mailing address:	P.O. Box 650 Scarborough, Ontario M1K 5E3
Telephone:	416-495-5499
Fax:	416-495-6072
E-mail:	egdregulatoryproceedings@enbridge.com

The Applicant's counsel:

Mr. David Stevens
Aird & Berlis LLP

Address for personal service and mailing address:	Brookfield Place, PO Box 754 Suite 1800, 181 Bay Street Toronto, Ontario M5J 2T9
Telephone:	416-865-7783
Fax:	416-863-1515
E-mail:	dstevens@airdberlis.com

DATED June 5, 2015 at Toronto, Ontario.

ENBRIDGE GAS DISTRIBUTION INC.

(Original Signed)

Per: ________________________

Andrew Mandyam
Director, Regulatory Affairs and Financial Performance

APPENDIX A

Part I – Identification of Applicant

Name of Applicant: Enbridge Gas Distribution Inc.	File No: EB-2015-0175
Address of Head Office: 500 Consumers Road Willowdale, Ontario M2J 1P8 P.O. Box 650 Scarborough, Ontario M1K 5E3	Telephone Number: 416-495-5499
	Facsimile Number: 416-495-6072
	E-mail Address: egdregulatoryproceedings@enbridge.com
Name of Individual to Contact: Andrew Mandyam Director, Regulatory Affairs and Financial Performance	Telephone Number: Same as above
	Facsimile Number: Same as above
	E-mail Address: Same as above

Part II – Needs, Costs and Benefits

2.1	A description of the proposed project that includes need, costs, benefits (such as this project improves the security of supply and the diversity of supply sources) and timelines.	Exhibit A, Tab 3, Schedule 1, pages 10 to13
2.2	An assessment of the landed costs (supply costs + transportation costs including fuel costs) for the newly contracted capacity and/or natural gas supply compared to the landed costs of the possible alternatives.	Exhibit A, Tab 3, Schedule 1, pages 19 to 26

Part III – Contract Diversity

3.1	A Description of all the relevant contract parameters such as transportation/supply provider, contract length, conditions of service, price, volume and receipt and delivery points.	Exhibit A, Tab 3, Schedule 1, page 13 to19
3.2	An assessment on how the contract fits into the applicant’s overall transportation and natural gas supply portfolio in terms of contract length, volume and services.	Exhibit A, Tab 3, Schedule 1, pages 26 to 34

Part IV – Risk Assessment

4.1	Identification of all the risks (such as forecasting risks, construction and operational risks, commercial risks and regulatory risks) and plans on how these risks are to be minimized and allocated between ratepayers, parties to the contract and/or the applicant's shareholders. For example, forecasting risks include future demand, prices, actual landed costs and performance of basin; commercial risks include competitive and credit-worthiness of provider/operator; construction and operational risks include costs escalations, delays or reliability issues pertaining to new construction, and gas interchangeability and quality issues; and regulatory risks include changes in laws or regulations.	Exhibit A, Tab 3, Schedule 1, pages 35 to 42

Part V – Other Considerations

5.1	A description of the relationship and any other conditions, rights or obligations between the parties to the contract and the applicant's parent company and/or affiliates.	Exhibit A, Tab 3, Schedule 1, page 12
5.2	An assessment of retail competition impacts and potential impacts on existing transportation pipeline facilities in the market (in terms of Ontario customers).	Exhibit A, Tab 3, Schedule 1, pages 42 to 43

Part VI – Contract

6.1	The contract for which the utility is seeking pre-approval for is filed in this application. The utility may request confidential treatment of its contract in accordance with the Ontario Energy Board's *Practice Direction on Confidential Filings*.	Exhibit A, Tab 3, Schedule 1, Appendices D and E (Plus related provisions found in Appendices G and H).

EVIDENCE IN SUPPORT OF THE APPLICATION FOR PRE-APPROVAL OF THE COST CONSEQUENCES OF THE NEXUS CONTRACT

A. OVERVIEW

1. Enbridge Gas Distribution “Enbridge” or the “Company” seeks preapproval of the cost consequences of a 15 year gas transportation agreement with NEXUS Gas Transmission, LLC on the NEXUS Gas Transmission Project (“NEXUS”). This preapproval is sought under the Ontario Energy Board’s (“Board”, or “OEB”) Filing Guidelines for the Pre-Approval of Long-Term Natural Gas Supply and/or Upstream Transportation Contracts (the “Guidelines”).

2. NEXUS is a proposed pipeline that will provide natural gas markets in Ohio, Michigan, Chicago, and the Dawn Hub in Ontario with a direct link to the vast natural gas resource located within the Appalachian basin. NEXUS requires the construction of approximately 250 miles of new greenfield pipeline and includes the efficient use of existing and expanded transportation capacity along the Texas Eastern Transmission, LP system in Ohio, the DTE Pipeline Company (“DTE”) gas transportation system in eastern Michigan, and the Vector Pipeline system in southeastern and eastern Michigan, northern Indiana, eastern Illinois and western Ontario (“Vector”).

3. NEXUS provides significant opportunity to further enhance Enbridge’s gas supply portfolio. The Appalachian basin, and specifically, the Utica and Marcellus supply basins are expected to account for over half the incremental North America gas production through 2035[1]. These basins have served as a primary catalyst for the changing dynamics within North America’s natural gas marketplace. Obtaining assured access to these supplies is a natural evolution

[1] EB-2014-0289 - Future Trends: Assessing Ontario Natural Gas Market Requirements Through 2020 presentation prepared by ICF International, November 25, 2014, page 4.

of Enbridge's gas supply planning and would fundamentally improve gas supply portfolio diversity, reliability, flexibility, and cost effectiveness. Although Enbridge has the potential to access Utica and Marcellus supply through purchases at Niagara, NEXUS provides additional benefits through increased diversity of path and the ability to obtain natural gas directly from the supply basins.

4. There are a significant number of new pipeline projects competing to transport Appalachian basin supplies to various markets across North America. The 2014 Natural Gas Market Review Final Report ("2014 NGMR Final Report") prepared for Board Staff examined the destination for Marcellus natural gas supply and noted "*the relatively small proportion of the Marcellus that is actually destined for the Ontario market*"[2]. If Enbridge does not actively participate now in these new pipeline projects, supplies from the Appalachian basin will continue to be contracted to other markets across North America. This will increase the risk of Appalachian supply bypassing Ontario and potentially limit access to these supplies in the future.

5. Developers of new pipeline facilities typically require shippers to contract for a minimum term ranging from 15 to 20 years. Participation in the NEXUS project requires a minimum contract term of 15 years and is therefore at the lower end of this range. The last time Enbridge entered into similar contract terms for greenfield pipeline capacity was in 2000 for transportation capacity on Alliance Pipeline and Vector Pipeline.

6. Enbridge has entered into a Precedent Agreement ("PA") with the lead developers of NEXUS, DTE and Spectra Energy Transmission, LLC ("Spectra"),

[2] EB-2014-0289 – 2014 Natural Gas Market Review Final Report by Navigant Consulting Inc., dated December 22, 2014, page 37.

for 110,000 Dth per day of firm transportation capacity starting in 2017. Enbridge is one of the shippers underpinning the decision to proceed with the project. Enbridge was able to negotiate favourable terms into the PA which protect Enbridge and its ratepayers from being responsible for pre-service project costs unless appropriate authorizations are received. These favourable terms include the right to terminate the agreement without harm if certain conditions precedent are not achieved to the satisfaction of Enbridge. One such condition precedent is the requirement that Enbridge obtain pre-approval from the OEB for the recovery of the transportation costs associated with the NEXUS transportation capacity.

7. If the requested pre-approval is received from the OEB, and other conditions precedent are satisfied, then Enbridge plans to enter into a gas transportation contract with NEXUS that will reflect the terms of the PA (the “NEXUS contract”).

8. In addition to the conditions precedent, the PA includes other favourable terms. Enbridge can elect to increase its contracted volume to 150,000 Dth per day (subject to pipeline capacity being available). If the election is made prior to the NEXUS commencement date, Enbridge will receive the benefit of “Most Favored Nations” status which provides for Enbridge to receive more favourable service provisions if those have already been granted to other anchor shippers. Enbridge has the option to make this election as late as 2020 to receive the preferred reservation rate granted to anchor shippers.

9. Enbridge evaluated the competitiveness of the NEXUS transportation capacity through a landed cost analysis. *Inter alia*, this analysis has been reviewed and supported as part of an independent Market Study conducted by Sussex Economic Advisors (“Sussex Study”) which is included in Schedule 2. The reservation rate of $0.70 in United States currency (“US”) per Dth will remain

fixed for the 15 year term of the NEXUS contract (subject to maximum adjustment of ±15%). The forecast cost of gas supply via the NEXUS pipeline is competitive with alternative pipeline projects or existing pipeline infrastructure that accesses the Dawn Hub.

10. Enbridge has analyzed the forecasting, construction, operational, commercial, and regulatory risks associated with NEXUS and has found them to be manageable. Enbridge finds that these risks are outweighed by the benefits to Enbridge's gas supply plan that are achieved by adding direct deliveries of Appalachian basin gas to the Dawn Hub. The risks associated with NEXUS have also been reviewed as part of the Sussex Study and found to be largely mitigated through the favourable terms negotiated into the PA, the strength of the lead developers, and current production expectations for the Utica and Marcellus supply basins.

11. This is an appropriate case for pre-approval under the Board's Guidelines. Enbridge's planned contract with NEXUS is an extraordinary contract (15 years in length) that is different from the Company's typical gas transportation arrangements. The costs associated with the NEXUS contract are competitive with other gas supply options, and the risks associated with the arrangement can be managed. The NEXUS contact supports new greenfield infrastructure that will provide for direct access to new natural gas supply from a developing supply basin directly to the Dawn Hub for the benefit of Enbridge's customers and natural gas markets in Ontario. Pre-approval of the cost consequences of the NEXUS contract will allow Enbridge to make the significant long-term commitment that is required to ensure the benefits of the project will be realized by Enbridge's customers.

12. The balance of this narrative evidence sets out the information required for pre-approval of the cost consequences of the PA in accordance with the Board's Guidelines. Appendix A contains a map of the NEXUS project which shows project routing and required facilities. Appendix B and Appendix C contain details on the landed cost analysis comparing the NEXUS path to possible alternatives. Appendix D contains the Restated PA and associated Exhibits/Attachments. Appendix E contains the First Amendment to Restated PA which includes changes to how the Capital Cost Tracking Adjustment will be performed and the elimination of references to the two phases of NEXUS as the project no longer includes multi-phases. Appendix F contains a blackline showing the amendments to the Restated PA for illustrative purposes and is not an operative agreement. This Appendix is provided to provide readers of the evidence with a clearer means to understand the complete and final terms of the PA. Appendix G contains the Statement of Negotiated Rates and the Rate Breakdown and Final Capital Cost Estimate is included in Appendix H.

13. The Sussex Study (found at Schedule 2) was commissioned by Enbridge and Union Gas to review the expectations for production from the Appalachian basin and specifically expectations regarding production from the Utica and Marcellus shale basins. It discusses the benefits of participation in NEXUS and concludes that it will increase the diversity, reliability, flexibility, and price stability of Enbridge's gas supply portfolio to the benefit of Enbridge's customers and the Ontario market. The Sussex Study also identifies the risks associated with NEXUS and discusses how they are mitigated.

B. ENBRIDGE'S GAS SUPPLY PLANNING APPROACH

14. Enbridge establishes its gas supply plan based on the principles of diversity, reliability, flexibility, and cost. The details of these principles are as follows:

- *Reliability* – Enbridge is the "supplier of last resort" and as a result supplies are sourced from established liquid hubs and transported to the markets served by Enbridge via firm transportation contracts in order to mitigate delivery interruption;
- *Diversity* – Mitigates reliability and cost risks by procuring supplies from multiple procurement points and transporting supplies to market and/or storage through several different transportation paths;
- *Flexibility* – Manages shifting demand requirements through differentiated supply procurement patterns and provides operational flexibility through service attributes and contract parameters; and
- *Landed Cost* – Balances gas supply costs with the other principles and ensures low cost natural gas supply for customers.

15. Further detail about Enbridge's gas supply planning approach is set out within Enbridge's 2014 – 2015 Gas Supply Memorandum which has been filed in the EB-2015-0122 proceeding, at Exhibit D, Tab 4, Schedule 1. A copy of that memorandum is included as Exhibit A, Tab 3, Schedule 3 to this evidence.

16. Expected shifts in natural gas flows resulting from North American shale gas production and new pipeline infrastructure have prompted Enbridge to further diversify its supply portfolio. The changes that have led to Enbridge's decision to further diversify its portfolio are described at length in the Sussex Study, and are also addressed in the Enbridge Gas Supply Memorandum. Failing to react to these changing dynamics would have maintained significant reliance on

traditional sources of supply from the Western Canadian Sedimentary Basin ("WCSB") and the Dawn Hub.

17. Enbridge has recently taken steps to diversify its portfolio, for example through transportation contracts which access additional supply from the Dawn Hub and Niagara. These contracts and market access were made possible through the GTA Project[3] and the Mainline Settlement Agreement[4] between TransCanada PipeLines Limited ("TransCanada"), Enbridge, Gaz Métro Limited Partnership, and Union Gas. Enbridge has also chosen not to renew contracts on the Alliance and Vector systems in order to provide the flexibility to access new supplies in light of expectations for new, cost effective and more proximate supply available to the markets served by Enbridge.

18. The incremental market access to the Dawn Hub has also resulted in a change to how direct purchase customers procure their natural gas supplies. The majority of Enbridge's direct purchase customers have elected to shift from existing services where supplies are delivered to Enbridge in the WCSB or directly in Enbridge's franchise area to a new, Board-approved, Dawn Transportation Service[5] where supplies are delivered to Enbridge at the Dawn Hub. Enbridge has adjusted its transportation portfolio in response to demand for the new Dawn Transportation Service.

19. Enbridge's contracting decisions, including its decision to bid into the NEXUS open season, recognize the changing dynamics in natural gas supply and pricing and the need to support the development of new facilities for Ontario markets to

[3] EB-2012-0451 Leave to Construct Application – GTA Project Application and Evidence filed December 21, 2012.
[4] RH-001-2014 TransCanada PipeLines Limited Application for Approval of Mainline 2013-2030 Settlement application filed December 2013, Attachment 1a.
[5] EB-2014-0323 Application filed 2014-10-27, Exhibit A, Tab 2, Schedule 1

receive assured natural gas supply from the Appalachian basin along new transportation paths.

C. MARCELLUS / UTICA GAS SUPPLY

20. As explained in the Sussex Study, and also discussed in the 2014 NGMR Final Report, the North American natural gas market has been deeply impacted by the "shale revolution" of abundant natural gas resources producible through horizontal drilling and hydraulic fracturing. This has increased the supply of natural gas in North America and has led to abundant and reasonably priced natural gas.

21. In recent years, the production and expected future production from the Marcellus and Utica producing areas in the Appalachian basin have grown immensely. Both basins have been serving demand not only in the U.S. Northeast, but also to the U.S. South, to the Gulf, to the Midwest, and to Eastern Canada.

22. As stated in the Sussex Study, the rise of the Marcellus and Utica shale basins as proximate and competitive sources of natural gas for the Ontario market presents new opportunities to source natural gas from these basins[6]. The production from these basins has increased each year, to the point where it is now at or beyond the production level from the WCSB.

23. The expectation is that production from the Marcellus and Utica basins will continue to increase. The Sussex Study describes the natural gas resource potential from these basins, and notes that the proved and possible resources

[6] Sussex Study page 3 and 33.

from these basins would meet the entire United States demand for natural gas for approximately 30 years[7].

24. To this point, the takeaway options from the Marcellus and Utica basins to provide supply to Ontario, and in particular to the Dawn Hub, have been limited. However, the fact that these are major supply sources that are close to the Ontario market makes this production an attractive option for Enbridge. Access to this supply will enhance Enbridge's gas supply planning principles of diversity, reliability, flexibility, and cost by displacing supplies transported on Vector to the Dawn Hub with supplies directly from the Marcellus and Utica basins.

25. Currently, Enbridge is planning to obtain some of its 2015/2016 gas supply (200,000 GJ/day) through receipts at Niagara. It is expected (though not required) that this gas supply will have been produced in the Marcellus basin. As described in the EB-2014-0276 evidence (Exhibit D1, Tab 2, Schedules 1 and 2), this service will begin in the 2015/2016 winter season, and will involve gas purchases at Niagara and delivery to Enbridge's CDA[8] via TransCanada's Mainline.

26. There is no current means for Enbridge to obtain direct supply of natural gas on a firm basis from the Marcellus and Utica basins to the Company's storage facilities at Dawn, nor to Enbridge's franchise area. This makes NEXUS a valuable new option for Enbridge to meet its gas supply requirements.

[7] Sussex Study page 28.
[8] Receipts from Niagara will be delivered to Enbridge Parkway CDA.

D. THE NEXUS PROJECT

27. NEXUS is a greenfield pipeline project that will transport growing supplies of natural gas from the Appalachian basin, including Marcellus and Utica shale production, to delivery points in Ohio, Michigan, Chicago and the Dawn Hub (including Enbridge's storage facility) in Ontario, Canada. The service commencement date is expected to be November 1, 2017.

28. The new greenfield pipeline will be constructed, owned and operated by NEXUS Gas Transmission, LLC and NEXUS Gas Transmission Canada[9] and will extend from Kensington, Ohio to the DTE gas transportation system west of Detroit in Willow Run, Michigan. Approximately 250 miles of 36-inch[10] diameter natural gas transmission mainline pipeline and associated compression facilities will be constructed in Ohio and Michigan and approximately 1.4 miles of new pipeline will be constructed in order to interconnect with the Texas Eastern and Tennessee Gas Pipeline systems. This smaller interconnect build is contemplated in order to provide additional upstream receipt point access to existing and prospective shippers.

29. A map of the NEXUS pipeline is set out below, and a more detailed map is found at Appendix A. Further detail about the NEXUS pipeline project is set out in the Sussex Study.

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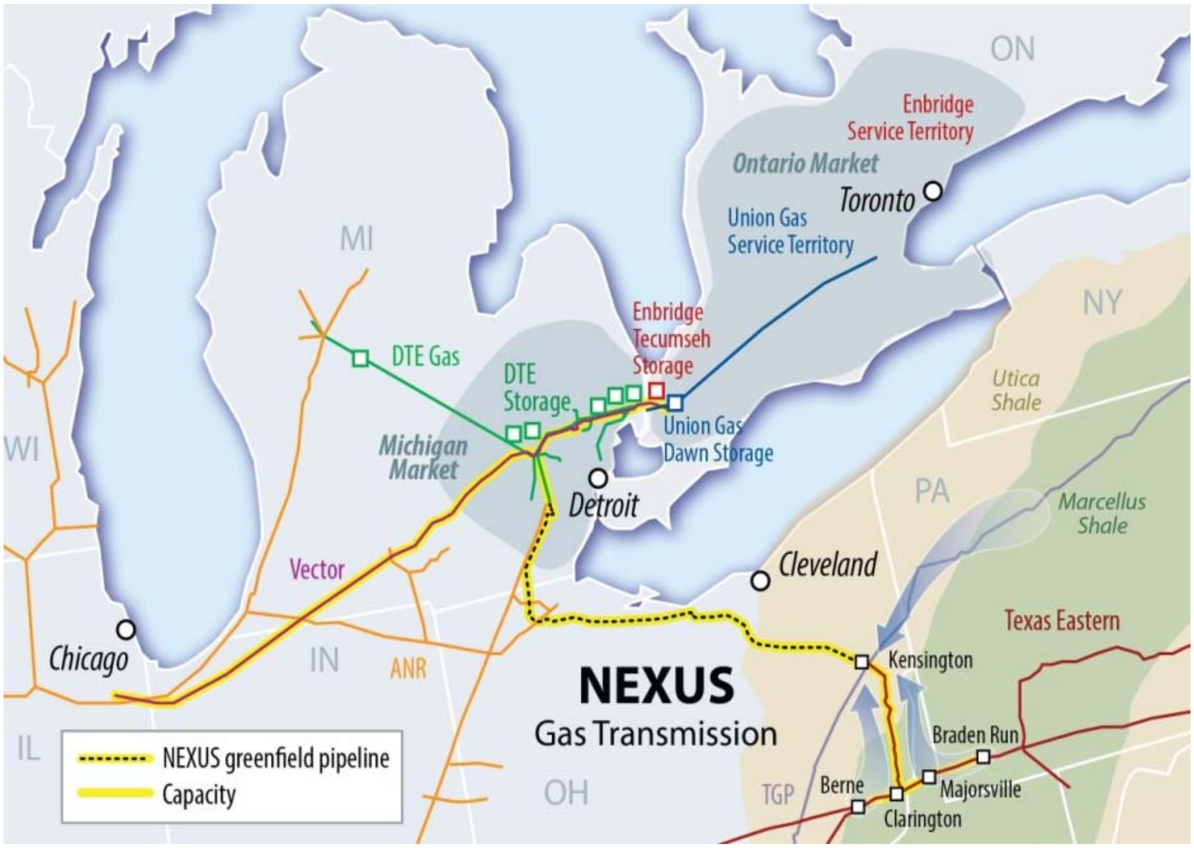
[9] NEXUS PA page 3.
[10] NEXUS Gas Transmission Project, Docket No. PF15-10-000 Updated Stakeholder List and Project Update to the Federal Energy Regulatory Commission dated March 20, 2015 indicated that the objectives of NEXUS can be met using a 36-inch diameter pipe for the greenfield portion of NEXUS.



30. As proposed, NEXUS includes both greenfield pipeline construction and, to minimize environmental disruption and optimize project efficiencies, the contracting of firm capacity on existing and expanded pipeline systems. Contracting of firm capacity on existing and expanded pipeline systems will entail the expansion of the Texas Eastern Transmission, LP system in Ohio where NEXUS initiates, the likely expansion of the DTE gas transportation system in eastern Michigan and extending to the U.S./Canada border and the likely expansion of Vector in southern and eastern Michigan, northern Indiana, eastern Illinois and western Ontario.

31. The NEXUS pipeline will offer direct access for shippers choosing to move natural gas to the Dawn Hub from the Marcellus and Utica basins. This will be effected by contracting on NEXUS for service to eastern Michigan (Willow Run), and then transporting gas from that point on other existing pipelines to the Dawn Hub. This additional transportation may be obtained through DTE and Enbridge's affiliate, Vector. Some reinforcement of those pipelines may be required, but it is not expected that any greenfield construction will be needed. This makes efficient use of existing infrastructure.

32. Lead developers of the project are DTE and Spectra, two of the leading energy service and infrastructure companies in North America. In September 2012, Enbridge Inc. executed a Memorandum of Understanding ("MOU") with DTE and Spectra to jointly develop NEXUS. The MOU has expired. Enbridge Inc., however, remains in discussions with Spectra and DTE regarding the terms of its potential participation in the project.

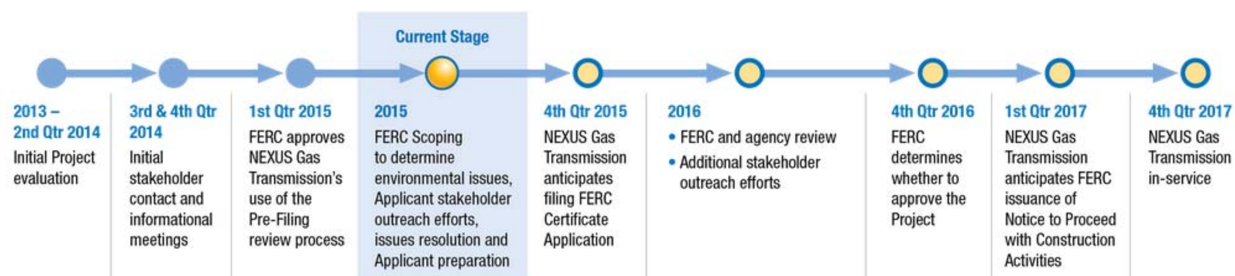
33. As with any major greenfield pipeline project, the NEXUS pipeline will not proceed without sufficient long-term support and commitment from major shippers. These shippers may be producers or consumers (such as utilities). To that end, NEXUS conducted open season processes, starting in late 2012, which resulted in a determination that there was sufficient market demand and commitment to support the project. Interested shippers have indicated that they are prepared to make the necessary long-term (15 year) commitment to obtain transportation service from the NEXUS pipeline.

34. On January 9, 2015 the Director of the Office of Energy Projects at the Federal Energy Regulatory Commission ("FERC") approved a request by NEXUS Gas Transmission, LLC to utilize the FERC's pre-filing process for the NEXUS project.

This process allows for early public consultation and involvement in evaluating the proposed facilities set prior to submitting a formal facilities application to the FERC. NEXUS has been assigned docket number PF15-10-000. NEXUS expects to file a formal FERC certificate application in the 4th quarter of 2015. Construction is expected to begin in the 1st quarter of 2017 and the in-service date of the NEXUS pipeline is expected to be during the 4th quarter of 2017, specifically November 1, 2017.

35. A detailed timeline of the NEXUS development schedule is provided below:

NEXUS Development Schedule[11]



E. ENBRIDGE'S AGREEMENT TO ACQUIRE CAPACITY ON NEXUS

36. From the time that the NEXUS project was announced, it has been a very interesting gas supply opportunity to Enbridge. This greenfield pipeline would provide direct firm transportation access to Marcellus and Utica supply that could be delivered to Enbridge's storage facilities at Dawn, and to the Dawn Hub. This would enhance Enbridge's gas supply planning principles (reliability, diversity, flexibility and cost). The benefits of the NEXUS capacity to Enbridge and its

[11] NEXUS Project Timeline from http://www.nexusgastransmission.com/timeline/ dated March 4, 2015.

customers are set out below, under the heading "*Benefits of the NEXUS Project for Enbridge*".

37. Enbridge participated in the initial open season for firm natural gas transportation capacity on the NEXUS Gas Transmission Project. This open season was held from October 15, 2012 to November 30, 2012. At the conclusion of the open season Enbridge was awarded long term firm transportation capacity on NEXUS. At the time of Enbridge's bid into the open season, NEXUS offered firm transportation service commencing November 2016 or earlier, for receipt points in Eastern Ohio to delivery points in the United States and Ontario for a minimum term of 15 years. Enbridge's bid was non-binding.

38. Pursuant to terms of the open season, any party awarded capacity committed to entering into discussions potentially leading to a binding PA. The PA describes the rights and obligations of the shipper and the lead developers. Enbridge's participation, amongst others, at the outset of the project provided a significant portion of the contractual commitments required to move ahead with the project.

39. NEXUS held two supplemental open seasons which expanded the project to its current scope and size. In its first supplemental open season for firm service NEXUS noted:

> With the commitments to date from a significant number of gas and electric utilities and Appalachian producers, NEXUS has sufficient commitments to advance development of the project[12]

40. The subsequent supplemental open season notice for firm service from NEXUS indicated:

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[12] NEXUS Gas Transmission Project, Supplemental Open Season Notice for Firm Service, July 23, 2014 – August 21, 2014.

> NEXUS previously conducted open seasons which resulted in contractual commitments, from local distribution companies and producers, for the majority of the project design capacity. With this necessary market support and the Federal Energy Regulatory Commission's January 2015 approval of our filing request, the project will move forward.[13]

41. At the time of Enbridge's participation in the initial NEXUS open season, it was not certain that NEXUS would advance. Clearly, however, commitments from utilities like Enbridge and others have provided part of the market support necessary for the project lead developers to proceed with NEXUS. Stated differently, without support from major shippers such as Enbridge, the new infrastructure build requiring the construction of approximately 250 miles of greenfield pipeline and associated compression facilities that directly feeds existing transportation to the Dawn Hub would not proceed.

42. Thus, Enbridge's participation in the project supports the development of new natural gas infrastructure that benefits its customers and the broader Ontario market. NEXUS provides direct access to new natural gas supply from the Utica and Marcellus shale formations. These supplies are not currently a component of Enbridge's supply portfolio in that Enbridge does not procure Utica or Marcellus gas from directly within the supply basin. Participation in the project will provide the Enbridge supply portfolio with direct access to new sources of supply.

43. As noted above, after Enbridge's open season bid was accepted, it was then necessary to negotiate a PA. Enbridge insisted that the PA be subject to OEB pre-approval as to cost consequences. Enbridge considered this appropriate because of the different nature of the NEXUS contract (15 years in length to support a greenfield pipeline on a new transportation path) as compared to other

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[13] NEXUS Gas Transmission Project, Supplemental Open Season Notice for Firm Service, January 14, 2015-February 12, 2015.

transportation contracts. Over the course of negotiation, it has been clear that the existence of a pre-approval condition precedent has assisted Enbridge in convincing the lead developers to provide fair and balanced terms so that the resulting PA represents a reasonable arrangement for the benefit of Enbridge's gas supply operations and ratepayers.

44. The parties entered into the initial PA on June 5, 2014. The initial PA contemplated two phases for the NEXUS project. The first phase was expected to transport 40,000 Dth per day from eastern Michigan to the Dawn Hub, effective November 1, 2015 for up to 3 years. The second phase was expected to transport 150,000 Dth per day from Kensington, Ohio to the Dawn Hub for 15 years, effective November 1, 2017. As part of the process to attain necessary Company approval, Enbridge negotiated a Restated PA dated December 17, 2014 that eliminated Enbridge's participation in the first phase and reduced the transportation volume of the second phase to 110,000 Dth per day. The Restated PA includes an option to increase capacity. Subsequent negotiations with the lead developers resulted in additional amendments to the Restated PA that are set out in the First Amendment to Restated PA, dated June 3, 2015. The amendments to the Restated PA include the removal of unnecessary references such as the two phases of the project since NEXUS is no longer a multi-phase project, and clarification on the Capital Cost Tracking Adjustment.

45. It is the final version of the PA that is included as Appendices D and E. There are several Exhibits to the executed PA: A Form of Firm Transportation Agreement that will be executed once each party to the PA fulfills its obligations; detail on a Capital Cost Tracking Adjustment (which provides details on the manner in which the actual capital costs for the project are to be reflected in final reservation rates); and a form of Guaranty and a form of Letter of Credit.

46. The transportation service awarded to Enbridge pursuant to its open season bid and subsequent negotiation and execution of the PA is as follows:

a) 110,000 Dth per day of firm transportation service from a point(s) near Kensington, Ohio to the point of interconnection with Vector's Milford Junction meter station near Highland, Michigan, commencing on November 1, 2017 for a term of 15 years; and

b) The option to increase contracted capacity to as much as 150,000 Dth per day, subject to certain conditions, on or before November 1, 2020.

47. Parameters for the NEXUS transportation agreement are provided below:

- *Transportation Provider*: NEXUS Gas Transmission
- *Service*: Firm Transportation
- *Primary Term*: 15 Years - November 1, 2017 to October 31, 2032
- *Volume:*
  i. 110,000 Dth per day;
  ii. Option to increase up to 150,000 Dth/d on or before November 1, 2020 subject to capacity availability.
- *Receipt Point*: Kensington, Ohio
- *Delivery Point*: Vector Pipeline, Milford Junction, near Highland, Michigan
- *Reservation Rate* (Estimated):
  i. $0.700 US per Dth per day;
  ii. If option to increase capacity is fully exercised then the reservation rate decreases to $0.685 US per Dth per day.
  Note: Final reservation rate subject to a ±15% capital cost tracking adjustment which is applicable to the greenfield portion of the toll.
  iii. If option to increase capacity is fully exercised prior to the in-service date then Enbridge may choose rate provisions (including the reservation rate) negotiated by other shippers ("Most Favored Nation" clause).
- *Fuel Ratio (Estimated)*: 1.6% to 2.6%; and
- *Renewal Rights*: Right of First Refusal ("ROFR").

48. The PA that Enbridge signed contains numerous protections and benefits for Enbridge and its ratepayers. Among these are the following:

a) *Requirement for review of supply* – there is a condition precedent included (section 7(c)(iii)) which requires Enbridge to complete a review of regional supply to support the NEXUS contract no later than 90 days following receipt of the Estimated Commencement Date.

b) *Requirement for OEB approval* – there is a condition precedent included (section 7(c)(v)) which requires Enbridge to obtain pre-approval of the cost consequences of the NEXUS contract from the OEB under the Guidelines, no later than October 1, 2015. Section 7(d) of the PA allows Enbridge to temporarily waive satisfaction of this condition precedent for up to 90 days.

c) *A 15 year term* – other greenfield projects require up to a 20 year commitment.

d) *The right to increase contracted volumes* – Enbridge is permitted to give notice that it wishes to increase its contract from 110,000 to 150,000 Dth per day. This provides flexibility to Enbridge (and would reduce unit costs because the cost for the increased volume is lower, and is protected by a "Most Favoured Nations" clause). More detail about the advantages of this option is described below, in the "Benefits" section of this evidence.

e) *The right to access secondary receipt and delivery points* – as described below in the "Benefits" section, this provides flexibility to Enbridge.

f) *Limits on the reservation rate to be charged* - the reservation rate is set based on the estimate of capital costs that have been provided by the lead developers and accepted by Enbridge. The actual capital costs will be tracked and the final reservation rate will be set based on the actual costs. The protection is that there is a cap of a 15% increase on the reservation rate, regardless of the amount of increase in capital costs. Further, if the capital costs decrease below the estimate, then the reservation rate will be reduced by up to 15%.

g) *A termination right in the event of delay* – if the NEXUS pipeline is not in service within 1 year of the Estimated Commencement Date, which may be as late as November 1, 2018, then Enbridge can terminate the PA without any cost consequences.

h) *Right of First Refusal* – Enbridge's rights to renew transportation capacity on NEXUS at the end of the contract term.

F. LANDED COST ANALYSIS

49. In order to confirm whether the NEXUS project is cost-effective for Enbridge, the Company has undertaken a review of the forecast costs associated with Marcellus or Utica gas supply via NEXUS, as compared to other supply options.

50. Annual demand charges based on current reservation rate, or toll, estimates provided by NEXUS will be approximately $28.1 million US. Should the option to increase capacity be exercised, the annual demand charges for NEXUS capacity could increase to a maximum of approximately $37.5 million US. Final reservation rates are subject to a ±15% capital cost tracking adjustment which is applicable to capital costs associated with the construction of new facilities, or the greenfield, portion of the reservation rate. The greenfield portion of the $0.700 US per Dth per day reservation rate is $0.650 US per Dth per day.

51. Total cost for NEXUS capacity over the term of the contract is approximately $421.6 million US. If the option to increase capacity is exercised, the total cost for NEXUS capacity over the term of the contract, assuming the capacity option

is exercised for commencement November 1, 2017, would be approximately $562.6 million US.

52. An assessment of the landed costs of the NEXUS path versus possible alternative transportation paths was completed prior to entering into the original PA with NEXUS. The analysis was updated in November 2014 to obtain the necessary Company approvals to proceed with the NEXUS Agreement. The landed cost analysis was updated again in May 2015 for purposes of this Application.

53. The landed cost analyses show, on a per unit basis, the total cost of landing gas at the Dawn Hub for several transportation paths. Costs included in the analysis are:
    (a) Commodity costs;
    (b) Transportation Tolls;
    (c) Fuel charges;
    (d) Other charges (FERC Annual Charge Adjustment ("ACA") and / or National Energy Board ("NEB") abandonment surcharge ("AS") as applicable); and
    (e) Foreign Exchange (as payments for certain paths are made in US).

54. The landed cost analyses are conducted using forecasted commodity prices for various supply points, estimated or currently approved transportation tolls as the case may be, estimated or forecast fuel charges as the case may be, estimated or currently approved other charges and forecast foreign exchange rates. Transportation tolls are assumed constant over the 15 year term of the analysis as are fuel ratios and other charges.

55. The recent landed cost analyses include four potential scenarios for the NEXUS path. The NEXUS base case assumes there are no adjustments to the reservation rate. There are two variants of the NEXUS base case. The first variant assumes the greenfield portion of the reservation rate is increased by 15% as a result of higher than expected final capital costs. The second variant assumes the greenfield portion of the reservation rate is decreased by 15% as a result of lower than expected final capital costs. The last scenario assumes that Enbridge increases its contracted volume to 150,000 Dth per day prior to November 1, 2017 and receives a reservation rate decrease of $0.015 per Dth per day.

56. The recent landed cost analyses also include the Rover Pipeline LLC pipeline project (“Rover”). The Rover project is a greenfield pipeline that is proposed to transport gas produced in the Marcellus and Utica basins to Ohio, eastern Michigan, and the Dawn Hub. The majority of the Rover pipeline will be utilized by customers on the U.S. segments of the pipeline, including multiple take-off points in Michigan, West Virginia and Ohio.[14] The cost associated with the NEXUS path is comparable to the Rover path.

57. Although the cost associated with Rover is comparable to NEXUS, Enbridge elected not to participate in the Rover open season. When the open season for Rover was announced in June 2014, Enbridge had already concluded initial negotiations with NEXUS and had executed the original PA. The PA included favourable condition precedent terms that Enbridge was able negotiate as a result of its ability to make significant long-term volumetric commitments that would underpin the development of the NEXUS pipeline. These terms were

[14] http://www.roverpipelinefacts.com/about/overview.html

critical for Enbridge to make such long-term commitments to the project. The Rover open season announcement indicated that it had signed long-term agreements with multiple shippers and had received internal approval to proceed with the project. Given that Rover had already received the long-term commitments required to proceed with the project, the ability for Enbridge to negotiate similar conditions precedent as with NEXUS was a risk.

58. Supporting Rover over NEXUS would increase the risk that NEXUS would not be constructed. By maintaining support for NEXUS, the likelihood that both projects would proceed would be higher and the Dawn Hub would benefit more from being linked to the Appalachian basin through both projects rather than just one.

59. Another consideration for not participating in the Rover open season was the minimum term requirement of 20 years to achieve the status of Negotiated Rate Shipper described as part of the open season document. Contracting for a term less than 20 years would subject a shipper to the recourse rate which is based on, *inter alia*, total project costs. The PA negotiated with NEXUS limits the risk of recourse rate adjustments to $\pm$15% with a term commitment of only 15 years.

60. A summary of the November 2014 landed cost analysis is found below in Table 1 and additional information can be found in Appendix B. The Average Landed Cost represents an average cost over the 15 timeframe of the NEXUS contact (from 2017 to 2032).

Table 1: November 2014 Landed Cost Analysis Summary

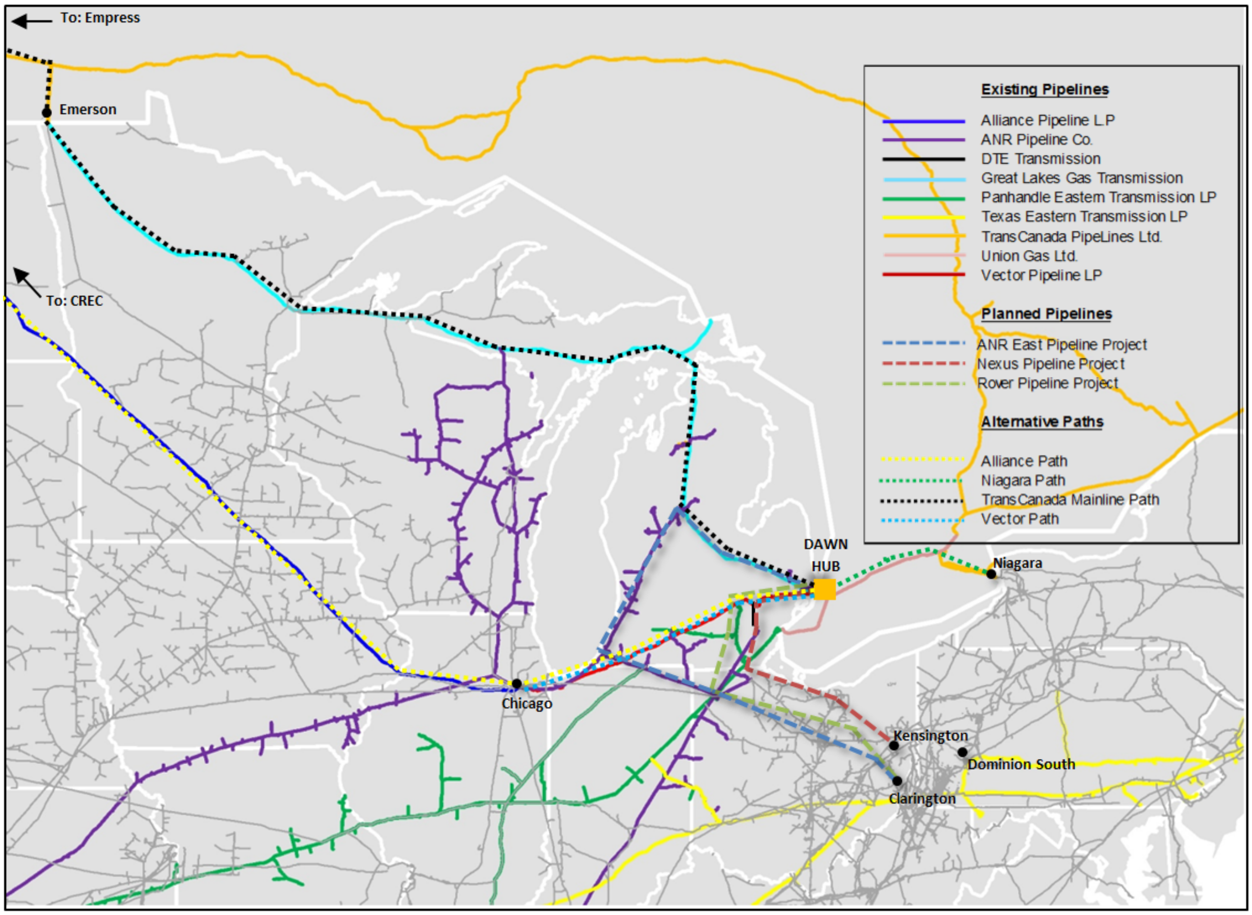
Path	Average Landed Cost $CDN per GJ
Dawn	4.93
Vector	5.21
Rover	5.30
TransCanada from Niagara	5.39
NEXUS (Base Case -15%)	5.43
NEXUS (Anchor)	5.51
NEXUS (Base Case)	5.53
NEXUS (Base Case +15%)	5.64
ANR East	5.73
Alliance	5.84
TransCanada from Empress	6.24

61. The May 2015 landed cost analysis is summarized below in Table 2 and additional information can be found in Appendix C.

Table 2: May 2015 Landed Cost Analysis Summary

Path	Average Landed Cost $CDN per GJ
Dawn	4.62
Vector	4.88
TransCanada from Niagara	4.90
NEXUS (Base Case -15%)	5.04
Rover	5.06
NEXUS (Anchor)	5.14
NEXUS (Base Case)	5.16
NEXUS (Base Case +15%)	5.27
ANR East	5.52
Alliance	5.70
TransCanada from Empress	6.19

62. A map illustrating the pipeline paths that were analysed as part of the landed cost analysis is included in the figure below.



63. The fifteen year average landed cost of NEXUS supply under the November 2014 analysis is projected to be $5.53 Canadian currency ("CDN") per GJ and under the more recent May 2015 analysis is projected to be $5.16 CDN per GJ. The decrease in landed cost can be primarily attributed to a broad decline in expected natural gas prices and change in transportation costs related to Vector transportation. Based on the assumptions contained in both landed cost analyses, the NEXUS path is projected to provide economically competitive supply relative to the other paths to which it was compared.

64. The Dawn, Vector, and Niagara paths are projected to provide lower landed cost options. However, these paths do not provide the additional benefits of the NEXUS path as discussed below.

G. BENEFITS OF THE NEXUS PROJECT FOR ENBRIDGE

65. As explained, Enbridge establishes its gas supply plan based on the principles of diversity, reliability, flexibility, and cost. The NEXUS contract offers benefits in each of these areas. Direct access to Marcellus and Utica basin gas, with connection to the Dawn Hub (including Enbridge's storage facilities at Dawn) will diversify Enbridge's gas supply portfolio. This will mitigate price differences between different supply points. The new transportation path, including pipelines interconnected to NEXUS, will provide flexibility and improve reliability. The option to increase NEXUS capacity further increases flexibility for Enbridge's future gas supply planning. Through the NEXUS project, liquidity at the Dawn Hub will be increased. Each of these items is discussed below.

66. NEXUS will diversify Enbridge's gas supply portfolio through direct access to the Utica and Marcellus shale supply basins. These two basins are expected to "account for over half of the incremental North America gas production through 2035".[15] Utica and Marcellus natural gas production forecasts are provided by several energy market analysts and government energy agencies. The Sussex Study has reviewed a number of these forecasts. These projections indicate that production levels will be at or near 20 PJ per day by 2020[16] and are expected to continue increasing well beyond the term of the NEXUS Agreement. Access to such prolific supply will enable Enbridge to benefit from market competition within

[15] EB-2014-0289, 2014 Natural Gas Market Review, Future Trends: Assessing Ontario Natural Gas Market Requirements Through 2020 presentation dated November 25, 2014 by ICF International, slide 4.
[16] Sussex Study pages 30 and 31.

these basins and provide the option to procure supply directly from producers at the Kensington processing plant in Ohio.

67. Through NEXUS, Enbridge will benefit from having two different paths to access Appalachian basin gas. The Company currently plans to procure gas supply from the Marcellus basin at Niagara, for transportation into the CDA. This will be done through purchases at that delivery point, and will not be underpinned by firm transportation held by Enbridge into the supply basin. NEXUS offers another option, which will lead to Appalachian basin natural gas being delivered directly from the Utica and Marcellus basins to the Dawn Hub. In the result, the NEXUS contract will promote flexibility and security of supply.

68. The security of supply enhancements from NEXUS are not only realized through the abundant supply forecasts for Utica and Marcellus. The supplemental open season initiated by NEXUS on January 14, 2015 provided access to additional upstream receipt points such as Clarington, Ohio. The additional upstream receipt points will be facilitated by NEXUS through contracted capacity on Texas Eastern Transmission which connects with other basins such as the Gulf Coast through Texas Eastern Transmission LP and northwestern Colorado and Wyoming through the Rockies Express Pipeline LLC ("REX"). Therefore, capacity on NEXUS will expand the supply options to which Enbridge's storage facilities at Dawn will be connected. Access to alternative supply basins through these pipelines ensures security of supply for Enbridge and its customers.

69. NEXUS also increases the benefits of market competition for Enbridge's gas supplies at the Dawn Hub. The NEXUS supplies from the Utica and Marcellus basins will be transported along the greenfield pipeline portion of the NEXUS project to Vector's Milford Junction meter station near Highland, Michigan and

into the Dawn Hub. The Utica and Marcellus supplies will offset a portion of the Chicago supplies that Enbridge currently transports on Vector thereby facilitating competition between the supply hubs while mitigating any localized price volatility that may occur at either of the supply points.

70. NEXUS increases the flexibility of contract terms within Enbridge's gas supply portfolio. The PA provides Enbridge with the opportunity to increase the contracted capacity from 110,000 Dth per day up to 150,000 Dth per day on or before November 1, 2020 subject to existing infrastructure being available. This provides Enbridge with the flexibility to observe how the North American natural gas marketplace has evolved before determining if Enbridge's gas supply portfolio would benefit from incremental Utica and Marcellus supply or supply from other receipt points on NEXUS.

71. Finally, the contracting for NEXUS capacity to deliver Appalachian basin natural gas to the Dawn Hub will increase liquidity at that point. As discussed in the Sussex Study, this will benefit all parties that rely on the Dawn Hub for natural gas supply.[17]

72. Supplies from the Dawn Hub will make up a significantly larger portion of Enbridge's supply portfolio in future years, largely due to its proximity and cost competitiveness. This is discussed in the next section of this evidence (and shown in Tables 3 and 4, below). The shift in demand for supplies at the Dawn Hub is not unique to Enbridge. Incremental market access to the Dawn Hub has enabled similar shifts in markets across Ontario, Quebec, and the northeast region of the United States.

[17] Sussex Study page 40.

73. The increase in demand for supply from the Dawn Hub could impact its liquidity and cost competitiveness absent investment in supporting infrastructure. NEXUS, in conjunction with other projects such as Rover, will diversify the supply basins to which the Dawn Hub has access. However, major consumers such as Enbridge must make sufficient commitments to the new infrastructure to ensure that the infrastructure will serve the Dawn Hub. Absent such commitments, the pipeline developers may opt to focus on other markets closer to the Marcellus/Utica supply basins, or will award capacity to shippers who will make use of interconnecting pipelines to deliver gas to markets other than Ontario. The commitment being made by Enbridge to the NEXUS pipeline helps ensure that significant Appalachian gas supplies will be delivered to the Dawn Hub, for use by Enbridge's customers.

74. The principles behind the benefits of NEXUS are very similar to those explained in the leave to construct applications filed by Enbridge and Union Gas Limited for the GTA Project (EB-2012-0451), the Parkway West Project (EB-2012-0433), and the Brantford-Kirkwall/Parkway D Project (EB-2013-0074) (collectively the "Parkway/GTA Projects"). Although the Parkway/GTA Projects were filed separately, their interdependencies resulted in the Board combining the proceedings and hearing them together. The Board noted in its decision related to these applications that:

> Ontario gas consumers will obtain additional certainty through this project concerning their access to alternative supply sources. The project will provide access to more supply and to more sources of supply while retaining market access to existing WCSB supplies. That is a clear benefit to Ontario consumers, and is a positive element in relation to the economic viability of the project. Supply diversity enhances security and has the tendency to lower gas prices from what they would otherwise be if the market continued to rely on fewer sources of supply.[18]

[18] EB-2012-0433, EB-2013-0074, EB-2012-0451 Decision and Order dated January 30, 2014, page 29.

75. Further in the same Board decision it was noted that:

> Even if the gas cost savings do not materialize, the project is justified on the grounds of enhanced security and diversity of gas supply, and the contribution that the project will make to enhance a competitive natural gas market in Ontario through increased liquidity at Dawn.[19]

H. FIT WITHIN NATURAL GAS SUPPLY PORTFOLIO

76. Enbridge's gas supply acquisition is underpinned by a variety of upstream transportation arrangements. These arrangements are differentiated by procurement point, transportation service provider, transportation path, contracted capacity, term and other service attributes.

77. The NEXUS capacity will fit well with Enbridge's planned supply portfolio, and will provide the diversity, reliability and flexibility benefits described above. Set out below is a discussion of the Company's planned gas supply portfolio, including the NEXUS capacity.

78. Table 3 provides a forecast of the expected gas supply acquisition for Enbridge absent NEXUS. The forecast includes supplies received from direct purchase customers. The annual volumes are based on a gas year that starts on November 1 of the previous year. The forecasts were completed at a point in time and, like any forecasting exercise, contain certain assumptions related to future events. Given the rapidly changing and dynamic nature of the North American natural gas market, actual supply acquisitions may not be exactly as shown.

[19] EB-2012-0433, EB-2013-0074, EB-2012-0451 Decision and Order dated January 30, 2014, page 30.

Table 3: Enbridge Gas Supply Acquisition Absent NEXUS (PJ)

Source	2017	2018	2019	2020	2021	2022	…	2032
WCSB	132.4	96.7	96.7	97.0	96.7	96.7		97.0
Chicago	67.4	67.4	67.4	67.6	67.4	67.4		67.6
Niagara	73.0	73.0	73.0	73.2	73.0	73.0		73.2
Dawn	149.4	187.5	189.4	191.5	192.6	195.4		217.9
Franchise	11.0	11.0	11.0	11.0	11.0	11.0		11.0
Total	433.2	435.6	437.5	440.3	440.7	443.5		466.7

79. Under current contracting arrangements, reliance on Dawn Hub supplies will increase in 2017. The increase is primarily due to decisions to contract for incremental transportation capacity from the Dawn Hub that has been made available through the GTA Project and the TransCanada Mainline Settlement Agreement, and decisions not to renew Enbridge's Alliance contracts and a portion of Enbridge's Vector contracts. These decisions were made, in part, to provide the flexibility to access new supply from basins proximate to the markets served by Enbridge. Subsequent increases in Dawn Hub supply acquisitions are forecasted to account for future increases in demand.

80. Absent NEXUS, Enbridge's only natural gas supply from the Appalachian basin will be procured at Niagara. This supply source is expected to make up approximately 15% of the total gas supply portfolio over the duration of the NEXUS contract.

81. Table 4 is similar to Table 3, except that the forecast of Enbridge's expected gas supply acquisition assumes NEXUS is incorporated into Enbridge's gas supply plan.

Table 4: Enbridge Gas Supply Acquisition including NEXUS (PJ)

Source	2017	2018	2019	2020	2021	2022	…	2032
WCSB	132.4	96.7	96.7	97.0	96.7	96.7		97.0
Chicago	67.4	25.0	25.0	25.1	25.0	25.0		25.1
Niagara	73.0	73.0	73.0	73.2	73.0	73.0		73.2
Dawn	149.4	187.5	189.4	191.5	192.6	195.4		217.9
NEXUS		42.4	42.4	42.5	42.4	42.4		42.5
Franchise	11.0	11.0	11.0	11.0	11.0	11.0		11.0
Total	433.2	435.6	437.5	440.3	440.7	443.5		466.7

82. The acquisition of gas supply from NEXUS equates to approximately 9% of the portfolio from 2018 to the end of the contract term and will be offset by an equivalent decrease in supplies procured from the Chicago hub from 15% to 6% over the same period.

83. This shift in procurement will diversify the supply being transported to the Dawn Hub along Vector. To facilitate this change, Enbridge expects to restructure its existing Vector capacity that transports 175,000 Dth per day between Joliet, Illinois and Dawn, Ontario. The restructuring will include the segmentation of 110,000 Dth per day by changing the receipt point to the Milford Junction connection with NEXUS. This shorter Vector path will be tolled at a rate of $0.16 US per Dth with a contract term that coincides with Enbridge's NEXUS capacity. The remaining 65,000 Dth per day on Vector will flow between Joliet, Illinois and Dawn, Ontario at a rate of $0.18 US per Dth for a 3 year term that can be renewed for subsequent 3 year increments with 1 year notice.

84. Should Enbridge elect to increase its transportation capacity on NEXUS, Enbridge will have the option to further segment up to 40,000 Dth per day of the remaining 65,000 Dth per day of Vector capacity by changing the receipt point to the Milford Junction connection with NEXUS at a rate of $0.16 US per Dth with a contract term that will align with the expiry of the NEXUS capacity.

85. The addition of NEXUS to Enbridge's gas supply portfolio will increase the supply being procured from the Appalachian basin to approximately 26% of the total portfolio over the term of the NEXUS contract. NEXUS provides the additional benefit of diversifying the access that Enbridge has to the Appalachian basin from both a supply and transportation path perspective. The NEXUS supplies will be predominately procured from the Utica basin, will contribute 37% of the total Appalachian basin supply and will be transported to the Dawn Hub via NEXUS and Vector. The remaining 63% will be procured at Niagara and likely produced in the Marcellus basin.

86. Enbridge does not intend to completely sever connectivity with WCSB supplies. Enbridge expects WCSB supply to remain an integral part of its supply portfolio for the foreseeable future. NEXUS will not impact the reliance on WCSB supplies which for illustrative purposes was held at approximately 22% of the total portfolio over the duration of the NEXUS contract. After 2020, commitments to the TransCanada Mainline Settlement Agreement will have been fulfilled at which point Enbridge may consider further changes to its gas supply portfolio that will impact its reliance on WCSB supplies. This could include exercising the option to increase NEXUS supply. However, no decisions have been made at this time.

87. While further diversification of the Enbridge supply portfolio made possible through NEXUS will reduce reliance on Chicago supplies, it will increase reliance on and direct access to a robust and growing supply basin. Risks and mitigants related to costs, project development and basin performance, amongst others, are described in a subsequent section below.

88. Enbridge expects to flow the NEXUS contract at a 100% load factor. As such, supply from NEXUS is expected to be baseload supply. Flexibility will come from planned purchases at the Dawn Hub and potentially seasonal supplies from other procurement points. Although the 15 year term for NEXUS will erode some of the transportation flexibility in Enbridge's gas supply portfolio, the direct access to supplies from the Appalachian basin will improve diversity, reliability, supply flexibility, and cost effectiveness of Enbridge's gas supply plan.

I. MITIGATION OF RISKS ASSOCIATED WITH NEXUS CONTRACT

89. Enbridge has identified the following risks associated with the NEXUS contract and project:

(1) Forecasting Risks
   (a) Demand
   (b) Prices/Landed Costs
   (c) Performance of Basin
   (d) Other

(2) Construction and Operational Risks
   (a) Cost escalation
   (b) Delays
   (c) Timing issues for new construction
   (d) Gas interchangeability and quality
   (e) Other

(3) Commercial Risks
   (a) Competitiveness of Service Provider
   (b) Creditworthiness of Service Provider
   (c) Other

(4) Regulatory Risks
   (a) Changes in laws or regulations
   (b) Other

90. Each of the risks identified above is discussed below, along with information about plans and/or actions taken by Enbridge to minimize each risk.

Forecasting Risks

91. There are forecasting risks and uncertainties associated with any long-term contract. In this case, however, these risks are managed by the fact that Enbridge will have access to abundant and competitively-priced natural gas from the Marcellus and Utica basins.

92. In any given year Enbridge must arrange for a level of transportation capacity to meet projected peak day demand. NEXUS capacity will provide added diversity to the transportation component of Enbridge's gas supply portfolio.

93. Enbridge expects to flow the NEXUS transportation capacity at 100% load factor. Flexibility in procurement will be primarily provided by procurement at the Dawn Hub. If projected demand does not materialize, Enbridge will have the flexibility to back off Dawn Hub purchases. If demand exceeds forecast, Enbridge has the option to procure gas seasonally at other supply points including Kensington (i.e. the NEXUS receipt point), the Dawn Hub, Niagara, Chicago and the WCSB.

94. Further, Enbridge will retain flexibility in its transportation capacity term structure such that the Company can opt not to renew other transportation contracts in the event that demand for natural gas declines. The NEXUS contract also provides the option to increase capacity should it be determined that this option is required to either meet increased demand or to displace further procurement at other hubs and/or basins.

95. The landed costs analysis presented in this evidence relies on a forecast of commodity prices which can and will vary from expectations. Natural gas prices can be volatile at times and are largely a function of market demand and supply availability. The winter of 2013/2014 is a testament to this volatility as market demand placed significant pressure on available supply. However, prices at points such as Henry Hub and AECO-C, despite the cold weather, were significantly less volatile than pricing at the Dawn Hub and other points such as Iroquois or Algonquin. By diversifying its supply portfolio, Enbridge effectively reduces pricing exposure to any particular procurement point.

96. The Dominion South point, the proxy point for the cost of Appalachian basin supply assumed in this evidence, is currently one of the lowest cost sources of supply in North America. The Sussex Study provides details on performance to date and expectations regarding the Appalachian basin, and in particular Utica and Marcellus, shale supplies. Enbridge expects that the relative cost of Appalachian basin supply will continue to be competitive or advantageous over the term of the NEXUS contract.

97. Furthermore, NEXUS has offered supplemental open seasons for firm transportation service from alternative receipt points such as Clarington, Ohio. Access to such receipt points provides access to supply alternatives such as the Gulf Coast through Texas Eastern Transmission, LLP and northwestern Colorado and Wyoming through REX. This will help ensure there is competition to moderate potential price increases in the Appalachian basin.

98. As shown in the section above, which sets out the fit of the NEXUS contract in the Enbridge supply portfolio, reliance on Appalachian basin supplies is expected to form a larger portion of the Company's future supply portfolio. However, that

portion is in line with exposure to other procurement points, thereby not excessively exposing ratepayers to any particular basin or hub**.**

99. Further, with NEXUS in service with committed capacity to the Dawn Hub from Enbridge and Union Gas, Enbridge expects the risk of pricing volatility at the Dawn Hub will be reduced due to the increase in supply sources connected to the Dawn Hub. This is a benefit not only to Enbridge and its ratepayers, but to any natural gas markets that rely on the Dawn Hub as discussed in the Sussex Study[20].

100. In terms of tolls, the reservation rate for NEXUS capacity, while subject to a capital cost tracking adjustment, will remain fixed for the fifteen year term of the contract. The increase to the reservation rate due to capital cost overages is capped at 15%, and there is the potential for the reservation rate to be reduced by up to 15% if capital costs are lower than forecast. There is no risk to the ratepayer of an increase in NEXUS reservation rates due to a loss of billing determinants on the NEXUS system.

101. Foreign exchange rates also pose a risk. Diversification of procurement amongst points in both Canada and the U.S. serves to mitigate this risk. However, as supply from NEXUS will be replacing supply that would otherwise be procured at Chicago there is no increase in exposure to foreign exchange risk as Chicago trades in US.

102. Fuel ratios will vary as will other charges such as the ACA charge and AS charge. However, these costs are *de minimis* relative to the costs of procurement and demand charges.

[20] Sussex Study page 36

103. A potential risk exists that there will be insufficient supply available to fill Enbridge's capacity on the NEXUS pipeline. Enbridge does not believe that there is any significant likelihood of this risk materializing. The NEXUS contract will provide direct access to a production basin that has and is expected to continue to grow for the foreseeable future. This is discussed at length in the Sussex Study.

Construction and Operational Risks

104. While there are risks associated with the construction and bringing into operation of a greenfield pipeline, the PA that Enbridge has negotiated places most of these risks on NEXUS, and caps Enbridge's exposure to the consequences of cost overruns.

105. The PA sets out the obligations of the pipeline and the customer throughout the pipeline development process. It also contains certain pre-conditions for the benefit of the pipeline and customer. The PA outlines steps and remedies that are available to NEXUS and Enbridge to monitor costs, deal with disputes, limit cost overrun exposure to Enbridge, provide for cost underrun exposure to Enbridge and, if required, terminate the PA.

106. Development of any new pipeline requires estimates of the costs to construct the pipeline. The reservation rate (toll) for service on the pipeline is largely based upon the capital costs. NEXUS has provided Enbridge with both the draft and final capital cost estimates and associated reservation rates. Enbridge has determined, based on the final reservation rate, that the NEXUS path is economic. This is seen in the landed cost analysis discussed above (May 2015 analysis).

107. Total capital costs pursuant to the final capital cost estimate provided by NEXUS are expected to be $2.019 billion US. Reservation rates for the NEXUS contract are subject to a capital cost tracking adjustment. This adjustment applies to the difference between the actual capital costs for the project and the final capital cost estimate. The adjustment is symmetrical and caps the increase or decrease in final reservation rates to plus or minus 15%. In the event that actual capital costs are greater than the final capital cost estimate, this mechanism allows the project developer to recover cost increases up to a maximum and Enbridge's exposure to cost increases is capped. In the event that actual capital costs are lower than the final capital cost estimate, the project developer must pass on these savings to Enbridge. The project developer is incented to keep actual capital costs in check and in doing so potentially gain a benefit from finding ways to reduce capital spend. Capital cost tracking adjustments such as this are commonplace in the U.S.

108. Enbridge has negotiated protections against unreasonable delays in the completion of the NEXUS pipeline. Under the PA, NEXUS is required to take the necessary steps to have the pipeline in-service for November 1, 2017. NEXUS is also required by the PA to provide Enbridge with quarterly updates on progress and indications as to whether or not the service commencement date will be November 1, 2017 or some other date. By November 1, 2015, NEXUS must provide a formal Estimated Commencement Date, which must be no later than November 1, 2018. NEXUS must provide at least 90 days' notice to Enbridge of the actual in-service date of the pipeline. In the event that the in-service date is delayed, the risk of a supply shortfall can be mitigated by Enbridge procuring the necessary supplies at Chicago or the Dawn Hub. In the event that the actual in-service date is more than 1 year beyond the Estimated Commencement Date,

then Enbridge has the right to terminate the PA without any responsibility to NEXUS, including pre-service costs.

109. Enbridge does not expect any risks related to gas interchangeability or quality. Enbridge's supply contracts stipulate that all supplies provided for transportation on behalf of Enbridge adhere to industry accepted quality and interchangeability standards. Enbridge will continue this practice for all supplies provided to NEXUS for transport. There are no significant gas quality or interchangeability standard differences between Canada and the U.S.

Commercial Risks

110. Enbridge does not foresee significant commercial risks associated with the contracts and arrangements necessary to obtain capacity on the NEXUS pipeline or to obtain supply of Marcellus or Utica basin gas to be transported.

111. The lead developers of NEXUS have extensive experience in the development and operation of large scale pipeline projects including natural gas transmission pipelines. Enbridge does not believe that the NEXUS project lead developers pose any credit or default risks.

112. Enbridge expects to procure natural gas directly from producers or agents acting on behalf of the producers in the Appalachian basin. Enbridge's gas supply procurement policies require that Enbridge purchase supply from parties with whom it has signed a Gas Supply Master Agreement and who have adequate creditworthiness. Based on these requirements Enbridge does not expect counterparties supplying natural gas to pose any credit or default risks. In the event that a counterparty fails to deliver natural gas, Enbridge expects that there will be sufficient supply for alternative supply arrangements based on the

Appalachian basin production forecast analysis (as discussed in the Sussex Study).

Regulatory Risks

113. Regulatory risks are mitigated through provisions in the PA. Failure to obtain the required permits/certificates from the appropriate regulatory and governmental bodies by either NEXUS or Enbridge triggers a right to terminate the PA, subject to certain conditions.

114. Changes in laws and regulations, particularly with respect to the production methods used to extract natural gas in the Appalachian basin, also pose a risk. The vast majority of natural gas produced in the Appalachian basin is natural gas extracted from shale formations using horizontal drilling and hydraulic fracturing techniques. These techniques continue to be the subject of debate and are at risk of being constrained through government intervention. This risk is typically taken into consideration to a degree when determining future levels of natural gas production, and yet forecasting agencies consistently predict that the natural gas production in the Appalachian basin will continue to be robust.

Retail Competition Impacts

115. While not a risk *per se*, the Board's Guidelines require an applicant seeking pre-approval of a long-term contract to indicate whether such approval would have adverse retail competition impacts, or would adversely impact existing pipeline facilities in Ontario. In Enbridge's view, the long-term contract with NEXUS has no such negative impacts.

116. The majority of Enbridge's direct purchase market will be moving gas procurement activity to the Dawn Hub in the coming years. This move will be

facilitated through the outcomes of the recently Board approved Dawn Access Consultative.[21] Enbridge expects that NEXUS will have a positive impact on retail competition. As discussed in the Sussex Study, getting additional gas to the Dawn Hub will have a positive impact on the natural gas market in Ontario. Utilities and gas marketers alike will benefit from the additional liquidity and supply options at the Dawn Hub provided by NEXUS.

117. Enbridge does not expect there will be any significant impacts on existing pipeline facilities that could affect Ontario consumers. As indicated previously, the NEXUS contract will be replacing supply that would have otherwise been procured at Chicago. Enbridge will utilize existing short haul contracts on the Union Gas and TransCanada systems to move NEXUS supplies to market during the winter and will inject NEXUS supply directly into Enbridge's storage facility at Dawn in the summer.

J. PRE-APPROVAL IS APPROPRIATE

118. In the February 2009 Report of the Board regarding the draft Guidelines, the Board indicated that a pre-approval process is appropriate for long-term contracts that support the development of new natural gas infrastructure.[22] The Board offered the option to utilities to seek pre-approval of the cost consequences of a long-term contract(s) and indicated that the application should be made prior to contract execution, or after execution if there is a condition precedent requiring OEB approval. The Board's Report and associated Guidelines set out the information that the utility should file in support of its pre-approval application.

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[21] EB-2014-0323 Transcript Volume 1 dated November 20, 2014, page 17.
[22] EB-2008-0280, Report of the Board – Draft Filing Guidelines for the Pre-Approval of Long-Term Natural Gas Supply and/or Upstream Transportation Contracts, February 11, 2009.

119. In its Decision and Order for EB-2010-0300/EB-2010-0333 dated January 27, 2011, the Board clarified its expectations with respect to the requirements for application of the pre-approval process for long-term contracts. In the same Decision, the Board provided its views on requirements for fulfillment of the Guidelines when applying for pre-approval.

120. The Board noted that the development and adoption of the pre-approval process for the cost consequences of long-term transportation or supply contracts is intended to serve a specific role in the development of natural gas infrastructure in the interests of Ontario consumers. The need for the unusual circumstance of pre-approval stemmed from recognition, by the Board, that developers of natural gas infrastructure in some circumstances require long-term commitments to support large infrastructure development. The Board also recognized that utilities would be a necessary and desirable element in new infrastructure development but would be reluctant to enter into long term commitments for new infrastructure without assurances of cost recovery.

121. In order to qualify for pre-approval the Board indicated that the Guidelines should apply to contacts which: 1) support the development of new natural gas infrastructure, and 2) provide access to new natural gas supply sources.

122. Through this Application, Enbridge is making use of the pre-approval opportunity that has been provided by the Board. Enbridge requests pre-approval of the cost consequences of a long-term contract that supports the development of a new pipeline, which will provide direct access to the most significant source of natural gas production in North America. Pre-approval will allow Enbridge to confidently proceed with this opportunity, and obtain the resulting gas supply benefits for its ratepayers.

Witnesses: J. LeBlanc
A. Welburn

123. Enbridge's evidence addresses all the information items required by the Guidelines. Further relevant information is set out in the Sussex Study.

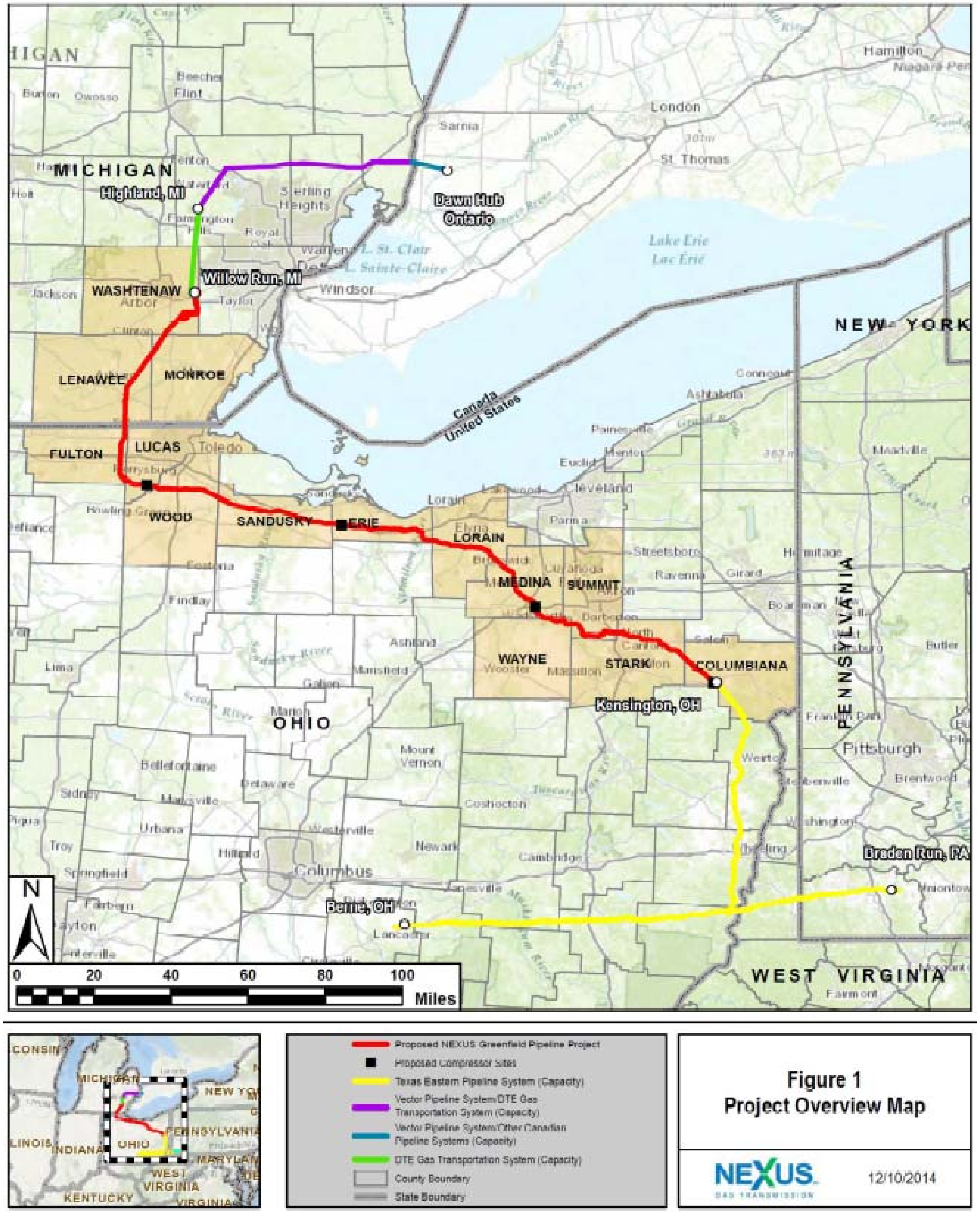
124. The evidence demonstrates that pre-approval of the cost consequences of the NEXUS contract is appropriate. The key items supporting this conclusion are the following:

a. NEXUS is a greenfield pipeline that will enable the direct transportation of natural gas from the important Appalachian basin to the Dawn Hub;
b. Enbridge's commitment to the NEXUS pipeline helps assure that the project will proceed, and ensures that Appalachian basin natural gas transported on the pipeline is directed to the Dawn Hub, rather than to other markets;
c. Enbridge's 15 year NEXUS contract is different from the Company's normal course contracting. The Company has not entered into any similar contract to support a significant new pipeline project bringing natural gas to Ontario since 2000;
d. The NEXUS contract will bring significant benefits to Enbridge's gas supply portfolio. The Appalachian basin gas supply that will be delivered directly to the Dawn Hub through the NEXUS pipeline will improve the reliability, diversity and flexibility of Enbridge's gas supply plan;
e. The costs of gas supply through the NEXUS pipeline are competitive with other options, and the addition of Appalachian Gas supply at the Dawn Hub will mitigate pricing volatility in future years;
f. The NEXUS contract fits well with the other elements of Enbridge's gas supply plan for future years. The Company has flexibility to make changes to other elements of the gas supply plan if conditions change from what is forecast; and

g. The risks associated with the NEXUS contract are manageable, and are addressed in large part through favourable terms that Enbridge has negotiated in the PA.

125. Under the terms of the PA, Enbridge must satisfy or waive the condition precedent of OEB pre-approval of the cost consequences of the NEXUS contract by October 1, 2015. In order for Enbridge to be able to review and consider the implications of the Board's decision in this Application, the Company requests that a Board decision be issued by September 24, 2015 (one week before the deadline in the PA).

Appendix A – NEXUS Project Map



Appendix B - November 2014 Landed Cost Analysis and Assumptions

November 2014 - NEXUS Landed Cost Analysis ($CAD/GJ)

Pipeline	Pricing Point	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Average
Dawn	Dawn	4.58	4.47	4.60	4.66	4.71	4.77	4.83	4.89	4.96	5.02	5.09	5.15	5.22	5.28	5.33	5.35	4.93
Vector	Chicago	4.81	4.75	4.87	4.93	4.99	5.04	5.11	5.17	5.24	5.30	5.37	5.44	5.50	5.56	5.61	5.64	5.21
Rover	Dominion South	4.82	4.82	4.98	5.03	5.08	5.14	5.21	5.27	5.34	5.40	5.47	5.54	5.61	5.67	5.72	5.74	5.30
TCPL from Niagara	Niagara	4.55	4.59	4.73	5.21	5.26	5.32	5.38	5.45	5.51	5.57	5.64	5.71	5.77	5.83	5.88	5.91	5.39
NEXUS (Base -15%)	Dominion South	4.93	4.94	5.09	5.15	5.20	5.26	5.33	5.40	5.46	5.53	5.60	5.67	5.74	5.80	5.85	5.87	5.43
NEXUS (Anchor)	Dominion South	5.01	5.02	5.18	5.23	5.29	5.35	5.41	5.48	5.55	5.61	5.68	5.75	5.82	5.88	5.93	5.96	5.51
NEXUS (Base)	Dominion South	5.03	5.04	5.20	5.25	5.31	5.37	5.43	5.50	5.57	5.64	5.70	5.77	5.84	5.90	5.96	5.98	5.53
NEXUS (Base+15%)	Dominion South	5.14	5.15	5.30	5.36	5.41	5.47	5.54	5.61	5.67	5.74	5.81	5.88	5.95	6.01	6.06	6.09	5.64
ANR East	Dominion South	5.24	5.24	5.40	5.45	5.51	5.56	5.63	5.70	5.76	5.83	5.90	5.97	6.04	6.10	6.15	6.17	5.73
Alliance	CREC	5.30	5.32	5.50	5.55	5.61	5.67	5.74	5.81	5.88	5.95	6.02	6.09	6.16	6.23	6.28	6.31	5.84
TCPL from Empress	Empress	5.73	5.74	5.91	5.97	6.02	6.08	6.14	6.21	6.28	6.34	6.41	6.48	6.54	6.60	6.66	6.68	6.24

November 2014 - Average Commodity Prices ($CAD/GJ)

	Pricing Point	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Average
	Dawn	4.58	4.47	4.61	4.66	4.71	4.77	4.83	4.89	4.96	5.02	5.09	5.15	5.22	5.28	5.33	5.36	4.95
	Chicago	4.50	4.43	4.56	4.61	4.67	4.72	4.78	4.85	4.91	4.98	5.04	5.11	5.17	5.23	5.28	5.31	4.90
	Dominion South	3.87	3.88	4.03	4.08	4.14	4.19	4.25	4.32	4.38	4.44	4.51	4.57	4.64	4.69	4.75	4.78	4.37
	CREC	3.76	3.77	3.94	3.99	4.04	4.10	4.16	4.22	4.29	4.35	4.42	4.48	4.55	4.60	4.65	4.68	4.28
	Empress	4.00	4.02	4.19	4.24	4.30	4.35	4.41	4.48	4.54	4.60	4.67	4.73	4.80	4.85	4.91	4.94	4.53
	Niagara	4.27	4.31	4.45	4.93	4.98	5.04	5.10	5.17	5.23	5.30	5.36	5.43	5.50	5.55	5.60	5.63	5.16

November 2014 - Average Foreign Exchange

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Average
CAD/USD	1.138	1.138	1.137	1.136	1.136	1.137	1.139	1.141	1.144	1.146	1.148	1.151	1.153	1.154	1.153	1.153	1.144

November 2014 - Fuel Ratio

Pipeline	Path	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Average
ANR East	Leesville-to-Dawn	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%
Rover	Leesville-to-Dawn	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%
Vector	Chicago-to-Dawn (Base Case)	0.93%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.09%	1.06%
Vector	Chicago-to-Dawn (Anchor)	0.93%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.09%	1.06%
NEXUS (-15%)	Kensington-to-Milford	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
NEXUS (Base Case)	Kensington-to-Milford	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
NEXUS (+15%)	Kensington-to-Milford	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
NEXUS (Anchor)	Kensington-to-Milford	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Alliance	CREC-to-Border	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%
Alliance	Border-to-Chicago	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
TCPL	Empress-to-Enbridge SWDA	4.13%	4.01%	4.01%	4.01%	4.01%	4.01%	4.01%	4.01%	4.01%	4.01%	4.01%	4.01%	4.01%	4.01%	4.01%	3.98%	4.01%
TCPL	Niagara-to-Kirkwall	0.37%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.13%	0.18%
Union	Kirkwall-to-Dawn (C1)	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%

November 2014 - Transportation Toll ($CAD/GJ)

Pipeline	Path	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Average
ANR East	Leesville-to-Dawn	1.262	1.262	1.261	1.260	1.260	1.261	1.263	1.265	1.268	1.270	1.273	1.276	1.279	1.280	1.279	1.278	1.269
Rover	Leesville-to-Dawn	0.863	0.863	0.862	0.861	0.861	0.862	0.863	0.865	0.867	0.869	0.871	0.873	0.875	0.875	0.874	0.874	0.867
Vector	Chicago-to-Dawn (Base Case)	0.270	0.270	0.269	0.269	0.269	0.269	0.270	0.270	0.271	0.271	0.272	0.273	0.273	0.273	0.273	0.273	0.271
Vector	Chicago-to-Dawn (Anchor)	0.270	0.270	0.269	0.269	0.269	0.269	0.270	0.270	0.271	0.271	0.272	0.273	0.273	0.273	0.273	0.273	0.271
NEXUS (-15%)	Kensington-to-Milford	0.650	0.650	0.649	0.649	0.649	0.649	0.650	0.652	0.653	0.654	0.656	0.657	0.659	0.659	0.659	0.658	0.653
NEXUS (Base Case)	Kensington-to-Milford	0.755	0.755	0.754	0.754	0.754	0.754	0.755	0.757	0.759	0.760	0.762	0.763	0.765	0.766	0.765	0.765	0.759
NEXUS (+15%)	Kensington-to-Milford	0.860	0.860	0.859	0.859	0.859	0.859	0.861	0.863	0.864	0.866	0.868	0.870	0.872	0.872	0.872	0.871	0.865
NEXUS (Anchor)	Kensington-to-Milford	0.733	0.733	0.733	0.732	0.732	0.733	0.734	0.735	0.737	0.738	0.740	0.742	0.743	0.744	0.743	0.743	0.737
Alliance	CREC-to-Border	0.560	0.560	0.560	0.560	0.560	0.560	0.560	0.560	0.560	0.560	0.560	0.560	0.560	0.560	0.560	0.560	0.560
Alliance	Border-to-Chicago	0.421	0.421	0.421	0.420	0.420	0.421	0.421	0.422	0.423	0.424	0.425	0.426	0.427	0.427	0.427	0.427	0.423
TCPL	Empress-to-Enbridge SWDA	1.422	1.422	1.422	1.422	1.422	1.422	1.422	1.422	1.422	1.422	1.422	1.422	1.422	1.422	1.422	1.422	1.422
TCPL	Niagara-to-Kirkwall	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217
Union	Kirkwall-to-Dawn (C1)	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040

November 2014 - ACA ($CAD/GJ)

Pipeline	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Average
Rover	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
NEXUS	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
ANR East	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002

November 2014 - Abandonment Surcharge ($CAD/GJ)

Pipeline	Path	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Average
Alliance	CREC-to-Border	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Vector	Michigan Boarder-to-Dawn	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TCPL	Empress-to-Enbridge SWDA	0.133	0.133	0.133	0.133	0.133	0.133	0.133	0.133	0.133	0.133	0.133	0.133	0.133	0.133	0.133	0.133	0.133
TCPL	Niagara-to-Kirkwall	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007

Appendix C – May 2015 Landed Cost Analysis and Assumptions

May 2015 - NEXUS Landed Cost Analysis ($CAD/GJ)

Pipeline	Pricing Point	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Average
Dawn	Dawn	4.24	4.04	4.08	4.19	4.26	4.35	4.44	4.54	4.62	4.72	4.83	4.93	5.03	5.14	5.23	5.30	4.62
Vector	Chicago	4.44	4.30	4.35	4.43	4.51	4.60	4.69	4.79	4.88	4.98	5.09	5.19	5.30	5.40	5.50	5.57	4.88
TCPL fron Niagara	Niagara	4.13	3.86	3.89	3.99	4.69	4.78	4.87	4.97	5.06	5.15	5.26	5.37	5.47	5.57	5.67	5.73	4.90
NEXUS (-15%)	Dominion South	4.42	4.33	4.50	4.59	4.69	4.78	4.88	4.98	5.07	5.17	5.28	5.39	5.49	5.60	5.70	5.77	5.04
Rover	Dominion South	4.46	4.36	4.53	4.62	4.72	4.81	4.90	5.00	5.09	5.19	5.30	5.41	5.51	5.62	5.72	5.78	5.06
NEXUS (Anchor)	Dominion South	4.52	4.43	4.60	4.69	4.79	4.88	4.98	5.07	5.16	5.27	5.38	5.49	5.59	5.70	5.80	5.86	5.14
NEXUS (Base Case)	Dominion South	4.54	4.44	4.62	4.71	4.80	4.90	4.99	5.09	5.18	5.28	5.40	5.50	5.61	5.72	5.81	5.88	5.16
NEXUS (+15%)	Dominion South	4.66	4.56	4.73	4.82	4.92	5.01	5.11	5.20	5.30	5.40	5.51	5.62	5.73	5.83	5.93	6.00	5.27
ANR East	Dominion South	4.91	4.81	4.98	5.07	5.17	5.26	5.36	5.45	5.55	5.65	5.76	5.87	5.98	6.09	6.19	6.25	5.52
Alliance	CREC	4.95	5.02	5.09	5.26	5.34	5.44	5.54	5.64	5.73	5.84	5.96	6.07	6.18	6.29	6.39	6.47	5.70
TCPL	Empress	5.49	5.54	5.61	5.78	5.86	5.95	6.05	6.14	6.23	6.33	6.44	6.54	6.65	6.75	6.85	6.92	6.19

May 2015 - Average Commodity Prices ($CAD/GJ)

	Pricing Point	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Average
	Dawn	4.24	4.04	4.09	4.19	4.26	4.35	4.44	4.54	4.62	4.72	4.83	4.93	5.04	5.14	5.23	5.30	4.64
	Chicago	4.20	4.05	4.09	4.17	4.25	4.34	4.43	4.52	4.61	4.71	4.82	4.92	5.02	5.13	5.22	5.29	4.63
	Dominion South	3.43	3.34	3.51	3.60	3.70	3.79	3.89	3.97	4.06	4.16	4.26	4.36	4.46	4.56	4.66	4.73	4.06
	CREC	3.43	3.49	3.55	3.72	3.79	3.88	3.98	4.07	4.15	4.25	4.35	4.46	4.56	4.66	4.75	4.82	4.15
	Empress	3.53	3.59	3.65	3.82	3.89	3.98	4.07	4.16	4.25	4.35	4.45	4.55	4.65	4.76	4.85	4.92	4.25
	Niagara	3.84	3.59	3.62	3.72	4.41	4.50	4.60	4.69	4.78	4.88	4.99	5.09	5.19	5.29	5.39	5.46	4.67

May 2015 - Average Foreign Exchange

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Average
CAD/USD	1.255	1.249	1.241	1.235	1.232	1.231	1.234	1.238	1.243	1.248	1.254	1.258	1.262	1.266	1.267	1.257	1.248

May 2015 - Fuel Ratio

Pipeline	Path	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Average
ANR East	Leesville-to-Dawn	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%
Rover	Leesville-to-Dawn	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%
Vector	Chicago-to-Dawn (Base Case)	0.27%	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%	0.52%	0.47%
Vector	Chicago-to-Dawn (Anchor)	0.27%	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%	0.52%	0.47%
NEXUS (-15%)	Kensington-to-Milford	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%
NEXUS (Base Case)	Kensington-to-Milford	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%
NEXUS (+15%)	Kensington-to-Milford	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%
NEXUS (Anchor)	Kensington-to-Milford	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%
Alliance	CREC-to-Border	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%
Alliance	Border-to-Chicago	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
TCPL	Empress-to-Enbridge SWDA	3.99%	3.87%	3.87%	3.87%	3.87%	3.87%	3.87%	3.87%	3.87%	3.87%	3.87%	3.87%	3.87%	3.87%	3.87%	3.85%	3.88%
TCPL	Niagara-to-Kirkwall	0.37%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.13%	0.18%
Union	Kirkwall-to-Dawn (C1)	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%

May 2015 - Transportation Toll ($CAD/GJ)

Pipeline	Path	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Average
ANR East	Leesville-to-Dawn	1.391	1.385	1.376	1.370	1.366	1.365	1.369	1.373	1.378	1.384	1.390	1.395	1.400	1.404	1.405	1.406	1.385
Rover	Leesville-to-Dawn	0.951	0.947	0.941	0.936	0.934	0.934	0.936	0.939	0.942	0.947	0.951	0.954	0.957	0.960	0.960	0.961	0.947
Vector	Chicago-to-Dawn (Base Case)	0.190	0.189	0.188	0.187	0.187	0.187	0.187	0.188	0.188	0.189	0.190	0.191	0.191	0.192	0.192	0.192	0.189
Vector	Chicago-to-Dawn (Anchor)	0.190	0.189	0.188	0.187	0.187	0.187	0.187	0.188	0.188	0.189	0.190	0.191	0.191	0.192	0.192	0.192	0.189
NEXUS (-15%)	Kensington-to-Milford	0.717	0.713	0.709	0.705	0.703	0.703	0.705	0.707	0.710	0.713	0.716	0.718	0.721	0.723	0.723	0.724	0.713
NEXUS (Base Case)	Kensington-to-Milford	0.832	0.829	0.823	0.819	0.817	0.817	0.819	0.822	0.825	0.828	0.832	0.835	0.838	0.840	0.840	0.841	0.829
NEXUS (+15%)	Kensington-to-Milford	0.948	0.944	0.938	0.934	0.931	0.931	0.933	0.936	0.940	0.944	0.948	0.951	0.954	0.957	0.957	0.958	0.944
NEXUS (Anchor)	Kensington-to-Milford	0.815	0.811	0.806	0.802	0.800	0.799	0.801	0.804	0.807	0.811	0.814	0.817	0.820	0.822	0.822	0.823	0.811
Alliance	CREC-to-Border	0.560	0.560	0.560	0.560	0.560	0.560	0.560	0.560	0.560	0.560	0.560	0.560	0.560	0.560	0.560	0.560	0.560
Alliance	Border-to-Chicago	0.464	0.462	0.459	0.457	0.456	0.456	0.457	0.458	0.460	0.462	0.464	0.465	0.467	0.468	0.469	0.469	0.462
TCPL	Empress-to-Enbridge SWDA	1.681	1.681	1.681	1.681	1.681	1.681	1.681	1.681	1.681	1.681	1.681	1.681	1.681	1.681	1.681	1.681	1.681
TCPL	Niagara-to-Kirkwall	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217
Union	Kirkwall-to-Dawn (C1)	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040

May 2015 - ACA ($CAD/GJ)

Pipeline	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Average
Rover	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
NEXUS	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
ANR East	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002

May 2015 - Abandonment Surcharge ($CAD/GJ)

Pipeline	Path	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Average
Alliance	CREC-to-Border	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021
Vector	Michigan Border-to-Dawn	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
TCPL	Empress-to-Enbridge SWDA	0.133	0.133	0.133	0.133	0.133	0.133	0.133	0.133	0.133	0.133	0.133	0.133	0.133	0.133	0.133	0.133	0.133
TCPL	Niagara-to-Kirkwall	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007

EXECUTION VERSION

RESTATED PRECEDENT AGREEMENT

This RESTATED PRECEDENT AGREEMENT ("Restated Precedent Agreement") is made and entered into this 17th day of December, 2014 ("Effective Date"), by and between DTE Pipeline Company, a Michigan corporation ("DTE"), and Spectra Energy Transmission, LLC, a Delaware limited liability company ("Spectra") (DTE and Spectra are collectively referred to herein as "Pipeline"), and Enbridge Gas Distribution Inc., an Ontario corporation ("Customer"). Pipeline and Customer are sometimes referred to individually as a "Party" and collectively as the "Parties."

W I T N E S S E T H:

WHEREAS, Pipeline is proposing a two-phased project that will ultimately provide approximately one (1) billion cubic feet per day or more of firm transportation service for natural gas production from the Appalachian production areas, including but not limited to the Utica Shale and Marcellus Shale production areas in Ohio and Pennsylvania, to the international border between the United States and Canada near St. Clair, Michigan (the "International Border") and continuing from the International Border to Dawn, Ontario ("Dawn"). In Phase I, Pipeline will provide firm transportation service from Willow Run, Michigan ("Willow Run") to Dawn utilizing subscriptions of firm pipeline capacity on existing pipeline systems ("Phase I"). In Phase II, Pipeline will construct an approximately 250-mile greenfield pipeline extending from points expected to be located at or near Kensington, Ohio to various interconnections in the State of Michigan, utilizing subscriptions of firm pipeline capacity on existing U.S. pipeline systems to transport to the International Border, and thereafter from the International Border to point(s) of delivery in or near Dawn, utilizing one or more of: subscriptions of firm pipeline capacity on existing Canadian pipeline systems, an expansion of the existing Vector Canada and/or Union Canadian pipeline systems, and/or construction of greenfield pipeline facilities ("Phase II") (the services and subscriptions contemplated herein and the facilities that Pipeline intends to construct (or use reasonable efforts to cause others to construct) and/or subscribe to provide such services are collectively referred to herein as the "Project");

WHEREAS, Pipeline is proposing to commence service for the Project in phases, with Phase I to commence on or about November 1, 2015 and Phase II targeted to commence on or about November 1, 2017;

WHEREAS Customer, based on its qualifying bid submitted in the Open Season conducted by Pipeline from October 15, 2012 through November 30, 2012 ("Open Season"), entered into a Precedent Agreement with Pipeline dated June 5, 2014, as amended on July 31, 2014, (the "Original Precedent Agreement") pursuant to which Pipeline agreed to construct certain pipeline facilities and to provide the services in respect of Phase I and Phase II to Customer and Customer agreed to pay for such service(s) in respect of Phase I and Phase II, all subject to various conditions precedent set forth in the Original Precedent Agreement;

WHEREAS, pursuant to the terms of the Original Precedent Agreement, Customer notified Pipeline that it did not obtain the approval contemplated in Section 7(c)(i) of the Original Precedent Agreement, and, as contemplated by Section 9(b) of the Original Precedent Agreement, the Parties desire to restate the Original Precedent Agreement as further set forth herein;

WHEREAS, in lieu of the service contemplated under the Original Precedent Agreement, Customer now desires firm natural gas transportation service in respect of Phase II only from points expected to be located at or near Kensington, Ohio to the point of interconnection with

Vector Pipeline L.P.'s Milford Junction meter station near Highland, Michigan;

WHEREAS, Pipeline has secured commercial support for the Project evidenced by executed precedent agreements, including this Restated Precedent Agreement with Customer**;**

WHEREAS, DTE and Spectra contemplate that pipeline companies in the name of NEXUS Gas Transmission, LLC and NEXUS Gas Transmission Canada have been or will be formed and owned by each of DTE and Spectra or by affiliates of each of them to fulfill the responsibilities of Pipeline hereunder and NEXUS Gas Transmission, LLC and NEXUS Gas Transmission Canada will take assignment of the rights and obligations of and be novated as the Pipeline for all purposes of this Restated Precedent Agreement;

WHEREAS, subject to the terms and conditions of this Restated Precedent Agreement, Pipeline is willing to undertake the steps necessary to provide the Phase II service for Customer described herein and other customers subscribing for capacity as part of the entire Project, to construct the Project facilities or subscribe for firm pipeline capacity that will extend from eastern Ohio to Dawn in order to provide such services, and, if necessary, to construct, or to use reasonable efforts to cause the construction of facilities on existing pipeline systems to provide service on the Project;

WHEREAS, subject to the terms and conditions of this Restated Precedent Agreement, Pipeline is willing to provide the firm transportation service to Customer described herein and Customer is willing to pay Pipeline for such service;

NOW, THEREFORE, in consideration of the mutual covenants herein assumed, and intending to be legally bound, Pipeline and Customer agree as follows:

1) Pipeline Obligations.

a) Subject to the terms and conditions of this Restated Precedent Agreement, Pipeline shall proceed with due diligence to file applications for and to obtain from all governmental and regulatory authorities having competent jurisdiction over Phase II of the Project, including, but not limited to, the Federal Energy Regulatory Commission ("FERC") and the National Energy Board of Canada ("NEB"), the authorizations, approvals, certificates, permits, notices and/or exemptions (collectively, the "Governmental Authorizations") Pipeline determines are necessary for Pipeline to construct, own, operate, and maintain (and, if necessary, to use reasonable efforts to cause others to construct, own, operate, and maintain) the Project facilities necessary to provide the firm transportation service contemplated for Phase II, including the Phase II service to Customer, commencing on the Phase II Service Commencement Date (as determined in accordance with Section 4 of this Restated Precedent Agreement); and (ii) for Pipeline to otherwise perform its obligations as contemplated in this Restated Precedent Agreement. Pipeline retains full control and discretion in the filing and prosecution of any and all applications for such Governmental Authorizations and/or any supplements or amendments thereto, and, if necessary, any court review, provided it does so in a manner that is consistent with the terms of this Restated Precedent Agreement and designed to implement the firm transportation service contemplated herein in a timely manner. Pipeline agrees to promptly notify Customer in writing when each of the Governmental Authorizations are received, obtained, rejected or denied. Pipeline shall also promptly notify Customer in writing as to whether each of the Governmental Authorizations received or obtained are acceptable to Pipeline.

b) During the term of this Restated Precedent Agreement, and provided it would be reasonable and prudent for Pipeline to do so, Pipeline agrees to use reasonable efforts to support and cooperate with the efforts of Customer to obtain all Customer's Authorizations and supplements and amendments thereto, to better understand and analyze the markets for the supply of gas at the proposed initial receipt points for Phase II of the Project and to otherwise perform its obligations as contemplated by this Restated Precedent Agreement.

c) Pipeline shall, no later than December 19, 2014**,** provide Customer with confirmation of the initial receipt points for Phase II transportation service (collectively, the "Initial Receipt Point Information").

d) The reservation rates payable for transportation service on Phase II (as set forth in the applicable Pipeline tariffs approved by the FERC and NEB, respectively the "Reservation Rates") will be set and applied for on a commercially reasonable basis.

2) Customer Obligations.

a) No later than December 19, 2014, Customer will advise Pipeline in writing of: (i) any facilities which Customer must construct, or cause to be constructed, in order for Customer to utilize the Phase II service contemplated in this Restated Precedent Agreement; and (ii) any necessary or desirable contractual and/or governmental or regulatory authorizations having jurisdiction over the Customer which Customer determines are necessary or desirable for Customer in order to execute and deliver the Phase II Service Agreement (as such term is defined in Section 3 below) and to fulfill its obligations thereunder and to otherwise perform its obligations under this Restated Precedent Agreement ("Customer's Authorizations").

b) Subject to the terms and conditions of this Restated Precedent Agreement, Customer shall proceed with due diligence to obtain the Customer's Authorizations. Customer retains full control and discretion in the filing and prosecution of any and all applications for such Customer's Authorizations and/or any supplements or amendments thereto, and, if necessary, any court review, provided it does so in a manner that is consistent with the terms of this Restated Precedent Agreement and in a manner designed to implement the Phase II firm transportation service contemplated herein in a timely manner. Customer agrees to promptly notify Pipeline in writing when each of the Customer's Authorizations, are received, obtained, rejected or denied. Customer shall also promptly notify Pipeline in writing as to whether each of the Customer's Authorizations received or obtained are acceptable to Customer.

c) During the term of this Restated Precedent Agreement, and provided it would be reasonable and prudent for Customer to do so, Customer agrees to use reasonable efforts to support and cooperate with the efforts of Pipeline to obtain all Governmental Authorizations and supplements and amendments thereto necessary for Pipeline to provide the Phase II services contemplated hereunder and to construct, own, operate, and maintain (or, if necessary, to use reasonable efforts to cause others to construct, own, operate and maintain) the Project facilities for the Phase II services and to otherwise perform its obligations as contemplated by this Restated Precedent Agreement.

d) As of the Effective Date, Customer agrees that its proposed quantity of firm transportation service that it wishes to contract for in respect of Phase II as its Maximum Daily Quantity ("MDQ") for the purpose of the Phase II Service Agreement is 110,000 Dth/d. Customer shall have the right, subject to available capacity, regulatory approvals, and the terms of Pipeline's FERC Gas Tariff, to increase its MDQ under the Phase II Service Agreement up to 150,000 Dth/d. Pipeline will notify Customer whether capacity is available to satisfy such request to increase Customer's MDQ, taking into consideration the terms of Pipeline's FERC Gas Tariff. If Pipeline, taking into consideration the terms of its FERC Gas Tariff, can only accommodate an increase to Customer's MDQ that is less than requested, Pipeline shall promptly notify Customer of the amount of the requested increase that can be accommodated, and Customer shall have ten (10) days from receipt of such notice to either: (i) agree to increase its MDQ to the amount that can be accommodated; or (ii) retract its request for an increase. If there is to be an increase to Customer's MDQ pursuant to this Section 2(d), then Pipeline and Customer shall amend the Phase II Service Agreement to reflect the increase as follows:

i) if Customer requests an increase to its MDQ prior to the Phase II Service Commencement Date to be effective on the Phase II Service Commencement Date, and as a result Customer's MDQ is increased to 150,000 Dth/d, then:

    (1) the Reservation Rate applicable to Customer's entire MDQ (including any increase) pursuant to the Phase II Service Agreement and the Phase II Rate Agreement for the firm transportation service as set forth under Paragraph 3(d) shall be reduced such that Customer's effective Reservation Rate for service on the portion of Phase II utilizing newly constructed facilities extending from a receipt point(s) to be located at or near Kensington, Ohio to an interconnection point(s) to be located at or near Willow Run, Michigan (the "Greenfield Facilities – Kensington to Willow Run") is equal to the effective Reservation Rate to be paid by Union Gas Limited for Phase II service on the Greenfield Facilities –

Kensington to Willow Run. As of the Effective Date of this Restated Precedent Agreement, Pipeline estimates that Customer's Reservation Rate would be reduced by approximately $0.015 per Dth/d, however, Pipeline and Customer acknowledge and agree that Pipeline's estimate is non-binding and any change to Customer's Reservation Rate for purposes of this Section 2(d)(i)(1) will be determined in accordance with the process outlined for establishing the reservation rates in Section 3(d); and

(2) Customer shall be entitled to the rights granted under Section 3(e).

ii) If Customer requests an increase to its MDQ after the Phase II Service Commencement Date or prior to the Phase II Service Commencement Date but to be effective after the Phase II Service Commencement Date, then:

(1) Customer's request shall be subject to the capacity award mechanism, including any posting and bidding requirements, set forth in Pipeline's FERC Gas Tariff; and

(2) if, pursuant to the terms of Pipeline's FERC Gas Tariff, Customer is awarded the requested capacity and its MDQ is increased to 150,000 Dth/d to be effective anytime on or before November 1, 2020, then the Reservation Rate applicable to Customer's entire MDQ (including any increase) pursuant to the Phase II Service Agreement and the Phase II Rate Agreement for the firm transportation service as set forth under Paragraph 3(d) shall be reduced, as of the effective date of the increased MDQ, such that Customer's effective Reservation Rate for service on the Greenfield Facilities – Kensington to Willow Run is equal to the effective Reservation Rate paid by Union Gas Limited for Phase II service on the

Greenfield Facilities – Kensington to Willow Run. As of the Effective Date of this Restated Precedent Agreement, Pipeline estimates that Customer's Reservation Rate would be reduced by approximately $0.015 per Dth/d as of the effective date of Customer's increased MDQ, however, Pipeline and Customer acknowledge and agree that Pipeline's estimate is non-binding and any change to Customer's Reservation Rate for purposes of this Section 2(d)(ii)(2) will be determined in accordance with the process outlined for establishing the reservations rates in Section 3(d).

iii) if Customer's MDQ is increased to an amount that is less than 150,000 Dth/d, the terms of service including Customer's Reservation Rate shall remain unchanged for all of Customer's MDQ (including any increase).

iv) The terms of this Section 2(d) shall be reflected in the Phase II Rate Agreement and are subject to applicable regulatory approvals. Except as set forth in this Section 2(d) or Section 3(e) (if applicable), all other terms of service and rates shall remain unchanged.

3) <u>Service Agreement.</u>

a) *Intentionally left blank*.

b) <u>Phase II Firm Service Agreement.</u> To effectuate the firm transportation service contemplated herein for the Phase II service, Customer and Pipeline agree that (i) no later than thirty (30) days following the date on which Pipeline provides written notice to Customer that the FERC, the Michigan Public Service Commission, and any other governmental agencies or authorities having jurisdiction over the U.S. portion of the Phase II service have all issued the necessary authorizations to Pipeline or other pipelines to construct the greenfield and expansion facilities necessary to provide the U.S. portion of the Phase II service, Pipeline and Customer will execute a firm transportation service agreement governing Customer's service on Phase II as described herein ("Phase II Service Agreement"). The Phase II Service Agreement and the rights and obligations arising thereunder shall only become effective if, in addition to receipt of the aforementioned authorizations for the U.S. portion of the Phase II Service, Pipeline has also provided confirmation that the NEB, Ontario Energy Board ("OEB") and any other governmental agencies or authorities having jurisdiction over the Canadian portion of the Phase II service have all issued the necessary authorizations to Pipeline or other pipelines proposing to construct facilities necessary to provide the Canadian portion of the Phase II service. For clarity, the Canadian portion of the Phase II service shall have no application to the transportation service that Customer is contracting for, but receipt of the Governmental Authorizations for the Canadian portion of Phase II are a condition precedent to the Phase II Service Agreement between Pipeline and Customer becoming effective as reflected in Section 7(b)(ii). The Parties agree to consider in good faith executing the Phase II Service Agreement at a time earlier than contemplated in the first sentence above if required to allow Pipeline to obtain the requisite notice to proceed with Phase II construction from any governmental agency or authority having jurisdiction. The Phase II Service Agreement will specify the following provisions that will constitute Customer's service on Phase II ("Customer's Phase II Service"): (i) an MDQ of 110,000 Dth/d (subject to increase in accordance with Section 2(d) above), exclusive of fuel requirements, effective on the Phase II Service Commencement Date; (ii) a primary term of fifteen (15) years commencing on the Phase II Service Commencement Date and continuing from year to year thereafter unless terminated in accordance with the provisions thereof; (iii) a Primary Point of Receipt (as such term will be defined in the Phase II Service Agreement) at the head of the Phase II facilities in Ohio (such point to be designated by Pipeline at such time as Pipeline provides notice to Customer in accordance with Section 3(c) below) with a Maximum Daily Receipt Obligation ("MDRO") of 110,000 Dth/d (subject to increase in accordance with Section 2(d) above); (iv) a Primary Point of Delivery (as such term will be defined in the Phase II Service Agreement) at the point of interconnection with Vector Pipeline L.P.'s Milford Junction meter station near Highland, Michigan with a Maximum Daily Delivery Obligation ("MDDO") of 110,000 Dth/d (subject to increase in accordance with Section 2(d) above); and (v) security requirements consistent with the provisions set forth in Section 13 below. To the extent Pipeline is authorized to offer access to secondary receipt and delivery points as part of the Phase II service, Customer shall have the right under the Phase II Service Agreement to access secondary receipt and delivery points in accordance with such authorization(s). Attached hereto as Exhibit A is an illustrative form of transportation service agreement for Customer's Phase II Service. . Pipeline provided Customer a copy of the rate agreement and a summary of the general terms and conditions that will be incorporated by reference into the transportation service agreement to form the FERC tariff pursuant to the terms of the Original Precedent Agreement, and Pipeline will provide Customer with any changes to the illustrative form of transportation service agreement in Exhibit A (collectively, the "Forms of Commercial Agreements"). Pipeline will seek Customer's review of the Forms of Commercial Agreements and will consider in good faith any comments provided by Customer.

Pipeline shall keep Customer informed of any revisions to the Forms of Commercial Agreements including revisions resulting from comments received from other Customers in respect of Phase II service. Pipeline shall apply for and seek the Governmental Authorizations in a manner consistent with the Forms of Commercial Agreements. The Parties acknowledge and agree that these Forms of Commercial Agreements may change, as required, as a result of the terms and conditions of approvals from the FERC.

c) Status of Phase II Service Commencement Date. Commencing on January 1, 2015, and continuing on a quarterly basis thereafter, Pipeline will notify Customer regarding Pipeline's progress regarding Phase II, and whether the Phase II Service Commencement Date (as determined in accordance with Section 4 of this Restated Precedent Agreement) is expected to occur on November 1, 2017, or some later date. No later than November 1, 2015, Pipeline shall in good faith have notified Customer of its *bona fide* estimate of the Phase II Service Commencement Date (the "Estimated Phase II Commencement Date"). In the event that Pipeline's *bona fide* estimate of the Estimated Phase II Commencement Date is a date that is after November 1, 2018, then, unless such deadline(s) are extended by mutual consent, Customer shall have no further obligation in respect of contracting for Customer's Phase II Service and Customer shall have the right to terminate this Restated Precedent Agreement in respect of Customer's Phase II Service without liability between the Parties including in respect of the Customer being required to pay any Pre-Service Costs.

d) Rates.

i) *Intentionally left blank.*

ii) The rates that will apply to the Phase II Service Agreement shall be as set forth in the rate agreement to be executed in accordance with this Section 3(d), for service under the Phase II Service Agreement. Pipeline and Customer have agreed to the following with regard to the rates for service under the Phase II Service Agreement:

(1) Subject to the terms and conditions set forth herein and in the Phase II Service Agreement and in the Phase II Rate Agreement (as defined below), upon execution of such service and rate agreements, Customer shall be obligated to pay Pipeline the rates specified for service under the Phase II Service Agreement commencing on the Phase II Service Commencement Date and continuing to the end of the primary term (as set forth in the Phase II Service Agreement) thereof.

(2) Pipeline and Customer acknowledge that the scope of the facilities necessary for Pipeline to provide Customer's Phase II Service and for all other customers subscribing for Phase II service (such facilities are collectively referred to herein as the "Phase II Facilities") is not known with precision at this time. For this reason, the estimated capital costs associated with construction of the Phase II Facilities and the estimated Reservation Rates and fuel rates for Customer's Phase II Service under the Phase II Service Agreement will be set forth in the Phase II Rate Agreement provided in accordance with Section 3(d)(ii)(3) below. Pipeline currently estimates that the Reservation Rate for Customer's Phase II Service under the Phase II Service Agreement will be $0.70 US per Dth/d (the "Estimated Phase II Rate"), plus the applicable U.S. fuel rate, with such fuel rate in the range of 1.6% - 2.6%. The Estimated Phase II Rate may be adjusted as more fully set forth in Section 3(d)(ii)(3) and subject to the terms of Section 3(d)(ii)(4) below.

(3) No later than December 19, 2014 Pipeline shall provide Customer with a draft estimate of the capital costs associated with construction of the New Phase II Facilities (as defined below), the revised Reservation Rate (the "Revised Phase II Rate") applicable to Customer's Phase II Service, subject to a fifteen percent (+/-15%) capital cost tracking adjustment (as more particularly described in Exhibit C (the "Capital Cost Tracking Adjustment") around the revised estimate, and the revised fuel rate estimate, to be set forth in the rate agreement for the Phase II Service Agreement. The capital cost estimate will be provided substantially in the same form as an Exhibit K - Cost of Facilities (as defined in the Federal Energy Regulatory Commission's Code of Federal Regulations) for the New Phase II Facilities. At such time as Pipeline provides Customer with the Revised Phase II Rate, Pipeline will provide information which sets forth a more detailed breakdown of how the Pipeline has derived such Revised Phase II Rate ("Rate Breakdown"), including a breakdown of such portion of the Reservation Rate for Customer's Phase II Service that is derived from the capital costs associated with the construction of the New Phase II Facilities for Customer's Phase II Service. No later than January 16, 2015, Pipeline shall deliver to Customer a final estimate of capital costs for the New Phase II Facilities, final Reservation Rate for Customer's Phase II Service (subject to the Capital Cost Tracking Adjustment) (the "Final Reservation Rate") and final estimated fuel rate to be set forth in the rate agreement for the Phase II Service Agreement and any final revisions to the Rate Breakdown as well as the final rate agreement for the Phase II Service Agreement (the "Phase II Rate Agreement"). Pipeline and Customer shall

promptly execute the Phase II Rate Agreement; provided that, if the Final Reservation Rate set forth in the Phase II Rate Agreement is higher than the Estimated Phase II Rate set forth in Section 3(d)(ii)(2) above, and such higher Reservation Rate has caused the value of the commercial transaction with respect to the natural gas to be transported under the Phase II Service Agreement to be uneconomical to Customer, as determined by Customer in its sole and absolute discretion, Customer shall not be obligated to execute the Phase II Rate Agreement.

(4) In the event that Customer has elected not to execute the Phase II Rate Agreement in accordance with the proviso in the last sentence of Section 3(d)(ii)(3), Pipeline and Customer shall promptly meet and work in good faith in an attempt to agree upon Reservation Rate that are commercially acceptable to both Parties, each Party in its sole discretion. If, after thirty (30) days, the Parties are unable to agree upon a mutually acceptable Reservation Rate, either Party shall have the right to terminate this Restated Precedent Agreement and, if executed, the Phase II Service Agreement. Any termination of this Restated Precedent Agreement pursuant to this Section will be without liability to either Party including in respect of the Customer being required to pay any Pre-Service Costs.

e) <u>Most Favored Nations.</u> The following provisions of this Section 3(e) shall only apply and become effective should the Customer make an election in accordance with Section 2(d)(i) to increase its MDQ to 150,000 Dth/day effective as of the Phase II Service Commencement Date and the entire amount requested to be increased can be accommodated by Pipeline.

i) Except as provided in Section 3(e)(ii) below, in the event that Pipeline enters into or has entered into firm transportation service and/or recourse, negotiated or discount rate agreements with other similarly situated customers (as to transportation path, quantity and length of term) in respect of Phase II containing any rate provisions and other terms of service that are more favorable to such other customers than the negotiated rate provisions set forth in the Phase II Rate Agreement, Pipeline shall offer Customer, within ten (10) business days of entering into the rate agreements (or to the extent such rate agreements existed prior to the exercise by Customer of the right in Section 2(e)), then within ten (10) business days of confirmation that Customer's MDQ has been increased to 150,000 Dth/d), those same rate provisions and other terms of service. If Customer is willing to accept the offer on the exact same terms and conditions as such other customer(s), including provisions regarding transportation path, volume and length of term, then Customer will so notify Pipeline within thirty (30) days of its acceptance, and Pipeline will make the necessary amendments to the Phase II Rate Agreement and the Phase II Service Agreement, as applicable, and the Parties will enter into amended agreements at the more favorable rate for the remainder of the term of the applicable agreement(s). This section will apply only to contracts Pipeline enters into for service utilizing Project capacity on or before the Phase II Service Commencement Date.

ii) *Exclusions.* Pipeline is not required to offer to Customer and Customer is not entitled to, any rate provisions provided to other customers if such rate provisions are contained in long-term firm service agreements for capacity that becomes available as a result of the breach, default or unauthorized termination of a precedent agreement or associated service agreement by a Project customer or the bankruptcy, insolvency, liquidation or other similar action affecting a Project customer. In addition, the most favored nation right set forth in this Section 3(e) will not be available to Customer in respect of any short term (i.e., less than one year) service. Further, the most favored nation right set forth in this section 3 will not apply to credit provisions.

(f) Right of First Refusal. Customer will, in respect of the Phase II Service Agreement be granted a contractual Right of First Refusal ("ROFR") in accordance with the Pipeline tariff approved by the FERC. Further, the Phase II Service Agreement will be considered a ROFR Agreement in accordance with, and as that term is used in, Pipeline's FERC tariff.

4) Commencement of Service.

(a) *Intentionally left blank.*

(b) Phase II. With respect to Phase II transportation service, Pipeline shall provide at least ninety (90) days' prior notice (the "In-Service Date Notice") to Customer of the projected service commencement date for service under the Phase II Service Agreement, which date shall be the beginning of a calendar month and cannot be earlier than the date upon which Pipeline has satisfied or waived all the conditions precedent, provided that the actual service commencement date for purposes of the Phase II Service Agreement (the "Phase II Service Commencement Date") shall be the date that is the later of: (i) November 1, 2017; (ii) the date provided in the In-Service Date Notice; (iii) the date that is the first day of the first calendar month following the date on which the Pipeline places the Phase II Facilities into service; or (iv) if, pursuant to Section 7(f), the Pipeline has filed an appeal or is pursuing a rehearing, reconsideration or clarification by the applicable regulatory authority of the Governmental Authorization, then 90 days from the date of receipt of a positive decision addressing Customer's concerns unless such period is waived by Customer. On and after the Phase II Service Commencement Date, Pipeline shall provide firm transportation service for Customer pursuant to the terms of the Phase II Service Agreement and Customer will pay Pipeline for all applicable charges required by the Phase II Service Agreement and the Phase II Rate Agreement.

5) Design and Permitting of Project Facilities. Pipeline will undertake with due diligence, or use reasonable efforts to cause others to undertake, the design of the Phase II Facilities and any other preparatory actions necessary for Pipeline, or Pipeline's designee(s), to complete and file application(s) related to the Phase II Facilities with the FERC, NEB and/or other governmental authorities as appropriate. Prior to satisfaction of the conditions precedent set forth in Section 7(b)(i) through 7(b)(vii) of this Restated Precedent Agreement, Pipeline, or Pipeline's designee(s), shall have the right, but not the obligation, to proceed with the necessary design of facilities, acquisition of materials, supplies, properties, rights-of-way and any other necessary preparations to implement the firm transportation service under the Phase II Service Agreement as contemplated in this Restated Precedent Agreement. Additionally, Pipeline will use commercially reasonable efforts to keep Customer informed on a regular basis and respond to any of Customer's requests for information concerning Phase II schedule changes, status of Governmental Authorizations, service commencement dates, and/or changes to any of the rates described herein.

6) Construction of Project. Upon satisfaction of the conditions precedent set forth in Sections 7(b)(i) through 7(b)(vii), inclusive and 7(c) of this Restated Precedent Agreement, or waiver of the same by Pipeline or Customer, as applicable, Pipeline shall proceed with due diligence

to construct, or to use reasonable efforts to cause others to construct, the authorized Phase II Facilities and to implement the firm transportation service contemplated in this Restated Precedent Agreement for Customer's Phase II Service on or about November 1, 2017, or such later date as may be designated by Pipeline in accordance with Section 3(c) above. If, notwithstanding Pipeline's due diligence, Pipeline, or Pipeline's designee(s), is unable to commence the Phase II service for Customer on November 1, 2017, or such later date as may be designated by Pipeline in accordance with Section 3(c) above, Pipeline will continue to proceed with due diligence to complete arrangements for such firm transportation service, and commence such service for Customer at the earliest practicable date thereafter. Subject to Section 9(a), Pipeline will neither be liable nor will this Restated Precedent Agreement or the Phase II Service Agreement be subject to cancellation if Pipeline, or Pipeline's designee(s), is unable to complete the construction of such authorized Project facilities and commence the Phase II service for Customer by November 1, 2017 or such later date as may be designated by Pipeline in accordance with Section 3(c) above.

7) Conditions Precedent. Commencement of service under the Phase II Service Agreement and Pipeline's and Customer's rights and obligations thereunder are expressly made subject to satisfaction or waiver, as applicable, of the following conditions precedent in Sections 7(b) and 7(c), provided that only Pipeline shall have the right to waive the conditions precedent set forth in Section 7(b) and only Customer shall have the right to waive the conditions precedent set forth in Section 7(c):

a) *Intentionally left blank.*

b) Pipeline's Conditions Precedent for Phase II Service.

i) Pipeline filing by April 1, 2015 the necessary requests with the FERC and/or NEB for approval to provide Phase II service as contemplated herein and in the Phase II Service Agreement;

ii) Subject to Section 7(d), Pipeline's receipt and acceptance in accordance with Section 7(f) by May 1, 2017, of all necessary Governmental Authorizations to construct, own, operate and maintain the Phase II Facilities (including FERC, NEB, and OEB authorizations, as applicable), all as described in Pipeline's applications as they may be amended from time to time, necessary to provide the Phase II service, including Customer's Phase II Service contemplated herein and in the Phase II Service Agreement;

iii) Pipeline (or Pipeline's owners or their respective affiliates) having received on or before May 1, 2017, a binding commitment from a financial institution(s) to provide the necessary financing of the construction of the Phase II Facilities;

iv) Other pipelines having received and accepted in accordance with Section 7(f) by May 1, 2017, all necessary Governmental Authorizations to construct, own, operate and maintain the Phase II Facilities, all as described in their applications as they may be amended from time to time, necessary to provide the Phase II service including Customer's Phase II Service contemplated herein and in the Phase II Service Agreement;

v) Pipeline receiving approval, no later than thirty (30) days after its acceptance of the certificates and authorizations specified in Section 7(b)(i), from its Management Committee, or similar governing body, to expend the capital necessary to construct the Phase II Facilities and to proceed with the Phase II-related firm pipeline transportation arrangements with other pipelines for service on the Phase II Facilities;

vi) Pipeline's receipt no later than four (4) months prior to the Phase II Service Commencement Date of all necessary authorizations required to construct the Phase II Facilities necessary to provide the Phase II firm transportation service including Customer's Phase II Service contemplated herein and in the Phase II Service Agreement, other than those specified in Section 7(b)(ii);

vii) Pipeline's procurement, no later than four (4) months prior to the Phase II Service Commencement Date, of all rights-of-way, easements or permits (in form and substance acceptable to Pipeline, acting reasonably) necessary for the construction and operation of the Phase II Facilities;

viii) Pipeline's completion of construction of the Phase II Facilities and all other facilities required to render Customer's Phase II Service pursuant to the Phase II Service Agreement and for other customers subscribing for Phase II service and Pipeline being ready, able and authorized to place such facilities into gas service; and

ix) The completion of the construction of the facilities necessary to create the pipeline capacity subscribed to Pipeline as part of Phase II of the Project by other pipelines, as applicable, and each such Party being ready, able and authorized to place such facilities into service.

c) <u>Customer's Conditions Precedent.</u>

i) Intentionally left blank.

ii) Customer's acceptance, no later than 30 days following receipt of Initial Receipt Point Information in accordance with Section 1(c), of the initial receipt points proposed by the Pipeline for Phase II transportation service;

iii) Customer's confirmation to Pipeline, no later than 90 days following receipt of the Estimated Phase II Commencement Date, that it has completed its review and approval of regional supply necessary to support natural gas supply arrangements associated with Customer's service under the Phase II Service Agreement, respectively; and

iv) If, pursuant Section 3(d)(ii), the Final Reservation Rate exceeds the Estimated Reservation Rate, then Customer's receipt, no later than 60 days following receipt of the requisite internal corporate approvals of such Final Reservation Rate for Phase II;

v) Customer's receipt and acceptance of the approvals from the OEB for its application related to the Customer's Phase II Service no later than October 1, 2015; and

vi) Subject to Section 7(d), Customer's receipt and acceptance no later than 30 days following satisfaction of the condition in Section 7(c)(iii), of any necessary Customer Authorizations identified in accordance with Section 2(a) of this Restated Precedent Agreement.

d) <u>Temporary Waiver of Conditions Precedent – Governmental Authorizations</u>. Notwithstanding Sections 7(b)(ii), 7(b)(iv), 7(c)(iii) and 7(c)(iv) and subject to Section 24, either Party may, in its sole discretion, temporarily waive satisfaction of its conditions precedent listed above for a period of 90 days. During such a delay, upon reasonable request by the other Party, the Party waiving its condition precedent shall use commercially reasonable efforts to provide timely notices to the other Party in writing regarding the filing of any applications for such Governmental Authorizations or Customer Authorization, as the context requires, and will provide periodic updates regarding the status of such applications, including notice when each of the authorizations are received, obtained, rejected or denied. The Party temporarily waiving it condition precedent shall also promptly notify the other Party in writing as to whether each of the Governmental Authorizations or Customer Authorizations, as the context requires, received or obtained are acceptable to such Party. If the Party temporarily waiving its condition precedent has not satisfied the conditions precedent associated with the receipt of all Governmental Authorizations or Customer Authorizations, as the context requires, within ninety (90) days' time, either Party may terminate this Restated Precedent Agreement on thirty (30) days' written notice and no Pre-Service Costs will be payable by Customer.

e) With respect to each condition precedent set forth in Section 7(b) of this Restated Precedent Agreement, with the exception of the conditions precedent set forth in clauses (vii) and (viii) of Section 7(b), Pipeline shall provide notice to Customer within five (5) days of the satisfaction of such condition precedent that the condition precedent has been satisfied. With respect to each condition precedent set forth in Section 7(c) of this Restated Precedent Agreement, Customer shall provide notice to Pipeline within five (5) days of the satisfaction of each such condition precedent that the condition precedent has been satisfied.

f) Unless otherwise provided for herein, the Governmental Authorization(s) contemplated in Section 1 of this Restated Precedent Agreement must be issued in form and substance satisfactory to both Parties, acting reasonably. For purposes of this Restated Precedent

Agreement, such Governmental Authorization(s) shall be deemed satisfactory if issued or granted with terms and conditions which are: (i) consistent with this Restated Precedent Agreement and all ancillary agreements and documents to be delivered pursuant to this Restated Precedent Agreement for the applicable service; and (ii) to the extent not contemplated by this Restated Precedent Agreement or any of the ancillary agreements and documents, not materially onerous on Pipeline, as determined by Pipeline, acting reasonably, and will not otherwise have a material adverse effect on Customer. Customer shall notify Pipeline in writing not later than fifteen (15) days after Pipeline notifies Customer of the issuance of the FERC and/or NEB certificate(s), authorization(s) and approval(s), including any order issued as a preliminary determination on non-environmental issues, contemplated in Section 1 of this Restated Precedent Agreement if Customer determines, acting reasonably, that such certificate(s), authorization(s) and approval(s) will have a material adverse effect on Customer. Customer cannot assert that any authorization will have a material adverse effect on Customer unless: (i) the governing provisions of such authorization differ materially and adversely from the provisions requested by Pipeline in its application, unless the provisions requested by Pipeline were inconsistent with the terms of this Restated Precedent Agreement; and (ii) such differences materially and adversely affect the rate to be charged pursuant to the rate agreement contemplated herein, or the terms and conditions of service pursuant to the service agreement contemplated herein, and the Parties cannot mutually agree upon a modification or alternative to such provision which preserves the relative economic positions of the Parties under the operative agreement(s). All other Governmental Authorizations that Pipeline must obtain must be issued in form and substance acceptable to Pipeline, acting reasonably. All Governmental Authorizations that Pipeline is required by this Restated Precedent Agreement to obtain must be duly granted by the FERC, NEB, or other governmental agency or authority having jurisdiction, and must be final and no longer subject to rehearing or appeal; provided, however, Pipeline may waive the requirement that such Governmental Authorizations be final and no longer subject to rehearing or appeal. If any of the Governmental Authorizations are issued on material terms not acceptable to either Party, subject to the foregoing provisions of this Section 7(f), then the non-accepting Party, acting reasonably, shall give notice to the other Party, and the Parties shall promptly meet and work in good faith in an attempt to agree upon a commercially acceptable resolution for both Parties, each Party in its sole discretion, to continue forward with respect to Phase II. If, after thirty (30) days, the Parties are unable to agree upon a mutually acceptable resolution, either Party shall have the right to terminate this Restated Precedent Agreement and, if executed, the Phase II Service Agreement and Phase II Rate agreement. Any termination of this Restated Precedent Agreement by a Party pursuant to this Section will be without liability between the Parties including in respect of the Customer being required to pay any Pre-Service Costs. Notwithstanding the foregoing, if the Parties cannot agree on a modification or alternate provision, Pipeline may, in its sole discretion, appeal or otherwise pursue rehearing, reconsideration or clarification by the applicable regulatory authority of any such provision(s) which Customer alleges will have a material adverse effect on it, and Customer may not terminate this Restated Precedent Agreement until a final order or decision is rendered by such regulatory authority which does not grant relief that is satisfactory to Customer, acting reasonably, to address such material adverse effect, or

180 days from the date that Pipeline makes its application for rehearing, reconsideration or clarification, whichever occurs first.

g) The Customer Authorization(s) contemplated in Section 2 of this Restated Precedent Agreement shall be deemed satisfactory if issued or granted in form and substance substantially as requested, or if issued in a manner acceptable to Customer and such Customer Authorization(s), as issued, will not otherwise have a material adverse effect on Pipeline. Pipeline cannot assert that any authorization will have a material adverse effect on Pipeline unless: (i) the governing provisions of such authorization differ materially and adversely from the provisions requested by Customer in its application, unless the provisions requested by Customer were inconsistent with the terms of this Restated Precedent Agreement; and (ii) such differences materially and adversely affect the rate to be charged pursuant to the rate agreement contemplated herein, or the terms and conditions of service pursuant to the service agreement contemplated herein, and the Parties cannot mutually agree upon a modification or alternative to such provision which preserves the relative economic positions of the Parties under the operative agreement(s). If any of the Customer Authorizations are issued on terms not acceptable to either Party, subject to the foregoing provisions of this Section 7(g), then the non-accepting Party shall give notice to the other Party, and the Parties shall promptly meet and work in good faith in an attempt to agree upon a commercially acceptable resolution for both Parties, each Party in its sole discretion, to continue forward with respect to Phase II. If, after thirty (30) days, the Parties are unable to agree upon a mutually acceptable resolution, either Party shall have the right to terminate this Restated Precedent Agreement and, if executed, the Phase II Service Agreement and Phase II Rate Agreement. Any termination of this Restated Precedent Agreement by a Party pursuant to this Section will be without liability between the Parties including in respect of the Customer being required to pay any Pre-Service Costs.

h) In the event the Estimated Phase II Commencement Date is changed to a date later than November 1, 2017 in accordance with Section 3(c), the Parties agree that each of the dates in Sections 3(d)(ii), 7(b)(i) through 7(b)(iii), Sections 7(c)(ii) through 7(c)(iv), and Section 10 will be changed to a later date by the same amount of time as such change to the Estimated Phase II Commencement Date.

8) Pre-Service Costs. If Customer is in material breach of any of its obligations arising pursuant to this Restated Precedent Agreement and such material breach is not cured within 30 days of notice to Customer by Pipeline of such breach, or if such breach is not capable of being cured within 30 days, and Customer is not continuing thereafter in good faith and with diligence to cure such breach, and, as a result thereof, the Phase II Service Commencement Date does not occur, then Customer shall, at the option and election of Pipeline, reimburse Pipeline within thirty (30) days of Pipeline's invoice, for its pro-rata share, based on Customer's MDQ for Phase II service to total contracted MDQ for Phase II service by all customers with executed Restated Precedent Agreements, for the Pre-Service Costs incurred or otherwise committed to by Pipeline up to the date of the occurrence of the material breach which resulted in the Phase II Service Commencement Date to not occur. In no event shall Customer's exposure to Pre-Service Costs exceed $163 million U.S. dollars if Customer's MDQ for Phase II service is 110,000 Dth/d, or $219 million U.S. dollars if Customer's MDQ for Phase II service is 150,000 Dth/d. Customer's liability for its share of the Pre-Service Costs in accordance with this Section 8 constitutes a genuine pre-estimation of Pipeline's

liquidated damages and not as a penalty, and the payment by Customer of such amount, if such payment is required to be made in accordance with this Section 8 shall constitute Pipeline's sole remedy in such instance, with no right to claim further damages or other remedies from Customer. If this Restated Precedent Agreement is terminated for any reason other than a material breach by Customer, then such termination shall be without any liability on the part of Customer to Pipeline, including in respect of the Customer being required to pay any Pre-Service Costs. The term, "Pre-Service Costs" for all purposes in this Restated Precedent Agreement means only those expenditures and/or costs reasonably and prudently incurred, accrued, allocated to, or for which Pipeline is contractually obligated to pay in furtherance of Pipeline's efforts to develop and construct Phase II of the Project and to satisfy its obligations under this Restated Precedent Agreement and all other precedent agreements for service on Phase II of the Project facilities, including such expenditures associated with design, testing, engineering, construction, commissioning, materials and equipment, environmental, regulatory, and/or legal activities, allowance for funds used during construction, negative salvage, internal overhead and administration and any other costs reasonably incurred in furtherance of Pipeline's efforts to develop and construct Phase II of the Project and to satisfy its obligations under this Restated Precedent Agreement and all other precedent agreements for service on Phase II of the Project facilities. In the event Customer incurs liability for Pre-Service Costs, Pipeline shall use commercially reasonable efforts to mitigate the amount of Pre-Service Costs. NOTWITHSTANDING THE FOREGOING, THE PARTIES HERETO AGREE THAT NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR ANY PUNITIVE, SPECIAL, EXEMPLARY, INDIRECT, INCIDENTAL OR CONSEQUENTIAL DAMAGES (INCLUDING,

WITHOUT LIMITATION, LOSS OF PROFITS OR FOR BUSINESS INTERRUPTIONS) ARISING OUT OF OR IN ANY MANNER RELATED TO THIS PRECEDENT AGREEMENT, AND WITHOUT REGARD TO THE CAUSE OR CAUSES THEREOF OR THE SOLE, CONCURRENT OR CONTRIBUTORY NEGLIGENCE (WHETHER ACTIVE OR PASSIVE), STRICT LIABILITY (INCLUDING, WITHOUT LIMITATION, STRICT STATUTORY LIABILITY AND STRICT LIABILITY IN TORT) OR OTHER FAULT OF EITHER PARTY. THE IMMEDIATELY PRECEDING SENTENCE SPECIFICALLY PROTECTS EACH PARTY AGAINST SUCH PUNITIVE, EXEMPLARY, INDIRECT, INCIDENTAL OR CONSEQUENTIAL DAMAGES EVEN IF WITH RESPECT TO THE NEGLIGENCE, GROSS NEGLIGENCE, WILLFUL MISCONDUCT, STRICT LIABILITY OR OTHER FAULT OR RESPONSIBILITY OF SUCH PARTY; AND ALL RIGHTS TO RECOVER SUCH DAMAGES OR PROFITS ARE HEREBY WAIVED AND RELEASED.

9) <u>Termination of Restated Precedent Agreement for Failure of Conditions Precedent.</u>

a) If the conditions precedent set forth in Section 7 of this Restated Precedent Agreement have not been fully satisfied or waived by Pipeline or Customer, as applicable, by the earlier of the applicable dates specified therein or within one year after the Estimated Phase II Commencement Date, and this Restated Precedent Agreement has not otherwise been terminated pursuant to the other terms of this Restated Precedent Agreement, including in respect of Sections 10 or 11 hereof, then this Restated Precedent Agreement (and any Phase II Service Agreement) shall terminate effective 30 days after the date such condition precedent was to be satisfied or waived by the applicable Party and such termination shall be without liability including in respect of Customer being required to pay any Pre-Service Costs, except to the extent the failure is as a result of a breach by a Party of its other obligations set forth in this Restated Precedent Agreement.

b) For any termination in accordance with Section 9(a) above, the Parties agree to promptly meet and work diligently and in good faith for a period of 30 days following the date such condition precedent was to be satisfied or waived to attempt to agree upon changes to this Restated Precedent Agreement that would allow the Restated Precedent Agreement to continue, which may include a waiver of and/or change in the deadline for any of the conditions precedent that are the subject of such termination notice, provided that if the Parties are unable to come to an agreement upon changes that would allow the Restated Precedent Agreement to continue, then this Restated Precedent Agreement (and the Phase II Service Agreement) shall nonetheless terminate effective on the expiry of such 30 day period.

c) Any delay or failure in the performance by either Party hereunder shall be excused if and to the extent caused by the occurrence of a Force Majeure. Notwithstanding the foregoing, if any condition precedent set forth in Section 7 hereof has not been satisfied as a result of an occurrence of Force Majeure, the deadline for satisfying the condition precedent shall be extended for each day that the occurrence of Force Majeure continues up to a maximum of ninety (90) days or as mutually agreed to by the Parties. For purposes of this Restated Precedent Agreement, "Force Majeure" as employed herein shall mean any cause, whether of the kind enumerated herein or otherwise, not within the reasonable control of the Party claiming suspension, and which by the exercise of due diligence, such Party has been unable to prevent or overcome, including without limitations acts of God, the government, or a public enemy; strikes, lockouts, or other industrial disturbances; wars, terrorism, blockades, or civil disturbances of any kind; epidemics, landslides, hurricanes, washouts, tornadoes, storms, fires, explosions, arrests, and restraints of governments or people, freezing of, breakage or accident to, or the necessity for making repairs to machinery or lines of pipe; and the inability of either the claiming Party to acquire, or the delays on the part of either of the claiming Party in acquiring, at reasonable cost and after the exercise of reasonable diligence: (a) any servitudes, rights of way, grants, permits or licenses; (b) any materials or supplies for the construction or maintenance of facilities; or (c) any Governmental Authorizations, permits or permissions form any governmental agency; if such are required to enable the claiming Party to fulfill its obligations hereunder.

10) Termination for Default. The occurrence and continuation of a material breach by a Party of any of its obligations under this Restated Precedent Agreement, unless caused by a breach by the other Party of its obligations under this Restated Precedent Agreement is referred to herein as a “Default". Upon the occurrence of a Default by a Party hereto, the non-defaulting Party may provide written notice to the defaulting Party, describing the Default in reasonable detail and requiring the defaulting Party to remedy the Default (the "Default Notice"). If the Default is not cured within 30 days of receipt by the defaulting Party of the Default Notice, or if such breach is not capable of being cured within 30 days, and the defaulting Party is not continuing thereafter in good faith and with diligence to cure such Default, the non-defaulting Party may, by termination notice to the defaulting Party, terminate this Restated Precedent Agreement effective on the tenth (10th) day following receipt of the termination notice by the defaulting Party; provided, however, that if during such ten (10) day period the defaulting Party has commenced to remedy the Default and is continuing in good faith its

efforts to remedy such Default, the entitlement of the non-defaulting Party to terminate this Restated Precedent Agreement will be suspended until the earlier of the cessation by the defaulting Party of such efforts and the date which is ninety (90) days after the date of the Default Notice.

11) Other Pipeline Termination Rights. In addition to the provisions of Section 9 hereof, Pipeline may terminate this Restated Precedent Agreement at any time upon fifteen (15) days' prior written notice to Customer, if: (i) Pipeline, in its sole and reasonable discretion, determines for any reason on or before October 1, 2016, that the Project contemplated herein is no longer economically viable, (ii) Pipeline incurs or will incur costs which are twenty-five percent (25%) or more than the cost estimate submitted as part of Pipeline's application to the FERC for the certificate of public convenience and necessity for the Project related to the Project construction, or (iii) on or before October 1, 2016, substantially all of the other precedent agreements, service agreements or other contractual arrangements for the firm transportation service to be made available by the Project are terminated, other than by reason of commencement of service. In the event Pipeline terminates this Restated Precedent Agreement in accordance with this Section 10, Customer shall not be liable pursuant to Section 8 above for Pre-Service Costs.

12) Termination Upon Service Commencement Date; Survival. If this Restated Precedent Agreement is not terminated pursuant to Sections 9, 10 or 11 hereof, or otherwise in accordance with the terms of this Restated Precedent Agreement, then, except for those provisions herein that are stated to survive any termination of this Restated Precedent Agreement, this Restated Precedent Agreement will terminate by its express terms on the Phase II Service Commencement Date and thereafter Pipeline's and Customer's rights and

obligations related to the transportation service contemplated herein shall be determined pursuant to the terms and conditions of the Phase II Service Agreement and Phase II Rate Agreement, as applicable, and Pipeline's FERC gas tariff, as effective from time to time. Notwithstanding any termination of this Restated Precedent Agreement, each Party shall remain liable to the other Party for all losses or damages suffered, sustained or incurred by the other Party as a result of a breach of any obligations of a Party which breach arose prior to termination of this Restated Precedent Agreement, provided that Customer's liability shall only apply if and to the extent it is to be liable in accordance with Section 8 and, such liability, if any, shall not exceed its share of Pre-Service Costs determined in accordance with Section 8. Notwithstanding any termination of this Restated Precedent Agreement pursuant to terms of this Restated Precedent Agreement, to the extent that a provision of this Restated Precedent Agreement contemplates that one or both Parties may have further rights and/or obligations hereunder following such termination, the provision shall survive such termination as necessary to give full effect to such rights and/or obligations.

13) Creditworthiness. At all times during the effectiveness of this Restated Precedent Agreement and the related Service Agreement(s), Customer, pursuant to the criteria and terms set forth in this Section 13, shall either maintain a Creditworthy status, as defined below, or furnish sufficient credit support to Pipeline.

a) Creditworthiness Standard. Customer shall at all times during the effectiveness of this Restated Precedent Agreement and the Service Agreement(s) be Creditworthy or provide the Guaranty or the Letter of Credit contemplated herein. For purposes herein, "Creditworthy" means, in respect of the applicable entity, such entity has and maintains: (i) a long-term senior unsecured debt rating from (a) Moody's Investors Service, Inc.

("Moody's") of Baa3 or higher, and (b) Standard & Poor's ("S&P") of BBB- or higher and, with respect to each rating, not on negative credit watch or outlook, and (ii) a sufficient open line of credit as of the Effective Date. Pipeline acknowledges and agrees that, as of the effective date of this Restated Precedent Agreement, Customer has a sufficient open line of credit with Pipeline and Customer shall not at any time hereafter be required to establish any line of credit in connection with this Restated Precedent Agreement. If Customer is rated by only one of the foregoing credit rating agencies, Customer shall be creditworthy if it has the rating described in the foregoing sentence from the agency by which it is rated. If Customer is rated by both of the rating agencies described above but one such agency's rating is lower than the other agency's rating, then Customer's creditworthiness shall be determined based on the lower of the Moody's or S&P rating. Alternatively, Customer may be accepted as Creditworthy by Pipeline if Pipeline determines that, notwithstanding the absence of the rating requirements in this Section 13(a), the financial position of Customer (or an entity that guarantees all of Customer's payment obligations) is and remains acceptable to Pipeline during the term of the Restated Precedent Agreement and the Phase II Service Agreement.

b) <u>Failure to Meet Creditworthiness Standard</u>. In the event Customer fails at any time or from time to time during the term of this Restated Precedent Agreement or the applicable service agreements to meet the Creditworthy standard set forth in Section 13(a) (including if its Guarantor, if applicable is no longer Creditworthy), Customer shall provide credit support to Pipeline in the form of one of the following methods set forth in this Section 13(b):

i) Guaranty. Customer will provide, or cause to be provided, a guaranty (a "Guaranty") from Customer's parent company or from an affiliate (a "Guarantor"), provided the Guaranty shall serve to satisfy Customer's obligations under this Section 13 only if such Guarantor is Creditworthy, and only for so long as the Guarantor remains Creditworthy and for so long as it guarantees Customer's payment obligations and the Guaranty otherwise satisfies the requirements of this clause (i). The Guaranty shall: (a) guarantee all payment obligations of Customer under this Restated Precedent Agreement and the Phase II Service Agreement, (b) remain in effect until all payment obligations under this Restated Precedent Agreement and the Phase II Service Agreement have been satisfied in full, and (c) be in a form and content substantially similar to Exhibit D hereto. Pipeline may require, at any time and from time to time, Customer to provide, or cause to be provided, an additional guaranty from a Creditworthy guarantor if the original Guarantor is, at any time, no longer Creditworthy. If Customer becomes Creditworthy after providing a Guaranty, Customer may request a discharge and return of such Guaranty, and following such request Pipeline shall promptly provide such discharge and return.

ii) Letter of Credit. If, at any time and from time to time, during the effectiveness of this Restated Precedent Agreement and/or the Phase II Service Agreement Customer fails to meet the requirements of Sections 13(a) and 13(b)(i) above, Customer shall provide, or cause to be provided, at its sole cost, a standby irrevocable letter of credit (a "Letter of Credit") from a Qualified Institution. For purposes herein, a "Qualified Institution" shall mean a major U.S. or Canadian commercial bank, or the U.S. branch offices of a foreign bank, which is not the Customer or Customer's Guarantor (or a subsidiary or affiliate of the Customer or Customer's Guarantor) and which has assets of at least $10 billion dollars and a credit rating of at least "A-" by S&P, or "A3" by Moody's. Pipeline may require Customer at Customer's cost to substitute a Qualified Institution if the Letter of Credit provided is, at any time, from a financial institution which is no longer a Qualified Institution. The Letter of Credit shall: (i) remain in effect until all payment obligations under this Restated Precedent Agreement and the Phase II Service Agreement have been satisfied in full, (ii) be in a form acceptable to Pipeline, which for purposes herein shall mean in form and content substantially similar to Exhibit E hereto, and (iii) be in the amount equal to twenty-four (24) months of reservation rates based on the MDQ and reservation rates under the Phase II Service Agreement. If Customer becomes Creditworthy after providing a Letter of Credit, Customer may request a discharge and return of such Letter of Credit, and following such request Pipeline shall promptly provide such discharge and return.

c) Demand for Assurances. At any time and from time to time, Pipeline shall have the right to require that Customer demonstrate Customer's, or its Guarantor's, continuing satisfaction of the creditworthiness and credit support requirements in this Section 13. Customer will have a period of five (5) business days to make such demonstration or to furnish credit support acceptable to Pipeline in accordance with this Section 13.

d) Failure to Comply. The failure of Customer to timely satisfy or maintain the requirements set forth in this Section 13 shall in no way relieve Customer of its other obligations under this Restated Precedent Agreement or the Phase II Service Agreement, nor shall it affect Pipeline's right to seek damages or performance under this Restated Precedent Agreement or the Phase II Service Agreement. Further, if, prior to the Phase II

Service Commencement Date, Customer fails to timely satisfy or maintain the requirements set forth in this Section 13, then Pipeline may give written notice to Customer of such failure, and, if such failure is has not been cured within five (5) business days following the receipt by Customer of such notice, then Pipeline may elect to suspend or terminate performance under this Restated Precedent Agreement, or to terminate this Restated Precedent Agreement and, if applicable, the Phase II Service Agreement.

e) Term of Credit Provisions and Survival. This Section 13 shall survive the termination of this Restated Precedent Agreement and shall remain in effect until all payment obligations under this Restated Precedent Agreement and the Phase II Service Agreement, if applicable, have been satisfied in full.

f) Replacement Customer Creditworthiness. In the event Customer assigns this Restated Precedent Agreement or the Phase II Service Agreement in accordance with the applicable assignment provision(s), or in the event Customer permanently releases all or a portion of Customer's capacity under the Phase II Service Agreement in accordance with Pipeline's FERC Gas tariff and/or NEB Gas tariff, then the assignee and/or the permanent replacement customer, as applicable, shall be required to satisfy the requirements of this Section 13 with respect to all such assigned or replacement agreements, and upon satisfaction of the requirements of this Section 13, Pipeline shall return to Customer any Guaranty or Letter of Credit which had been furnished by Customer pursuant to this Section 13.

14) Amendments. This Restated Precedent Agreement may not be modified or amended unless the Parties execute written agreements to that effect.

15) Successors; Assignments. Any company which succeeds by purchase, merger, or consolidation of title to all or substantially all of the assets of a Party will be entitled to the rights and will be subject to the obligations of such Party in title under this Restated Precedent Agreement, and in such respect, no consent to such an assignment shall be required from the other Party. In addition, this Restated Precedent Agreement is assignable in whole or in part without the prior written consent of the Customer: (a) by Pipeline or either DTE or Spectra to either or both of: (i) NEXUS Gas Transmission, LLC; and (ii) NEXUS Gas Transmission Canada; (b) by Pipeline to any joint venture or similar collaborative entity created between DTE and Spectra, provided such entity is created for the sole purpose of advancing the Project (it being understood that it is the intention of DTE and Spectra to establish pipeline companies in the name of NEXUS Gas Transmission, LLC and NEXUS Gas Transmission Canada, or another joint venture or similar collaborative, to advance the Project); or (c) between DTE and Spectra, in respect of each Party's interests in the Project. Otherwise, neither Customer nor Pipeline may assign any of its rights or obligations under this Restated Precedent Agreement without the prior written consent of the other Party hereto, such consent not to be unreasonably withheld. Notwithstanding the foregoing, Pipeline shall have the right, without obtaining Customer's consent, to pledge or assign its rights under this Restated Precedent Agreement, the Phase II Service Agreement or the Phase II Rate Agreement as collateral security for indebtedness incurred by Pipeline (or by an affiliate of Pipeline) for the Project.

16) No Third-Party Rights. Except as expressly provided for in this Restated Precedent Agreement, nothing herein expressed or implied is intended or shall be construed to confer

upon or give to any person not a Party hereto any rights, remedies or obligations under or by reason of this Restated Precedent Agreement.

17) Joint Efforts: No Presumptions. Each and every provision of this Restated Precedent Agreement shall be considered as prepared through the joint efforts of the Parties and shall not be construed against either Party as a result of the preparation or drafting thereof. It is expressly agreed that no consideration shall be given or presumption made on the basis of who drafted this Restated Precedent Agreement or any specific provision hereof.

18) Recitals and Representations. The recitals and representations appearing first above are hereby incorporated in and made a part of this Restated Precedent Agreement.

19) Choice of Law. This Restated Precedent Agreement shall be governed by, construed, interpreted, and performed in accordance with the laws of the State of Ohio, without recourse to any laws governing the conflict of laws.

20) Notices. Except as herein otherwise provided, any notice, request, demand, statement, or bill provided for in this Restated Precedent Agreement, or any notice which either Party desires to give to the other, must be in writing and will be considered duly delivered when mailed by registered or certified mail or overnight courier or when provided by personal delivery or electronic mail to the other Party's address set forth below:

Pipeline: Vice President, Business Development
5400 Westheimer Court
Houston, TX 77056
brmckerlie@spectraenergy.com
Phone – (713) 627-4582
Fax – (713) 627-4727

Customer: Director, Energy Supply and Policy
500 Consumers Road
North York, Ontario
M1K 5E3
Jamie.LeBlanc@enbridge.com
Phone - (416) 495-5241
Fax - (416) 495-6072

or at such other address as either Party designates by written notice. Routine communications, including monthly statements, will be considered duly delivered when mailed by registered mail, certified mail, ordinary mail, or overnight courier or when provided by electronic mail to the person and at the addresses noted above or as otherwise designated pursuant to this Section 20.

21) Waivers. The waiver by either Party of a breach or violation of any provision of this Restated Precedent Agreement will not operate as or be construed to be a waiver of any subsequent breach or violation hereof.

22) Counterparts. This Restated Precedent Agreement may be executed in any number of counterparts, each of which will be an original, but such counterparts together will constitute one and the same instrument.

23) Headings. The headings contained in this Restated Precedent Agreement are for reference purposes only and shall not affect the meaning or interpretation of this Restated Precedent Agreement.

24) Governmental Authorizations. Notwithstanding any provision to the contrary, each provision of this Restated Precedent Agreement shall be subject to all applicable laws, statutes, ordinances, regulations, rules, court decisions and Governmental Authorizations.

25) Definitions. Capitalized terms used herein have the meanings ascribed to them in the body of this Restated Precedent Agreement, and for the purposes of reference only are listed in Exhibit F attached hereto.

[signature page follows]

IN WITNESS WHEREOF, the Parties hereto have caused this Restated Precedent Agreement to be duly executed by their duly authorized officers as of the day and year first above written.

DTE PIPELINE COMPANY	ENBRIDGE GAS DISTRIBUTION, INC.
By: (Original Signed By David Slater)	By: (Original Signed By Glen Beaumont)
Title: President	Title President

SPECTRA ENERGY TRANSMISSION, LLC

By: (Original Signed By William T. Yardley)	(Original Signed By James Lord)
Title President, US Transmission and Storage	Vice President, Law &Information Technology

EXECUTION VERSION

EXHIBIT A

Form of Service Agreement

See Attached.

FORM OF FIRM TRANSPORTATION AGREEMENT
TRANSPORTATION AGREEMENT
FOR FIRM TRANSPORTATION (FT-1) OF NATURAL GAS

Firm Transportation Agreement No. ____________

This TRANSPORTATION AGREEMENT FOR FIRM TRANSPORTATION OF NATURAL GAS ("Firm Transportation Agreement" or "Agreement") is made and entered into this ____ day of ____________, ______, between:

("Transporter"),

and

____________, ("Shipper")

WITNESSETH: That in consideration of the mutual covenants contained herein the parties agree as follows:

Section 1. Service to be Rendered

Transporter shall perform and Shipper shall receive service in accordance with the provisions of Transporter's effective Rate Schedule FT-1 and the applicable General Terms and Conditions of Transporter's FERC Gas Tariff on file with the Federal Energy Regulatory Commission ("Commission") as the same may be amended or superseded in accordance with the Rules and Regulations of the Commission.

Section 2. Representations and Warranties

2.1 Representations and Warranties of Transporter: Transporter represents and warrants that: (i) it is duly organized and validly existing under the laws of the State of Delaware and has all requisite legal power and authority to execute this Agreement and carry out the terms, conditions and provisions thereof; (ii) this Agreement constitutes the valid, legal and binding obligation of Transporter, enforceable in accordance with the terms hereof; (iii) there are no actions, suits or proceedings pending or, to Transporter's knowledge, threatened against or affecting Transporter before any court of authorities that might materially adversely affect the ability of Transporter to meet and carry out its obligations under this Agreement; and (iv) the execution and delivery by Transporter of this Agreement has been duly authorized by all requisite partnership action.

2.2 Representations and Warranties of Shipper: Shipper represents and warrants that: (i) it is duly organized and validly existing under the laws of the State/Province of _____________ and has all requisite legal power and authority to execute this Agreement and carry out the terms, conditions and provisions hereof; (ii) there are no actions, suits or proceedings pending, or to Shipper's knowledge, threatened against or affecting Shipper before any court or authorities that might materially adversely affect the ability of Shipper to meet and carry out its obligations under this Agreement; and (iii) the execution and delivery by Shipper of this Agreement has been duly authorized by all requisite corporate action.

Section 3. Term

3.1 This Agreement shall be effective from the date hereof (the "Effective Date"). Transporter's obligation to provide Transportation Services and Shipper's obligation to accept and pay for such services, shall commence on _____________ for a term of _____________, unless otherwise agreed to by mutual agreement of the parties.

3.2 Shippers paying Negotiated Rates may extend the term of this Agreement under terms acceptable to Transporter.

Section 4. Rates

4.1 [Shipper shall pay the Recourse Rates in accordance with Transporter's currently effective Rate Schedule FT-1.]

OR

[Shipper shall pay Negotiated Rates in accordance with Transporter's currently effective Rate Schedule FT-1.]

Section 5. Notices

Unless herein provided to the contrary, any notice called for in this Agreement shall be in writing and shall be considered as having been given if delivered by certified mail or fax with all postage or charges prepaid, to either Transporter or Shipper, at the location designated herein. Written communications shall be considered as duly delivered when received by ordinary mail. Unless otherwise notified in writing, the addresses of the parties are as set forth herein.

Notices to Transporter under this Agreement shall be addressed to

Notices to Shipper under this Agreement shall be addressed to:

____
____
____
____
____

Wire transfer payments to Transporter shall be accompanied with the instructions "to credit the account of " " and shall be sent to the following bank and account number:

c/o:______________________________
____
____
____

Remittance detail supporting wire transfer payments to Transporter, and any notice, request or demand regarding statements, bills, or payments shall be mailed to the following address:

Section 6. Superseded Agreements

This Agreement supersedes and cancels as of the effective date hereof the following agreements: ________________, ________________.

Section 7. Miscellaneous

7.1 This Agreement shall be interpreted according to the laws of the State of

7.2 Performance of this Agreement shall be subject to all valid laws, orders, decisions, rules and regulations of duly constituted governmental authorities having jurisdiction or control of any matter related hereto. Should either of the parties, by force of any such law, order, decision, rule or regulation, at any time during the term of this Agreement be ordered or required to do any act inconsistent with the provisions hereof, then for the period during which the requirements of such law, order, decision, rule or regulation are applicable, this Agreement shall be deemed modified to conform with the requirement of such law, order, decision, rule or regulation; provided, however, nothing in this section 7.2 shall alter, modify or otherwise affect the respective rights of the parties to cancel or terminate this Agreement under the terms and conditions hereof.

7.3 A waiver by either party of any one or more defaults by the other hereunder shall not operate as a waiver of any future default or defaults, whether of a like or of a different character.

7.4 This Agreement may only be amended by an instrument in writing executed by both parties hereto.

7.5 Nothing in this Agreement shall be deemed to create any rights or obligations between the parties hereto after the expiration of the term set forth herein, except that termination of this Agreement shall not relieve either party of the obligation to correct any quantity imbalances or Shipper of the obligation to pay any amounts due hereunder to Transporter.

7.6 Exhibit A attached hereto is incorporated herein by reference and made a part hereof for all purposes.

7.7 The parties hereby agree, subject to the primary jurisdiction of the Commission, that any dispute arising out of or relating to this Agreement, or any breach thereof shall be submitted to final and binding arbitration in _____, _____, in accordance with the Rules of Commercial Arbitration of the American Arbitration Association (AAA) then in effect. The dispute shall be decided by a panel of three neutral arbitrators, qualified by education, training, and experience to hear the dispute, chosen as follows. The party initiating the arbitration proceeding shall name one arbitrator at the time it notifies the other party of its intention to arbitrate their dispute, and the responding party shall name an arbitrator within fifteen (15) days of receiving the above notification. Within twenty (20) days of the appointment of the second arbitrator, the two arbitrators shall select a third arbitrator to act as chairman of the tribunal. If either party fails to appoint an arbitrator within the allotted time or the two party-appointed, neutral arbitrators fail to appoint a third arbitrator as provided above, the AAA shall appoint the arbitrator(s). Any vacancies will be filled in accordance with the above procedure. The parties expressly agree to the consolidation of separate arbitral proceedings for the resolution in a single proceeding of all disputes that arise from the same factual situation, and the parties further expressly agree that any issue of arbitrability or the existence, validity, and scope of the agreement to arbitrate shall be decided by the arbitrators. The parties further agree that either party may apply to a court of competent jurisdiction, pending arbitration, for injunctive relief to preserve the status quo, to preserve assets, or to protect documents from loss or destruction, and such application will not be deemed inconsistent with or operate as a waiver of the party's right to arbitration. The arbitrators shall apply as the substantive law to the dispute the laws of the State of _____ as specified in section 7.1 of this Agreement.

Section 8. <u>Negotiable Terms</u>

Transporter and Shipper mutually agree to the following terms and conditions of service under this Agreement. Where blank spaces are not filled in, the parties have not reached an agreement on that matter and the referenced provision of the General Terms and Conditions (GT&C) applies.

Pursuant to GT&C section , the following rate discount(s) apply:

____

____.

IN WITNESS WHEREOF, the parties hereto have duly executed this Agreement in one or more counterparts, which counterparts shall constitute one integrated agreement, by their duly authorized officers effective as of the day first above written.

Date:________________________ By:________________________________

Title:_______________________________

SHIPPER:___________________________

Date:________________________ By:________________________________

Title:_______________________________

Exhibit A
To
Firm Transportation Agreement No. _______
Under Rate Schedule FT-1 Between
and ____________________

Primary Term:	________________
Contracted Capacity:	________________ **Dth/Day**
Primary Receipt Points:	________________
Primary Delivery Points:	________________
Rate Election (Recourse or Negotiated):	________________

EXHIBIT B

Intentionally Left Blank.

EXHIBIT C

Capital Cost Tracking Adjustment for Statement of Negotiated Rates

New US Phase II Facilities

Capital Cost Estimate U.S. Pipeline and Customer acknowledge that the capital costs attributable to the construction of the Phase II Facilities that are required to be constructed and owned by Pipeline or constructed and owned by third parties on third party owned existing pipeline systems for the provision of Customer's Phase II Service (the "**New US Phase II Facilities**"), which capital costs will underlie a portion of the Reservation Rate for Customer's Phase II Service are reasonably estimated to be $1,625,000,000.00 (U.S.). In accordance with Section 3(d)(ii)(3) of the Restated Precedent Agreement, Pipeline will deliver to Customer a final capital cost estimate (the "**Final U.S. Capital Cost Estimate**") for the New US Phase II Facilities, which estimate will underlie a portion of the Final Reservation Rate (as defined in Section 3(d)(ii)(3) of the Restated Precedent Agreement) for Customer's Phase II Service (as further described in the final revised Rate Breakdown to be provided by Pipeline to Customer in accordance with Section 3(d)(ii)(3)). The Final U.S. Capital Cost Estimate will be provided substantially in the same form as an Exhibit K – Cost of Facilities (as defined in the Federal Energy Regulatory Commission's Code of Federal Regulations) ("**Exhibit K**") and will be included with the certificate application filed by Pipeline with the Federal Energy Regulatory Commission ("**Commission**") for Phase II of the Project.

Negotiated Reservation Rate Adjustment. The Final Reservation Rate will be adjusted, pursuant to the provisions set forth herein, to reflect any differences between the Final U.S. Capital Cost Estimate and the actual amount of capital costs attributable to the New US Phase II Facilities, as reflected by Pipeline in an updated cost report for the New US Phase II Facilities, substantially in the form of Exhibit K (the "**Actual U.S. Capital Cost**"). Pipeline will file such Actual U.S. Capital Cost report with the Commission at least thirty (30) days, but not more than sixty (60) days, prior to the Phase II Service Commencement Date.

Pipeline will adjust such portion of the Final Reservation Rate attributable to the New US Phase II Facilities (the "**New U.S. Facility Rate Portion**") to reflect the percentage increase or decrease between the Actual U.S. Capital Cost and the Final U.S. Capital Cost Estimate. In the event that the Actual U.S. Capital Cost exceeds the Final U.S. Capital Cost Estimate, the New U.S. Facility Rate Portion of the Final U.S. Reservation Rate will be adjusted upward by multiplying it to the ratio of the Actual U.S. Capital Cost to the Final U.S. Capital Cost Estimate; provided that if the Actual U.S. Capital Cost exceeds the Final U.S. Capital Cost Estimate by more than 15%, then the multiplier to the New U.S. Facility Rate Portion will be 1.15. In the event that the Actual U.S. Capital Cost is less than the Final U.S. Capital Cost Estimate, the New U.S. Facility Rate Portion of the Final Reservation Rate will be adjusted downward by multiplying it to the ratio of the Actual U.S. Capital Cost to the Final U.S. Capital Cost Estimate; provided that if the Actual U.S. Capital Cost is less than the Final U.S. Capital Cost Estimate by more than 15%, then the multiplier to the New U.S. Facility Rate Portion will be .85.

Recourse Reservation Rate Adjustment. In the case of an upward adjustment to the Final Reservation Rate, Pipeline will file the Actual U.S. Capital Cost report, together with an adjusted recourse rate applicable to transportation service for Phase II, with the Commission at least thirty (30) days, but no more than sixty (60) days, prior to the Phase II Service Commencement Date. In the case of a downward adjustment to the Final Reservation Rate, Pipeline has the right, but not any obligation, to prepare and file such Actual U.S. Capital Cost report and/or an adjustment to the recourse rate applicable to transportation service for Phase II with the Commission.

True-Up. No later than 210 days after the Phase II Service Commencement Date, Pipeline will file with the Commission an adjustment to Customer's then-effective adjusted Reservation Rate to reflect any increase or decrease between the Final U.S. Capital Cost Estimate and the final actual U.S. capital costs ("**Final Actual U.S. Capital Costs**") as set forth in Pipeline's post-construction cost report filed with the Commission pursuant to Part 157.20(c)(3) of Title 18 of the Code of Federal Regulations. In the event that the adjusted Reservation Rate decreases because the Final Actual U.S. Capital Costs are less than the Final U.S. Capital Cost Estimate, Pipeline will refund Customer an amount (including interest at the Commission's approved interest rate pursuant to 18 C.F.R. §154.501, hereafter the "FERC Interest Rate") equal to the difference between such rates for the time period that Customer paid the higher rate. In the event that the adjusted Reservation Rate increases because the Final Actual U.S. Capital Costs are more than the Final U.S. Capital Cost Estimate, Customer will pay Pipeline an amount (including interest at the FERC Interest Rate) equal to the difference between such rates for the time period that Customer paid such lower rate.

Cost Reports. Pipeline will prepare the Actual U.S. Capital Cost report in accordance with Section 157.14(a)(13) of Title 18 of the Code of Federal Regulations. Such report will reflect Pipeline's reasonable good faith estimate at the time of the total capital costs attributable to New US Phase II Facilities as constructed. Pipeline will prepare the Final Actual U.S. Capital Cost report in accordance with Section 157.14(a)(13) of Title 18 of the Code of Federal Regulations. Such report will reflect Pipeline's final actual capital costs attributable to the New US Phase II Facilities as constructed.

EXECUTION VERSION

EXHIBIT D

Form of Guarantee

See Attached.

GUARANTY

This Guaranty ("Guaranty"), dated as of ____________, is made by ____________________, a [state and corporate structure] ("Guarantor"), in favor of ____________ a [state & corporate structure] ("Beneficiary").

WHEREAS, from time to time, ______________, a ______________ [state and corporate structure] ("Counterparty"), and Beneficiary may enter into one or more contracts, agreements and commitments for the storage or transportation of natural gas (referred collectively as "Agreement");

WHEREAS, Counterparty is a wholly-owned subsidiary of Guarantor; and Guarantor will directly or indirectly benefit from the Agreement to be entered into between Counterparty and Beneficiary; and

WHEREAS, as an inducement to Beneficiary to enter into the Agreement, Guarantor has agreed to provide this Guaranty; and

WHEREAS, Guarantor has agreed to execute and deliver this Guaranty with respect to Counterparty's payment obligations under the Agreement:

NOW THEREFORE, in consideration of the premises, Guarantor hereby agrees as follows:

1. Guaranty. Guarantor hereby absolutely, irrevocably and unconditionally guarantees the timely payment when due of Counterparty's payment obligations arising under any Agreement, as such Agreement may be amended or modified from time to time, together with any interest thereon and fees and costs of collection (including attorney's fees and court costs) in connection therewith ("Obligation"). In the event Counterparty defaults in the payment of any of the Obligation, within ten (10) days after receiving written notice from Beneficiary, Guarantor shall make such payment or otherwise cause same to be paid. This Guaranty may be enforced by Beneficiary at any time without the necessity of first resorting to or exhausting any other security or collateral. All amounts payable by Guarantor hereunder shall be in freely transferable funds.

2. Effectiveness. This Guaranty is effective as of the date set forth above and is a continuing guaranty which shall remain in full force and effect throughout the term of the Agreement, including any extensions or renewals thereof, until Guarantor has completely fulfilled the Obligation. If at any time during the effectiveness of this Guaranty, Guarantor no longer qualifies as Creditworthy as defined in Paragraph XX of that certain precedent agreement between Counterparty and Beneficiary dated _____ ("Precedent Agreement"), Guarantor shall, or shall cause Counterparty to, immediately provide the collateral specified in Paragraph XX(X) of the Precedent Agreement.

3. Waivers. (a) Guarantor waives any right to require as a condition to its obligations hereunder any of the following should Beneficiary seek to enforce the obligations of Guarantor:

(i) presentment, demand for payment, notice of dishonor or non-payment, protest, notice of protest, or any similar type of notice;

(ii) any suit be brought against, or any other action be brought against, or any notice of default or other similar notice be given to, or any demand be made upon Counterparty or any other person or entity;

(iii) notice of acceptance of this Guaranty, of the creation or existence of the Obligation, and/or any action by Beneficiary in reliance hereon or connection herewith;

(iv) notice of entering into any Agreement between Counterparty and Beneficiary, and/or any amendments, supplements or modifications thereto, or any waiver of consent under any Agreement, including waiver of the payment and performance of the Obligation thereunder; and/or

(v) notice of any increase, reduction or rearrangement of Counterparty's Obligation under any Agreement, or any extension of time for payment of any amounts due Beneficiary under any Agreement.

(b) Guarantor also waives the right to require, substantively or procedurally, that a judgment has been previously rendered against Counterparty or any other person or entity, or that Counterparty or any other person or entity be joined in any action against Guarantor.

4. Assignment. Guarantor shall not assign its duties hereunder without the prior written consent of Beneficiary. Beneficiary shall be entitled to assign its rights hereunder in its sole discretion upon prior written notice to Guarantor. Any assignment without such prior written consent or notice, as applicable, shall be null and void and of no force or effect.

5. Notice. All demands, notices or other communications to be given by any party to another must be in writing and shall be deemed to have been given when delivered personally or otherwise actually received or on the third (3rd) day after being deposited in the United States mail if registered or certified, postage prepaid, or one (1) day after delivery to a nationally recognized overnight courier service, fee prepaid, return receipt requested, and addressed as follows:

Guarantor's Name & Address	Beneficiary's Name & Address
____________________	____________________
____________________	____________________
____________________	____________________
____________________	____________________
____________________	____________________
	____________________

or such other addresses as they may change from time to time by giving prior written notice to the other party.

6. Applicable Law. THIS GUARANTY SHALL IN ALL RESPECTS BE GOVERNED BY, ENFORCED UNDER AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF ____________.

7. Effect of Certain Events. Guarantor agrees that its liability hereunder will not be released, reduced, impaired or affected by the occurrence of any one or more of the following events:

(i) the insolvency, bankruptcy, reorganization, or disability of Counterparty;

(ii) the renewal, consolidation, extension, modification or amendment from time to time of the Agreement;

(iii) the failure, delay, waiver, or refusal by Beneficiary to exercise any right or remedy held by Beneficiary with respect to the Agreement;

(iv) the sale, encumbrance, transfer or other modification of the ownership of Counterparty or the change in the financial condition or management of Counterparty; or

(v) the settlement or compromise of any Obligation.

8. Representations and Warranties. Guarantor hereby represents and warrants the following:

(i) Guarantor is duly organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation and has full corporate power to execute, deliver and perform this Guaranty;

(ii) the execution, delivery and performance of this Guaranty have been and remain duly authorized by all necessary corporate action and do not contravene Guarantor's constitutional documents or any contractual restriction binding on Guarantor or its assets; and

(iii) this Guaranty constitutes the legal, valid and binding obligation of Guarantor enforceable against Guarantor in accordance with its terms, subject, as to enforcement, to bankruptcy, insolvency, reorganization and other similar laws and to general principles of equity.

9. Subrogation. Until all amounts which may be or become payable under the Agreement have been irrevocably and indefeasibly paid in full, Guarantor shall not by virtue of this Guaranty be subrogated to any rights of Counterparty or claim in competition with Beneficiary against Counterparty in connection with any matter relating to or arising from the Obligation or this Guaranty. If any amount shall be paid to Guarantor on account of such subrogation rights at any time before all of the Obligation has been irrevocably paid in full, such amounts shall be held in trust for the benefit of Beneficiary and shall promptly be paid to Beneficiary to be applied to the Obligation.

10. Amendment. No term or provision of this Guaranty shall be amended, modified, altered, waived, supplemented or terminated unless first agreed to by Guarantor and Beneficiary and then set forth in a written amendment to this Guaranty.

11. Counterparts. This Guaranty may be executed in any number of counterparts, each of which shall be deemed an original, but all of which together shall constitute one document.

12. Entire Agreement. This Guaranty embodies the entire agreement and understanding between Guarantor and Beneficiary regarding payment of the Obligation under the Agreement and supersedes all prior agreements and understandings relating to the subject matter hereof.

IN WITNESS WHEREOF, Guarantor has executed this Guaranty effective as of the date first herein written.

GUARANTOR' S NAME

By:______________________________

Name:____________________________

Title:_____________________________

EXECUTION VERSION

EXHIBIT E

Form of Letter of Credit

See Attached.

SPECIAL TERMS AND CONDITIONS

1. Partial and multiple drawings are allowed hereunder. The amount that may be drawn by Beneficiary under this Letter of Credit shall be automatically reduced by the amount of any payments made through Issuing Bank referencing this Letter of Credit.

2. This Letter of Credit shall automatically extend without amendment for periods of one year each from the present or any future expiry date unless Issuing Bank notifies Beneficiary in writing at least sixty (60) days prior to such present or future expiry date, as applicable, that Issuing Bank elects not to further extend this Letter of Credit.

3. This Letter of Credit is transferable without charge any number of times, but only in the amount of the full unutilized balance hereof and not in part and with the approval of Account Party which consent shall not be unreasonably withheld, conditioned or delayed.

4. The term "Beneficiary" includes any successor by operation of law of the named beneficiary to this Letter of Credit, including, without limitation, any liquidator, any rehabilitator, receiver or conservator.

5. Presentations for drawing may be delivered in person, by mail, by express delivery, or by facsimile.

6. All Bank charges are for the account of Account Party.

7. Article 36 under UCP 600 is modified as follows: If the Letter of Credit expires while the place for presentation is closed due to events described in said Article, the expiry date of this Letter of Credit shall be automatically extended without amendment to a date thirty (30) calendar days after the place for presentation reopens for business.

Issuing Bank hereby agrees with Beneficiary that documents presented for drawing in compliance with the terms of this Letter of Credit will be duly honored upon presentation at Issuing Bank's counters if presented on or before the expiry date.

Unless otherwise expressly stated herein, this Letter of Credit is subject to the Uniform Customs and Practice for Documentary Credits ("UCP"), 2007 Revision, International Chamber of Commerce Publication No. 600. Matters not covered by the UCP shall be governed and construed in accordance with the laws of the state of New York.

ISSUING BANK SIGNATURE

q) **"Force Majeure"** has the meaning ascribed to that term in Section 9(c).

r) **"Forms of Commercial Agreements"** has the meaning ascribed to that term in Section 3(b).

s) **"Governmental Authorizations"** has the meaning ascribed to that term in Section 1(a).

t) **"Greenfield Facilities – Kensington to Willow Run"** has the meaning ascribed to that term in Section 2(d)(i)(1).

u) **"Guarantor"** has the meaning ascribed to that term in Section 13(b)(i).

v) **"Guaranty"** has the meaning ascribed to that term in Section 13(b)(i).

w) **"In-Service Date Notice"** has the meaning ascribed to that term in Section 4(b).

x) **"Initial Receipt Point Information"** has the meaning ascribed to that term in Section 1(c).

y) **"International Border"** has the meaning ascribed to that term in the recitals.

z) **"Letter of Credit"** has the meaning ascribed to that term in Section 13(b)(ii).

aa) **"MDDO"** has the meaning ascribed to that term in Section 3(b).

bb) **"MDRO"** has the meaning ascribed to that term in Section 3(b).

cc) **"MDQ"** has the meaning ascribed to that term in Section 3(b).

dd) **"Moody's"** has the meaning ascribed to that term in Section 13(a).

ee) **"NEB"** has the meaning ascribed to that term in Section 1(a).

ff) **"New Phase II Facilities"** means the Phase II Facilities that will be required to be constructed and owned by Pipeline or constructed and owned by a third party on third party owned existing pipeline systems for the provision of Customer's Phase II Service.

gg) **"Original Precedent Agreement"** has the meaning ascribed to that term in the recitals.

hh) **"Open Season"** has the meaning ascribed to that term in the recitals.

ii) "**OEB**" has the meaning ascribed to that term in Section 3(b).

jj) "**Party**" or "**Parties**" has the meaning ascribed to that term in the recitals.

kk) "**Phase I**" has the meaning ascribed to that term in the recitals.

ll) "**Phase II**" has the meaning ascribed to that term in the recitals.

mm) "**Phase II Facilities**" has the meaning ascribed to that term in Section 3(d)(ii)(2)

nn) "**Phase II Rate Agreement**" has the meaning ascribed to that term in Section 3(d)(ii)(3).

oo) "**Phase II Service Agreement**" has the meaning ascribed to that term in Section 3(b).

pp) "**Phase II Service Commencement Date**" has the meaning ascribed to that term in Section 4(b).

qq) "**Pipeline**" has the meaning ascribed to that term in the recitals.

rr) "**Pre-Service Costs**" has the meaning ascribed to that term in Section 8.

ss) "**Project**" has the meaning ascribed to that term in the recitals.

tt) "**Qualified Institution**" has the meaning ascribed to that term in Section 13(b)(ii).

uu) "**Rate Breakdown**" has the meaning ascribed to that term in Section 3(d)(ii)(3)

vv) "**Reservation Rate**" has the meaning ascribed to that term in Section 3(d)(i).

ww) "**Restated Precedent Agreement**" has the meaning ascribed to that term in the headings.

xx) "**Revised Phase II Rate**" has the meaning ascribed to that term in Section 3(d)(ii)(3).

yy) "**ROFR**" has the meaning ascribed to that term in Section 3(f).

zz) "**S&P**" has the meaning ascribed to that term in Section 13(a).

aaa) "**Spectra**" has the meaning ascribed to that term in the recitals.

bbb) "**Willow Run**" has the meaning ascribed to that term in the recitals.

EXECUTION VERSION

FIRST AMENDMENT TO RESTATED PRECEDENT AGREEMENT

This First Amendment ("Amendment") to the Restated Precedent Agreement dated December 17, 2014 between Enbridge Gas Distribution Inc., an Ontario corporation, (hereafter referred to as "Customer"), and Spectra Energy Transmission, LLC, a Delaware limited liability company ("Spectra") and DTE Pipeline Company, a Michigan corporation ("DTE") (Spectra and DTE are collectively referred to herein as "Pipeline") is effective June 3, 2015. Customer and Pipeline are sometimes referred to herein as a "Party" or collectively as the "Parties." Capitalized terms used but not defined herein have the meanings given to them in the PA (as the same is defined below).

WHEREAS, the Parties entered into that certain Restated Precedent Agreement ("PA") dated December 17, 2014 for the purpose of setting forth the terms and conditions according to which Customer would commit to, and Pipeline would provide to Customer, firm transportation service on the Project; and

WHEREAS, the Parties wish to amend the PA to reflect the terms and conditions for service on the Project to be provided by Pipeline to Customer.

NOW THEREFORE for good and valuable consideration, the receipt of which is acknowledged by all Parties hereto as sufficient and received, the Parties herby agree that the PA shall be amended as follows, effective as of the date indicated above:

1. The phase "Phase II" and all references thereto shall be deleted in each place where it is found in the PA. For these purposes, the term "Project" or the term "transportation" shall be substituted where the context may require to maintain the continuity and meaning of the statement; otherwise, the term shall simply be deleted.

2. The references to the "NEB" in the following sections shall be deleted: Section 1(d); Section 5; Section 7(b)(i); and Section 7(f).

3. The first WHEREAS clause is amended by the following: deleting the phrase "two-phased" in the first line; adding the words "up to" after the word "provide" in the first line; striking the words "one (1) billion" and replacing them with "one and one half (1.5) billion"; striking the words "or more" in the second line; and, in the seventh, eighth and ninth lines, deleting the words from "In Phase I" through "In Phase II,".

4. The second WHEREAS clause is amended by deleting the words "in phases, with Phase I to commence on or about November 1, 2015 and Phase II targeted to commence".

5. The third WHEREAS clause is amended by deleting the phase beginning with "pursuant to which" and through the end of the clause.

6. Section 3(b) is amended by inserting the following at the end of the third to last sentence: "provided that, for clarity, the Rate Agreement shall not be revised by Pipeline other than for the sole purpose of conforming the terms of the same with the terms of the NEXUS FERC Gas Tariff (when approved by FERC) and, to the extent not materially adverse to Customer within the context of its participation as a shipper in the Project, with the terms agreed to in rate agreements of other anchor shippers for the Project."

7. Section 3(d)(ii)(2) is deleted in its entirety and replaced with the following:

   The estimated Reservation Rates and fuel rates for service under the Service Agreement shall be set forth in the Rate Agreement provided in accordance with Section 3(d)(ii)(3) below. The estimated capital costs associated with the construction of the facilities necessary for Pipeline to provide Project service for Customer and all other customers subscribing Project service in the U.S. (the "Project Facilities") will be reflected in an estimate to be provided by Pipeline to Customer in accordance with Section 3(d)(ii)(3) below.

8. Section 3(d)(ii)(3) is deleted in its entirety and replaced with the following:

   Contemporaneously with the execution of the First Amendment to this Restated Precedent Agreement, Pipeline shall deliver to Customer the following: (a) the final rate agreement for the Service Agreement (the "Rate Agreement"), which shall include the final estimate of the Reservation Rate (the "Final Estimated Reservation Rate") (subject only to the Capital Cost Tracking Adjustment, as defined below) and estimated fuel rate; (b) a final breakdown of how Pipeline derived the Final Estimated Reservation Rate, including a breakdown of such portion of the Final Estimated Reservation Rate that is derived from the Final Capital Cost Estimate (as defined below) ("Rate Breakdown"); and (c) an estimate of the capital costs associated with the construction of the Project Facilities ("Final Capital Cost Estimate"). The Rate Agreement shall provide, consistent with Exhibit C, that the Final Estimated Reservation Rate shall be subject to an aggregate fifteen percent (+ / - 15%) capital cost tracking adjustment (as more particularly described in Exhibit C, the "Capital Cost Tracking Adjustment"). Pipeline and Customer shall hereafter execute the Rate Agreement as expeditiously as is practicable.

9. Section 3(d)(ii)(4) is deleted in its entirety.

10. Section 7(b)(i) is amended by replacing "2015" with "2016" in the first line.

11. Section 7(c)(ii) is deleted in its entirety and replaced with "*Intentionally left blank*".

12. Section 7(c)(iv) is deleted in its entirety and replaced with "*Intentionally left blank*".

13. Section 7(c)(v) is amended by adding the words "Subject to Section 7(d)" at the beginning of the section.

14. Add a new Section 7(c)(vii) stating as follows: "Subject to the other terms of this Restated Precedent Agreement, Customer acknowledges that it has received, prior to the Effective Date, the requisite internal corporate approvals for the performance of Customer's obligations under this Restated Precedent Agreement and other agreements related to the service contemplated hereunder."

15. Section 7(d) is amended by adding "7(c)(v)" after "7(c)(iii)" and by replacing the reference to "7(c)(iv)" with "7(c)(vi)".

16. Section 8 is amended by adding the word "material" added after "its' in the first line, and by adding the following after the sentence ending "or other remedies from Customer." and prior to the sentence beginning "If this Restated Precedent Agreement is terminated":

    Pipeline represents that no work to be conducted in relation to Pre-Service Costs will be conducted in Canada. In the event that Pipeline issues to Customer an invoice in relation to Pre-Service Costs work conducted in Canada, Pipeline shall separate the invoice between work performed in Canada and outside of Canada, identify on the invoice the number of days performing work in Canada (including travel days to/from Canada) and the physical location, indicating city and province, where the Canadian work was performed. Customer shall request from Pipeline the relevant documentation necessary to determine the appropriate withholding amount, if any, for tax purposes. In the event that taxes are withheld from the Pre-Service Costs paid by Customer, then Customer shall remit such withheld taxes to the applicable taxing authority and the Customer will provide to Pipeline, after the applicable calendar year end, Pipeline's U.S. Federal Form 1099, a comparable state form or Canadian Revenue Authority equivalent, if applicable, within the applicable statutory time frame. In the event that Customer is assessed for any non-resident withholding taxes payable, Pipeline agrees to forthwith reimburse Customer for such amount together with applicable interest and penalties, if any."

17. Section 9(a) is amended by adding the word "direct" before the word "result" in the last sentence, and by adding the word "material" prior to the word "breach" in the last sentence.

18. Section 9(c) is amended by adding the following, beginning prior to the period at the end of the first sentence, and ending prior to the words "Notwithstanding the foregoing,":

    , provided that such Party claiming Force Majeure shall give written notice of the suspension of such performance for this reason as soon as reasonably possible to the other Party and stating the date and extent of such suspension and the cause thereof. The Party whose obligations have been suspended as aforesaid shall resume the performance of such obligations as soon as reasonably possible after the removal of the cause and shall so notify, in writing, the other Party that the suspension has terminated.

19. Add a new Section 26, as follows: "Entire Agreement. This Restated Precedent Agreement and the other agreements contemplated herein to be executed and delivered by the Parties embody the complete agreement and understanding among the Parties with respect to the subject matter hereof and supersede and pre-empt any prior understandings, agreements (including, without limitation, the Original Precedent Agreement) or representations by or among the Parties, written or oral, which may have related to the subject matter hereof in any way."

20. Exhibit C is deleted in its entirety and replaced with the language set forth on Exhibit 1 to this Amendment.

21. Exhibit F is amended as follows:

a. Delete the following defined terms: (i) "Class III Estimate"; (ii) "Estimated Phase II Rate"; (iii) "New Phase II Facilities"; (iv) "Phase I"; (v) "Phase II"; (vi) "Revised Phase II Rate".

b. In respect of the defined term "Final Reservation Rate" add the words "Estimated" between "Final" and "Reservation Rate";

c. Add the following defined term: "**Exhibit K**" has the meaning ascribed to that term in the FERC regulations in Title 18 of the Code of Federal Regulations;

d. Add the following defined term: **"Final Reservation Rate"** has the meaning ascribed to that term in Exhibit C;

e. Add the following defined term: **"Final Capital Cost"** has the meaning ascribed to that term in Exhibit C;

f. Add the following defined term: **"Final Capital Cost Estimate"** has the meaning ascribed to that term in Section 3(d)(ii)(3);

g. Add the following defined term: **"Project Facilities Rate Portion"** has the meaning ascribed to that term in Exhibit C;

h. Add the following defined term: **"Updated Capital Cost"** has the meaning ascribed to such term in Exhibit C.

i. Add the following defined term: **"Updated Reservation Rate"** has the meaning ascribed to that term in Exhibit C;

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK]

IN WITNESS WHEREOF, the Parties have caused their duly authorized representatives to execute this Amendment, effective as of the date first above written.

ENBRIDGE GAS DISTRIBUTION INC.:

BY: (Original Signed)

NAME: Malini Giridhar

TITLE: Vice President, Gas Supply & Business Development

BY: (Original Signed)

NAME: Glen Beaumont

TITLE: President

SPECTRA ENERGY TRANSMISSION, LLC

BY: (Original Signed)

NAME: William T. Yardley

TITLE: President

DTE PIPELINE COMPANY

BY: (Original Signed)

NAME: David Slater

TITLE: President

Exhibit 1

REPLACEMENT EXHIBIT C TO RESTATED PRECEDENT AGREEMENT

Capital Cost Tracking Adjustment for Statement of Negotiated Rates

Project Facilities

Pipeline and Customer acknowledge that the capital costs attributable to the Project Facilities, which capital costs will underlie a portion of the Reservation Rate for firm transportation service for the Project, will be reflected in the Final Capital Cost Estimate to be provided to Customer by Pipeline in accordance with Sections 3(d)(ii)(2) and 3(d)(ii)(3).

Negotiated Reservation Rate Adjustment

The Final Estimated Reservation Rate will be adjusted, pursuant to the provisions set forth herein, to reflect any differences between the Final Capital Cost Estimate and the actual amount of capital costs attributable to the Project Facilities.

Pipeline will adjust the portion of the Final Estimated Reservation Rate attributable to the Project Facilities as set forth in the final Rate Breakdown (the "**Project Facilities Rate Portion**") at least thirty (30) days, but not more than sixty (60) days, prior to the Service Commencement Date. The adjustment to the Project Facilities Rate Portion will be based on a comparison between the Final Capital Cost Estimate and an updated cost report prepared by Pipeline and provided to Customer which updates the estimate of the capital costs for the Project Facilities, substantially in the form of an Exhibit K (the "**Updated Capital Cost**"). Pipeline will file such Updated Capital Cost report with the Federal Energy Regulatory Commission ("Commission") at least thirty (30) days, but not more than sixty (60) days, prior to the Service Commencement Date.

In making the adjustment described above, Pipeline will adjust the Project Facilities Rate Portion to reflect the percentage increase or decrease between the Updated Capital Cost and the Final Capital Cost Estimate. In the event that the Updated Capital Cost exceeds the Final Capital Cost Estimate, the Project Facilities Rate Portion of the Final Estimated Reservation Rate will be adjusted upward by multiplying it to the ratio of the Updated Capital Cost to the Final Capital Cost Estimate; provided that, notwithstanding any other provision contained herein, if the Updated Capital Cost exceeds the Final Capital Cost Estimate by more than 15%, then the multiplier to the Project Facilities Rate Portion will be 1.15. For the avoidance of doubt, in any event, the maximum upward adjustment to the Project Facilities Rate Portion shall be capped at 1.15 of what was set forth in the Rate Breakdown for the Project Facilities Rate Portion provided by Pipeline pursuant to Section 3(d)(ii)(3). In the event that the Updated Capital Cost is less than the Final Capital Cost Estimate, the Project Facilities Rate Portion of the Final Estimated Reservation Rate will be adjusted downward by multiplying it to the ratio of the Updated

Capital Cost to the Final Capital Cost Estimate; provided that, notwithstanding any other provision contained herein, if the Updated Capital Cost is less than the Final Capital Cost Estimate by more than 15%, then the multiplier to the Project Facilities Rate Portion will be .85. For the avoidance of doubt, in any event, the maximum downward adjustment to the Project Facilities Rate Portion shall be capped at .85 of what was set forth in the Rate Breakdown for the Project Facilities Rate Portion provided by Pipeline pursuant to Section 3(d)(ii)(3). The reservation rate resulting from the adjustment provided for in this paragraph shall be the "**Updated Reservation Rate**".

Pipeline will make a final adjustment to the Project Facilities Rate Portion no later than 210 days after the Service Commencement Date. In making the final adjustment, Pipeline shall prepare and provide to Customer a final cost report which sets forth the actual capital costs for the Project Facilities, substantially in the form of an Exhibit K ("**Final Capital Cost**"). In the event the Final Capital Cost exceeds the Updated Capital Cost, then the Project Facilities Rate Portion of the Updated Reservation Rate will be adjusted by multiplying the Project Facilities Rate Portion of the Final Estimated Reservation Rate to the ratio of the Final Capital Cost to the Final Capital Cost Estimate; provided that, in any event, the maximum upward adjustment to the Project Facilities Rate Portion shall be capped at 1.15 of what was set forth in the Rate Breakdown for the Project Facilities Rate Portion provided by Pipeline pursuant to Section 3(d)(ii)(3). In the event the Final Capital Cost is less than the Updated Capital Cost, then the Project Facilities Rate Portion of the Updated Reservation Rate will be adjusted by multiplying the Project Facilities Rate Portion of the Final Estimated Reservation Rate to the ratio of the Final Capital Cost to the Final Capital Cost Estimate; provided that, in any event, the maximum downward adjustment to the Project Facilities Rate Portion shall be capped at .85 of what was set forth in the Rate Breakdown for the Project Facilities Rate Portion provided by Pipeline pursuant to Section 3(d)(ii)(3). The reservation rate resulting from the adjustment provided for in this paragraph shall be the "**Final Reservation Rate**".

In the event that the adjusted Reservation Rate decreases because the Final Capital Cost is less than the Updated Capital Cost, Pipeline will refund Customer an amount (including interest at the Commission's approved interest rate pursuant to 18 C.F.R. §154.501, hereafter the "**FERC Interest Rate**") equal to the difference between the revenue received from Customer for the time period that Customer paid the Updated Reservation Rate and the revenue that Pipeline would receive for such time period had Customer paid the Final Reservation Rate. In the event that the adjusted Reservation Rate increases because the Final Capital Cost is more than the Updated Capital Cost, Customer will pay Pipeline an amount (including interest at the FERC Interest Rate) equal to the difference between the revenue received from Customer for the time period that Customer paid the Updated Reservation Rate and the revenue that Pipeline would have received for the time period had Customer paid the Final Reservation Rate.

Recourse Reservation Rate Adjustment

In the case of an upward adjustment to the Final Estimated Reservation Rate, Pipeline will file the Updated Capital Cost report, together with an adjusted recourse rate applicable to transportation service for the Project, with the Commission at least thirty (30) days, but no more than sixty (60) days, prior to the Service Commencement Date. In the case of a downward adjustment to the Final Estimated Reservation Rate, Pipeline has the right, but not any obligation, to prepare and file such Updated Capital Cost report and/or an adjustment to the recourse rate applicable to transportation service for the Project with the Commission.

Cost Reports

Pipeline will prepare the Updated Capital Cost report in accordance with Section 157.14(a)(13) of Title 18 of the Code of Federal Regulations. Such report will reflect Pipeline's reasonable good faith estimate at the time of the total capital costs attributable to Project Facilities as constructed. Pipeline will prepare the Final Capital Cost report in accordance with Section 157.14(a)(13) of Title 18 of the Code of Federal Regulations. Such report will reflect Pipeline's actual capital costs attributable to the Project Facilities as constructed.

EXECUTION VERSION

RESTATED PRECEDENT AGREEMENT

This RESTATED PRECEDENT AGREEMENT ("Restated Precedent Agreement") is made and entered into this __ day of December, 2014 ("Effective Date"), by and between DTE Pipeline Company, a Michigan corporation ("DTE"), and Spectra Energy Transmission, LLC, a Delaware limited liability company ("Spectra") (DTE and Spectra are collectively referred to herein as "Pipeline"), and Enbridge Gas Distribution Inc., an Ontario corporation ("Customer"). Pipeline and Customer are sometimes referred to individually as a "Party" and collectively as the "Parties."

W I T N E S S E T H:

WHEREAS, Pipeline is proposing a ~~two-phased~~ project that will ultimately provide up to approximately one and one half (~~1~~1.5) billion cubic feet per day ~~or more~~ of firm transportation service for natural gas production from the Appalachian production areas, including but not limited to the Utica Shale and Marcellus Shale production areas in Ohio and Pennsylvania, to the international border between the United States and Canada near St. Clair, Michigan (the "International Border") and continuing from the International Border to Dawn, Ontario ("Dawn"). ~~In Phase I, Pipeline will provide firm transportation service from Willow Run, Michigan ("Willow Run") to Dawn utilizing subscriptions of firm pipeline capacity on existing pipeline systems ("Phase I"). In Phase II,~~ Pipeline will construct an approximately 250-mile greenfield pipeline extending from points expected to be located at or near Kensington, Ohio to various interconnections in the State of Michigan, utilizing subscriptions of firm pipeline capacity on existing U.S. pipeline systems to transport to the International Border, and thereafter from the International Border to point(s) of delivery in or near Dawn, utilizing one or more of:

subscriptions of firm pipeline capacity on existing Canadian pipeline systems, an expansion of the existing Vector Canada and/or Union Canadian pipeline systems, and/or construction of greenfield pipeline facilities ~~("Phase II")~~ (the services and subscriptions contemplated herein and the facilities that Pipeline intends to construct (or use reasonable efforts to cause others to construct) and/or subscribe to provide such services are collectively referred to herein as the "Project");

WHEREAS, Pipeline is proposing to commence service for the Project ~~in phases, with Phase I to commence on or about November 1, 2015 and Phase II targeted to commence~~ on or about November 1, 2017;

WHEREAS Customer, based on its qualifying bid submitted in the Open Season conducted by Pipeline from October 15, 2012 through November 30, 2012 ("Open Season"), entered into a Precedent Agreement with Pipeline dated June 5, 2014, as amended on July 31, 2014, (the "Original Precedent Agreement") ~~pursuant to which Pipeline agreed to construct certain pipeline facilities and to provide the services in respect of Phase I and Phase II to Customer and Customer agreed to pay for such service(s) in respect of Phase I and Phase II, all subject to various conditions precedent set forth in the Original Precedent Agreement~~;

WHEREAS, pursuant to the terms of the Original Precedent Agreement, Customer notified Pipeline that it did not obtain the approval contemplated in Section 7(c)(i) of the Original Precedent Agreement, and, as contemplated by Section 9(b) of the Original Precedent Agreement, the Parties desire to restate the Original Precedent Agreement as further set forth herein;

WHEREAS, in lieu of the service contemplated under the Original Precedent Agreement, Customer now desires firm natural gas transportation service in respect of ~~Phase II only~~the

Project from points expected to be located at or near Kensington, Ohio to the point of interconnection with Vector Pipeline L.P.'s Milford Junction meter station near Highland, Michigan;

WHEREAS, Pipeline has secured commercial support for the Project evidenced by executed precedent agreements, including this Restated Precedent Agreement with Customer**;**

WHEREAS, DTE and Spectra contemplate that pipeline companies in the name of NEXUS Gas Transmission, LLC and NEXUS Gas Transmission Canada have been or will be formed and owned by each of DTE and Spectra or by affiliates of each of them to fulfill the responsibilities of Pipeline hereunder and NEXUS Gas Transmission, LLC and NEXUS Gas Transmission Canada will take assignment of the rights and obligations of and be novated as the Pipeline for all purposes of this Restated Precedent Agreement;

WHEREAS, subject to the terms and conditions of this Restated Precedent Agreement, Pipeline is willing to undertake the steps necessary to provide the ~~Phase II~~Project service for Customer described herein and other customers subscribing for capacity as part of the entire Project, to construct the Project facilities or subscribe for firm pipeline capacity that will extend from eastern Ohio to Dawn in order to provide such services, and, if necessary, to construct, or to use reasonable efforts to cause the construction of facilities on existing pipeline systems to provide service on the Project;

WHEREAS, subject to the terms and conditions of this Restated Precedent Agreement, Pipeline is willing to provide the firm transportation service to Customer described herein and Customer is willing to pay Pipeline for such service;

NOW, THEREFORE, in consideration of the mutual covenants herein assumed, and intending to be legally bound, Pipeline and Customer agree as follows:

1) Pipeline Obligations.

a) Subject to the terms and conditions of this Restated Precedent Agreement, Pipeline shall proceed with due diligence to file applications for and to obtain from all governmental and regulatory authorities having competent jurisdiction over ~~Phase II of~~ the Project, including, but not limited to, the Federal Energy Regulatory Commission ("FERC") and the National Energy Board of Canada ("NEB"), the authorizations, approvals, certificates, permits, notices and/or exemptions (collectively, the "Governmental Authorizations") Pipeline determines are necessary for Pipeline to construct, own, operate, and maintain (and, if necessary, to use reasonable efforts to cause others to construct, own, operate, and maintain) the Project facilities necessary to provide the firm transportation service contemplated for ~~Phase II~~the Project, including the ~~Phase II~~Project service to Customer, commencing on the ~~Phase II~~ Service Commencement Date (as determined in accordance with Section 4 of this Restated Precedent Agreement); and (ii) for Pipeline to otherwise perform its obligations as contemplated in this Restated Precedent Agreement. Pipeline retains full control and discretion in the filing and prosecution of any and all applications for such Governmental Authorizations and/or any supplements or amendments thereto, and, if necessary, any court review, provided it does so in a manner that is consistent with the terms of this Restated Precedent Agreement and designed to implement the firm transportation service contemplated herein in a timely manner. Pipeline agrees to promptly notify Customer in writing when each of the Governmental Authorizations are received, obtained, rejected or denied. Pipeline shall also promptly notify Customer in writing as to whether each of the Governmental Authorizations received or obtained are acceptable to Pipeline.

b) During the term of this Restated Precedent Agreement, and provided it would be reasonable and prudent for Pipeline to do so, Pipeline agrees to use reasonable efforts to support and cooperate with the efforts of Customer to obtain all Customer's Authorizations and supplements and amendments thereto, to better understand and analyze the markets for the supply of gas at the proposed initial receipt points for ~~Phase II of~~ the Project and to otherwise perform its obligations as contemplated by this Restated Precedent Agreement.

c) Pipeline shall, no later than December 19, 2014, provide Customer with confirmation of the initial receipt points for ~~Phase II~~ transportation service (collectively, the "Initial Receipt Point Information").

d) The reservation rates payable for transportation service on ~~Phase II~~the Project (as set forth in the applicable Pipeline tariffs approved by the FERC~~ and NEB, respectively~~ the "Reservation Rates") will be set and applied for on a commercially reasonable basis.

2) Customer Obligations.

a) No later than December 19, 2014, Customer will advise Pipeline in writing of: (i) any facilities which Customer must construct, or cause to be constructed, in order for Customer to utilize the ~~Phase II~~ Project service contemplated in this Restated Precedent Agreement; and (ii) any necessary or desirable contractual and/or governmental or regulatory authorizations having jurisdiction over the Customer which Customer determines are necessary or desirable for Customer in order to execute and deliver the ~~Phase II~~ Service Agreement (as such term is defined in Section 3 below) and to fulfill its obligations thereunder and to otherwise perform its obligations under this Restated Precedent Agreement ("Customer's Authorizations").

b) Subject to the terms and conditions of this Restated Precedent Agreement, Customer shall proceed with due diligence to obtain the Customer's Authorizations. Customer retains full control and discretion in the filing and prosecution of any and all applications for such Customer's Authorizations and/or any supplements or amendments thereto, and, if necessary, any court review, provided it does so in a manner that is consistent with the terms of this Restated Precedent Agreement and in a manner designed to implement the ~~Phase II~~ firm transportation service contemplated herein in a timely manner. Customer agrees to promptly notify Pipeline in writing when each of the Customer's Authorizations, are received, obtained, rejected or denied. Customer shall also promptly notify Pipeline in writing as to whether each of the Customer's Authorizations received or obtained are acceptable to Customer.

c) During the term of this Restated Precedent Agreement, and provided it would be reasonable and prudent for Customer to do so, Customer agrees to use reasonable efforts to support and cooperate with the efforts of Pipeline to obtain all Governmental Authorizations and supplements and amendments thereto necessary for Pipeline to provide the ~~Phase II~~Project services contemplated hereunder and to construct, own, operate, and maintain (or, if necessary, to use reasonable efforts to cause others to construct, own, operate and maintain) the Project facilities for the ~~Phase II~~Project services and to otherwise perform its obligations as contemplated by this Restated Precedent Agreement.

d) As of the Effective Date, Customer agrees that its proposed quantity of firm transportation service that it wishes to contract for in respect of ~~Phase II~~the Project as its Maximum Daily Quantity ("MDQ") for the purpose of the ~~Phase II~~ Service Agreement is

110,000 Dth/d. Customer shall have the right, subject to available capacity, regulatory approvals, and the terms of Pipeline's FERC Gas Tariff, to increase its MDQ under the ~~Phase II~~ Service Agreement up to 150,000 Dth/d. Pipeline will notify Customer whether capacity is available to satisfy such request to increase Customer's MDQ, taking into consideration the terms of Pipeline's FERC Gas Tariff. If Pipeline, taking into consideration the terms of its FERC Gas Tariff, can only accommodate an increase to Customer's MDQ that is less than requested, Pipeline shall promptly notify Customer of the amount of the requested increase that can be accommodated, and Customer shall have ten (10) days from receipt of such notice to either: (i) agree to increase its MDQ to the amount that can be accommodated; or (ii) retract its request for an increase. If there is to be an increase to Customer's MDQ pursuant to this Section 2(d), then Pipeline and Customer shall amend the ~~Phase II~~ Service Agreement to reflect the increase as follows:

i) if Customer requests an increase to its MDQ prior to the ~~Phase II~~ Service Commencement Date to be effective on the ~~Phase II~~ Service Commencement Date, and as a result Customer's MDQ is increased to 150,000 Dth/d, then:

  (1) the Reservation Rate applicable to Customer's entire MDQ (including any increase) pursuant to the ~~Phase II~~ Service Agreement and the ~~Phase II~~ Rate Agreement for the firm transportation service as set forth under Paragraph 3(d) shall be reduced such that Customer's effective Reservation Rate for service on the portion of ~~Phase II~~the Project utilizing newly constructed facilities extending from a receipt point(s) to be located at or near Kensington, Ohio to an interconnection point(s) to be located at or near Willow Run, Michigan (the "Greenfield Facilities – Kensington to Willow Run") is equal to the effective

Reservation Rate to be paid by Union Gas Limited for ~~Phase II~~ service on the Greenfield Facilities – Kensington to Willow Run. As of the Effective Date of this Restated Precedent Agreement, Pipeline estimates that Customer's Reservation Rate would be reduced by approximately $0.015 per Dth/d, however, Pipeline and Customer acknowledge and agree that Pipeline's estimate is non-binding and any change to Customer's Reservation Rate for purposes of this Section 2(d)(i)(1) will be determined in accordance with the process outlined for establishing the reservation rates in Section 3(d); and

(2) Customer shall be entitled to the rights granted under Section 3(e).

ii) If Customer requests an increase to its MDQ after the ~~Phase II~~ Service Commencement Date or prior to the ~~Phase II~~ Service Commencement Date but to be effective after the ~~Phase II~~ Service Commencement Date, then:

(1) Customer's request shall be subject to the capacity award mechanism, including any posting and bidding requirements, set forth in Pipeline's FERC Gas Tariff; and

(2) if, pursuant to the terms of Pipeline's FERC Gas Tariff, Customer is awarded the requested capacity and its MDQ is increased to 150,000 Dth/d to be effective anytime on or before November 1, 2020, then the Reservation Rate applicable to Customer's entire MDQ (including any increase) pursuant to the ~~Phase II~~ Service Agreement and the ~~Phase II~~ Rate Agreement for the firm transportation service as set forth under Paragraph 3(d) shall be reduced, as of the effective date of the increased MDQ, such that Customer's effective Reservation Rate for service on the Greenfield Facilities – Kensington to Willow Run is equal to the effective

Reservation Rate paid by Union Gas Limited for ~~Phase II~~ service on the Greenfield Facilities – Kensington to Willow Run. As of the Effective Date of this Restated Precedent Agreement, Pipeline estimates that Customer's Reservation Rate would be reduced by approximately $0.015 per Dth/d as of the effective date of Customer's increased MDQ, however, Pipeline and Customer acknowledge and agree that Pipeline's estimate is non-binding and any change to Customer's Reservation Rate for purposes of this Section 2(d)(ii)(2) will be determined in accordance with the process outlined for establishing the reservations rates in Section 3(d).

iii) if Customer's MDQ is increased to an amount that is less than 150,000 Dth/d, the terms of service including Customer's Reservation Rate shall remain unchanged for all of Customer's MDQ (including any increase).

iv) The terms of this Section 2(d) shall be reflected in the ~~Phase II~~ Rate Agreement and are subject to applicable regulatory approvals. Except as set forth in this Section 2(d) or Section 3(e) (if applicable), all other terms of service and rates shall remain unchanged.

3) Service Agreement.

a) *Intentionally left blank.*

b) ~~Phase II~~ Firm Service Agreement. To effectuate the firm transportation service contemplated herein for the ~~Phase II~~transportation service, Customer and Pipeline agree that (i) no later than thirty (30) days following the date on which Pipeline provides written notice to Customer that the FERC, the Michigan Public Service Commission, and any other governmental agencies or authorities having jurisdiction over the U.S. portion of the ~~Phase II~~Project service have all issued the necessary authorizations to Pipeline or other pipelines to construct the greenfield and expansion facilities necessary to provide the U.S. portion of the ~~Phase II~~Project service, Pipeline and Customer will execute a firm transportation service agreement governing Customer's service on ~~Phase II~~the Project as described herein ("~~Phase II~~ Service Agreement"). The~~ Phase II~~ Service Agreement and the rights and obligations arising thereunder shall only become effective if, in addition to receipt of the aforementioned authorizations for the U.S. portion of the ~~Phase II Service~~Project service, Pipeline has also provided confirmation that the NEB, Ontario Energy Board ("OEB") and any other governmental agencies or authorities having jurisdiction over the Canadian portion of the ~~Phase II~~Project service have all issued the necessary authorizations to Pipeline or other pipelines proposing to construct facilities necessary to provide the Canadian portion of the ~~Phase II~~Project service. For clarity, the Canadian portion of the ~~Phase II~~Project service shall have no application to the transportation service that Customer is contracting for, but receipt of the Governmental Authorizations for the Canadian portion of ~~Phase II~~the Project are a condition precedent to the ~~Phase II~~ Service Agreement between Pipeline and Customer becoming effective as reflected in Section 7(b)(ii). The Parties agree to consider in good faith executing the ~~Phase II~~ Service Agreement at a time earlier than contemplated in the first sentence above if required to allow Pipeline to obtain the requisite notice to proceed with ~~Phase II~~Project construction from any governmental agency or authority having jurisdiction. The~~ Phase II~~ Service Agreement will specify the following provisions that will constitute Customer's service on ~~Phase II~~the Project ("Customer's~~ Phase II~~ Service"): (i) an MDQ of 110,000 Dth/d (subject to increase in accordance with Section 2(d) above), exclusive of fuel requirements, effective on the ~~Phase II~~ Service Commencement Date; (ii) a primary term of fifteen (15) years commencing on the ~~Phase II~~ Service Commencement Date and continuing from year to year thereafter unless terminated in accordance with the provisions thereof; (iii) a Primary Point of Receipt (as such term will be defined in the ~~Phase II~~ Service Agreement) at the head of the ~~Phase II~~Project facilities in Ohio (such point to be designated by Pipeline at such time as Pipeline provides notice to Customer in accordance with Section 3(c) below) with a Maximum Daily Receipt Obligation ("MDRO") of 110,000 Dth/d (subject to increase in accordance with Section 2(d) above); (iv) a Primary Point of Delivery (as such term will be defined in the ~~Phase II~~ Service Agreement) at the point of interconnection with Vector Pipeline L.P.'s Milford Junction meter station near Highland, Michigan with a Maximum Daily Delivery Obligation ("MDDO") of 110,000 Dth/d (subject to increase in accordance with Section 2(d) above); and (v) security requirements consistent with the provisions set forth in Section 13 below. To the extent Pipeline is authorized to offer access to secondary receipt and delivery points as part of the ~~Phase II~~Project service, Customer shall have the right under the ~~Phase II~~ Service Agreement to access secondary receipt and delivery points in accordance with such authorization(s). Attached hereto as Exhibit A is an illustrative form of transportation service agreement for Customer's ~~Phase II~~ Service. ~~.~~ Pipeline provided Customer a copy of the rate agreement and a summary of the general terms and conditions that will be incorporated by reference into the transportation service agreement to form the FERC tariff pursuant to the terms of the Original Precedent Agreement, and Pipeline will provide Customer with any changes to the illustrative form of transportation service agreement in Exhibit A (collectively, the "Forms of Commercial

Agreements"). Pipeline will seek Customer's review of the Forms of Commercial Agreements and will consider in good faith any comments provided by Customer. Pipeline shall keep Customer informed of any revisions to the Forms of Commercial Agreements including revisions resulting from comments received from other Customers in respect of ~~Phase II service~~Project service; provided that, for clarity, the Rate Agreement shall not be revised by Pipeline other than for the sole purpose of conforming the terms of the same with the terms of the NEXUS FERC Gas Tariff (when approved by FERC) and, to the extent not materially adverse to Customer within the context of its participation as a shipper in the Project, with the terms agreed to in rate agreements of other anchor shippers for the Project. Pipeline shall apply for and seek the Governmental Authorizations in a manner consistent with the Forms of Commercial Agreements. The Parties acknowledge and agree that these Forms of Commercial Agreements may change, as required, as a result of the terms and conditions of approvals from the FERC.

c) Status of ~~Phase II~~ Service Commencement Date. Commencing on January 1, 2015, and continuing on a quarterly basis thereafter, Pipeline will notify Customer regarding Pipeline's progress regarding ~~Phase II~~the Project, and whether the ~~Phase II~~ Service Commencement Date (as determined in accordance with Section 4 of this Restated Precedent Agreement) is expected to occur on November 1, 2017, or some later date. No later than November 1, 2015, Pipeline shall in good faith have notified Customer of its *bona fide* estimate of the ~~Phase II~~ Service Commencement Date (the "Estimated ~~Phase II~~ Commencement Date"). In the event that Pipeline's *bona fide* estimate of the Estimated ~~Phase II~~ Commencement Date is a date that is after November 1, 2018, then, unless such deadline(s) are extended by mutual consent, Customer shall have no further obligation in respect of contracting for Customer's ~~Phase II~~ Service and Customer shall have the right to terminate this Restated Precedent Agreement in respect of Customer's ~~Phase II~~ Service without liability between the Parties including in respect of the Customer being required to pay any Pre-Service Costs.

d) Rates.

i) *Intentionally left blank.*

ii) The rates that will apply to the ~~Phase II~~ Service Agreement shall be as set forth in the rate agreement to be executed in accordance with this Section 3(d), for service under the ~~Phase II~~ Service Agreement. Pipeline and Customer have agreed to the following with regard to the rates for service under the ~~Phase II~~ Service Agreement:

(1) Subject to the terms and conditions set forth herein and in the ~~Phase II~~ Service Agreement and in the ~~Phase II~~ Rate Agreement (as defined below), upon execution of such service and rate agreements, Customer shall be obligated to pay Pipeline the rates specified for service under the ~~Phase II~~ Service Agreement commencing on the ~~Phase II~~ Service Commencement Date and continuing to the end of the primary term (as set forth in the ~~Phase II~~ Service Agreement) thereof.

(2) ~~Pipeline and Customer acknowledge that the scope of the facilities necessary for Pipeline to provide Customer's Phase II Service and for all other customers subscribing for Phase II service (such facilities are collectively referred to herein as the "Phase II Facilities") is not known with precision at this time. For this reason, the estimated capital costs associated with construction of the Phase II Facilities and the~~The estimated Reservation Rates and fuel rates for ~~Customer's Phase II Service~~service under the ~~Phase II~~ Service Agreement ~~will~~shall be set

forth in the ~~Phase II~~ Rate Agreement provided in accordance with Section 3(d)(ii)(3) below. ~~Pipeline currently estimates that the Reservation Rate for Customer's Phase II Service under the Phase II Service Agreement will be $0.70 US per Dth/d (the "Estimated Phase II Rate"), plus the applicable U.S. fuel rate, with such fuel rate in the range of 1.6% - 2.6%. The Estimated Phase II Rate may be adjusted as more fully set forth in Section 3(d)(ii)(3) and subject to the terms of Section 3(d)(ii)(4~~The estimated capital costs associated with the construction of the facilities necessary for Pipeline to provide Project service for Customer and all other customers subscribing Project service in the U.S. (the "Project Facilities") will be reflected in an estimate to be provided by Pipeline to Customer in accordance with Section 3(d)(ii)(3) below.

(3) ~~No later than December 19, 2014 Pipeline shall provide Customer with a draft estimate of the capital costs associated with construction of the New Phase II Facilities (as defined below), the revised Reservation Rate (the "Revised Phase II Rate") applicable to Customer's Phase II Service, subject to a fifteen percent (+/- 15%) capital cost tracking adjustment (as more particularly described in Exhibit C (the "~~Contemporaneously with the execution of the First Amendment to this Restated Precedent Agreement, Pipeline shall deliver to Customer the following: (a) the final rate agreement for the Service Agreement (the "Rate Agreement"), which shall include the final estimate of the Reservation Rate (the "Final Estimated Reservation Rate") (subject only to the Capital Cost Tracking Adjustment~~") around the revised estimate, and the revised fuel rate estimate, to be set forth in the rate agreement for the Phase II Service Agreement. The capital~~

~~cost estimate will be provided substantially in the same form as an Exhibit K - Cost of Facilities (as defined in the Federal Energy Regulatory Commission's Code of Federal Regulations) for the New Phase II Facilities. At such time as Pipeline provides Customer with the Revised Phase II Rate, Pipeline will provide information which sets forth a more detailed breakdown of how the~~, as defined below) and estimated fuel rate; (b) a final breakdown of how Pipeline ~~has derived such Revised Phase II Rate ("Rate Breakdown")~~derived the Final Estimated Reservation Rate, including a breakdown of such portion of the Final Estimated Reservation Rate~~ for Customer's Phase II Service~~ that is derived from the Final Capital Cost Estimate (as defined below) ("Rate Breakdown"); and (c) an estimate of the capital costs associated with the construction of the ~~New Phase II Facilities for Customer's Phase II Service. No later than January 16, 2015, Pipeline shall deliver to Customer a final estimate of capital costs for the New Phase II Facilities, final Reservation Rate for Customer's Phase II Service (subject to the~~ Project Facilities ("Final Capital Cost Estimate"). The Rate Agreement shall provide, consistent with Exhibit C, that the Final Estimated Reservation Rate shall be subject to an aggregate fifteen percent (+ / - 15%) capital cost tracking adjustment (as more particularly described in Exhibit C, the "Capital Cost Tracking Adjustment~~) (the "Final Reservation Rate") and final estimated fuel rate to be set forth in the rate agreement for the Phase II Service Agreement and any final revisions to the Rate Breakdown as well as the final rate agreement for the Phase II Service Agreement (the "Phase II Rate Agreement").~~"). Pipeline and Customer shall ~~promptly execute the Phase II Rate Agreement;~~

~~provided that, if the Final Reservation Rate set forth in the Phase II Rate Agreement is higher than the Estimated Phase II Rate set forth in Section 3(d)(ii)(2) above, and such higher Reservation Rate has caused the value of the commercial transaction with respect to the natural gas to be transported under the Phase II Service Agreement to be uneconomical to Customer, as determined by Customer in its sole and absolute discretion, Customer shall not be obligated to execute the Phase II Rate Agreement~~hereafter execute the Rate Agreement as expeditiously as is practicable.

~~(4) In the event that Customer has elected not to execute the Phase II Rate Agreement in accordance with the proviso in the last sentence of Section 3(d)(ii)(3), Pipeline and Customer shall promptly meet and work in good faith in an attempt to agree upon Reservation Rate that are commercially acceptable to both Parties, each Party in its sole discretion. If, after thirty (30) days, the Parties are unable to agree upon a mutually acceptable Reservation Rate, either Party shall have the right to terminate this Restated Precedent Agreement and, if executed, the Phase II Service Agreement. Any termination of this Restated Precedent Agreement pursuant to this Section will be without liability to either Party including in respect of the Customer being required to pay any Pre-Service Costs.~~

e) Most Favored Nations. The following provisions of this Section 3(e) shall only apply and become effective should the Customer make an election in accordance with Section 2(d)(i) to increase its MDQ to 150,000 Dth/day effective as of the~~ Phase II~~ Service Commencement Date and the entire amount requested to be increased can be accommodated by Pipeline.

i) Except as provided in Section 3(e)(ii) below, in the event that Pipeline enters into or has entered into firm transportation service and/or recourse, negotiated or discount rate agreements with other similarly situated customers (as to transportation path, quantity and length of term) in respect of ~~Phase II~~the Project containing any rate provisions and other terms of service that are more favorable to such other customers than the negotiated rate provisions set forth in the ~~Phase II~~ Rate Agreement, Pipeline shall offer Customer, within ten (10) business days of entering into the rate agreements (or to the extent such rate agreements existed prior to the exercise by Customer of the right in Section 2(e)), then within ten (10) business days of confirmation that Customer's MDQ has been increased to 150,000 Dth/d), those same rate provisions and other terms of service. If Customer is willing to accept the offer on the exact same terms and conditions as such other customer(s), including provisions regarding transportation path, volume and length of term, then Customer will so notify Pipeline within thirty (30) days of its acceptance, and Pipeline will make the necessary amendments to the ~~Phase II~~ Rate Agreement and the ~~Phase II~~ Service Agreement, as applicable, and the Parties will enter into amended agreements at the more favorable rate for the remainder of the term of the applicable agreement(s). This section will apply only to contracts Pipeline enters into for service utilizing Project capacity on or before the ~~Phase II~~ Service Commencement Date.

ii) *Exclusions.* Pipeline is not required to offer to Customer and Customer is not entitled to, any rate provisions provided to other customers if such rate provisions are contained in long-term firm service agreements for capacity that becomes available as a result of the breach, default or unauthorized termination of a precedent agreement or associated service agreement by a Project customer or the bankruptcy, insolvency, liquidation or other similar action affecting a Project customer. In addition, the most favored nation right set forth in this Section 3(e) will not be available to Customer in respect of any short term (i.e., less than one year) service. Further, the most favored nation right set forth in this section 3 will not apply to credit provisions.

(f) Right of First Refusal. Customer will, in respect of the ~~Phase II~~ Service Agreement be granted a contractual Right of First Refusal ("ROFR") in accordance with the Pipeline tariff approved by the FERC. Further, the ~~Phase II~~ Service Agreement will be considered a ROFR Agreement in accordance with, and as that term is used in, Pipeline's FERC tariff.

4) Commencement of Service.

(a) *Intentionally left blank.*

(b) ~~Phase II.~~ With respect to ~~Phase II~~Project transportation service, Pipeline shall provide at least ninety (90) days' prior notice (the "In-Service Date Notice") to Customer of the projected service commencement date for service under the ~~Phase II~~ Service Agreement, which date shall be the beginning of a calendar month and cannot be earlier than the date upon which Pipeline has satisfied or waived all the conditions precedent, provided that the actual service commencement date for purposes of the ~~Phase II~~ Service Agreement (the "~~Phase II~~ Service Commencement Date") shall be the date that is the later of: (i) November 1, 2017; (ii) the date provided in the In-Service Date Notice; (iii) the date that is the first day of the first calendar month following the date on which the Pipeline places the ~~Phase II~~Project Facilities into service; or (iv) if, pursuant to Section 7(f), the Pipeline has filed an appeal or is pursuing a rehearing, reconsideration or clarification by the applicable regulatory authority of the Governmental Authorization, then 90 days from the date of receipt of a positive decision addressing Customer's concerns unless such period is waived by Customer. On and after the ~~Phase II~~ Service Commencement Date, Pipeline shall provide firm transportation service for Customer pursuant to the terms of the ~~Phase II~~ Service Agreement and Customer will pay Pipeline for all applicable charges required by the ~~Phase II~~ Service Agreement and the ~~Phase II~~ Rate Agreement.

5) Design and Permitting of Project Facilities. Pipeline will undertake with due diligence, or use reasonable efforts to cause others to undertake, the design of the ~~Phase II~~Project Facilities and any other preparatory actions necessary for Pipeline, or Pipeline's designee(s), to complete and file application(s) related to the ~~Phase II~~Project Facilities with the FERC~~, NEB~~ and/or other governmental authorities as appropriate. Prior to satisfaction of the conditions precedent set forth in Section 7(b)(i) through 7(b)(vii) of this Restated Precedent Agreement, Pipeline, or Pipeline's designee(s), shall have the right, but not the obligation, to proceed with the necessary design of facilities, acquisition of materials, supplies, properties, rights-of-way and any other necessary preparations to implement the firm transportation service under the ~~Phase II~~ Service Agreement as contemplated in this Restated Precedent Agreement. Additionally, Pipeline will use commercially reasonable efforts to keep Customer informed on a regular basis and respond to any of Customer's requests for information concerning ~~Phase II~~Project schedule changes, status of Governmental Authorizations, service commencement dates, and/or changes to any of the rates described herein.

6) Construction of Project. Upon satisfaction of the conditions precedent set forth in Sections 7(b)(i) through 7(b)(vii), inclusive and 7(c) of this Restated Precedent Agreement, or waiver

of the same by Pipeline or Customer, as applicable, Pipeline shall proceed with due diligence to construct, or to use reasonable efforts to cause others to construct, the authorized ~~Phase II~~Project Facilities and to implement the firm transportation service contemplated in this Restated Precedent Agreement for Customer's ~~Phase II~~ Service on or about November 1, 2017, or such later date as may be designated by Pipeline in accordance with Section 3(c) above. If, notwithstanding Pipeline's due diligence, Pipeline, or Pipeline's designee(s), is unable to commence the ~~Phase II~~Project service for Customer on November 1, 2017, or such later date as may be designated by Pipeline in accordance with Section 3(c) above, Pipeline will continue to proceed with due diligence to complete arrangements for such firm transportation service, and commence such service for Customer at the earliest practicable date thereafter. Subject to Section 9(a), Pipeline will neither be liable nor will this Restated Precedent Agreement or the ~~Phase II~~ Service Agreement be subject to cancellation if Pipeline, or Pipeline's designee(s), is unable to complete the construction of such authorized Project facilities and commence the ~~Phase II~~Project service for Customer by November 1, 2017 or such later date as may be designated by Pipeline in accordance with Section 3(c) above.

7) Conditions Precedent. Commencement of service under the ~~Phase II~~ Service Agreement and Pipeline's and Customer's rights and obligations thereunder are expressly made subject to satisfaction or waiver, as applicable, of the following conditions precedent in Sections 7(b) and 7(c), provided that only Pipeline shall have the right to waive the conditions precedent set forth in Section 7(b) and only Customer shall have the right to waive the conditions precedent set forth in Section 7(c):

a) *Intentionally left blank.*

b) Pipeline's Conditions Precedent for ~~Phase II~~Project Service.

i) Pipeline filing by April 1, ~~2015~~2016 the necessary requests with the FERC ~~and/or NEB~~ for approval to provide ~~Phase II~~ service as contemplated herein and in the ~~Phase II~~ Service Agreement;

ii) Subject to Section 7(d), Pipeline's receipt and acceptance in accordance with Section 7(f) by May 1, 2017, of all necessary Governmental Authorizations to construct, own, operate and maintain the ~~Phase II~~Project Facilities (including FERC, NEB, and OEB authorizations, as applicable), all as described in Pipeline's applications as they may be amended from time to time, necessary to provide the ~~Phase II~~Project service, including Customer's ~~Phase II~~ Service contemplated herein and in the ~~Phase II~~ Service Agreement;

iii) Pipeline (or Pipeline's owners or their respective affiliates) having received on or before May 1, 2017, a binding commitment from a financial institution(s) to provide the necessary financing of the construction of the ~~Phase II~~Project Facilities;

iv) Other pipelines having received and accepted in accordance with Section 7(f) by May 1, 2017, all necessary Governmental Authorizations to construct, own, operate and maintain the ~~Phase II~~Project Facilities, all as described in their applications as they may be amended from time to time, necessary to provide the ~~Phase II~~ service including Customer's ~~Phase II~~ Service contemplated herein and in the ~~Phase II~~ Service Agreement;

v) Pipeline receiving approval, no later than thirty (30) days after its acceptance of the certificates and authorizations specified in Section 7(b)(i), from its Management Committee, or similar governing body, to expend the capital necessary to construct the ~~Phase II~~Project Facilities and to proceed with the ~~Phase II~~Project-related firm pipeline transportation arrangements with other pipelines for service on the ~~Phase II~~Project Facilities;

vi) Pipeline's receipt no later than four (4) months prior to the ~~Phase II~~ Service Commencement Date of all necessary authorizations required to construct the ~~Phase II~~Project Facilities necessary to provide the ~~Phase II~~ firm transportation service including Customer's ~~Phase II~~ Service contemplated herein and in the ~~Phase II~~ Service Agreement, other than those specified in Section 7(b)(ii);

vii) Pipeline's procurement, no later than four (4) months prior to the ~~Phase II~~ Service Commencement Date, of all rights-of-way, easements or permits (in form and substance acceptable to Pipeline, acting reasonably) necessary for the construction and operation of the ~~Phase II~~Project Facilities;

viii) Pipeline's completion of construction of the ~~Phase II~~Project Facilities and all other facilities required to render Customer's ~~Phase II~~ Service pursuant to the ~~Phase II~~ Service Agreement and for other customers subscribing for ~~Phase II~~Project service and Pipeline being ready, able and authorized to place such facilities into gas service; and

ix) The completion of the construction of the facilities necessary to create the pipeline capacity subscribed to Pipeline as part of ~~Phase II of~~ the Project by other pipelines, as applicable, and each such Party being ready, able and authorized to place such facilities into service.

c) Customer's Conditions Precedent.

i) Intentionally left blank.

ii) ~~Customer's acceptance, no later than 30 days following receipt of Initial Receipt Point Information in accordance with Section 1(c), of the initial receipt points proposed by the Pipeline for Phase II transportation service;~~*Intentionally left blank.*

iii) Customer's confirmation to Pipeline, no later than 90 days following receipt of the Estimated ~~Phase II~~ Commencement Date, that it has completed its review and approval of regional supply necessary to support natural gas supply arrangements associated with Customer's service under the ~~Phase II~~ Service Agreement, respectively; and

iv) ~~If, pursuant Section 3(d)(ii), the Final Reservation Rate exceeds the Estimated Reservation Rate, then Customer's receipt, no later than 60 days following receipt of the requisite internal corporate approvals of such Final Reservation Rate for Phase II;~~*Intentionally left blank.*

v) Subject to Section 7(d), Customer's receipt and acceptance of the approvals from the OEB for its application related to the ~~Customer's Phase II Service~~Project no later than October 1, 2015; and

vi) Subject to Section 7(d), Customer's receipt and acceptance no later than 30 days following satisfaction of the condition in Section 7(c)(iii), of any necessary Customer Authorizations identified in accordance with Section 2(a) of this Restated Precedent Agreement

vii) Subject to the other terms of this Restated Precedent Agreement, Customer acknowledges that it has received, prior to the Effective Date, the requisite internal corporate approvals for the performance of Customer's obligations under this Restated Precedent Agreement and other agreements related to the service contemplated hereunder.

d) Temporary Waiver of Conditions Precedent – Governmental Authorizations. Notwithstanding Sections 7(b)(ii), 7(b)(iv), 7(c)(iii), 7(c)(v) and 7(c)(~~iv~~vi) and subject to Section 24, either Party may, in its sole discretion, temporarily waive satisfaction of its conditions precedent listed above for a period of 90 days. During such a delay, upon reasonable request by the other Party, the Party waiving its condition precedent shall use commercially reasonable efforts to provide timely notices to the other Party in writing regarding the filing of any applications for such Governmental Authorizations or Customer Authorization, as the context requires, and will provide periodic updates regarding the status of such applications, including notice when each of the authorizations are received, obtained, rejected or denied. The Party temporarily waiving it condition precedent shall also promptly notify the other Party in writing as to whether each of the Governmental Authorizations or Customer Authorizations, as the context requires, received or obtained are acceptable to such Party. If the Party temporarily waiving its condition precedent has not satisfied the conditions precedent associated with the receipt of all Governmental Authorizations or Customer Authorizations, as the context requires, within ninety (90) days' time, either Party may terminate this Restated Precedent Agreement on thirty (30) days' written notice and no Pre-Service Costs will be payable by Customer.

e) With respect to each condition precedent set forth in Section 7(b) of this Restated Precedent Agreement, with the exception of the conditions precedent set forth in clauses (vii) and (viii) of Section 7(b), Pipeline shall provide notice to Customer within five (5) days of the satisfaction of such condition precedent that the condition precedent has been satisfied. With respect to each condition precedent set forth in Section 7(c) of this Restated Precedent Agreement, Customer shall provide notice to Pipeline within five (5) days of the satisfaction of each such condition precedent that the condition precedent has been satisfied.

f) Unless otherwise provided for herein, the Governmental Authorization(s) contemplated in Section 1 of this Restated Precedent Agreement must be issued in form and substance satisfactory to both Parties, acting reasonably. For purposes of this Restated Precedent Agreement, such Governmental Authorization(s) shall be deemed satisfactory if issued or granted with terms and conditions which are: (i) consistent with this Restated Precedent Agreement and all ancillary agreements and documents to be delivered pursuant to this Restated Precedent Agreement for the applicable service; and (ii) to the extent not contemplated by this Restated Precedent Agreement or any of the ancillary agreements and documents, not materially onerous on Pipeline, as determined by Pipeline, acting reasonably, and will not otherwise have a material adverse effect on Customer. Customer shall notify Pipeline in writing not later than fifteen (15) days after Pipeline notifies Customer of the issuance of the FERC ~~and/or NEB~~ certificate(s), authorization(s) and approval(s), including any order issued as a preliminary determination on non-environmental issues, contemplated in Section 1 of this Restated Precedent Agreement if Customer determines, acting reasonably, that such certificate(s), authorization(s) and approval(s) will have a material adverse effect on Customer. Customer cannot assert that any authorization will have a material adverse effect on Customer unless: (i) the governing provisions of such authorization differ materially and adversely from the provisions requested by Pipeline in its application, unless the provisions requested by Pipeline were inconsistent with the terms of this Restated Precedent Agreement; and (ii) such differences materially and adversely affect the rate to be charged pursuant to the rate agreement contemplated herein, or the terms and conditions of service pursuant to the service agreement contemplated herein, and the Parties cannot mutually agree upon a modification or alternative to such provision which preserves the relative economic positions of the Parties under the operative agreement(s). All other Governmental Authorizations that Pipeline must obtain must be issued in form and substance acceptable to Pipeline, acting reasonably. All Governmental Authorizations that Pipeline is required by this Restated Precedent Agreement to obtain must be duly granted by the FERC, ~~NEB,~~ or other governmental agency or authority having jurisdiction, and must be final and no longer subject to rehearing or appeal; provided, however, Pipeline may waive the requirement that such Governmental Authorizations be final and no longer subject to rehearing or appeal. If any of the Governmental Authorizations are issued on material terms not acceptable to either Party, subject to the foregoing provisions of this Section 7(f), then the non-accepting Party, acting reasonably, shall give notice to the other Party, and the Parties shall promptly meet and work in good faith in an attempt to agree upon a commercially acceptable resolution for both Parties, each Party in its sole discretion, to continue forward with respect to ~~Phase II~~the Project. If, after thirty (30) days, the Parties are unable to agree upon a mutually acceptable resolution, either Party shall have the right to terminate this Restated Precedent Agreement and, if executed, the ~~Phase II~~ Service Agreement and ~~Phase II~~ Rate agreement. Any termination of this Restated Precedent Agreement by a Party pursuant to this Section will be without liability between the Parties including in respect of the Customer being required to pay any Pre-Service Costs. Notwithstanding the foregoing, if the Parties cannot agree on a modification or alternate provision, Pipeline may, in its sole discretion, appeal or otherwise pursue rehearing, reconsideration or clarification by the applicable regulatory authority of any such provision(s) which Customer alleges will have a material adverse effect on it, and Customer may not terminate this Restated Precedent Agreement until a final order or decision is rendered by such regulatory authority which does not grant relief that is satisfactory to Customer, acting reasonably, to address such material adverse effect, or 180 days from the date that Pipeline makes its application for rehearing, reconsideration or clarification, whichever occurs first.

g) The Customer Authorization(s) contemplated in Section 2 of this Restated Precedent Agreement shall be deemed satisfactory if issued or granted in form and substance substantially as requested, or if issued in a manner acceptable to Customer and such Customer Authorization(s), as issued, will not otherwise have a material adverse effect on Pipeline. Pipeline cannot assert that any authorization will have a material adverse effect on Pipeline unless: (i) the governing provisions of such authorization differ materially and adversely from the provisions requested by Customer in its application, unless the provisions requested by Customer were inconsistent with the terms of this Restated Precedent Agreement; and (ii) such differences materially and adversely affect the rate to be charged pursuant to the rate agreement contemplated herein, or the terms and conditions of service pursuant to the service agreement contemplated herein, and the Parties cannot mutually agree upon a modification or alternative to such provision which preserves the relative economic positions of the Parties under the operative agreement(s). If any of the Customer Authorizations are issued on terms not acceptable to either Party, subject to the foregoing provisions of this Section 7(g), then the non-accepting Party shall give notice to the other Party, and the Parties shall promptly meet and work in good faith in an attempt to agree upon a commercially acceptable resolution for both Parties, each Party in its sole discretion, to continue forward with respect to ~~Phase II~~the Project. If, after thirty (30) days, the Parties are unable to agree upon a mutually acceptable resolution, either Party shall have the right to terminate this Restated Precedent Agreement and, if executed, the ~~Phase II~~ Service Agreement and ~~Phase II~~ Rate Agreement. Any termination of this Restated Precedent Agreement by a Party pursuant to this Section will be without liability between the Parties including in respect of the Customer being required to pay any Pre-Service Costs.

h) In the event the Estimated ~~Phase II~~ Commencement Date is changed to a date later than November 1, 2017 in accordance with Section 3(c), the Parties agree that each of the dates in Sections 3(d)(ii), 7(b)(i) through 7(b)(iii), Sections 7(c)(ii) through 7(c)(iv), and Section 10 will be changed to a later date by the same amount of time as such change to the Estimated ~~Phase II~~ Commencement Date.

8) Pre-Service Costs. If Customer is in material breach of any of its material obligations arising pursuant to this Restated Precedent Agreement and such material breach is not cured within 30 days of notice to Customer by Pipeline of such breach, or if such breach is not capable of being cured within 30 days, and Customer is not continuing thereafter in good faith and with

diligence to cure such breach, and, as a result thereof, the ~~Phase II~~ Service Commencement Date does not occur, then Customer shall, at the option and election of Pipeline, reimburse Pipeline within thirty (30) days of Pipeline's invoice, for its pro-rata share, based on Customer's MDQ for ~~Phase II~~ service to total contracted MDQ for ~~Phase II~~ service by all customers with executed Restated Precedent Agreements, for the Pre-Service Costs incurred or otherwise committed to by Pipeline up to the date of the occurrence of the material breach which resulted in the ~~Phase II~~ Service Commencement Date to not occur. In no event shall Customer's exposure to Pre-Service Costs exceed $163 million U.S. dollars if Customer's MDQ for ~~Phase II~~ service is 110,000 Dth/d, or $219 million U.S. dollars if Customer's MDQ for ~~Phase II~~ service is 150,000 Dth/d. Customer's liability for its share of the Pre-Service Costs in accordance with this Section 8 constitutes a genuine pre-estimation of Pipeline's liquidated damages and not as a penalty, and the payment by Customer of such amount, if such payment is required to be made in accordance with this Section 8 shall constitute Pipeline's sole remedy in such instance, with no right to claim further damages or other remedies from Customer. Pipeline represents that no work to be conducted in relation to Pre-Service Costs will be conducted in Canada. In the event that Pipeline issues to Customer an invoice in relation to Pre-Service Costs work conducted in Canada, Pipeline shall separate the invoice between work performed in Canada and outside of Canada, identify on the invoice the number of days performing work in Canada (including travel days to/from Canada) and the physical location, indicating city and province, where the Canadian work was performed. Customer shall request from Pipeline the relevant documentation necessary to determine the appropriate withholding amount, if any, for tax purposes. In the event that taxes are withheld from the Pre-Service Costs paid by Customer, then Customer shall remit such withheld taxes to the applicable taxing authority and the Customer will provide to Pipeline, after the applicable calendar year end, Pipeline's U.S. Federal Form 1099, a comparable state form or Canadian Revenue Authority equivalent, if applicable, within the applicable statutory time frame. In the event that Customer is assessed for any non-resident withholding taxes payable, Pipeline agrees to forthwith reimburse Customer for such amount together with applicable interest and penalties, if any. If this Restated Precedent Agreement is terminated for any reason other than a material breach by Customer, then such termination shall be without any liability on the part of Customer to Pipeline, including in respect of the Customer being required to pay any Pre-Service Costs. The term, "Pre-Service Costs" for all purposes in this Restated Precedent Agreement means only those expenditures and/or costs reasonably and prudently incurred, accrued, allocated to, or for which Pipeline is contractually obligated to pay in furtherance of Pipeline's efforts to develop and construct ~~Phase II of~~ the Project and to satisfy its obligations under this Restated Precedent Agreement and all other precedent agreements for service on ~~Phase II of~~ the Project facilities, including such expenditures associated with design, testing, engineering, construction, commissioning, materials and equipment, environmental, regulatory, and/or legal activities, allowance for funds used during construction, negative salvage, internal overhead and administration and any other costs reasonably incurred in furtherance of Pipeline's efforts to develop and construct ~~Phase II of~~ the Project and to satisfy its obligations under this Restated Precedent Agreement and all other precedent agreements for service on ~~Phase II of~~ the Project facilities. In the event Customer incurs liability for Pre-Service Costs, Pipeline shall use commercially reasonable efforts to mitigate the amount of Pre-Service Costs. NOTWITHSTANDING THE FOREGOING, THE PARTIES HERETO AGREE THAT

NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR ANY PUNITIVE, SPECIAL, EXEMPLARY, INDIRECT, INCIDENTAL OR CONSEQUENTIAL DAMAGES (INCLUDING, WITHOUT LIMITATION, LOSS OF PROFITS OR FOR BUSINESS INTERRUPTIONS) ARISING OUT OF OR IN ANY MANNER RELATED TO THIS PRECEDENT AGREEMENT, AND WITHOUT REGARD TO THE CAUSE OR CAUSES THEREOF OR THE SOLE, CONCURRENT OR CONTRIBUTORY NEGLIGENCE (WHETHER ACTIVE OR PASSIVE), STRICT LIABILITY (INCLUDING, WITHOUT LIMITATION, STRICT STATUTORY LIABILITY AND STRICT LIABILITY IN TORT) OR OTHER FAULT OF EITHER PARTY. THE IMMEDIATELY PRECEDING SENTENCE SPECIFICALLY PROTECTS EACH PARTY AGAINST SUCH PUNITIVE, EXEMPLARY, INDIRECT, INCIDENTAL OR CONSEQUENTIAL DAMAGES EVEN IF WITH RESPECT TO THE NEGLIGENCE, GROSS NEGLIGENCE, WILLFUL MISCONDUCT, STRICT LIABILITY OR OTHER FAULT OR RESPONSIBILITY OF SUCH PARTY; AND ALL RIGHTS TO RECOVER SUCH DAMAGES OR PROFITS ARE HEREBY WAIVED AND RELEASED.

9) Termination of Restated Precedent Agreement for Failure of Conditions Precedent.

a) If the conditions precedent set forth in Section 7 of this Restated Precedent Agreement have not been fully satisfied or waived by Pipeline or Customer, as applicable, by the earlier of the applicable dates specified therein or within one year after the Estimated ~~Phase II~~ Commencement Date, and this Restated Precedent Agreement has not otherwise been terminated pursuant to the other terms of this Restated Precedent Agreement, including in respect of Sections 10 or 11 hereof, then this Restated Precedent Agreement (and ~~any Phase II~~the Service Agreement) shall terminate effective 30 days after the date such condition precedent was to be satisfied or waived by the applicable Party and such termination shall be without liability including in respect of Customer being required to pay any Pre-Service Costs, except to the extent the failure is as a direct result of a material breach by a Party of its other obligations set forth in this Restated Precedent Agreement.

b) For any termination in accordance with Section 9(a) above, the Parties agree to promptly meet and work diligently and in good faith for a period of 30 days following the date such condition precedent was to be satisfied or waived to attempt to agree upon changes to this Restated Precedent Agreement that would allow the Restated Precedent Agreement to continue, which may include a waiver of and/or change in the deadline for any of the conditions precedent that are the subject of such termination notice, provided that if the Parties are unable to come to an agreement upon changes that would allow the Restated Precedent Agreement to continue, then this Restated Precedent Agreement (and the ~~Phase II~~ Service Agreement) shall nonetheless terminate effective on the expiry of such 30 day period.

c) Any delay or failure in the performance by either Party hereunder shall be excused if and to the extent caused by the occurrence of a Force Majeure, provided that such Party claiming Force Majeure shall give written notice of the suspension of such performance for this reason as soon as reasonably possible to the other Party and stating the date and extent of such suspension and the cause thereof. The Party whose obligations have been suspended as aforesaid shall resume the performance of such obligations as soon as reasonably possible after the removal of the cause and shall so notify, in writing, the other Party that the suspension has terminated. Notwithstanding the foregoing, if any condition precedent set forth in Section 7 hereof has not been satisfied as a result of an occurrence of Force Majeure, the deadline for satisfying the condition precedent shall be extended for each day that the occurrence of Force Majeure continues up to a maximum of ninety (90) days or as mutually agreed to by the Parties. For purposes of this Restated Precedent Agreement, "Force Majeure" as employed herein shall mean any cause, whether of the kind enumerated herein or otherwise, not within the reasonable control of the Party claiming suspension, and which by the exercise of due diligence, such Party has been unable to prevent or overcome, including without limitations acts of God, the government, or a public enemy; strikes, lockouts, or other industrial disturbances; wars, terrorism, blockades, or civil disturbances of any kind; epidemics, landslides, hurricanes, washouts, tornadoes, storms, fires, explosions, arrests, and restraints of governments or people, freezing of, breakage or accident to, or the necessity for making repairs to machinery or lines of pipe; and the inability of either the claiming Party to acquire, or the delays on the part of either of the claiming Party in acquiring, at reasonable cost and after the exercise of reasonable diligence: (a) any servitudes, rights of way, grants, permits or licenses; (b) any materials or supplies for the construction or maintenance of facilities; or (c) any Governmental Authorizations, permits or permissions form any governmental agency; if such are required to enable the claiming Party to fulfill its obligations hereunder.

10) Termination for Default. The occurrence and continuation of a material breach by a Party of any of its obligations under this Restated Precedent Agreement, unless caused by a breach by the other Party of its obligations under this Restated Precedent Agreement is referred to herein as a "Default". Upon the occurrence of a Default by a Party hereto, the non-defaulting

Party may provide written notice to the defaulting Party, describing the Default in reasonable detail and requiring the defaulting Party to remedy the Default (the "Default Notice"). If the Default is not cured within 30 days of receipt by the defaulting Party of the Default Notice, or if such breach is not capable of being cured within 30 days, and the defaulting Party is not continuing thereafter in good faith and with diligence to cure such Default, the non-defaulting Party may, by termination notice to the defaulting Party, terminate this Restated Precedent Agreement effective on the tenth (10th) day following receipt of the termination notice by the defaulting Party; provided, however, that if during such ten (10) day period the defaulting Party has commenced to remedy the Default and is continuing in good faith its efforts to remedy such Default, the entitlement of the non-defaulting Party to terminate this Restated Precedent Agreement will be suspended until the earlier of the cessation by the defaulting Party of such efforts and the date which is ninety (90) days after the date of the Default Notice.

11) Other Pipeline Termination Rights. In addition to the provisions of Section 9 hereof, Pipeline may terminate this Restated Precedent Agreement at any time upon fifteen (15) days' prior written notice to Customer, if: (i) Pipeline, in its sole and reasonable discretion, determines for any reason on or before October 1, 2016, that the Project contemplated herein is no longer economically viable, (ii) Pipeline incurs or will incur costs which are twenty-five percent (25%) or more than the cost estimate submitted as part of Pipeline's application to the FERC for the certificate of public convenience and necessity for the Project related to the Project construction, or (iii) on or before October 1, 2016, substantially all of the other precedent agreements, service agreements or other contractual arrangements for the firm transportation service to be made available by the Project are terminated, other than by

reason of commencement of service. In the event Pipeline terminates this Restated Precedent Agreement in accordance with this Section 10, Customer shall not be liable pursuant to Section 8 above for Pre-Service Costs.

12) Termination Upon Service Commencement Date; Survival. If this Restated Precedent Agreement is not terminated pursuant to Sections 9, 10 or 11 hereof, or otherwise in accordance with the terms of this Restated Precedent Agreement, then, except for those provisions herein that are stated to survive any termination of this Restated Precedent Agreement, this Restated Precedent Agreement will terminate by its express terms on the ~~Phase II~~ Service Commencement Date and thereafter Pipeline's and Customer's rights and obligations related to the transportation service contemplated herein shall be determined pursuant to the terms and conditions of the ~~Phase II~~ Service Agreement and ~~Phase II~~ Rate Agreement, as applicable, and Pipeline's FERC gas tariff, as effective from time to time. Notwithstanding any termination of this Restated Precedent Agreement, each Party shall remain liable to the other Party for all losses or damages suffered, sustained or incurred by the other Party as a result of a breach of any obligations of a Party which breach arose prior to termination of this Restated Precedent Agreement, provided that Customer's liability shall only apply if and to the extent it is to be liable in accordance with Section 8 and, such liability, if any, shall not exceed its share of Pre-Service Costs determined in accordance with Section 8. Notwithstanding any termination of this Restated Precedent Agreement pursuant to terms of this Restated Precedent Agreement, to the extent that a provision of this Restated Precedent Agreement contemplates that one or both Parties may have further rights and/or obligations hereunder following such termination, the provision shall survive such termination as necessary to give full effect to such rights and/or obligations.

13) Creditworthiness. At all times during the effectiveness of this Restated Precedent Agreement and the related Service Agreement(s), Customer, pursuant to the criteria and terms set forth in this Section 13, shall either maintain a Creditworthy status, as defined below, or furnish sufficient credit support to Pipeline.

a) Creditworthiness Standard. Customer shall at all times during the effectiveness of this Restated Precedent Agreement and the Service Agreement(s) be Creditworthy or provide the Guaranty or the Letter of Credit contemplated herein. For purposes herein, “Creditworthy” means, in respect of the applicable entity, such entity has and maintains: (i) a long-term senior unsecured debt rating from (a) Moody’s Investors Service, Inc. (“Moody’s”) of Baa3 or higher, and (b) Standard & Poor’s (“S&P”) of BBB- or higher and, with respect to each rating, not on negative credit watch or outlook, and (ii) a sufficient open line of credit as of the Effective Date. Pipeline acknowledges and agrees that, as of the effective date of this Restated Precedent Agreement, Customer has a sufficient open line of credit with Pipeline and Customer shall not at any time hereafter be required to establish any line of credit in connection with this Restated Precedent Agreement. If Customer is rated by only one of the foregoing credit rating agencies, Customer shall be creditworthy if it has the rating described in the foregoing sentence from the agency by which it is rated. If Customer is rated by both of the rating agencies described above but one such agency’s rating is lower than the other agency’s rating, then Customer’s creditworthiness shall be determined based on the lower of the Moody’s or S&P rating. Alternatively, Customer may be accepted as Creditworthy by Pipeline if Pipeline determines that, notwithstanding the absence of the rating requirements in this Section 13(a), the financial position of Customer (or an entity that guarantees all of

Customer's payment obligations) is and remains acceptable to Pipeline during the term of the Restated Precedent Agreement and the ~~Phase II~~ Service Agreement.

b) Failure to Meet Creditworthiness Standard. In the event Customer fails at any time or from time to time during the term of this Restated Precedent Agreement or the applicable service agreements to meet the Creditworthy standard set forth in Section 13(a) (including if its Guarantor, if applicable is no longer Creditworthy), Customer shall provide credit support to Pipeline in the form of one of the following methods set forth in this Section 13(b):

   i) Guaranty. Customer will provide, or cause to be provided, a guaranty (a "Guaranty") from Customer's parent company or from an affiliate (a "Guarantor"), provided the Guaranty shall serve to satisfy Customer's obligations under this Section 13 only if such Guarantor is Creditworthy, and only for so long as the Guarantor remains Creditworthy and for so long as it guarantees Customer's payment obligations and the Guaranty otherwise satisfies the requirements of this clause (i). The Guaranty shall: (a) guarantee all payment obligations of Customer under this Restated Precedent Agreement and the ~~Phase II~~ Service Agreement, (b) remain in effect until all payment obligations under this Restated Precedent Agreement and the ~~Phase II~~ Service Agreement have been satisfied in full, and (c) be in a form and content substantially similar to Exhibit D hereto. Pipeline may require, at any time and from time to time, Customer to provide, or cause to be provided, an additional guaranty from a Creditworthy guarantor if the original Guarantor is, at any time, no longer Creditworthy. If Customer becomes Creditworthy after providing a Guaranty, Customer may request a discharge and return of such Guaranty, and following such request Pipeline shall promptly provide such discharge and return.

ii) Letter of Credit. If, at any time and from time to time, during the effectiveness of this Restated Precedent Agreement and/or the ~~Phase II~~ Service Agreement Customer fails to meet the requirements of Sections 13(a) and 13(b)(i) above, Customer shall provide, or cause to be provided, at its sole cost, a standby irrevocable letter of credit (a "Letter of Credit") from a Qualified Institution. For purposes herein, a "Qualified Institution" shall mean a major U.S. or Canadian commercial bank, or the U.S. branch offices of a foreign bank, which is not the Customer or Customer's Guarantor (or a subsidiary or affiliate of the Customer or Customer's Guarantor) and which has assets of at least $10 billion dollars and a credit rating of at least "A-" by S&P, or "A3" by Moody's. Pipeline may require Customer at Customer's cost to substitute a Qualified Institution if the Letter of Credit provided is, at any time, from a financial institution which is no longer a Qualified Institution. The Letter of Credit shall: (i) remain in effect until all payment obligations under this Restated Precedent Agreement and the ~~Phase II~~ Service Agreement have been satisfied in full, (ii) be in a form acceptable to Pipeline, which for purposes herein shall mean in form and content substantially similar to Exhibit E hereto, and (iii) be in the amount equal to twenty-four (24) months of reservation rates based on the MDQ and reservation rates under the ~~Phase II~~ Service Agreement. If Customer becomes Creditworthy after providing a Letter of Credit, Customer may request a discharge and return of such Letter of Credit, and following such request Pipeline shall promptly provide such discharge and return.

c) Demand for Assurances. At any time and from time to time, Pipeline shall have the right to require that Customer demonstrate Customer's, or its Guarantor's, continuing satisfaction of the creditworthiness and credit support requirements in this Section 13. Customer will have a period of five (5) business days to make such demonstration or to furnish credit support acceptable to Pipeline in accordance with this Section 13.

d) Failure to Comply. The failure of Customer to timely satisfy or maintain the requirements set forth in this Section 13 shall in no way relieve Customer of its other obligations under this Restated Precedent Agreement or the ~~Phase II~~ Service Agreement, nor shall it affect Pipeline's right to seek damages or performance under this Restated Precedent Agreement or the ~~Phase II~~ Service Agreement. Further, if, prior to the ~~Phase II~~ Service Commencement Date, Customer fails to timely satisfy or maintain the requirements set forth in this Section 13, then Pipeline may give written notice to Customer of such failure, and, if such failure is has not been cured within five (5) business days following the receipt by Customer of such notice, then Pipeline may elect to suspend or terminate performance under this Restated Precedent Agreement, or to terminate this Restated Precedent Agreement and, if applicable, the ~~Phase II~~ Service Agreement.

e) Term of Credit Provisions and Survival. This Section 13 shall survive the termination of this Restated Precedent Agreement and shall remain in effect until all payment obligations under this Restated Precedent Agreement and the ~~Phase II~~ Service Agreement, if applicable, have been satisfied in full.

f) Replacement Customer Creditworthiness. In the event Customer assigns this Restated Precedent Agreement or the ~~Phase II~~ Service Agreement in accordance with the applicable assignment provision(s), or in the event Customer permanently releases all or a portion of Customer's capacity under the ~~Phase II~~ Service Agreement in accordance with Pipeline's FERC Gas tariff and/or NEB Gas tariff, then the assignee and/or the permanent replacement customer, as applicable, shall be required to satisfy the requirements of this Section 13 with respect to all such assigned or replacement agreements, and upon satisfaction of the requirements of this Section 13, Pipeline shall return to Customer any Guaranty or Letter of Credit which had been furnished by Customer pursuant to this Section 13.

14) Amendments. This Restated Precedent Agreement may not be modified or amended unless the Parties execute written agreements to that effect.

15) Successors; Assignments. Any company which succeeds by purchase, merger, or consolidation of title to all or substantially all of the assets of a Party will be entitled to the rights and will be subject to the obligations of such Party in title under this Restated Precedent Agreement, and in such respect, no consent to such an assignment shall be required from the other Party. In addition, this Restated Precedent Agreement is assignable in whole or in part without the prior written consent of the Customer: (a) by Pipeline or either DTE or Spectra to either or both of: (i) NEXUS Gas Transmission, LLC; and (ii) NEXUS Gas Transmission Canada; (b) by Pipeline to any joint venture or similar collaborative entity created between DTE and Spectra, provided such entity is created for the sole purpose of advancing the Project (it being understood that it is the intention of DTE and Spectra to establish pipeline companies in the name of NEXUS Gas Transmission, LLC and NEXUS Gas Transmission Canada, or another joint venture or similar collaborative, to advance the Project); or (c) between DTE and Spectra, in respect of each Party's interests in the Project.

Otherwise, neither Customer nor Pipeline may assign any of its rights or obligations under this Restated Precedent Agreement without the prior written consent of the other Party hereto, such consent not to be unreasonably withheld. Notwithstanding the foregoing, Pipeline shall have the right, without obtaining Customer's consent, to pledge or assign its rights under this Restated Precedent Agreement, the ~~Phase II~~ Service Agreement or the ~~Phase II~~ Rate Agreement as collateral security for indebtedness incurred by Pipeline (or by an affiliate of Pipeline) for the Project.

16) <u>No Third-Party Rights.</u> Except as expressly provided for in this Restated Precedent Agreement, nothing herein expressed or implied is intended or shall be construed to confer upon or give to any person not a Party hereto any rights, remedies or obligations under or by reason of this Restated Precedent Agreement.

17) <u>Joint Efforts: No Presumptions.</u> Each and every provision of this Restated Precedent Agreement shall be considered as prepared through the joint efforts of the Parties and shall not be construed against either Party as a result of the preparation or drafting thereof. It is expressly agreed that no consideration shall be given or presumption made on the basis of who drafted this Restated Precedent Agreement or any specific provision hereof.

18) <u>Recitals and Representations.</u> The recitals and representations appearing first above are hereby incorporated in and made a part of this Restated Precedent Agreement.

19) <u>Choice of Law.</u> This Restated Precedent Agreement shall be governed by, construed, interpreted, and performed in accordance with the laws of the State of Ohio, without recourse to any laws governing the conflict of laws.

20) <u>Notices.</u> Except as herein otherwise provided, any notice, request, demand, statement, or bill provided for in this Restated Precedent Agreement, or any notice which either Party desires

to give to the other, must be in writing and will be considered duly delivered when mailed by registered or certified mail or overnight courier or when provided by personal delivery or electronic mail to the other Party's address set forth below:

Pipeline: Vice President, Business Development
5400 Westheimer Court
Houston, TX 77056
brmckerlie@spectraenergy.com
Phone – (713) 627-4582
Fax – (713) 627-4727

Customer: Director, Energy Supply and Policy
500 Consumers Road
North York, Ontario
M1K 5E3
Jamie.LeBlanc@enbridge.com
Phone - (416) 495-5241
Fax - (416) 495-6072

or at such other address as either Party designates by written notice. Routine communications, including monthly statements, will be considered duly delivered when mailed by registered mail, certified mail, ordinary mail, or overnight courier or when provided by electronic mail to the person and at the addresses noted above or as otherwise designated pursuant to this Section 20.

21) Waivers. The waiver by either Party of a breach or violation of any provision of this Restated Precedent Agreement will not operate as or be construed to be a waiver of any subsequent breach or violation hereof.

22) Counterparts. This Restated Precedent Agreement may be executed in any number of counterparts, each of which will be an original, but such counterparts together will constitute one and the same instrument.

23) Headings. The headings contained in this Restated Precedent Agreement are for reference purposes only and shall not affect the meaning or interpretation of this Restated Precedent Agreement.

24) Governmental Authorizations. Notwithstanding any provision to the contrary, each provision of this Restated Precedent Agreement shall be subject to all applicable laws, statutes, ordinances, regulations, rules, court decisions and Governmental Authorizations.

25) Definitions. Capitalized terms used herein have the meanings ascribed to them in the body of this Restated Precedent Agreement, and for the purposes of reference only are listed in Exhibit F attached hereto.

26) Entire Agreement. This Restated Precedent Agreement and the other agreements contemplated herein to be executed and delivered by the Parties embody the complete agreement and understanding among the Parties with respect to the subject matter hereof and supersede and pre-empt any prior understandings, agreements (including, without limitation, the Original Precedent Agreement) or representations by or among the Parties, written or oral, which may have related to the subject matter hereof in any way.

[signature page follows]

IN WITNESS WHEREOF, the Parties hereto have caused this Restated Precedent Agreement to be duly executed by their duly authorized officers as of the day and year first above written.

DTE PIPELINE COMPANY	ENBRIDGE GAS DISTRIBUTION, INC.
By: ______________________________	By: ______________________________
Title: ____________________________	Title:______________________________

SPECTRA ENERGY TRANSMISSION, LLC

By: ______________________________

Title: ____________________________

<u>EXHIBIT A</u>

<u>Form of Service Agreement</u>

See Attached.

EXHIBIT B

Intentionally Left Blank.

EXHIBIT C

Capital Cost Tracking Adjustment for Statement of Negotiated Rates

~~New US Phase II~~Project Facilities

~~Capital Cost Estimate U.S. –~~ Pipeline and Customer acknowledge that the capital costs attributable to the ~~construction of the Phase II Facilities that are required to be constructed and owned by Pipeline or constructed and owned by third parties on third party owned existing pipeline systems for the provision of Customer's Phase II Service (the "**New US Phase II Facilities**")~~Project Facilities, which capital costs will underlie a portion of the Reservation Rate for ~~Customer's Phase II Service are reasonably estimated to be $1,625,000,000.00 (U.S.). In accordance with Section 3(d)(ii)(3) of the Restated Precedent Agreement, Pipeline will deliver to Customer a final capital cost estimate (the "**Final U.S. Capital Cost Estimate**") for the New US Phase II Facilities, which estimate will underlie a portion of the Final Reservation Rate (as defined in Section 3(d)(ii)(3) of the Restated Precedent Agreement) for Customer's Phase II Service (as further described in the final revised Rate Breakdown to be provided by Pipeline to Customer in accordance with Section 3(d)(ii)(3)). The Final U.S. Capital Cost Estimate will be provided substantially in the same form as an Exhibit K – Cost of Facilities (as defined in the Federal Energy Regulatory Commission's Code of Federal Regulations) ("**Exhibit K**") and will be included with the certificate application filed by Pipeline with the Federal Energy Regulatory Commission ("**Commission**") for Phase II of the Project~~firm transportation service for the Project, will be reflected in the Final Capital Cost Estimate to be provided to Customer by Pipeline in accordance with Sections 3(d)(ii)(2) and 3(d)(ii)(3).

Negotiated Reservation Rate Adjustment~~.~~

The Final Estimated Reservation Rate will be adjusted, pursuant to the provisions set forth herein, to reflect any differences between the Final ~~U.S.~~ Capital Cost Estimate and the actual amount of capital costs attributable to the ~~New US Phase II Facilities, as reflected by Pipeline in an updated cost report for the New US Phase II~~Project Facilities.

Pipeline will adjust the portion of the Final Estimated Reservation Rate attributable to the Project Facilities as set forth in the final Rate Breakdown (the "**Project Facilities Rate Portion**") at least thirty (30) days, but not more than sixty (60) days, prior to the Service Commencement Date. The adjustment to the Project Facilities Rate Portion will be based on a comparison between the Final Capital Cost Estimate and an updated cost report prepared by Pipeline and provided to Customer which updates the estimate of the capital costs for the Project Facilities, substantially in the form of an Exhibit K (the "~~**Actual U.S.**~~**Updated Capital Cost**"). Pipeline will file such ~~Actual U.S.~~Updated Capital Cost report with the Federal Energy Regulatory Commission ("Commission") at least thirty (30) days, but not more than sixty (60) days, prior to the ~~Phase II~~ Service Commencement Date.

In making the adjustment described above, Pipeline will adjust ~~such portion of the Final Reservation Rate attributable to the New US Phase II~~the Project Facilities ~~(the "**New U.S. Facility**~~ Rate Portion~~")~~ to reflect the percentage increase or decrease between the ~~Actual U.S.~~Updated Capital Cost and the Final ~~U.S.~~ Capital Cost Estimate. In the event that the ~~Actual U.S.~~Updated Capital Cost exceeds the Final ~~U.S.~~ Capital Cost Estimate, the ~~New U.S. Facility~~Project Facilities Rate Portion of the Final ~~U.S.~~Estimated Reservation Rate will be adjusted upward by multiplying it to the ratio of the ~~Actual U.S.~~Updated Capital Cost to the Final ~~U.S.~~ Capital Cost Estimate; provided that, notwithstanding any other provision contained herein, if the ~~Actual U.S.~~Updated Capital Cost exceeds the Final ~~U.S.~~ Capital Cost Estimate by more than 15%, then the multiplier to the ~~New U.S. Facility~~Project Facilities Rate Portion will be 1.15. ~~In the event that the Actual U.S.~~ For the avoidance of doubt, in any event, the maximum upward adjustment to the Project Facilities Rate Portion shall be capped at 1.15 of what was set forth in the Rate Breakdown for the Project Facilities Rate Portion provided by Pipeline pursuant to Section 3(d)(ii)(3). In the event that the Updated Capital Cost is less than the Final ~~U.S.~~ Capital Cost Estimate, the ~~New U.S. Facility~~Project Facilities Rate Portion of the Final Estimated Reservation Rate will be adjusted downward by multiplying it to the ratio of the ~~Actual U.S.~~Updated Capital Cost to the Final ~~U.S.~~ Capital Cost Estimate; provided that, notwithstanding any other provision contained herein, if the ~~Actual U.S.~~Updated Capital Cost is less than the Final ~~U.S.~~ Capital Cost Estimate by more than 15%, then the multiplier to the ~~New U.S. Facility~~Project Facilities Rate Portion will be .85.~~Recourse Reservation Rate Adjustment. In the case of an upward adjustment to the Final Reservation Rate, Pipeline will file the Actual U.S. Capital Cost report, together with an adjusted recourse rate applicable to transportation service for Phase II, with the Commission at least thirty (30) days, but no more than sixty (60) days, prior to the Phase II Service Commencement Date. In the case of a~~ For the avoidance of doubt, in any event, the maximum downward adjustment to the ~~Final Reservation Rate, Pipeline has the right, but not any obligation, to prepare and file such Actual U.S. Capital Cost report and/or an adjustment to the recourse rate applicable to transportation service for Phase II with the Commission.~~Project Facilities Rate Portion shall be capped at .85 of what was set forth in the Rate Breakdown for the Project Facilities Rate Portion provided by Pipeline pursuant to Section 3(d)(ii)(3). The reservation rate resulting from the adjustment provided for in this paragraph shall be the "**Updated Reservation Rate**".

~~True-Up. No~~Pipeline will make a final adjustment to the Project Facilities Rate Portion no later than 210 days after the ~~Phase II~~ Service Commencement Date. In making the final adjustment, Pipeline ~~will file with the Commission an adjustment to Customer's then-effective adjusted Reservation Rate to reflect any increase or decrease between the Final U.S. Capital Cost Estimate and the final actual U.S. capital costs ("**Final Actual U.S. Capital Costs**") as set forth in Pipeline's post-construction cost report filed with the Commission pursuant to Part 157.20(c)(3) of Title 18 of the Code of Federal Regulations.~~ shall prepare and provide to Customer a final cost report which sets forth the actual capital costs for the Project Facilities, substantially in the form of an Exhibit K ("**Final Capital Cost**"). In the event the Final Capital Cost exceeds the Updated Capital Cost, then the Project Facilities Rate Portion of the Updated Reservation Rate will be adjusted by multiplying the Project Facilities Rate Portion of the Final Estimated Reservation Rate to the ratio of the Final Capital Cost to the Final Capital Cost Estimate; provided that, in any event, the maximum upward adjustment to the Project Facilities Rate Portion shall be capped at 1.15 of what was set forth in the Rate Breakdown for the Project Facilities Rate Portion provided by Pipeline pursuant to Section 3(d)(ii)(3). In the event the Final Capital Cost is less than the

Updated Capital Cost, then the Project Facilities Rate Portion of the Updated Reservation Rate will be adjusted by multiplying the Project Facilities Rate Portion of the Final Estimated Reservation Rate to the ratio of the Final Capital Cost to the Final Capital Cost Estimate; provided that, in any event, the maximum downward adjustment to the Project Facilities Rate Portion shall be capped at .85 of what was set forth in the Rate Breakdown for the Project Facilities Rate Portion provided by Pipeline pursuant to Section 3(d)(ii)(3). The reservation rate resulting from the adjustment provided for in this paragraph shall be the “**Final Reservation Rate**”.

In the event that the adjusted Reservation Rate decreases because the Final ~~Actual U.S.~~ Capital ~~Costs are~~Cost is less than the ~~Final U.S.~~Updated Capital Cost~~ Estimate~~, Pipeline will refund Customer an amount (including interest at the Commission~~'~~’s approved interest rate pursuant to 18 C.F.R. §154.501, hereafter the ~~"~~“**FERC Interest Rate**~~"~~”) equal to the difference between the revenue received from Customer for the time period that Customer paid the Updated Reservation Rate and the revenue that Pipeline would receive for such ~~rates for the~~ time period ~~that~~had Customer paid the ~~higher rate.~~Final Reservation Rate. In the event that the adjusted Reservation Rate increases because the Final ~~Actual U.S.~~ Capital ~~Costs are~~Cost is more than the ~~Final U.S.~~Updated Capital Cost~~ Estimate~~, Customer will pay Pipeline an amount (including interest at the FERC Interest Rate) equal to the difference between ~~such rates for the time period that Customer paid such lower rate~~the revenue received from Customer for the time period that Customer paid the Updated Reservation Rate and the revenue that Pipeline would have received for the time period had Customer paid the Final Reservation Rate.

Recourse Reservation Rate Adjustment

In the case of an upward adjustment to the Final Estimated Reservation Rate, Pipeline will file the Updated Capital Cost report, together with an adjusted recourse rate applicable to transportation service for the Project, with the Commission at least thirty (30) days, but no more than sixty (60) days, prior to the Service Commencement Date. In the case of a downward adjustment to the Final Estimated Reservation Rate, Pipeline has the right, but not any obligation, to prepare and file such Updated Capital Cost report and/or an adjustment to the recourse rate applicable to transportation service for the Project with the Commission.

Cost Reports~~:~~

Pipeline will prepare the ~~Actual U.S.~~Updated Capital Cost report in accordance with Section 157.14(a)(13) of Title 18 of the Code of Federal Regulations. Such report will reflect Pipeline~~'~~’s reasonable good faith estimate at the time of the total capital costs attributable to ~~New US Phase II~~Project Facilities as constructed. Pipeline will prepare the Final ~~Actual U.S.~~ Capital Cost report in accordance with Section 157.14(a)(13) of Title 18 of the Code of Federal Regulations. Such report will reflect Pipeline~~'~~’s ~~final~~ actual capital costs attributable to the ~~New US Phase II~~Project Facilities as constructed.

EXHIBIT D

Form of Guarantee

See Attached.

EXHIBIT E

Form of Letter of Credit

See Attached.

EXHIBIT F

DEFINITIONS

1) **Definitions**

In the Restated Precedent Agreement:

a) **"Capital Cost Tracking Adjustment"** has the meaning ascribed to that term in Section 3(d)(ii)(3).

~~b) **"Class III Estimate"** has the meaning ascribed to that term in Section 3(d)(ii)(3)~~

b) ~~c)~~ "**Creditworthy**" has the meaning ascribed to that term in Section 12(a).

c) ~~d)~~ "**Customer**" has the meaning ascribed to that term in the recitals.

d) ~~e)~~ "**Customer's Authorizations**" has the meaning ascribed to that term in Section 2(a).

e) ~~f)~~ "**Customer's ~~Phase II~~ Service**" has the meaning ascribed to that term in Section 3(b).

f) ~~g)~~ "**Dawn**" has the meaning ascribed to that term in the recitals.

g) ~~h)~~ "**Default**" has the meaning ascribed to that term in Section 10.

h) ~~i)~~ "**Default Notice**" has the meaning ascribed to that term in Section 10.

i) ~~j)~~ "**DTE**" has the meaning ascribed to that term in the recitals.

j) ~~k)~~ "**Effective Date**" has the meaning ascribed to that term in the recitals.

k) ~~l)~~ "**Enbridge**" has the meaning ascribed to that term in the recitals.

l) ~~m)~~ "**Estimated ~~Phase II~~ Commencement Date**" has the meaning ascribed to that term in Section 3(c).

m) ~~n)~~ **"~~Estimated Phase II Rate~~Exhibit K"** has the meaning ascribed to that term in ~~Section 3(d)(ii)(2)~~the FERC regulations in Title 18 of the Code of Federal Regulations.

n) ~~o)~~ "**FERC**" has the meaning ascribed to that term in Section 1(a).

o) ~~p)~~ "**Final Estimated Reservation Rate**" has the meaning ascribed to that term in Section 3(d)(ii)(3).

p) **"Final Reservation Rate"** has the meaning ascribed to that term in Exhibit C.

q) **"Final Capital Cost"** has the meaning ascribed to that term in Exhibit C.

r) **"Final Capital Cost Estimate"** has the meaning ascribed to that term in Section 3(d)(ii)(3).

s) ~~q)~~ "**Force Majeure**" has the meaning ascribed to that term in Section 9(c).

t) ~~r)~~ "**Forms of Commercial Agreements**" has the meaning ascribed to that term in Section 3(b).

u) ~~s)~~ "**Governmental Authorizations**" has the meaning ascribed to that term in Section 1(a).

v) ~~t)~~ "**Greenfield Facilities – Kensington to Willow Run**" has the meaning ascribed to that term in Section 2(d)(i)(1).

w) ~~u)~~ "**Guarantor**" has the meaning ascribed to that term in Section 13(b)(i).

x) ~~v)~~ "**Guaranty**" has the meaning ascribed to that term in Section 13(b)(i).

y) ~~w)~~ "**In-Service Date Notice**" has the meaning ascribed to that term in Section 4(b).

z) ~~x)~~ "**Initial Receipt Point Information**" has the meaning ascribed to that term in Section 1(c).

aa) ~~y)~~ "**International Border**" has the meaning ascribed to that term in the recitals.

bb) ~~z)~~ "**Letter of Credit**" has the meaning ascribed to that term in Section 13(b)(ii).

cc) ~~aa)~~ "**MDDO**" has the meaning ascribed to that term in Section 3(b).

dd) ~~bb)~~ "**MDRO**" has the meaning ascribed to that term in Section 3(b).

ee) ~~cc)~~ "**MDQ**" has the meaning ascribed to that term in Section 3(b).

ff) ~~dd)~~ "**Moody's**" has the meaning ascribed to that term in Section 13(a).

gg) ~~ee)~~ "**NEB**" has the meaning ascribed to that term in Section 1(a).

~~ff) "**New Phase II Facilities**" means the Phase II Facilities that will be required to be constructed and owned by Pipeline or constructed and owned by a third party on third party owned existing pipeline systems for the provision of Customer's Phase II Service.~~

hh) ~~gg)~~ "**Original Precedent Agreement**" has the meaning ascribed to that term in the recitals.

ii) ~~hh)~~ "**Open Season**" has the meaning ascribed to that term in the recitals.

jj) ~~ii)~~ "**OEB**" has the meaning ascribed to that term in Section 3(b).

kk) ~~jj)~~ "**Party**" or "**Parties**" has the meaning ascribed to that term in the recitals.

ll) ~~kk) "**Phase I**~~ "**Project Facilities**" has the meaning ascribed to that term in ~~the recitals.~~Section 3(d)(ii)(2)

~~ll) "**Phase II**" has the meaning ascribed to that term in the recitals.~~

mm) "**~~Phase II~~Project Facilities Rate Portion**" has the meaning ascribed to that term in ~~Section 3(d)(ii)(2)~~Exhibit C.

nn) "**~~Phase II~~ Rate Agreement**" has the meaning ascribed to that term in Section 3(d)(ii)(3).

oo) "**~~Phase II~~ Service Agreement**" has the meaning ascribed to that term in Section 3(b).

pp) "**~~Phase II~~ Service Commencement Date**" has the meaning ascribed to that term in Section 4(b).

qq) "**Pipeline**" has the meaning ascribed to that term in the recitals.

rr) "**Pre-Service Costs**" has the meaning ascribed to that term in Section 8.

ss) "**Project**" has the meaning ascribed to that term in the recitals.

tt) "**Qualified Institution**" has the meaning ascribed to that term in Section 13(b)(ii).

uu) "**Rate Breakdown**" has the meaning ascribed to that term in Section 3(d)(ii)(3)

vv) "**Reservation Rate**" has the meaning ascribed to that term in Section 3(d)(i).

ww) "**Restated Precedent Agreement**" has the meaning ascribed to that term in the headings.

~~xx) "**Revised Phase II Rate**" has the meaning ascribed to that term in Section 3(d)(ii)(3).~~

xx) ~~yy)~~ "**ROFR**" has the meaning ascribed to that term in Section 3(f).

yy) ~~zz)~~ "**S&P**" has the meaning ascribed to that term in Section 13(a).

zz) ~~aaa)~~ "**Spectra**" has the meaning ascribed to that term in the recitals.

aaa) **"Updated Capital Cost"** has the meaning ascribed to such term in Exhibit C.

bbb) **"Updated Reservation Rate"** has the meaning ascribed to that term in Exhibit C.

ccc) ~~bbb)~~ "**Willow Run**" has the meaning ascribed to that term in the recitals.

NEXUS GAS TRANSMISSION

June 3, 2015

Jamie LeBlanc
Director, Energy Supply and Policy
Enbridge Gas Distribution Inc.
500 Consumers Road
North York, Ontario
M1K 5E3

Re: NEXUS-US Negotiated Rate Letter Agreement for Service Agreement No. 00003

Dear Jamie:

DTE Pipeline Company ("DTE") and Spectra Energy Transmission, LLC ("Spectra") (where DTE and Spectra are collectively referred to herein as "Pipeline") and Enbridge Gas Distribution Inc. ("Customer") have entered into a Restated Precedent Agreement dated December 17, 2014, amended as of June 3, 2015, to contract for firm transportation service as part of the NEXUS Gas Transmission Project (the "Precedent Agreement"). The Precedent Agreement contemplates, *inter alia*, that Pipeline and Customer will enter into a negotiated rate agreement applicable to service provided by Pipeline to Customer pursuant to the terms and conditions contained in the Service Agreement. Customer acknowledges that it is electing negotiated rates as an alternative to the recourse rates that will be available for service under the NEXUS FERC Gas Tariff, as it may be in effect from time to time. The NEXUS FERC Gas Tariff will include appropriate provisions allowing for Pipeline to provide service to customers at negotiated rates in accordance with FERC's negotiated rates policies. In this letter and the attached Pro Forma Statement of Negotiated Rates, capitalized terms not otherwise defined herein and therein which are defined terms in the Precedent Agreement and Service Agreement, or either of them, as applicable, shall have the meanings given to them in such agreements, as applicable

Pipeline and Customer hereby agree that the provisions of the attached *Pro Forma* Statement of Negotiated Rates reflect the terms of their agreement, including the effectiveness of the negotiated rate. After execution of this letter by both Pipeline and Customer and on or about 30 to 60 days prior to the Service Commencement Date, Pipeline shall file a Statement of Negotiated Rates with the Federal Energy Regulatory Commission ("FERC") containing rate-related provisions identical to those provisions on the attached *Pro Forma* Statement of Negotiated Rates in accordance with the General Terms and Conditions of the NEXUS FERC Gas Tariff. To the extent necessary to conform terms used in the NEXUS FERC Gas Tariff when filed with terms used in this negotiated rate agreement, the attached *Pro Forma* Statement of Negotiated Rates may be revised before Pipeline files it with FERC to conform to the NEXUS FERC Gas Tariff.

If the foregoing accurately sets forth your understanding of the matters contemplated herein, please so indicate by having a duly authorized representative sign in the space provided below and returning an original signed copy to the undersigned.

Sincerely,

NEXUS GAS TRANSMISSION (PIPELINE)

(Original Signed)

____

Name: David Slater
President – DTE Gas Storage & Pipelines
DTE Pipeline Company

(Original Signed)

____

Name: Brian McKerlie
Vice President
Spectra Energy Transmission, LLC

ACCEPTED AND AGREED TO
THIS 3rd DAY OF JUNE, 2015

ENBRIDGE GAS DISTRIBUTION LIMITED (CUSTOMER)

(Original Signed)

____

Name: Malini Giridhar
Title: Vice President, Gas Supply & Business Development

(Original Signed)

____

Name: Glen Beaumont
Title: President

STATEMENT OF NEGOTIATED RATES 1/ 8/

Customer Name: Enbridge Gas Distribution Inc.

Service Agreement: Service Agreement No. 00003 2/ 4/

Project: As used in this Negotiated Rate Agreement, the term "Project" shall mean an approximately 250-mile greenfield pipeline and related facilities extending from eastern Ohio to various interconnections in Michigan, along with subscriptions of firm pipeline capacity on existing or expanding pipeline systems in Michigan for ultimate delivery to the international border between the United States and Canada near St. Clair, Michigan.

Term of Negotiated Rate: The term of this negotiated rate commences on the Service Commencement Date and continues for the Primary Term.

Rate Schedule: FT

MDQ: 110,000 Dth/d

Customer shall pay the following Reservation Rate, Commodity Rate, Fuel and Other Charges for service provided pursuant to Service Agreement 00003:

Reservation Rate: During the Primary Term, shall be as follows:

(1) Customer shall pay on a monthly basis a negotiated Reservation Charge per Dth per day of Customer's MDQ under Service Agreement No. 00003, equal to US$0.70, subject to further adjustment as set forth herein and in the Restated Precedent Agreement dated December 17, 2014, amended as of June 3, 2015 (the "Precedent Agreement"). 3/ 5/ 6/ 7/

(2) Customer shall also pay all other FERC approved demand charges and demand surcharges applicable to Customer's Contract No. 00003. 7/

Usage Rate and Fuel Rate: During the Primary Term, shall be as follows:

(1) The Usage-1 Charge shall be zero ($0.00) multiplied by the quantity of gas, in Dekatherms, delivered during the applicable Day. For all purposes hereunder, the "Usage-1 Charge" shall mean the charge at the negotiated commodity rate for volumes up to Customer's MDQ.

(2) The Usage-2 Charge shall be the maximum applicable Rate Schedule FT recourse Usage-2 Charge multiplied by the quantity of gas, in Dekatherms, delivered during the applicable Day that qualifies under NEXUS Pipeline's Rate Schedule FT for the Usage-2 Charge. For all purposes hereunder, the "Usage-2 Charge" shall mean the the maximum recourse commodity charge rate applicable to Authorized Overrun

quantities delivered by the Pipeline multiplied by the quantity of gas, in Dekatherms, delivered during the applicable Day in excess of the MDQ under the Service Agreement, plus the applicable Fuel Rate as provided immediately below and shrinkage and lost and unaccounted for gas charges applicable to Rate Schedule FT, in-kind.

(3) Customer shall also pay the Fuel Rate equal to the applicable Fuel Rate under NEXUS Pipeline's Rate Schedule FT (as calculated based upon the Commission approved ASA methodology and / or application of any Commission approved tracking mechanism), which Fuel Rate is currently anticipated to be 1.6%-2.6%%, and all other FERC approved usage charges and usage surcharges applicable to Customer's Contract No. 0003. 7/

Primary Receipt Point: The head of the Project facilities in eastern Ohio, which shall be the most upstream mainline receipt point into the greenfield pipeline portion of the Project, as Pipeline shall notify Customer, and which is currently anticipated to be at or near Kensington, OH.

Primary Delivery Point: The point of interconnection with Vector Pipeline L.P.'s Milford Junction meter station near Highland, Michigan.

Recourse Rate(s): The Recourse Rate(s) applicable to this service is the applicable maximum rate(s) stated on Pipeline's Statement of Rates for Rate Schedule FT as such rate may be in effect from time to time. Customer acknowledges that the negotiated rate may be lower than or higher than the applicable Recourse Rate as it may be in effect from time to time.

MDQ Adjustment: As provided in Section 2(d) of the Precedent Agreement, Customer shall have the right, subject to available capacity, regulatory approvals, and the terms of Pipeline's FERC Gas Tariff, to increase its MDQ under the Service Agreement up to 150,000 Dth/d. Pipeline will notify Customer whether capacity is available to satisfy such request to increase Customer's MDQ, taking into consideration the terms of Pipeline's FERC Gas Tariff. If Pipeline, taking into consideration the terms of its FERC Gas Tariff, can only accommodate an increase to Customer's MDQ that is less than requested, Pipeline shall promptly notify Customer of the amount of the requested increase that can be accommodated, and Customer shall have ten (10) days from receipt of such notice to either: (i) agree to increase its MDQ to the amount that can be accommodated; or (ii) retract its request for an increase. If there is to be an increase to Customer's MDQ pursuant to Section 2(d), then Pipeline and Customer shall amend the Service Agreement to reflect the increase as follows:

i) if Customer requests an increase to its MDQ prior to the Service Commencement Date to be effective on the Service Commencement Date, and as a result Customer's MDQ is increased to 150,000 Dth/d, then:

(1) the Reservation Rate applicable to Customer's entire MDQ (including any increase) pursuant to the Service Agreement and as set forth herein shall be reduced such that Customer's effective Reservation Rate for service on the portion of the Project utilizing newly constructed facilities extending from a receipt point(s) to be located at or near Kensington, Ohio to an interconnection point(s) to be located at or near Willow Run, Michigan (the "Greenfield Facilities – Kensington to Willow Run") is equal to the effective Reservation Rate to be paid by Union Gas Limited for service on the Greenfield Facilities – Kensington to Willow Run. As of the effective date hereof, Pipeline estimates that Customer's Reservation Rate would be reduced by approximately $0.015 per Dth/d, however, Pipeline and Customer acknowledge and agree that Pipeline's estimate is non-binding and any change to Customer's Reservation Rate for these purposes will be subject to the rate adjustment provisions set forth herein; and

(2) Customer shall be entitled to the rights granted under Section 3(e) of the Precedent Agreement.

(ii) If Customer requests an increase to its MDQ after the Service Commencement Date or prior to the Service Commencement Date but to be effective after the Service Commencement Date, then:

(1) Customer's request shall be subject to the capacity award mechanism, including any posting and bidding requirements, set forth in Pipeline's FERC Gas Tariff; and

(2) if, pursuant to the terms of Pipeline's FERC Gas Tariff, Customer is awarded the requested capacity and its MDQ is increased to 150,000 Dth/d to be effective anytime on or before November 1, 2020, then the Reservation Rate applicable to Customer's entire MDQ (including any increase) pursuant to the Service Agreement and as set forth herein for the firm transportation service shall be reduced, as of the effective date of the increased MDQ, such that Customer's effective Reservation Rate for service on the Greenfield Facilities – Kensington to Willow Run is equal to the effective Reservation Rate paid by Union Gas Limited for service on the Greenfield Facilities – Kensington to Willow Run. As of the effective date hereof, Pipeline estimates that Customer's Reservation Rate would be reduced by approximately $0.015 per Dth/d as of the effective date of Customer's increased MDQ, however, Pipeline and Customer acknowledge and agree that Pipeline's estimate is non-binding and any change to Customer's Reservation Rate for these purposes will be subject to the rate adjustment provisions set forth herein.

(iii) if Customer's MDQ is increased to an amount that is less than 150,000 Dth/d, the terms of service including Customer's Reservation Rate shall remain unchanged for all of Customer's MDQ (including any increase).

<u>FOOTNOTES:</u>

1/ This negotiated rate transaction does not deviate in any material respect from the form of service agreement to be set forth in Pipeline's FERC Gas Tariff.

2/ This negotiated rate shall apply only to transportation service under Service Agreement No. 00003, up to Customer's MDQ, using the Primary Receipt Point(s) and Primary Delivery Point(s) designated herein, and including at the negotiated rate any secondary receipt and delivery points available under Rate Schedule FT that are within the path of Customer's Primary Receipt Point(s) and Primary Delivery Point(s) ("Customer In Path Nominations", and the total scheduled quantity of Customer In Path Nominations for a given day, the "Customer Daily In Path Quantity"), except as otherwise provided herein.

Customer nominations from or to points outside of the path of Customer's primary point(s) are referred to hereinafter as "Customer Out of Path Nominations", and the total scheduled quantity of Customer Out of Path Nominations for a given day is hereinafter referred to as the "Customer Daily Out of Path Quantity". Related replacement shipper nominations that are outside of the path of Customer's primary points are referred to hereinafter as "Related Replacement Shipper Daily Out of Path Nominations", and the total scheduled quantity of Related Replacement Shipper Daily Out of Path Nominations (across all related replacement contracts) is hereinafter referred to as the "Related Replacement Shipper Daily Out of Path Quantity". The sum of the Customer Daily Out of Path Quantity plus the Related Replacement Shipper Daily Out of Path Quantity for a given day shall hereinafter be referred to as the Total Daily Out of Path Quantity. The Total Daily Out of Path Quantity shall be charged to Customer at the greater of the then effective maximum applicable rates for Rate Schedule FT, or the applicable negotiated rates, as more fully detailed below.

The reservation charges pursuant to this negotiated rate agreement will be calculated daily. When the negotiated Reservation Rate set forth above and applicable to Customer's service hereunder is <u>greater than or equal to</u> the then effective maximum applicable recourse reservation rate (inclusive of all reservation surcharges and other reservation charges) for Rate Schedule FT, the daily equivalent negotiated Reservation Rate shall apply each day to the MDQ. When the negotiated Reservation Rate set forth above is <u>less than</u> the then effective maximum applicable recourse reservation rate for Rate Schedule FT (inclusive of all reservation surcharges and other reservation charges), (1) the negotiated Reservation Rate shall apply each day to the greater of a) zero or b) the MDQ less the Total Daily Out of Path Quantity and (2) the daily equivalent maximum applicable recourse reservation rate (inclusive of all reservation surcharges and other reservation charges) applicable to service under Contract No. 00003 as effective from time to time under Pipeline's Rate Schedule FT-1 shall apply each day to the lesser of a) the MDQ or b) the Total Daily Out of Path Quantity.

The negotiated Usage-1 Rate as set forth above shall apply to the Customer Daily In Path Quantity. When the negotiated Usage-1 Rate set forth above is <u>greater than or equal to</u> the then effective maximum applicable recourse Usage-1 rate (inclusive of all usage surcharges and other usage charges) for Rate Schedule FT, the negotiated Usage-1 Rate shall apply to the Total Daily Out of Path Quantity, less a credit for the total Usage-1 charges assessed for the Related Replacement Shipper Daily Out of Path Quantity. When the negotiated Usage-1 Rate set forth above is <u>less than</u> the then effective maximum applicable recourse Usage-1 rate (inclusive of all usage surcharges and other usage charges) for Rate Schedule FT, the then effective maximum applicable recourse Usage-1 rate (inclusive of all usage surcharges and other usage charges) for Rate Schedule FT shall apply to the Total Daily Out of Path Quantity, less a credit for the total Usage-1 charges assessed for the Related Replacement Shipper Daily Out of Path Quantity.

The negotiated Fuel Rate as set forth above shall apply to the Customer Daily In Path Quantity and to the Customer Daily Out of Path Quantity.

The negotiated Usage-2 rate as set forth above shall apply to the portion of both the Customer Daily In Path Quantity and the Customer Daily Out of Path Quantity that qualifies under NEXUS Pipeline's Rate Schedule FT for the Usage-2 charge.

Provided, if Customer changes its primary point(s) listed above or the related MDROs or MDDOs at any time or from time to time, pursuant to the provisions of Pipeline's FERC Gas Tariff but without the written approval of Pipeline to continue the negotiated rate, Pipeline shall have the option to terminate this negotiated rate by providing Customer with written notice of Pipeline's intent to do so and, in such case, this negotiated rate shall terminate and Pipeline's maximum applicable Recourse Rates for Rate Schedule FT shall apply for the remaining term of Service Agreement No. 00003, unless and until otherwise mutually agreed in writing between Customer and Pipeline.

3/ Pipeline and Customer acknowledge that the estimate of capital costs attributable to the greenfield facilities necessary to be constructed by Pipeline for the provision of service on the Project (the "Project Facilities"), which underlie a portion of the monthly Reservation Charge described in the Reservation Rate section above, is reflected in a letter dated June 3, 2015 (the "Cost Estimate Letter") provided by Pipeline to Customer in accordance with the Precedent Agreement ("Final Capital Cost Estimate").

4/ Pipeline and Customer agree that Service Agreement No. 00003 is a ROFR Agreement.

5/ The Reservation Charge described in the Reservation Rate section above (for the avoidance of doubt, the "Final Estimated Reservation Rate" as described in the Precedent Agreement) will be adjusted, pursuant to the provisions of this footnote 5, to reflect any difference between the Final Capital Cost Estimate and the actual amount of capital costs attributable to the Project Facilities. Pipeline will adjust the portion of the Final Estimated Reservation Rate attributable to the Project Facilities as set forth in the final Rate Breakdown (the "**Project Facilities Rate Portion**") at least thirty (30) days, but not more than sixty (60) days, prior to the Service Commencement Date. The adjustment to the Project Facilities Rate Portion will be based on a comparison between the Final Capital Cost Estimate and an updated cost report prepared by Pipeline and provided to Customer which updates the estimate of the capital costs for the Project Facilities, substantially in the form of an Exhibit K (the "**Updated Capital Cost**"). Pipeline will file such Updated Capital Cost report with the Federal Energy

Regulatory Commission ("Commission") at least thirty (30) days, but not more than sixty (60) days, prior to the Service Commencement Date.

In making the adjustment described above, Pipeline will adjust the Project Facilities Rate Portion to reflect the percentage increase or decrease between the Updated Capital Cost and the Final Capital Cost Estimate. In the event that the Updated Capital Cost exceeds the Final Capital Cost Estimate, the Project Facilities Rate Portion of the Final Estimated Reservation Rate will be adjusted upward by multiplying it to the ratio of the Updated Capital Cost to the Final Capital Cost Estimate; provided that, notwithstanding any other provision contained herein, if the Updated Capital Cost exceeds the Final Capital Cost Estimate by more than 15%, then the multiplier to the Project Facilities Rate Portion will be 1.15. For the avoidance of doubt, in any event, the maximum upward adjustment to the Project Facilities Rate Portion shall be capped at 1.15 of what was set forth in the Rate Breakdown for the Project Facilities Rate Portion provided by Pipeline pursuant to Section 3(d)(ii)(3) of the Precedent Agreement. In the event that the Updated Capital Cost is less than the Final Capital Cost Estimate, the Project Facilities Rate Portion of the Final Estimated Reservation Rate will be adjusted downward by multiplying it to the ratio of the Updated Capital Cost to the Final Capital Cost Estimate; provided that, notwithstanding any other provision contained herein, if the Updated Capital Cost is less than the Final Capital Cost Estimate by more than 15%, then the multiplier to the Project Facilities Rate Portion will be .85. For the avoidance of doubt, in any event, the maximum downward adjustment to the Project Facilities Rate Portion shall be capped at .85 of what was set forth in the Rate Breakdown for the Project Facilities Rate Portion provided by Pipeline pursuant to Section 3(d)(ii)(3) of the Precedent Agreement. The reservation rate resulting from the adjustment provided for in this paragraph shall be the "**Updated Reservation Rate**".

Pipeline will make a final adjustment to the Project Facilities Rate Portion no later than 210 days after the Service Commencement Date. In making the final adjustment, Pipeline shall prepare and provide to Customer a final cost report which sets forth the actual capital costs for the Project Facilities, substantially in the form of an Exhibit K ("**Final Capital Cost**"). In the event the Final Capital Cost exceeds the Updated Capital Cost, then the Project Facilities Rate Portion of the Updated Reservation Rate will be adjusted by multiplying the Project Facilities Rate Portion of the Final Estimated Reservation Rate to the ratio of the Final Capital Cost to the Final Capital Cost Estimate; provided that, in any event, the maximum upward adjustment to the Project Facilities Rate Portion shall be capped at 1.15 of what was set forth in the Rate Breakdown for the Project Facilities Rate Portion provided by Pipeline pursuant to Section 3(d)(ii)(3) of the Precedent Agreement. In the event the Final Capital Cost is less than the Updated Capital Cost, then the Project Facilities Rate Portion of the Updated Reservation Rate will be adjusted by multiplying the Project Facilities Rate Portion of the Final Estimated Reservation Rate to the ratio of the Final Capital Costs to the Final Capital Cost Estimate; provided that, in any event, the maximum downward adjustment to the Project Facilities Rate Portion shall be capped at .85 of what was set forth in the Rate Breakdown for the Project Facilities Rate Portion provided by Pipeline pursuant to Section 3(d)(ii)(3) of the Precedent Agreement. The reservation rate resulting from the adjustment provided for in this paragraph shall be the "**Final Reservation Rate**".

6/ Prior to filing this statement of negotiated rates to reflect the Updated Capital Cost, the negotiated Reservation Rate stated above will be replaced with the Final Reservation Rate, which is the applicable rate updated to reflect estimated and actual cost increases or decreases according to the cost sharing rate adjustments set forth in footnotes 3 and 5.

7/ Customer agrees to pay the applicable Annual Charge Adjustment surcharge and any existing and any future surcharge or other charge approved by FERC in a generic proceeding or in a Pipeline-specific proceeding, which mechanism recovers cost components not reflected in Pipeline’s initial recourse rates applicable to this FT Service Agreement and which surcharge or other charge is designed to recover costs that are incurred due to a mandate from FERC or any other governmental authority, or otherwise related to pipeline safety or environmental compliance costs associated with Pipeline’s operations pursuant to the NEXUS FERC Gas Tariff.

8/ In this Negotiated Rate Agreement, capitalized terms not otherwise defined herein which are defined terms in the Precedent Agreement and Service Agreement, or either of them, as applicable, shall have the meanings given to them in such agreements, as applicable.

NEXUS
GAS TRANSMISSION

June 3, 2015

Jamie LeBlanc
Director, Energy Supply and Policy
Enbridge Gas Distribution Inc.
500 Consumers Road
North York, Ontario
M1K 5E3

Re: Rate Breakdown and Final Capital Cost Estimate Under Restated Precedent Agreement Dated December 17, 2014, as amended

Dear Jamie:

DTE Pipeline Company ("DTE") and Spectra Energy Transmission, LLC ("Spectra") (where DTE and Spectra are collectively referred to herein as "Pipeline") and Enbridge Gas Distribution Inc. ("Customer") have entered into a Restated Precedent Agreement dated December 17, 2014, as the same has been amended as of June 3, 2015 (the "Precedent Agreement") to contract for firm transportation service as part of the NEXUS Gas Transmission Project. All capitalized terms used but not defined in this letter have the meanings given them in the Precedent Agreement.

The Precedent Agreement provides in Section 3(d)(ii)(3) that Pipeline shall deliver to Customer a Rate Breakdown in connection with the Rate Agreement, consisting of a final breakdown of how Pipeline derived the Final Estimated Reservation Rate reflected in the Rate Agreement, including a breakdown of such portion of the Final Estimated Reservation Rate that is derived from the estimated capital costs associated with the construction of the Project Facilities that will be required to be constructed and owned by Pipeline or constructed and owned by a third party on third party owned existing pipeline systems for the provision of transportation service for the Project. Section 3(d)(ii)(3) further provides that Pipeline shall deliver to Customer an estimate of the capital costs associated with the construction of the Project Facilities (defined as the "Final Capital Cost Estimate").

Consistent with Section 3(d)(ii)(3), the Rate Breakdown and the Final Capital Cost Estimate are set forth below. Consistent with Exhibit C to the Precedent Agreement and the Rate Agreement, such Final Capital Cost Estimate will be the base cost for purposes of comparison to the Updated Capital Cost, the Final Capital Costs and application of the capital cost tracker and rate adjustment provisions of Exhibit C to the Precedent Agreement and the Rate Agreement.

Rate Breakdown

The Final Estimated Reservation Rate, as set forth in the separately provided Rate Agreement, includes the following portion derived from the estimated capital costs associated with the construction of the Project Facilities for Customer's service under the Service Agreement: $0.65 US/dth. For the avoidance of doubt, such amount is the Project Facilities Rate Portion as such term is defined and used in the Precedent Agreement and the Rate Agreement.

Final Capital Cost Estimate

The capital costs associated with construction of the Project Facilities are currently estimated to be $2,019,000,000.00. For the avoidance of doubt, such estimate is the Final Capital Cost Estimate as such term is defined and used in the Precedent Agreement and the Rate Agreement.

If the foregoing accurately sets forth your understanding of the matters contemplated herein, please so indicate by having a duly authorized representative sign in the space provided below and returning an original signed copy to the undersigned.

Sincerely,

NEXUS GAS TRANSMISSION
(PIPELINE)

(Original Signed)

Name: William T. Yardley
Title: President
Spectra Energy Transmission, LLC

ACCEPTED AND AGREED TO
THIS 3rd DAY OF JUNE, 2015

ENBRIDGE GAS DISTRIBUTION INC. (CUSTOMER)

(Original Signed)

Name: Malini Giridhar
Title: Vice President, Gas Supply and Business Development

(Original Signed)

Name: Glen Beaumont
Title: President

Union Gas Limited and Enbridge Gas Distribution, Inc.
NEXUS Gas Transmission – Market Study

May 2015

Prepared by
Sussex Economic Advisors, LLC

I. INTRODUCTION

Sussex Economic Advisors, LLC ("Sussex") was retained by Union Gas Limited ("Union") and Enbridge Gas Distribution, Inc. ("Enbridge"), collectively the Ontario LDCs, to conduct an independent evaluation of the NEXUS Gas Transmission Project (the "Project" or "NEXUS"). The Ontario LDCs have entered into precedent agreements with NEXUS ("Precedent Agreements") in order to secure capacity on the Project. In particular, the Precedent Agreements with NEXUS will: (1) support the development of new natural gas transportation infrastructure; (2) provide a new path to transport natural gas supplies from the Marcellus and Utica shale basins to Dawn, Ontario; (3) provide significant volumes of natural gas to the Dawn Hub; and (4) be a significant investment for the Ontario LDCs. Finally, as discussed in the evidence of the Ontario LDCs, Union and Enbridge are requesting the Ontario Energy Board ("OEB") to pre-approve the cost consequences of the long-term transportation contract with NEXUS as detailed in the NEXUS Precedent Agreements.

DTE Energy Company ("DTE")[1] and Spectra Energy Partners, LP ("Spectra")[2] are the lead developers of NEXUS, which is a proposed 400 kilometer (250 mile), 36-inch greenfield natural gas pipeline that will deliver 1.5 Bcf/day of natural gas supplies from the Appalachian Basin to Ohio, Michigan, and Ontario markets. To facilitate the delivery of natural gas to these markets, NEXUS has executed agreements for pipeline capacity with Vector Pipeline ("Vector"), Texas Eastern Transmission, LP ("Texas Eastern" or "TETCO"), and DTE Gas Company (an indirect wholly owned subsidiary of DTE). With respect to shippers, NEXUS has executed precedent agreements with both "demand pull" entities (*e.g.*, the Ontario LDCs and DTE) and "supply push" entities (*i.e.*, natural gas producers). Finally, NEXUS initiated the Federal Energy Regulatory Commission ("FERC") pre-filing process in 2014, and is expected to enter service in late 2017.[3]

1 DTE is headquartered in Detroit, Michigan and owns regulated electric and natural gas distribution utilities in Michigan, intrastate and interstate natural gas storage and transportation assets, and other related assets. The marketing capitalization of DTE is approximately $15 billion. DTE is rated A3 by Moody's, BBB+ by S&P, and BBB by Fitch Ratings.

2 Spectra is headquartered in Houston, Texas. It is the owner of more than 22,000 miles of interstate natural gas transmission pipelines, and approximately 300 Bcf of natural gas storage assets. Spectra also owns Union Gas Limited. Spectra is rated BBB by S&P, and has a market capitalization of approximately $22 billion.

3 *In Re: Request for Approval to Use the Pre-Filing Process NEXUS Gas Transmission, LLC – NEXUS Gas Transmission Project*, FERC Docket No. PF15-10-000, December 30, 2014; and *In Re: NEXUS Gas Transmission, LLC, NEXUS Gas Transmission Project, Updated Stakeholder List and Project Update*, FERC Docket No. PF15-10-0200, March 20, 2015.

With respect to our assessment of NEXUS, Sussex conducted the following analyses and evaluations:

1. Reviewed current trends in the production and supply of natural gas in certain relevant supply basins;
2. Assessed the benefits associated with contracting for pipeline capacity on the proposed Project;
3. Reviewed the approach used by the Ontario LDCs to evaluate the cost of the NEXUS capacity relative to alternative transportation paths and natural gas supply basins (*i.e.*, landed cost analysis);
4. Reviewed certain risks associated with NEXUS and potential mitigating factors; and
5. Reviewed the regulatory process used in other jurisdictions when considering pre-approval of pipeline transportation contracts.

Based on the results of those analyses, Sussex has the following findings and conclusions:

Natural Gas Market Trends

- The Canadian and U.S. natural gas markets are evolving to accommodate large, emerging sources of natural gas in the U.S. Northeast and Mid-Atlantic (*i.e.*, Marcellus and Utica shale), which is displacing more traditional sources of natural gas (*e.g.*, Western Canada and the Gulf of Mexico) serving eastern markets in the U.S. and Canada.
- The Ontario market has been predominately supplied with natural gas from the Western Canadian Sedimentary Basin ("WCSB"). Since 2006, two market dynamics have contributed to the decrease in natural gas flowing from the WCSB to the Ontario market: (1) increased natural gas consumption within the WCSB for certain market segments (*e.g.*, industrial-oil sands and power generation); and (2) decreased conventional natural gas production from the WCSB.
- The rise of the Marcellus and Utica shale basins as proximate and competitive sources of natural gas for the Ontario market presents new opportunities to source natural gas from these basins.
- The natural gas supply reserves and production in the Marcellus and Utica supply basins are expected to be more than adequate for the term of the NEXUS transportation

agreements. In addition, NEXUS provides access to other pipelines and, therefore, other natural gas supply basins.

- The ability to access these sources of natural gas is premised on sufficient natural gas transportation capacity to deliver Marcellus and Utica natural gas to the Ontario market.

Benefits of NEXUS

- NEXUS will provide numerous reliability and price stability benefits to the Ontario LDCs, including:
    1. Access to proximate and competitive natural gas supply;
    2. Natural gas supply basin diversity;
    3. Enhanced liquidity for natural gas purchases made at the Dawn Hub;
    4. Transportation path diversity;
    5. Transportation cost stability;
    6. Natural gas price index diversity; and
    7. Service flexibility.
- The NEXUS benefits (*e.g.*, reliability, diversity, and price stability) increase the flexibility of the Union and Enbridge natural gas supply portfolios; thus providing additional options to the Ontario LDCs to manage natural gas supply and transportation costs, improve overall reliability, and provide increased priced stability.
- NEXUS will also provide several benefits to other Ontario natural gas market participants (*e.g.,* the power generation segment and direct purchase customers), including: (1) access to new natural gas supply basins; (2) pipeline diversity; and (3) improved liquidity at the Dawn Hub.

Landed Cost Analysis

- Sussex reviewed the landed cost analysis prepared by the Ontario LDCs and concluded that: (1) the approach used by Union and Enbridge is reasonable and consistent with typical landed cost approaches; (2) alternative options were identified and modeled; and (3) the Ontario LDCs' decision process and analysis were documented.

- The landed cost analysis prepared by Union and Enbridge consisted of four components: (1) alternative[4] paths to transport natural gas supply to a specific delivery point were identified; (2) the natural gas supply basin associated with each transportation path was identified; (3) the natural gas supply cost was developed for each path; and (4) the transportation cost for all pipelines within the path was calculated.
- The transportation paths identified and modeled by the Ontario LDCs represent a reasonable range of alternative options to NEXUS. Specifically, the Union landed cost analysis evaluated fifteen transportation paths to the Dawn Hub; and Enbridge identified and modeled four options associated with the NEXUS capacity and seven alternative transportation routes to the Dawn Hub.
- The Union and Enbridge landed cost analyses used reasonable approaches to develop the gas supply cost and transportation cost (*i.e.*, demand, variable, and fuel charges). The landed cost analyses prepared by the Ontario LDCs covered the full contract term (*i.e.*, 15 years) of the capacity obligation outlined in the NEXUS Precedent Agreements.
- As illustrated by the results of the Ontario LDCs' landed cost analyses, the NEXUS transportation path is competitive with the alternatives evaluated.
- Both Union and Enbridge developed appropriate documentation of their approach, analysis and results. In addition, the approach used by Union and Enbridge with respect to their landed cost analysis is reasonable and consistent with typical landed cost analysis. Please see Schedules 4 and 5 of the Union evidence, and Appendices B and C of the Enbridge evidence.

Risk Assessment

- As summarized in Table 1.1 below, Sussex identified and reviewed six categories of risk related to NEXUS. For each risk category, Sussex identified the potential impact on the Project, and the mitigation strategies employed by the Ontario LDCs and NEXUS.

4 For purposes of the Sussex report, the term "alternative" with respect to the Union and Enbridge landed cost analyses includes both existing transportation routes (*i.e.*, paths from the Ontario LDCs' existing supply portfolios), as well as certain proposed transportation routes (*e.g.*, Rover Pipeline).

Table 1.1: NEXUS Risk Review

Risk Category	Risk Mitigation
Construction Risk	The Ontario LDCs were able to mitigate their exposure to construction-related risks by entering into negotiated rate agreements. A negotiated rate agreement apportions the majority of the risk associated with schedule delays and construction cost overruns to the party that is best positioned to manage that risk (*i.e.*, the project developer). In addition, the Ontario LDCs have certain termination rights that can also facilitate management of this risk.
Demand Forecasting Risk	The Ontario LDCs' Precedent Agreements with NEXUS are not dependent on load growth, as the NEXUS capacity will replace existing transportation capacity contracts. The term (*i.e.*, 15 years) of the firm transportation agreement outlined in the Precedent Agreements is on the shorter end of the range of typical firm transportation agreements associated with new infrastructure, thus mitigating the risk of long-term demand erosion. The Ontario LDCs also have the ability to manage their respective gas supply portfolios by terminating other transportation/supply contracts.
Supply Risk	The Marcellus/Utica shale basins (*i.e.*, the origination point for NEXUS) are the fastest growing natural gas supply basins in North America. Various third-party forecasts support the availability of sufficient natural gas supply for the duration of the NEXUS contract. In addition, NEXUS has access to other natural gas supply basins via interconnections with other pipelines. The term (*i.e.*, 15 years) of the firm transportation agreement outlined in the Precedent Agreements is on the shorter end of the range of typical firm transportation agreements associated with new infrastructure, thus mitigating the risk of a long-term reduction in natural gas supply from the Marcellus/Utica shale basins.
Regulatory Risk	The NEXUS lead developers (*i.e.*, Spectra and DTE) have significant and recent experience regarding the federal and state regulatory approval processes for pipeline infrastructure; and Spectra/DTE have initiated the FERC pre-filing process for NEXUS. The Ontario LDCs are requesting the OEB's pre-approval of the cost consequences outlined in the NEXUS Precedent Agreements to manage the provincial regulatory risks.
Project Development Risk	The NEXUS lead developers are highly experienced pipeline developers that have begun outreach to landowners and have held three open seasons to secure shipper demand. The open seasons have resulted in shipper commitments from a mix of "supply push" and "demand pull" entities, which is further evidence of the viability of the Project. Both lead developers are subsidiaries of large, creditworthy holding companies.
Operational Risk	The NEXUS lead developers have extensive experience with pipeline operations. Further, any operational issue or cost would likely be subject to the FERC review and approval process.

- Sussex concludes that the overall risk to the Ontario LDCs and their customers are largely mitigated by: (1) the usual and customary terms and conditions in the NEXUS Precedent Agreements, (2) the strength of the lead developers, (3) the strategy employed by the Ontario LDCs to limit their exposure to potential construction cost overruns, and (4) the current production expectations for the Marcellus and Utica supply basins.

Pre-Approval of Cost Consequences of NEXUS

- The NEXUS transportation agreements, as outlined in the Ontario LDCs' Precedent Agreements, represent a significant commitment of 15 years at approximately USD $1.0 billion of pipeline demand charges for Union and Enbridge.
- Pre-approval of the cost consequences outlined in the Precedent Agreements would eliminate the risk to the Ontario LDCs of an ex-post facto cost disallowance, assure an opportunity to recover the pipeline demand charges, and facilitate the development of new natural gas infrastructure.
- Certain state utility regulatory commissions in the U.S. have adopted pre-approval guidelines to facilitate the development of new natural gas pipeline infrastructure.

Report Organization

The remainder of the report is organized into the following sections:

II. Description and Overview of NEXUS – Provides a detailed description of NEXUS, including its proposed capital costs, route, and schedule for completing the development and construction of the Project.

III. Natural Gas Supply Trends and Impact on the Ontario Market – Reviews certain natural gas supply trends to provide a common understanding of the effects of certain fundamental changes in the natural gas market. This section includes a review of natural gas supply dynamics in the U.S. Mid-Atlantic region associated with the Marcellus and Utica shale basins, as well as the traditional natural gas supply source for the Ontario market (*i.e.,* Western Canada).

IV. Benefits of NEXUS – Reviews the benefits of NEXUS, including the benefits that accrue directly to the Ontario LDCs and to the Ontario market generally.

V. Landed Cost Analysis – Summarizes the Sussex review of the landed cost analysis used by the Ontario LDCs to evaluate several natural gas transportation paths to the Dawn Hub from various natural gas supply basins.

VI. Risk Assessment – Assesses certain potential risks associated with NEXUS and discusses the risk mitigation options that may limit the risks to the Ontario LDCs.

VII. Review of State Processes for Pre-Approval – Summarizes how certain U.S. state jurisdictions have implemented pre-approvals of long-term natural gas transportation agreements.

VIII. Conclusions – Summarizes the Sussex findings and conclusions.

Appendix A: Summary Biographies of Sussex Project Team

Overview of Sussex and Project Team

Sussex is a management and economic advisory firm providing consulting services to regulated industries such as natural gas, electricity, water, and thermal energy distribution. The firm's Partners have held senior positions in utility companies, competitive energy suppliers, management consulting firms, and business focused academic institutions.

Our Consulting Staff, Executive Advisors, and Affiliated Experts have substantial experience and training in matters relating to regulatory strategy and policy development, natural gas infrastructure development and open season processes, gas supply planning and capacity portfolio optimizing, energy market analysis and assessments, financial and economic analysis, rate proceedings and regulatory compliance, due diligence and valuation, and management reviews and audits. Sussex has a substantial list of clients including natural gas distribution companies, electric utilities, combination utilities, electric transmission providers, natural gas pipeline companies, municipal utilities, state agencies, and non-regulated energy market participants.

Sussex has previously appeared before the OEB and La Régie de l'Énergie du Québec to support energy market studies.

The Sussex project team responsible for this report consists of Mr. James M. Stephens, Mr. Peter Newman, Ms. Kim Nguyen, and Mr. Samuel G. Eaton. Please see Appendix A for the summary biographies of the Sussex project team.

II. DESCRIPTION AND OVERVIEW OF NEXUS

Project Overview

NEXUS is a proposed 36-inch natural gas pipeline that will transport approximately 1.5 Bcf/day of natural gas supplies from the Appalachian Basin to markets in Ohio, Michigan, and Ontario, with an anticipated in-service date of November 2017.[5] DTE and Spectra are the lead developers of NEXUS, and initiated the FERC pre-filing process in late 2014.

The estimated capital expenditures for the Project are approximately USD $2.0 billion.[6] Please see Table 2.1 (below) for context regarding capital expenditures for greenfield pipeline projects that are in various stages of development.

Table 2.1: Estimated Capital Expenditures

Project	Number of Pipeline Miles	Estimated Capital Expenditures (USD$)	Capital Expenditures per Mile (USD$000/Mile)
NEXUS	250	$2.0 billion	$8.00
Rover Pipeline[7]	474	$4.2 billion	$8.90
Constitution Pipeline[8]	125	$0.7 billion	$5.60
Northeast Energy Direct – Market Path[9]	188	$2.9 - $3.5 billion	$15.40 - $18.60

Project Description

The proposed Project will consist of approximately 250 miles of 36-inch greenfield pipeline from the Utica East Ohio Midstream Processing Plant in Kensington, Ohio (the "Kensington Processing Plant") to interconnects with the existing DTE system and Vector in Michigan as

5 *In Re: Request for Approval to Use the Pre-Filing Process NEXUS Gas Transmission, LLC – NEXUS Gas Transmission Project*, FERC Docket No. PF15-10-000, December 30, 2014; and *In Re: NEXUS Gas Transmission, LLC, NEXUS Gas Transmission Project, Updated Stakeholder List and Project Update*, FERC Docket No. PF15-10-000, March 20, 2015.

6 *See*, *Qualifications and Direct Testimony of Mr. Robert G. Lawshe*, Michigan PSC Case No. U-17691, December 30, 2014, at 43.

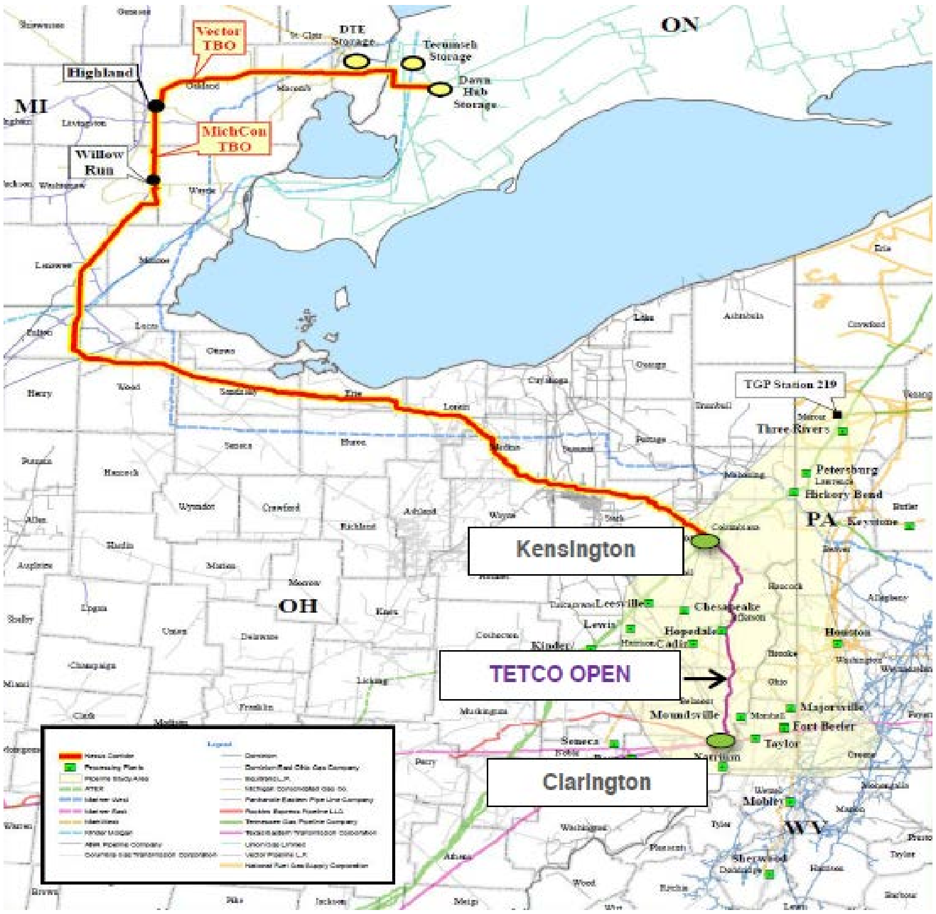
7 *See*, *Application of Rover Pipeline LLC for a Certificate of Public Convenience and Necessity, Volume I*, FERC Docket No. 15-93-000, February 20, 2015, at 10, 26. Rover Pipeline consists of approximately 474 miles of 42-inch greenfield pipeline and 237 miles of supply laterals.

8 *See*, Constitution Pipeline, *Media Statement: NYS DEC Section 401 WQC Permit Request*, April 29, 2015.

9 *See*, Kinder Morgan, *Natural Gas Pipelines*, presentation at the Kinder Morgan 2015 Analyst Conference, January 28, 2015.

shown in Figure 2.1 below.[10] Natural gas will flow to the Dawn Hub via transportation agreements held by NEXUS with DTE and Vector or other arrangements.[11]

Figure 2.1: NEXUS Proposed Route



As shown by Figure 2.1, NEXUS will consist of the construction of the following new infrastructure:

- Approximately 200 miles of new pipeline in Columbiana, Stark, Summit, Wayne, Medina, Lorain, Erie, Sandusky, Wood, Lucas, and Fulton Counties in Ohio;
- Approximately 50 miles of new pipeline in Lenawee, Monroe, and Washtenaw Counties in Michigan;

10 *In Re: NEXUS Gas Transmission, LLC, NEXUS Gas Transmission Project, Updated Stakeholder List and Project Update*, FERC Docket No. PF15-10-000, March 20, 2015, at 2; and *NEXUS Gas Transmission Project Resource Report 1*, FERC Docket PF15-10-000, January 23, 2015.

11 *See*, Vector Electronic Bulletin Board, *Results of the 2017 Mainline Expansion Project Open Season,* http://bit.ly/1GAr7cz, accessed March 4, 2015.

- Approximately 1,000 feet of lateral pipeline to connect the Kensington Processing Plant to the TETCO system in Columbiana County, Ohio; and
- Approximately 1.2 miles of lateral pipeline to connect the Kensington Processing Plant to the Tennessee Gas Pipeline ("TGP") in Columbiana County, Ohio.[12]

In addition to the pipeline construction, NEXUS anticipates installing up to 52,000 horsepower ("HP") of compression at the Columbiana station (Ohio), up to 26,000 HP at the Medina station (Ohio), up to 26,000 HP at the Erie station (Ohio), and up to 26,000 HP at the Lucas station (Ohio). Finally, four new meter stations are anticipated to be installed as part of NEXUS; one station each at the interconnections to the TETCO and TGP systems, one at the Kensington Processing Plant, and one at the terminus of the greenfield construction at Willow Run, Michigan.[13]

The Kensington Processing Plant (located at the origination point of NEXUS) is a greenfield natural gas processing facility that is part of the Utica East Ohio Processing project sponsored by Access Midstream Partners, LP, M3 Midstream LLC, and EnerVest, Limited.[14] The first phase (or "train") of the Kensington Processing Plant entered service in July 2013 and provided 200 MMcf/day of processing capacity.[15] Two additional trains (*i.e.*, expansion of processing capacity) of the Kensington Processing Plant recently entered service and provide an aggregate nameplate capacity of 600 MMcf/day of processing capacity.[16] Once fully completed, the Utica East Ohio Processing project, including the Kensington Processing Plant, will have a gas processing capacity of over 1.1 Bcf/day.[17] The Kensington Processing Plant has received firm commitments from natural gas producers in the Marcellus and Utica basins located in Ohio,

12 *NEXUS Gas Transmission Project Resource Report 1*, FERC Docket PF15-10-000, January 23, 2015, at 1-1, 1-2.

13 Ibid, at 1-2.

14 Access Midstream Partners, LP merged with Williams Partners in February 2015. In addition, Williams Partners recently announced an agreement to purchase EnerVest, Limited's 21% interest in the Utica East Ohio Project. *See*, Williams Companies, Inc., *Williams, Williams Partners and Access Midstream Partners Announce Closing of Merger*, February 2, 2015; and Williams Companies, Inc., *Williams Partners Agrees to Acquire Additional Interest in Utica East Ohio Midstream Partnerships*, April 6, 2015.

15 M3 Midstream LLC, *Utica East Ohio Facilities Begin Sales July 28,* July 29, 2013.

16 Akron Beacon Journal, *Utica East Ohio's gas-processing system to grow to provide additional capacity,* January 7, 2015.

17 Access Midstream Partners, *Utica East Ohio Announces Major Expansion*, May 12, 2014.

West Virginia and Pennsylvania, including affiliates of Chesapeake Energy Corporation ("Chesapeake"), Total Gas & Power North America, and American Energy Partners.[18]

The Texas Eastern Appalachian Lease ("TEAL") project may present additional natural gas supply certainty by providing NEXUS shippers access to supply delivered by natural gas producers in southern Ohio, West Virginia, and Pennsylvania to a new interconnection with the greenfield portion of NEXUS at Kensington, Ohio. NEXUS will lease up to 950,000 Dth/Day of capacity on the TEAL project, which is scheduled to enter service in November 2017.[19]

Finally, NEXUS will interconnect with the DTE Gas Company (formerly, Michigan Consolidated Gas Company) and Consumers Energy systems in Michigan, and, via Union and Vector to certain Ontario natural gas infrastructure (*e.g.*, the Enbridge Storage facility and Union's Dawn Hub).[20]

NEXUS held an initial open season in late 2012, resulting in approximately 1.0 Bcf/day of interested shippers.[21] Two supplemental open seasons were conducted, enabling shippers to adjust receipt point access or request lateral locations.[22] Initial project shippers include both demand-pull parties (*e.g.*, the Ontario LDCs and DTE) and supply push entities (*e.g.*, Chesapeake, CONSOL Energy, and Noble Energy).[23]

NEXUS Development Schedule

In late 2014, NEXUS filed an application to initiate the FERC pre-filing process, which was accepted by the FERC on January 9, 2015.[24] In 2015, NEXUS anticipates that the FERC will complete its scoping of preliminary issues related to the Project. Concurrently, NEXUS expects to complete and file its application for a FERC Certificate of Public Convenience and Necessity ("CPCN"). The FERC review of the NEXUS CPCN application is expected to require approximately one year, with construction of NEXUS commencing in early 2017, and an in-

[18] Ibid.

[19] *In Re: Request for Approval of Pre-Filing Review Texas Eastern Transmission, LP – Texas Eastern Appalachian Lease Project*, FERC Docket No. PF15-11-000, January 16, 2015.

[20] NEXUS Gas Transmission, *Supplemental Open Season Notice for Firm Service – July 23, 2014 – August 21, 2014*.

[21] Ibid.

[22] Ibid; and NEXUS Gas Transmission, *Supplemental Open Season Notice for Firm Service – January 14, 2015 – February 12, 2015*.

[23] PRN Newswire, *Spectra Energy Reports Third Quarter 2014 Results*, November 5, 2014.

[24] *In Re: Approval of Pre-Filing Request*, FERC Docket No. PF15-10-000, January 9, 2015.

service date of late 2017. Table 2.2 (below) provides a summary of the NEXUS development schedule.

Table 2.2: NEXUS Project Development Schedule[25]

Activity	Anticipated Timeline
Initial Project Evaluation	2013 – 2nd Quarter 2014
Initial Information Meetings	3rd & 4th Quarter 2014
FERC Pre-Filing Process Initiated	4th Quarter 2014
FERC Issue Scoping	2015
FERC CPCN Application Filing	4th Quarter 2015
FERC Review; Stakeholder Engagement	2016
FERC Approval	4th Quarter 2016
FERC Notice to Proceed with Construction	1st Quarter 2017
Major Construction Initiated	Early 2017
Proposed In-Service Date	4th Quarter 2017

25 *See*, NEXUS Gas Transmission, *Fact Sheet: Project Overview*, April 1, 2015; and *In Re: Request for Approval to Use the Pre-Filing Process NEXUS Gas Transmission, LLC – NEXUS Gas Transmission Project*, FERC Docket No. PF15-10-000, December 30, 2014.

III. <u>NATURAL GAS SUPPLY TRENDS AND IMPACT ON THE ONTARIO MARKET</u>

Introduction

The Ontario market has been predominantly supplied by natural gas sourced from the WCSB. The natural gas supplies from the WCSB are generally transported to Ontario via three transportation paths: (1) TransCanada Pipelines Limited ("TCPL" or "TransCanada") Canadian Mainline from Empress to Ontario; (2) Great Lakes Gas Transmission ("GLGT") from Emerson to Dawn; and (3) Alliance Pipeline ("Alliance") and Vector to Dawn from the WCSB and Chicago, respectively.

Recently, the Canadian-U.S. natural gas market has undergone fundamental changes that have affected natural gas supplies to the Ontario market, as well as the transportation paths utilized to deliver that natural gas. Specifically, the volume of natural gas shipped from the WCSB to markets in Eastern Canada and the U.S. Northeast has declined. This trend in the availability of WCSB volume for other markets (*e.g.*, Ontario) is the result of certain market dynamics including: (1) decreased production of conventional natural gas resources in the WCSB; (2) increasing natural gas consumption by certain market segments in Alberta (*e.g.*, industrial-oil sands and power generation); and (3) increasing natural gas production from the Marcellus and Utica shale basins, which are geographically closer to the traditional demand markets. In addition, WCSB producers have begun to investigate alternative markets for existing and new natural gas production, including the export of liquefied natural gas ("LNG") from Western Canada to natural gas markets in the Western Pacific.

Given the importance of the WCSB and Appalachian gas supplies to the Ontario market, each supply basin is reviewed in detail below.

WCSB Overview

As illustrated by Figure 3.1, the WCSB natural gas production basin is situated in Alberta, British Columbia and Saskatchewan.

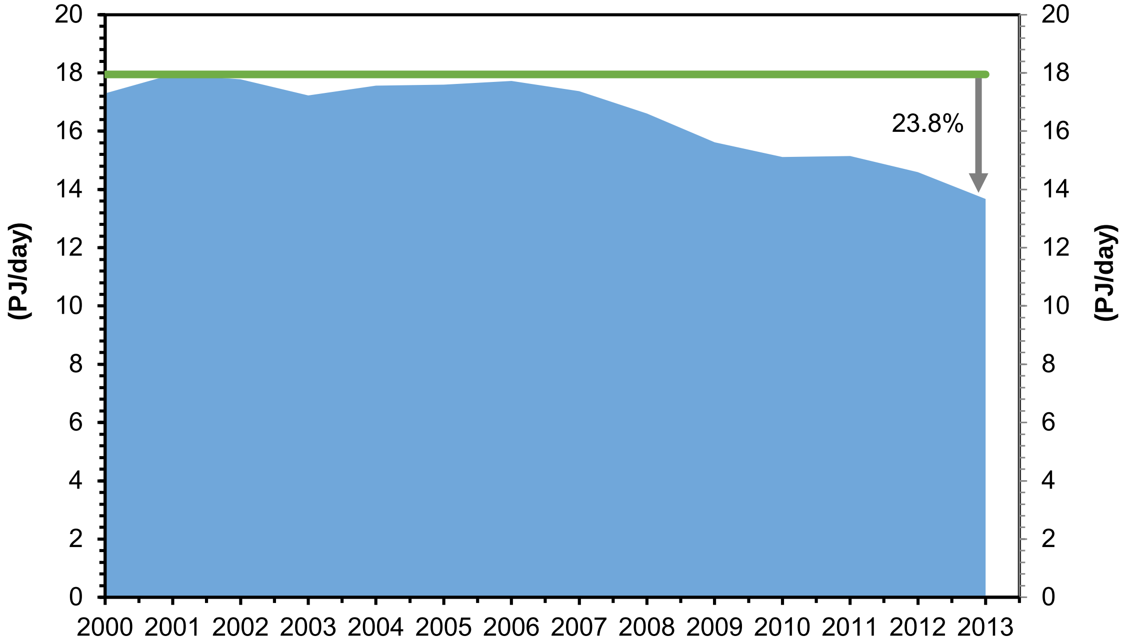
Figure 3.1: Map of WCSB[26]

Declining Production from Traditional WCSB Resources

The WCSB is a major source of natural gas supply for Canadian and U.S. markets; however, over the past several years, the production of conventional natural gas resources has declined. Specifically, as illustrated by Figure 3.2, natural gas production in the WCSB has declined since 2006.

26 FNR Asset Management Inc., http://www.fnrm.ca/html/swca/index.cfm, accessed July 14, 2014.

Figure 3.2: WCSB Production[27]



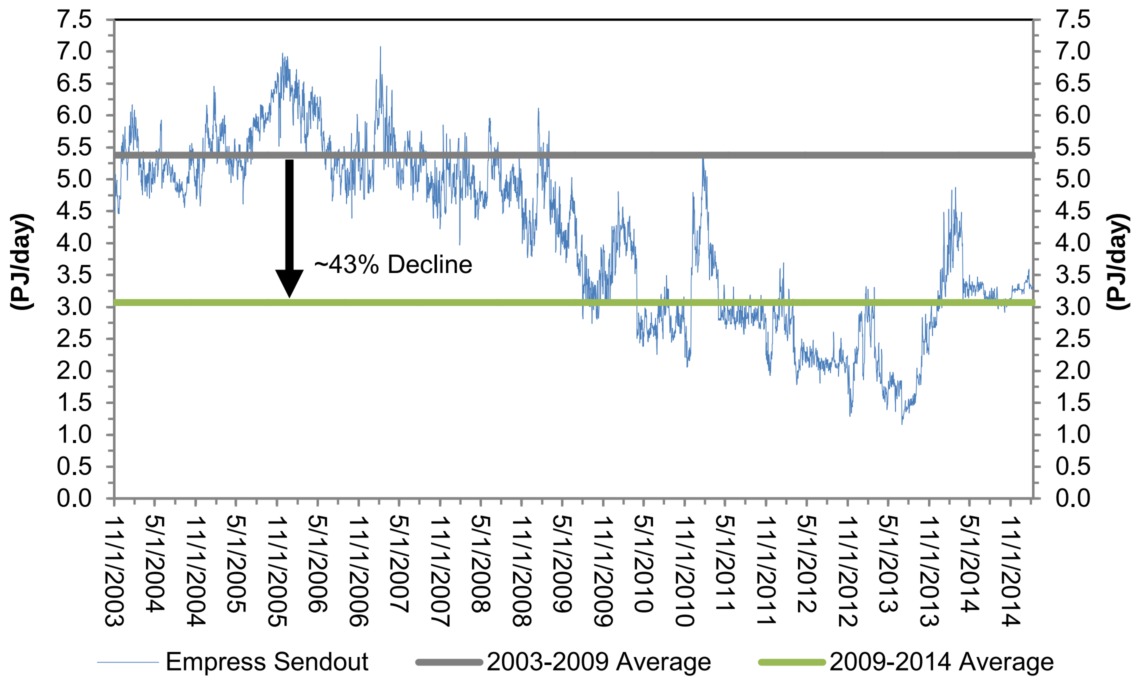
As shown by Figure 3.2, the WCSB produced approximately 17.3 PJ/day of natural gas in 2000, however, by 2006 natural gas production begin to decline and averaged 13.6 PJ/day by 2013, a decline of approximately 24% from its 2001 level.[28]

The reduction in natural gas supply availability from the WCSB to other markets is illustrated by a review of nominated volumes at Empress (*i.e.*, the interconnection point between the TransCanada NGTL System and the Canadian Mainline). As illustrated in Figure 3.3, the nominated deliveries at Empress have declined over the 2006 to 2014 period.

[27] National Energy Board of Canada, *Canada's Energy Future 2013 – Energy Supply & Demand Projections to 2035*, November 2013, Figure 6.2 at 52. *See also*, Appendix 4: Natural Gas. Values have been converted from 10^6m^3/day to PJ/day at a rate of 0.0374 10^6m^3/day per PJ/day.

[28] Ibid.

Figure 3.3: TransCanada Canadian Mainline Nominated Deliveries (2007-January 2015)[29]



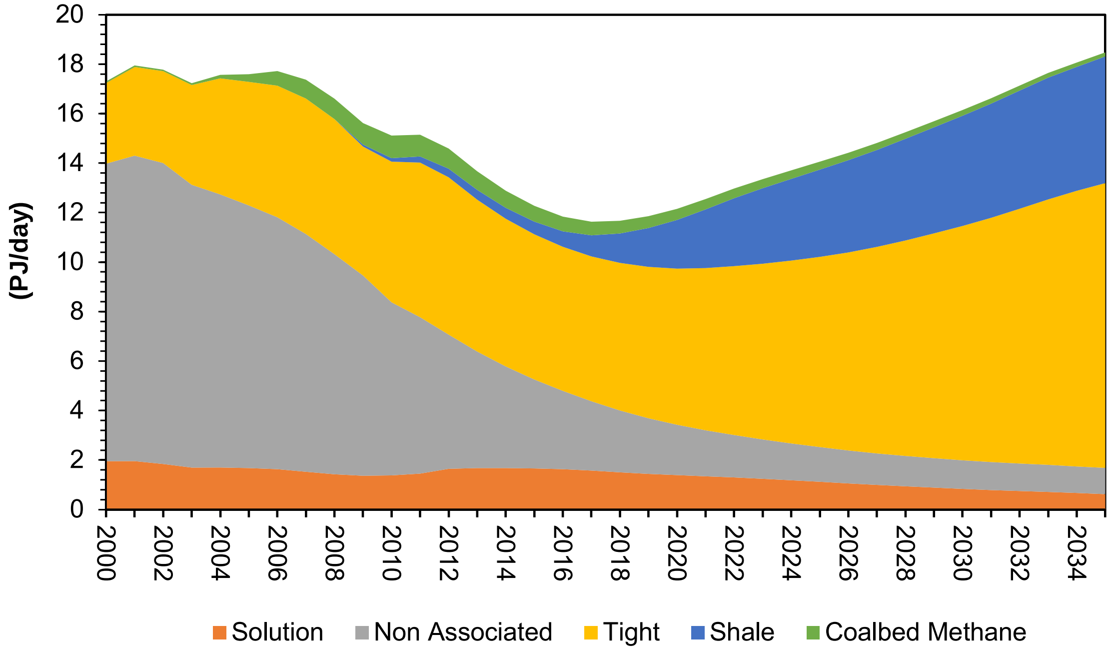
As shown in Figure 3.3, from November 2003 to October 2008, the daily volume at Empress ranged between 4.0 PJ/day and 7.0 PJ/day. In 2006, shipments from Empress began to decline, since 2009 daily volumes at Empress have been well below 4.0 PJ/day, and by 2013 daily volumes were below 2.0 PJ/day. This decline in flows from 5.4 PJ/day (*i.e.*, 2003-2009 average) to 3.0 PJ/day (*i.e.*, 2009-2014 average) is a reduction of approximately 43%.

In terms of forecasted natural gas production from the WCSB, certain publicly available forecasts, including one prepared by the National Energy Board of Canada ("NEB"), suggest that the decline in WCSB production is likely to continue until at least 2018. For example, the NEB recently noted that: (1) overall Canadian natural gas production would continue to decline until 2018 when new LNG facilities provide additional price support for WCSB production; and (2) production will not achieve the levels seen in 2000 until 2035.[30] Please see Figure 3.4 (below).

29 Source: Union Gas Limited.

30 National Energy Board of Canada, *Canada's Energy Future 2013 – Energy Supply & Demand Projections to 2035*, November 2013, Figure 6.2 at 52. *See also*, Appendix 4: Natural Gas.

Figure 3.4: Canadian Natural Gas Production Forecast[31]



As seen in Figure 3.4, the majority of the long-term WCSB production will consist of non-traditional sources such as tight gas and shale gas. Specifically, combined production from these sources will increase from 3.3 PJ/day in 2000 to 16.6 PJ/day in 2035, a 400% increase. Conversely, production from non-associated gas will decline from 12.0 PJ/day in 2000 to 1.1 PJ/day in 2035, or a decline of over 90%.

<u>Increasing Intra-regional Demand</u>

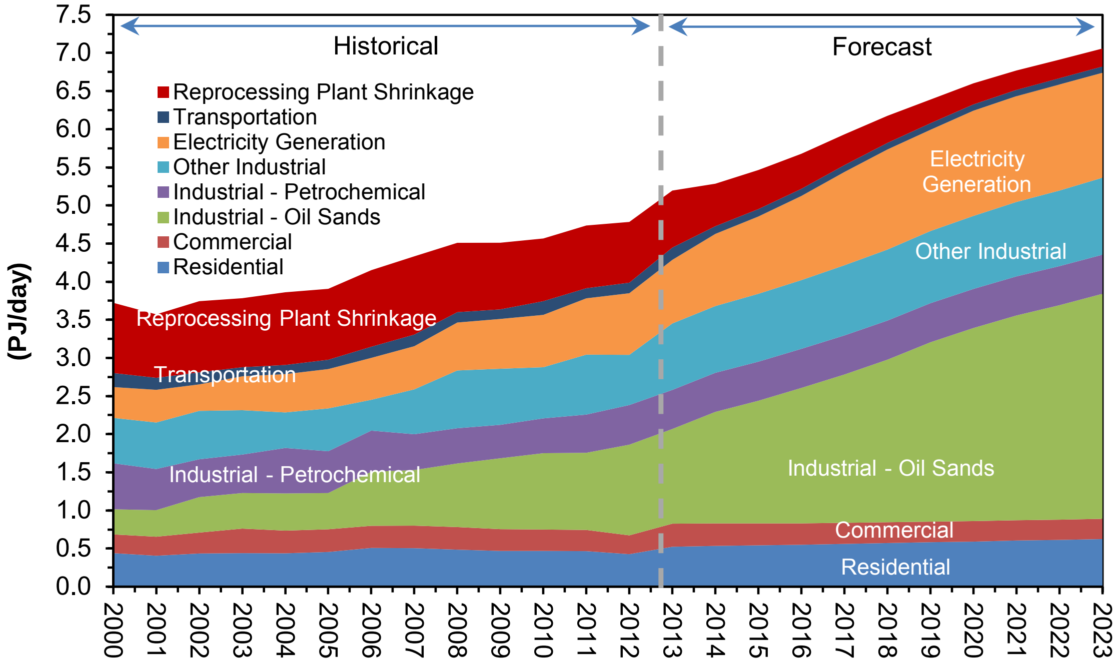
With respect to the second factor influencing the reduction in WCSB volumes shipped eastward (*i.e.*, increasing demand for natural gas from the industrial-oil sands and power generation segments), the NEB noted that intra-regional demand in the WCSB increased by approximately 25% between 2006 (4.8 PJ/day) and 2012 (6.0 PJ/day).[32] The NEB attributed this growth in consumption to increased natural gas demand by the oil sands industry.[33] The NEB also noted that increasing demand for natural gas in the WCSB region would result in a reduction in WCSB natural gas available for inter-regional shipment.[34]

31 Ibid.
32 Ibid, at 15.
33 Ibid.
34 Ibid.

Separately, the Alberta Energy Regulator ("AER") has noted that natural gas demand in Alberta was approximately 5.2 PJ/day in 2013 and represented approximately 50% of the total Alberta production.[35] By 2023, the AER expects natural gas demand in Alberta to reach 7.1 PJ/day, or approximately 78% of the total Alberta production.[36] The AER has further forecasted that the available natural gas supply for export from Alberta will decline from approximately 11.7 PJ/day in 2001 to approximately 2.0 PJ/day in 2022.[37]

The actual and forecasted natural gas demand in Alberta by segment is illustrated in Figure 3.5.

Figure 3.5: Alberta Natural Gas Demand (2000-2023)[38]



In terms of actual demand, the AER has noted that the use of natural gas for oil sands extraction has increased approximately 275% between 2000 and 2013 (*i.e.*, from approximately 0.3 PJ/day to 1.2 PJ/day), and the use of natural gas for electricity generation has increased by

35 The AER notes that the remainder of the natural gas production was transported to other Canadian provinces and the U.S. *See*, Alberta Energy Regulator, *Alberta's Energy Reserves 2013 and Supply/Demand Outlook 2014-2023*, ST98-2014, at 5-51.

36 Ibid, at 5-46.

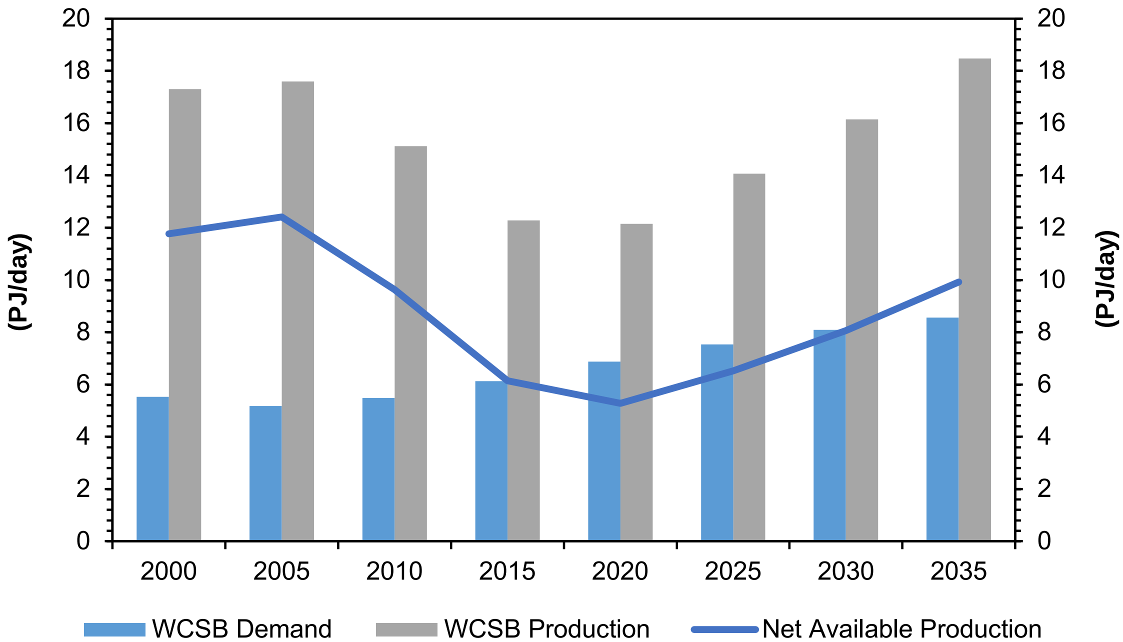
37 Ibid.

38 Ibid.

more than 100% (*i.e.*, from approximately 0.4 PJ/day to 0.8 PJ/day).[39] With respect to forecasted demand, the AER is forecasting that natural gas consumption for oil sands extraction will have increased by approximately 800% of its 2000 levels by 2023 (*i.e.*, from approximately 0.3 PJ/day to 2.9 PJ/day), or at a compound annual growth rate of approximately 10%.[40] The additional demand from oil sands extraction is expected to provide price support for natural gas production in the WCSB region.

To summarize the impact of certain market dynamics on the availability of WCSB natural gas production for other markets (*e.g.*, Ontario), the expected production from the WCSB is compared to the forecasted regional consumption – please see Figure 3.6.

Figure 3.6: WCSB Regional Production and Consumption[41]



As shown above, the NEB forecasts a decline in available production with a low point of approximately 6 PJ/day in 2020. Following 2020, the NEB is forecasting a return to growth in

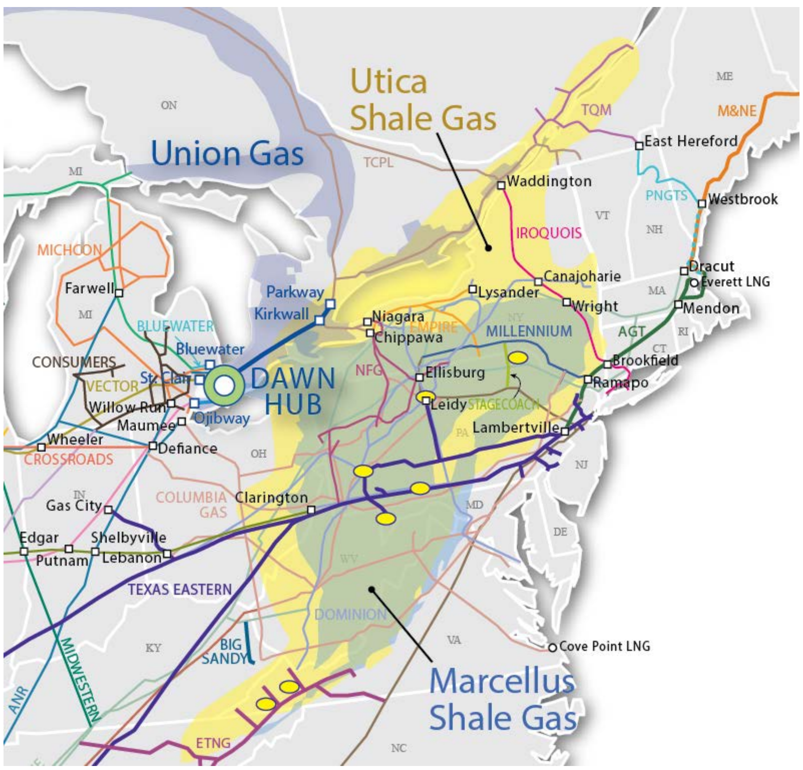
39 Ibid, Figure S5.16.
40 Ibid.
41 National Energy Board of Canada, *Canada's Energy Future 2013 – Energy Supply & Demand Projections to 2035*, November 2013, Appendix 2: Energy Demand, Appendix 4: Natural Gas.

natural gas production and net available supply; however, that growth is likely dependent upon the NEB's assumptions for additional LNG export demand.[42]

Marcellus and Utica Supply Basins

Concurrent with the decline in the availability of WCSB natural gas to Eastern Canadian and U.S. markets is the rise of natural gas production in the Marcellus and Utica shale basins in the U.S. Northeast and Mid-Atlantic. The Marcellus and Utica Shale basins are the fastest growing natural gas supply basins in North America and extend from Western Ohio to West Virginia, Pennsylvania, and New York, and are proximate to demand centers in Eastern Canada and the U.S. Northeast. Figure 3.7 (below) illustrates the location of the Marcellus and Utica shale basins.

Figure 3.7: Map of Marcellus and Utica Shale Basins[43]



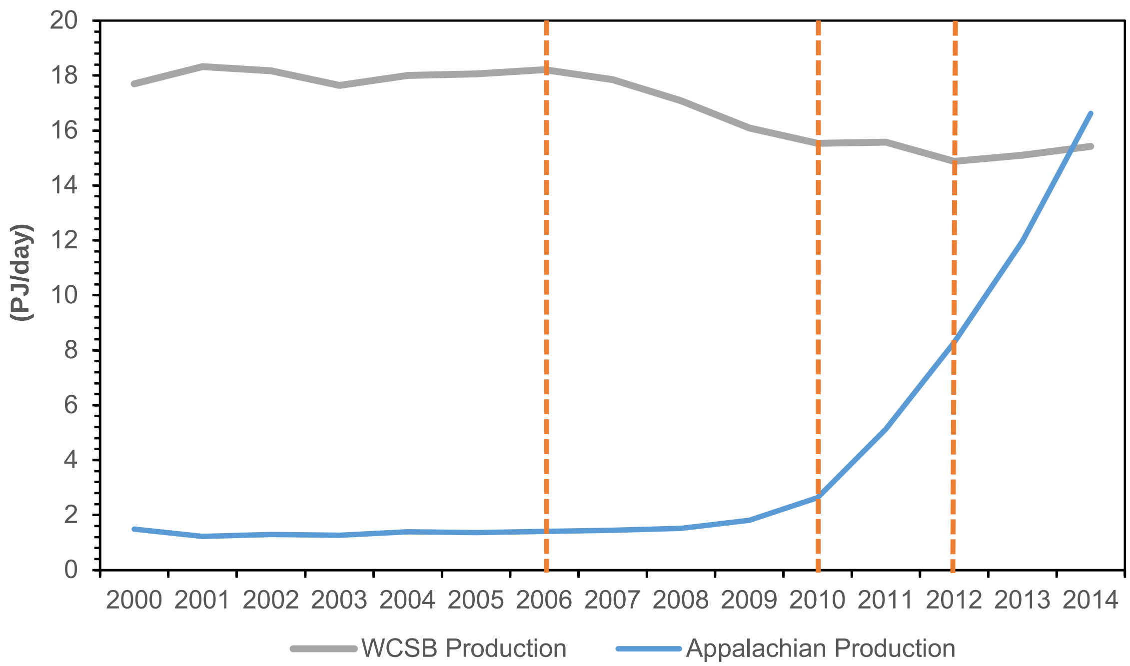
42 WCSB natural gas producers and project sponsors are considering the export of LNG from the Canadian and U.S. West Coast in response to the changing natural gas market dynamics. The NEB has received 30 applications for natural gas export licenses, encompassing 21 export facilities, and approved nine licenses relating to LNG facilities along the coast of British Columbia and the Oregon coast. The proposed LNG export facilities are expected to encourage WCSB production by creating additional demand and price support for natural gas. *See*, National Energy Board of Canada, *LNG Export and Import License Applications*, https://www.neb-one.gc.ca/pplctnflng/mjrpp/lngxprtlcnc/index-eng.html, accessed January 2015.

43 Source: Union Gas Limited.

As illustrated by Figure 3.7, there are several pipelines with direct access to the Marcellus and Utica supply basins; however, none of these pipelines directly connect to the Dawn Hub.

To provide perspective regarding the rapid development of the Marcellus and Utica production basins, Figure 3.8 is a comparison of natural gas production from the WCSB and Appalachian basins.

Figure 3.8: Comparison of Appalachian and WCSB Production (2000-2014)[44]



As illustrated above, from 2000 to 2006, natural gas production in the Appalachian region was nearly flat at an average of approximately 1.3 PJ/day. Beginning in 2006, Appalachian production began to trend slightly upward as producers applied newer technologies and extraction techniques to the Marcellus and Utica shale basins. By 2009 through 2011, the increases in Appalachian production accelerated with average daily production rising to 5.1

[44] U.S. Energy Information Administration, *Natural Gas Gross Withdrawals & Production for West Virginia, Pennsylvania, and Ohio*, http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm, accessed February 2015; U.S. Energy Information Administration, *Drilling Productivity Report for Marcellus Region and Utica Region*, http://www.eia.gov/petroleum/drilling/, accessed February 2015; and National Energy Board of Canada, *Canadian Marketable Natural Gas Production 2000-2014,* https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/stt/mrktblntrlgsprdctn-eng.html, accessed February 2015.

PJ/day by 2011. From 2011 through 2013, the growth of Appalachian production further accelerated and reached an average of 12.0 PJ/day by 2013, and over 16.0 PJ/day by the end of 2014.

In contrast, WCSB production remained relatively flat until 2006 at approximately 18 PJ/day. Subsequent to 2006, WCSB production declined to approximately 15.5 PJ/day in 2010, and to approximately 15 PJ/day in 2012 before trending upward in 2014 when production averaged 15.4 PJ/day.

Marcellus and Utica Proved Reserve Estimates

Given the significant impact of the Marcellus and Utica basins on U.S. and Canadian natural gas market dynamics, a review of this potential resource is discussed below. To analyze the long-term availability of natural gas in the Marcellus and Utica supply basins, Sussex relied on several sources of independent reserve assessments and production forecasts including forecasts from the Energy Information Administration ("EIA"); the Potential Gas Committee ("PGC"), an independent research entity affiliated with the Colorado School of Mines; and citations from several other third-party forecasts.

The EIA is the data and analysis division of the U.S. Department of Energy, and, as such, the EIA: (1) accumulates and publishes data from energy consumers and suppliers; and (2) produces annual forecasts of long-term trends in energy supply and consumption. For this report, Sussex relied on two sources of information published by the EIA:

- U.S. Oil and Natural Gas Proved Reserves – An annual estimate of regional and U.S. wide proved reserves of oil and natural gas.
- Annual Energy Outlook ("AEO") – An annual forecast of energy production, which includes natural gas production for the Marcellus and Utica supply basins.

Because natural gas pipelines generally require 15 to 20 year contract terms to support the construction of new infrastructure, Sussex reviewed natural gas production estimates through 2035 (*i.e.*, the likely termination date of the primary term of a contract starting in the 2017 to 2020 time period). As described below, the forecast and analyses by the EIA, the PGC, and the other third parties provide support for the long-term availability of natural gas in the Marcellus and Utica basins.

In general, an estimate of the natural gas resource potential is divided into two categories: (1) proved reserves; and (2) potential resources. Proved reserves are those resources that are demonstrated with reasonable certainty to be recoverable from known reservoirs under existing economic and operational conditions.[45] Potential resources are more expansive and, as discussed below, include resources that may be considered speculative based on current natural gas prices and extraction technologies. In addition, production forecasts are an indication of the rate at which the Marcellus and Utica shale basins have been, and are expected to be, developed by natural gas producers.

The U.S. EIA annually produces an estimate of proved reserves. The EIA considers proved reserves the most certain resource category. Proved reserves are defined as the natural gas reserves that are demonstrated with reasonable certainty (*i.e.*, 90% probability or greater) to be recoverable from known reservoirs under existing economic and operation conditions.[46]

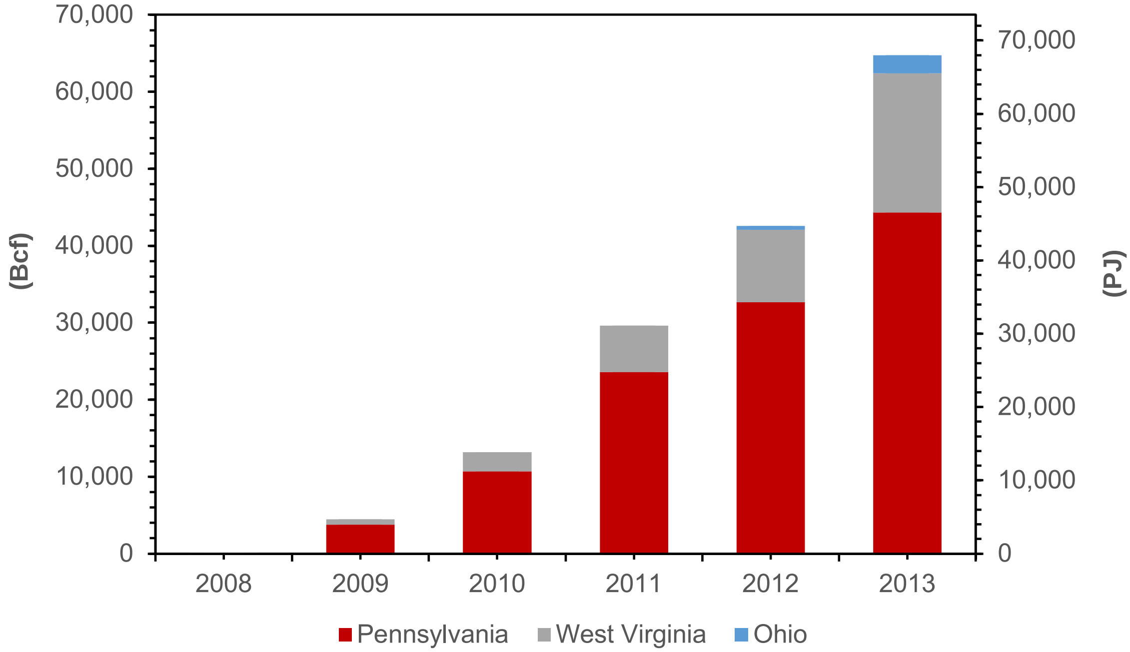
The EIA's estimate of proved reserves depicts an overall increase in U.S. proved reserves in 2013 of 9.7% (to 371,694 PJ or 353,994 Bcf) due to an improvement in natural gas prices and additional development in certain shale basins, including the Marcellus Shale. The EIA's estimate of proved reserves in the Marcellus Shale gas play increased in 2013, and surpassed those of the Barnett Shale in Texas to become the largest natural gas shale play in the U.S.[47] Figure 3.9 (below) illustrates the EIA's estimate of proved reserves in the Marcellus and Utica regions; specifically, in the states of Ohio, Pennsylvania, and West Virginia (*i.e.*, the likely sources of supply for NEXUS).

45 *See*, U.S. Energy Information Administration, *U.S. Crude Oil and Natural Gas Proved Reserves, 2012,* April 2014, at 6.

46 U.S. Energy Information Administration, *Oil and natural gas resources categories reflect varying degrees of certainty,* Today in Energy, July 17, 2014, at 2.

47 U.S. Energy Information Administration, *U.S. Crude Oil and Natural Gas Proved Reserves, 2012,* April 2014, at 16.

Figure 3.9: EIA Shale Gas Proved Reserves – Ohio, Pennsylvania, and West Virginia[48]



As illustrated by Figure 3.9, Pennsylvania has the greatest volume of proved reserves associated with the Marcellus and Utica shale basins, and experienced substantial growth in proved reserves each year since 2008. West Virginia has experienced similar growth in its proved reserves since 2008, but the total volume of proved reserves in West Virginia is approximately 40% of the Pennsylvania reserves. The growth of proved reserves in Ohio is just beginning to follow the trend of Pennsylvania and West Virginia. The aggregate 2013 proved reserves estimate for all three states is approximately 67,958 PJ (64,722 Bcf) compared to the 2008 estimate of 107 PJ (102 Bcf). Stated differently, the proved reserves in the Appalachian supply basin for 2013 are approximately 634 times the proved reserves in 2008. The substantial growth in proved reserves, the most certain of the resource estimates, suggests that the basin will sustain future production.

The second broad category of resource potential is an estimate of potential resources. The PGC, an independent research analyst affiliated with the Colorado School of Mines, produces

48 Ibid, at 38-39.

biennial estimates of potential natural gas resources in the U.S.[49] The estimates are delineated into three categories as described below:

1. Probable resources are discovered but unconfirmed resources associated with known fields and field extensions, and undiscovered resources in new pools in both productive and nonproductive areas of known fields.
2. Possible resources are undiscovered resources associated with new field and pool discoveries in known productive formations and productive areas.
3. Speculative resources are undiscovered resources associated with new field and pool discoveries in as-yet nonproductive areas.[50]

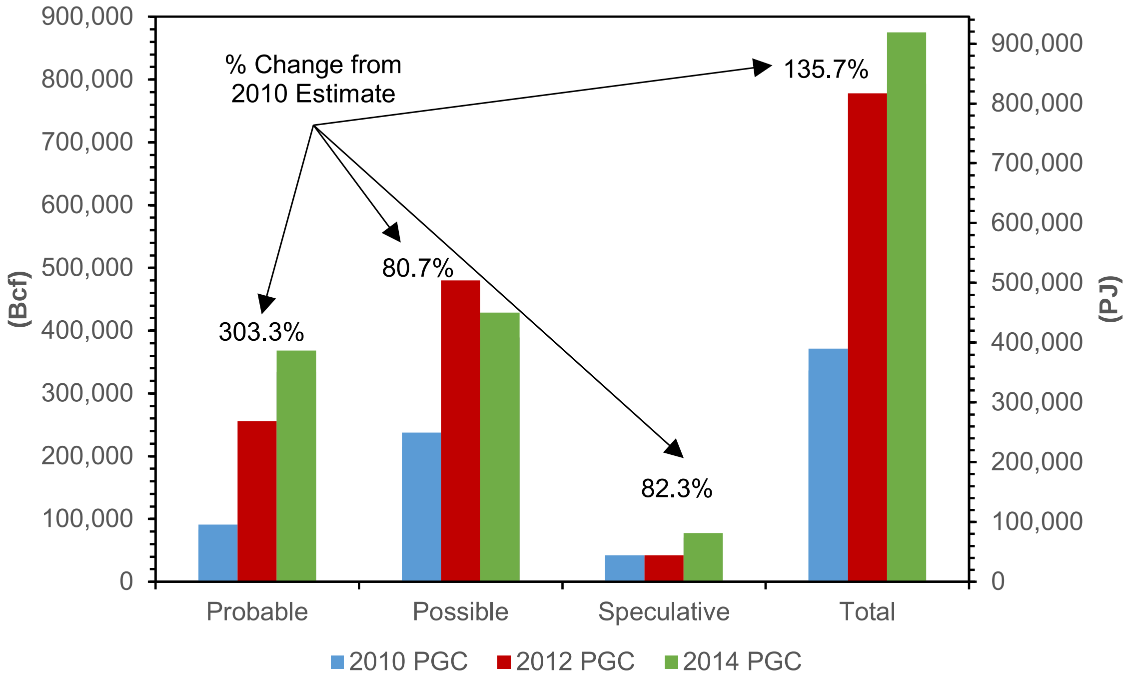
The PGC's most recent estimate of potential natural gas resources was completed in spring 2015 based on data from 2014,[51] while the prior PGC estimate of potential natural gas resources was completed in 2013 utilizing data from 2012. The 2014 PGC estimate of potential natural gas resources shows significant gains for the U.S. overall and even greater gains for the Atlantic Region, which encompasses the Marcellus and Utica supply basins. As illustrated in Figure 3.10, the 2014 PGC estimate for Total Projected Gas Resources in the Atlantic Region is over 875,000 PJ (833,000 Bcf) compared to 371,000 PJ (353,000 Bcf) in the 2010 PGC estimate, a change of approximately 136%.

49 *See*, Potential Gas Committee, *What We Do*, http://potentialgas.org/what-we-do-2, accessed May 2015.

50 Ibid.

51 Potential Gas Agency, *Potential Supply of Natural Gas in the United States, Report of the Potential Gas Committee (December 31, 2014),* April 2015.

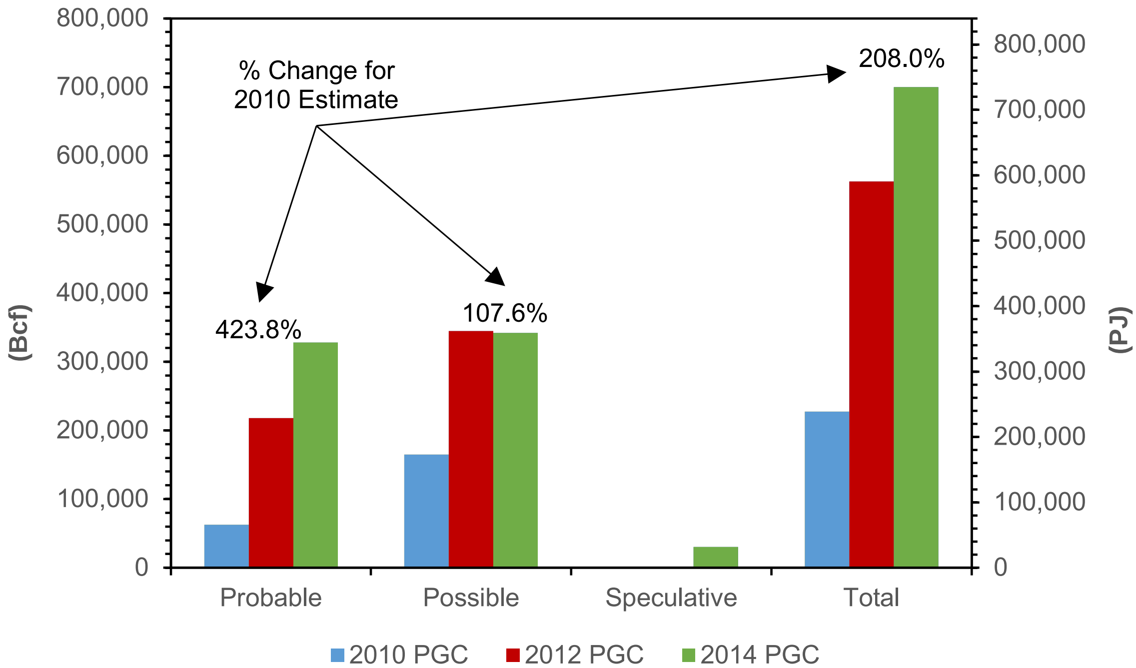
Figure 3.10: Atlantic Region Projected Gas Resources (2010-2014)[52]



Additionally, the PGC provided a separate Atlantic Region shale gas assessment in 2014, which is one component of the overall Atlantic Region resource assessment.[53] Figure 3.11 (below) illustrates that shale gas in the Atlantic Region accounts for nearly all of the Atlantic Region's growth in potential resources between the 2010, 2012 and 2014 PGC assessments.[54]

52 Ibid.
53 Ibid.
54 Ibid.

Figure 3.11: Atlantic Region Shale Gas Resources (2010-2014)[55]



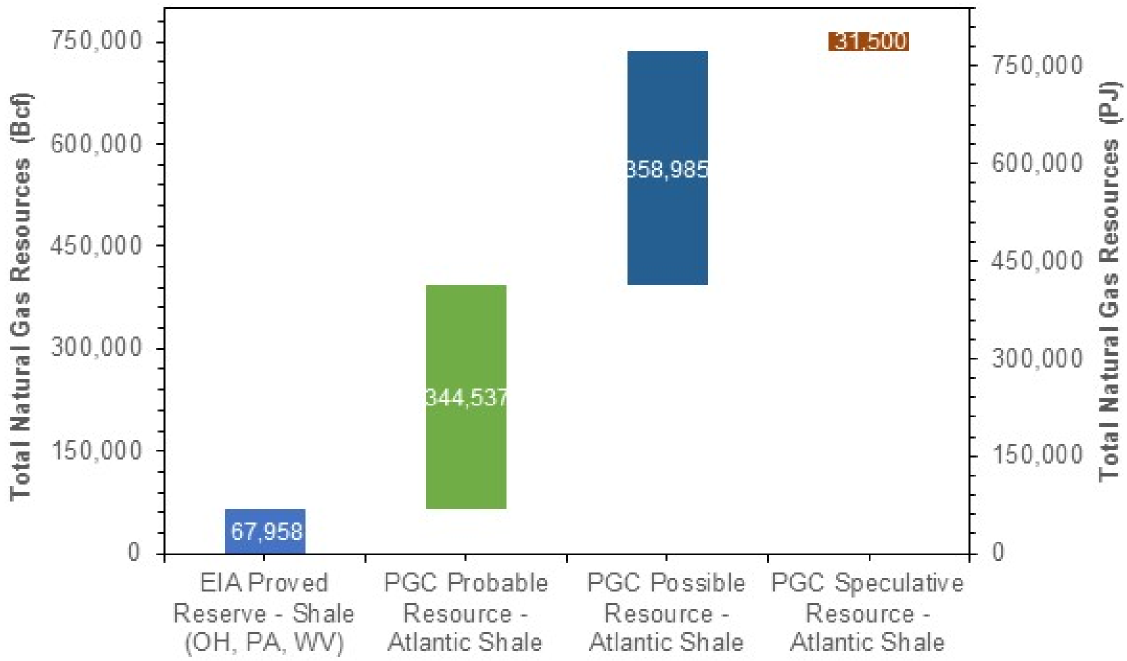
As illustrated in Figure 3.11, the 2012 PGC forecast of Atlantic Region shale natural gas is more than double the 2010 PGC forecast. In 2014, the PGC forecast of Atlantic Region shale natural gas has continued to increase with largest increase in the resources classified as probable resources. Between 2010 and 2014, this group of resources has grown more than 423%. Overall, the Atlantic Region shale natural gas resources has grown more than 208% from the 2010 PGC forecast to the 2014 PGC forecast.

In order to determine the total natural gas resource potential, an estimate can be made by summing the EIA's proved reserve estimates (*i.e.*, Reference Case) discussed earlier with the PGC's potential resource assessment (*i.e.*, Most Likely Case) for similar time periods.[56] Figure 3.12 (below) illustrates the total future natural gas resources estimate for northeast shale by the source and type of resource.

55 Ibid.

56 Potential Gas Agency, *Potential Supply of Natural Gas in the United States, Report of the Potential Gas Committee (December 31, 2014)*, slides accompanying press release, April 8, 2015.

Figure 3.12: Total Future Natural Gas Resource Assessment – Atlantic Shale[57]



As depicted above, the EIA proved reserves for natural gas from shale developments in Ohio, Pennsylvania, and West Virginia constitute 8.5% of the total Atlantic shale natural gas resource estimate of approximately 803 EJ (765 Tcf). Approximately 42.9% of the total Atlantic shale resource estimate is probable resources, 44.7% is possible resources, and 3.9% are speculative resources. To provide context, and assuming an annual overall U.S. natural gas consumption level of 27.4 EJ (26.1 Tcf),[58] the combined EIA proved reserves of shale natural gas and PGC potential shale resources in the Atlantic Region alone would provide sufficient supply for all U.S. natural gas demand for approximately 30 years. When compared with prior estimates of the natural gas resource potential, these production basins (*i.e.*, Marcellus and Utica) have shown significant growth and, given the location of the supply, provide competitive supply alternatives for the Eastern Canada natural gas markets.

57 U.S. Energy Information Administration, *U.S. Crude Oil and Natural Gas Proved Reserves, 2012,* April 2014, at 16; and Potential Gas Agency, *Potential Supply of Natural Gas in the United States, Report of the Potential Gas Committee (December 31, 2014),* April 2015.

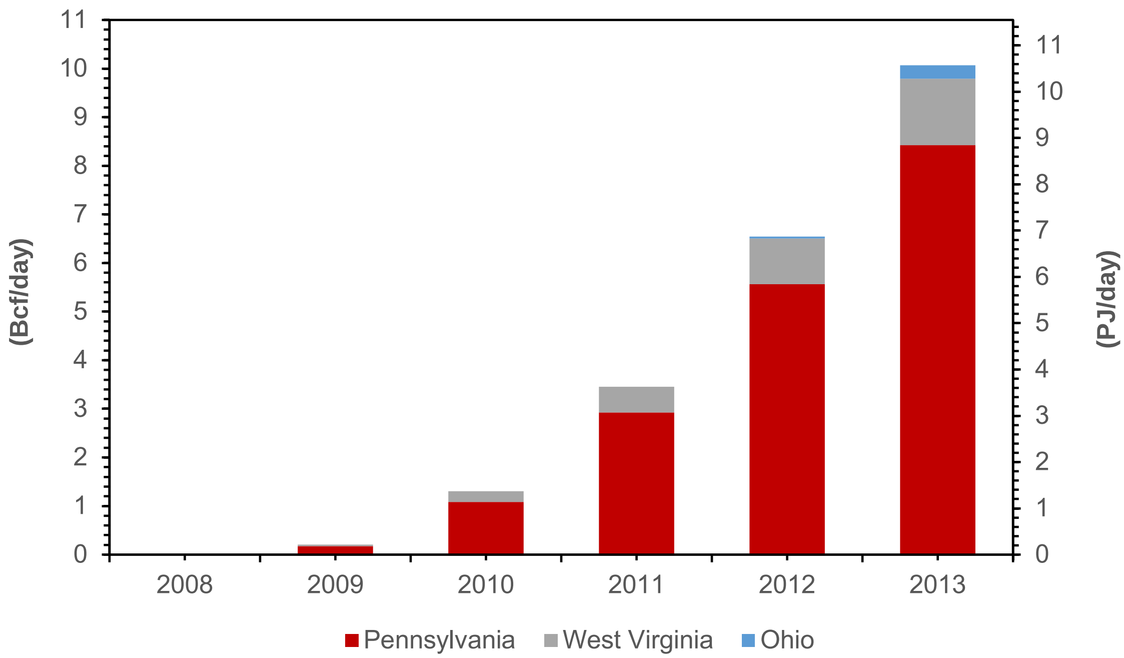
58 The EIA notes that the 2013 annual consumption of natural gas in the U.S. was 26,131 Bcf or 27,438 PJ, which converts to approximately 71.5 Bcf/day or 75.1 PJ/day. *See*, U.S. Energy Information Administration, *Natural Gas Consumption by End Use*, http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_m.htm, accessed February 2015.

Marcellus and Utica Production Forecasts

In addition to the natural gas reserves analysis, Sussex also evaluated natural gas production estimates. Estimates of natural gas production are necessary to understand the level of natural gas that will be extracted in a given period. EIA and several third-party natural gas market analysts periodically prepare production forecasts that include the Marcellus and Utica basins.

Figure 3.13 (below) provides a summary of the EIA's natural gas production estimate from 2008 to 2014 in Ohio, Pennsylvania, and West Virginia from its 2014 estimate of U.S. proved reserves. In total, the annual production for the three states increased from approximately 500 PJ (or 1.4 PJ/day) in 2010 to approximately 3,860 PJ (or 10.6 PJ/day) in 2013.[59]

Figure 3.13: EIA Shale Gas Production – Ohio, Pennsylvania, and West Virginia[60]



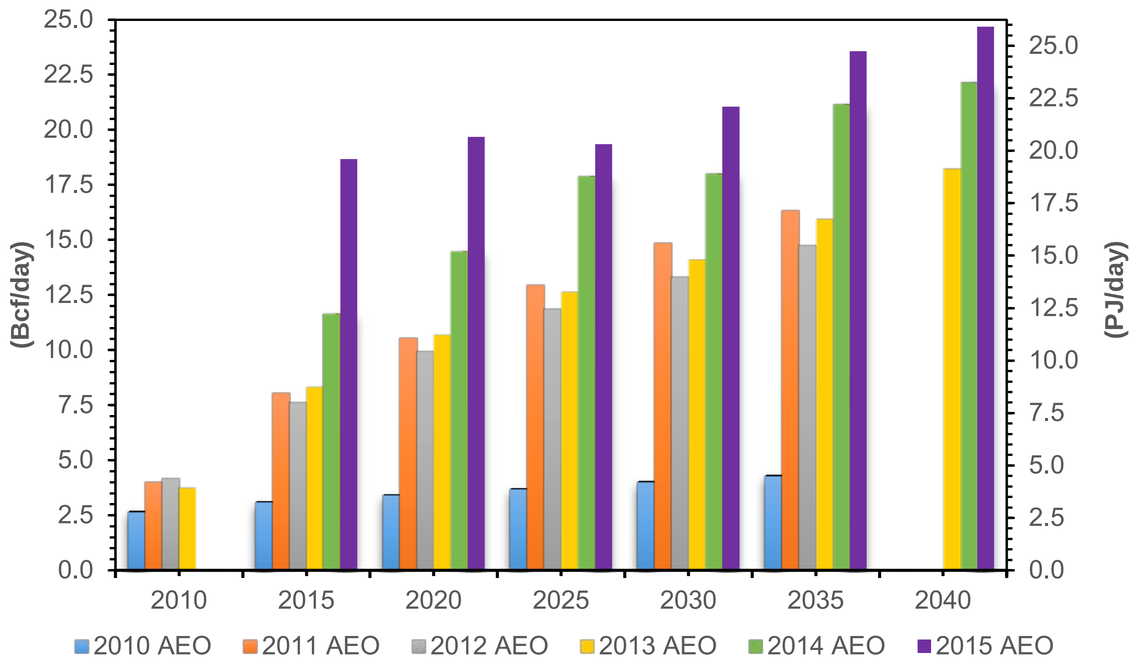
The EIA also produces a forecast of natural gas production in its AEO. Specifically, the AEO, which covers a 30 to 35 year forecast horizon, includes a forecast of natural gas production in the Northeast region (*i.e.*, Marcellus and Utica shale basins). As illustrated in Figure 3.14, for the 2010 and 2011 AEOs, the production forecast increased substantially in every forecast period. Between 2011 and 2013, the EIA's production forecast was relatively consistent.

59 U.S. Energy Information Administration, *U.S. Crude Oil and Natural Gas Proved Reserves, 2012,* April 2014, at 38-39.

60 Ibid.

However, by 2014, the EIA was again forecasting an increase in natural gas production for the Northeast region; and in the 2015 AEO, there is a substantial increase in production compared to the 2014 forecast. Specifically, in the 2015 AEO, the increase in natural gas production occurs early in the forecast period (*i.e.*, before 2020) and remains relatively flat until 2030 with increasing production through 2040.

Figure 3.14: 2010-2015 EIA AEO Northeast Natural Gas Production Forecast[61]



As illustrated by Figure 3.14, by 2020, the difference in Northeast natural gas production between the 2010 AEO and 2015 AEO is approximately 17.1 PJ/day (16.3 Bcf/day), or an approximately 475% increase in forecasted production.[62] By 2035, the difference between the two AEO forecasts is 20.3 PJ/day (19.3 Bcf/day), or a nearly 450% increase in production.[63]

Other third-party market analysts provide support for sustained or increasing natural gas production from the Marcellus and Utica supply basins. In general, those forecasts call for large increases in Marcellus and Utica production. For example, BENTEK Energy ("BENTEK")

61 U.S. Energy Information Administration, *Annual Energy Outlook 2010 – 2015, Lower 48 Natural Gas Production and Supply Prices by Supply Region, Reference Case*, April 2010 through April 2015.

62 Ibid.

63 Ibid.

recently noted that it expects production in the Marcellus and Utica supply basins to grow by approximately 9.5 PJ/day over the next ten years.[64] In addition, BENTEK has separately estimated approximately 2,000 wells have been drilled in the Marcellus/Utica region, but are not producing.[65]

Wood Mackenzie, another firm specializing in natural gas market forecasting, noted in a recent report prepared for Gaz Métro Limited Partnership ("Gaz Métro") and Gazifère Inc. that Northeast production is expected to grow to 29.6 PJ/day by 2020.[66]

Lastly, a projection from ICF International ("ICF") indicates substantially increased production from the Marcellus and Utica regions between 2015 and 2035. In total, ICF expects daily production to increase to 21 PJ/day by 2016, 35.7 PJ/day by 2025, and 39.9 PJ/day by 2035.[67]

Summary of Ontario Natural Gas Supply Dynamics

Traditionally, the Ontario market was predominately supplied with natural gas from the WCSB. Since 2006, two primary effects have contributed to a decrease in the availability of natural gas from the WCSB to the Ontario market: (1) increased natural gas consumption within the WCSB for certain market segments (*e.g.*, industrial-oil sands and power generation); and (2) decreased production of conventional resources from the WCSB. The combination of the 25% increase in intra-regional demand and the approximately 24% reduction in WCSB conventional production, results in less natural gas available for west to east shipments.[68] The rise of the Marcellus and Utica shale basins as proximate and competitive sources of natural gas for the Ontario market presents new opportunities to source natural gas from these basins. The reserve estimates and natural gas production forecasts indicate long-term natural gas availability from the Marcellus and Utica basins. Overall, the estimates of the resource potential in the Marcellus and Utica shale basins, and the production forecasts have grown dramatically since 2010. Although takeaway capacity from the Marcellus and Utica basins is currently limited, the proximity of the

64 BENTEK Energy, *Son of a Beast: Utica Triggers Regional Role Reversal*, October 2013, at 5.

65 BENTEK Energy, *Welcome Back Volatility*, June 18, 2014.

66 Wood Mackenzie, *Proposed Energy East Pipeline Project White Paper,* September 2, 2014, at 5.

67 ICF International, *Future Trends: Assessing Ontario Natural Gas Market Requirements Through 2020,* November 25, 2014, at 16.

68 Ibid. *See also*, National Energy Board of Canada, NEB Docket No. RH-003-2011, *Reasons for Decision – TransCanada Pipelines Limited, Nova Gas Transmission Ltd., and Foothills Pipe Lines Ltd.*, March 2013, for the NEB's assessment of the long-term declines in west to east natural gas flows and effects of that trend on the TransCanada Canadian Mainline.

basins to the demand centers in Eastern Canada positions the Marcellus and Utica supply basins to be competitive with natural gas sourced from the WCSB.

IV. BENEFITS OF NEXUS

In addition to the landed cost analysis discussed in Section V, Sussex reviewed the benefits of NEXUS that accrue to: (1) customers of the Ontario LDCs; (2) other Ontario natural gas market participants including power generation customers and direct purchase customers; and (3) the Province of Ontario in general.

Benefits to the Ontario LDCs

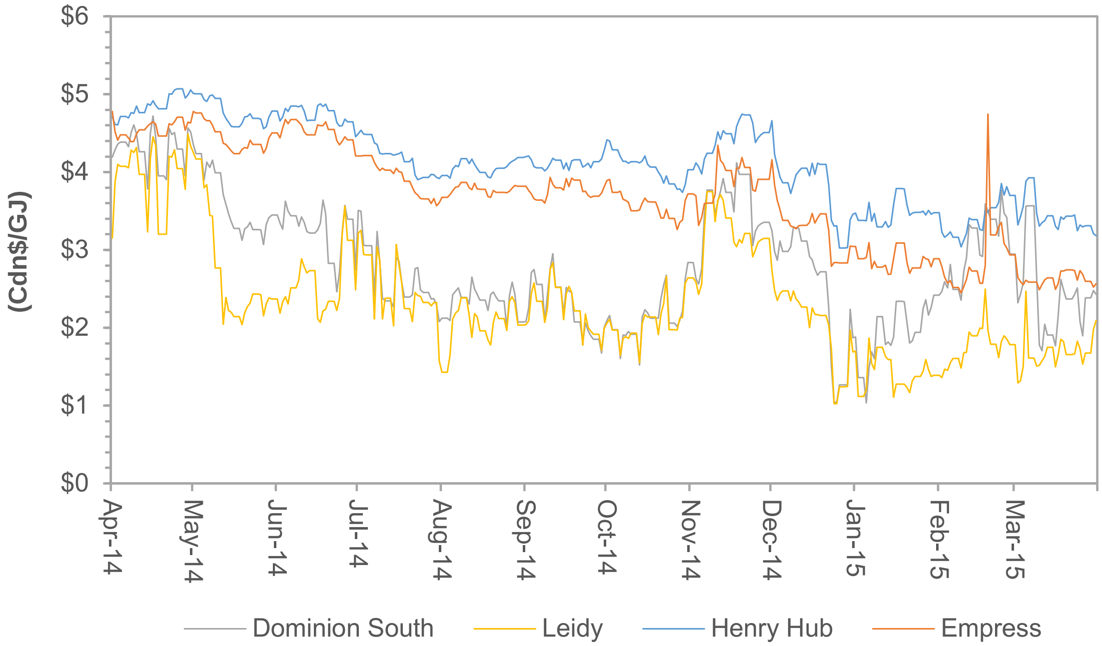
The benefits of NEXUS to the Ontario LDCs include: (1) access to proximate and competitive natural gas supply; (2) natural gas supply basin diversity; (3) enhanced liquidity for natural gas purchases made at the Dawn Hub; (4) transportation path diversity; (5) transportation cost stability; (6) natural gas price index diversity; and (7) service flexibility. For the Ontario LDCs, these benefits represent important objectives in managing their respective natural gas transportation capacity portfolios. Specifically, the identified benefits improve the optionality of the natural gas supply portfolios of the Ontario LDCs, particularly with respect to the management of natural gas supply and transportation costs, improving overall portfolio reliability, and providing increased priced stability.

Access to Proximate and Competitive Natural Gas Supply

As proposed, NEXUS will provide the Ontario LDCs with direct access to the Marcellus and Utica natural gas supply basins, which are located in a region that is proximate to southwestern Ontario. Specifically, the distance from Kensington, Ohio (*i.e.*, the origination point of NEXUS) to Sarnia, Ontario (*i.e.*, the Dawn Hub) is approximately 480 kilometers (300 miles), or the relative distance of Sarnia to Toronto or Chicago. By comparison, the distance from Empress, Alberta (*i.e.*, the interconnection between the NGTL system and the Canadian Mainline) to Sarnia, Ontario is approximately 2,900 kilometers (1,800 miles).

In addition to being proximate to Ontario, the Marcellus and Utica natural gas supply is competitive from a price perspective. Specifically, over the last twelve months, some of the lowest natural gas prices are associated with price indices for the Marcellus and Utica basins. By way of example, Figure 4.1 compares the daily spot prices of two price indices associated with the Marcellus and Utica basins (*i.e.*, Dominion South Point and Leidy) to the Henry Hub and Empress price indices.

Figure 4.1: Daily Spot Prices (April 2014-March 2015)[69]



Supply Basin Diversity and Associated Reliability

NEXUS will provide the Ontario LDCs with direct access to the Marcellus and Utica supply basins, which increases gas supply diversity. Currently, the Ontario LDCs do not have direct access to the Marcellus/Utica supply, which, as discussed in Section III, is one of the largest and fastest growing North American natural gas supply basins. This direct access to the Marcellus/Utica production augments the current gas supply basins and market hubs accessed by the Ontario LDCs, which include natural gas production or availability in the WCSB, Chicago Hub, Gulf of Mexico, and U.S. Mid-continent. By diversifying its natural gas supply basins, the Ontario LDCs will increase the overall reliability of their portfolio and, therefore, service to customers. Similarly, natural gas supply basin diversity mitigates the risk to the Ontario LDCs of any individual supply basin being negatively impacted by operational, regulatory, economic, social, or political developments that inhibit or reduce natural gas production.

Enhanced Dawn Liquidity

As proposed, NEXUS provides a direct pipeline path between the Marcellus and Utica supply basins and the Dawn Hub, allowing more supply to be delivered to the Dawn Hub. NEXUS will

69 Daily spot prices and currency exchange rates from SNL Financial.

not only increase the physical supply to the Dawn Hub, but also increase the number of counterparties that are active at the Dawn Hub (*e.g.*, the NEXUS capacity holders that are natural gas producers). This increase in natural gas supply and counterparties will increase the overall liquidity of the Dawn Hub. In addition, the transportation capacity on NEXUS that is contracted by the Ontario LDCs will be utilized to deliver physical natural gas supply to the Dawn Hub to meet customer demand. Stated differently, NEXUS capacity contracted by the Ontario LDCs provides more certainty that Marcellus and Utica natural gas supply will be delivered to the Dawn Hub. This diversification of natural gas supply at the Dawn Hub will benefit the counterparties that may transact certain volumes at the Dawn Hub price index.

Transportation Path Diversity and Associated Reliability

A contract on NEXUS provides the Ontario LDCs with additional diversity in their transportation portfolio and, therefore, more reliability from a delivery perspective. Currently, the Ontario LDCs receive most of their flowing natural gas supplies via transportation paths that connect the WCSB, U.S. Mid-continent, or Chicago Hub to Ontario. NEXUS will provide an alternative natural gas supply basin and transportation path by directly connecting the Marcellus/Utica basin to the Dawn Hub. By adding a new pipeline path, the Ontario LDCs will increase the reliability of the overall transportation portfolio and, therefore, service to their customers. For example, NEXUS provides an alternative delivery path if one of the existing pipelines utilized by the Ontario LDCs experiences a delivery curtailment. The additional pipeline path diversity may also provide the Ontario LDCs with increased leverage in negotiating with other pipelines with respect to services and associated rates.

Transportation Cost Stability

One of the benefits provided to the Ontario LDCs from NEXUS is the option to negotiate a fixed rate for the term of the firm transportation agreement or to choose the cost based recourse rate. While the recourse rate may increase subject to review and approval by the FERC, the negotiated rate provides a fixed, known rate for the duration of the firm transportation agreement. Specifically, under the recourse rate, a shipper is exposed to any cost increase (*e.g.*, construction cost overrun) that is approved by the FERC. Under a negotiated rate, the shipper usually caps its exposure to construction cost overruns and shares in certain reductions should the construction cost of the project be lower than expected. In this manner, the shipper has a known rate for the duration of the term of the firm transportation contract. Therefore, under a negotiated rate agreement, the risk of construction cost overrun is shared with the shipper up to an agreed cap and, thereafter, the risk is borne by the pipeline development entity. The Ontario LDCs have elected to enter into a negotiated rate agreement with NEXUS, thus placing a cap on their exposure to construction cost overruns. Stated differently, by contracting for a negotiated rate, the Ontario LDCs have shifted some of the risk of construction cost from their customers to the NEXUS developers. In addition, by entering into a negotiated rate agreement, the Ontario LDCs have a capped rate for the 15-year term of the contract.

Finally, with respect to total pipeline transport charges in the overall portfolio of the Ontario LDCs, a negotiated rate on NEXUS provides a known and stable rate that may augment certain rate uncertainty on other pipelines.

Natural Gas Price Index Diversity and Associated Cost Stability

In addition to natural gas supply basin and transportation path diversity, direct access to the Marcellus and Utica supply basins will provide the Ontario LDCs with increased price diversity. Specifically, the Marcellus/Utica gas supply basins will have certain price signals and price indices not previously accessed by the Ontario LDCs, thus increasing overall price diversity and providing more stability with respect to natural gas costs for the Ontario LDCs' customers. By way of example, adding direct access to Marcellus/Utica supplies may provide the Ontario LDCs with the ability to leverage diverse price signals and maximize flow on specific pipelines when warranted by market conditions.

Service Flexibility

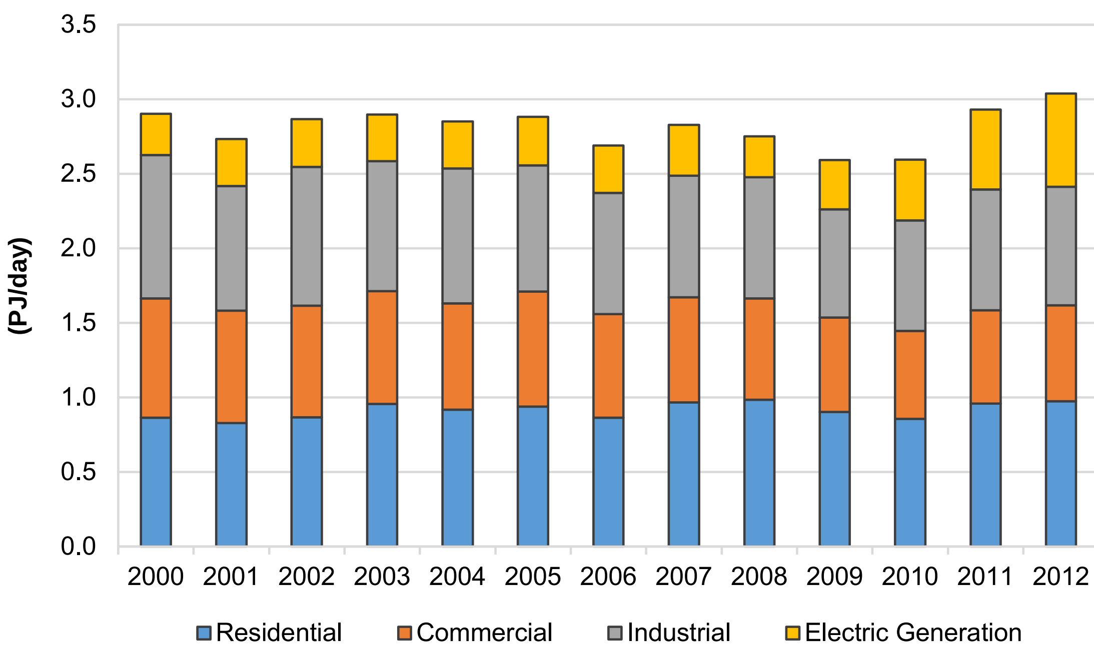
NEXUS will be a FERC regulated pipeline and, as such, will provide certain service flexibility to the portfolio of the Ontario LDCs, which may augment existing contracts on other pipelines (*e.g.*, the TransCanada Canadian Mainline). For example, NEXUS will likely provide various terms and conditions that provide service flexibility, including access to secondary receipt and delivery points, windows for nomination adjustments, and capacity segmentation/release to mitigate demand charges. With respect to capacity release, this service will provide the Ontario LDCs with an opportunity to manage un-utilized capacity and develop revenues to offset capacity demand charges. NEXUS will access various markets in Ohio and Michigan (*i.e.*, within the capacity contract path of the Ontario LDCs), which should provide the Ontario LDCs with various counterparties to structure deals or provide bids for available capacity.

Other Benefits

In addition to benefiting the Ontario LDCs, NEXUS will benefit other stakeholders, including: (1) power generation entities; (2) direct purchase customers; (3) other transportation customers; and (4) the Province of Ontario. The benefits to these customers are directly related to more natural gas supply (*i.e.,* volume), counterparties, and liquidity available at the Dawn Hub as a result of NEXUS. The Province of Ontario will generally benefit by preserving, and potentially improving, its economic competitiveness relative to regions that currently have access or are developing access to the Marcellus and Utica supply basins.

The benefits to these customer segments from NEXUS (*e.g.*, more supply and price discovery) are particularly important in light of the natural gas demand trends in Ontario. For example, demand for natural gas in the Province increased by 4.6% from 2.9 PJ/day in 2000 to 3.0 PJ/day in 2012, mainly due to increased usage from the electric generation sector beginning in 2010.[70] Please see Figure 4.2.

Figure 4.2: Historical Natural Gas Demand by Segment[71]

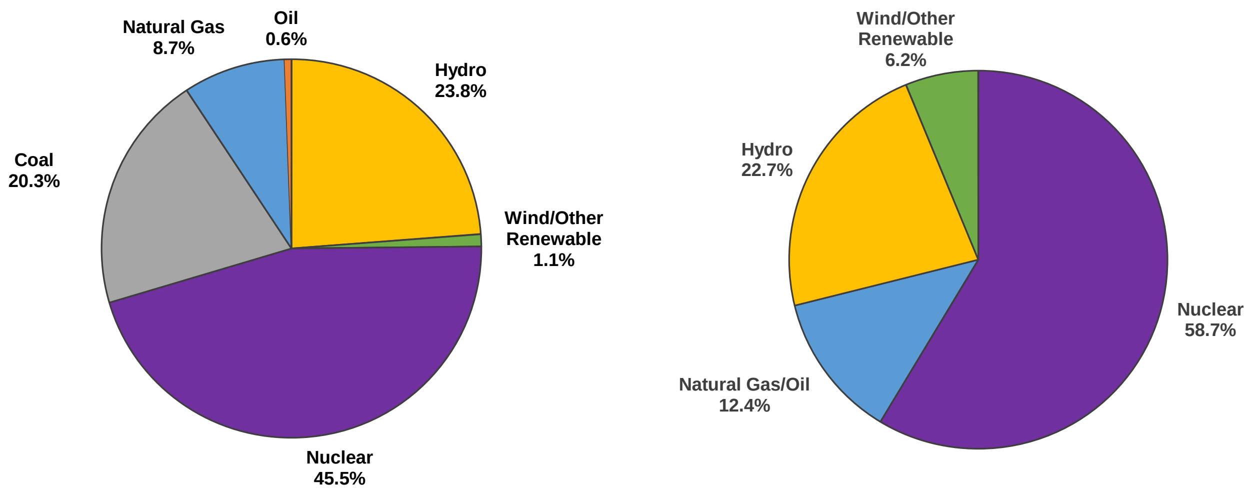


[70] National Energy Board of Canada, *Canada's Energy Future 2013 – Energy Supply & Demand Projections to 2035*, November 2013, Appendix 2.7.

[71] Ibid.

As shown in Figure 4.2 (above), the electric generation segment represented 10% (*i.e.*, 0.3 of 2.9 PJ/day) of the natural gas consumed in 2000, but by 2012, this segment represented approximately 20% (*i.e.*, 0.6 of 3.0 PJ/day).[72] As illustrated in Figure 4.3 (below), by 2015, the Province of Ontario completed the phase-out of coal-fired generation, which was replaced by nuclear, natural gas-fired, and wind generation.

Figure 4.3: Historical Ontario Generation by Fuel[73]



Generation by Fuel (2005) **Generation by Fuel (2015YTD)**

Consistent with the historical trends discussed above, a primary driver of future natural gas demand in Ontario is the electric generation segment. The increase in natural gas consumption associated with this sector is in response to refurbishments (primarily nuclear generation) and retirements (coal and nuclear generation).[74]

72 Ibid.

73 National Energy Board of Canada, *Canada's Energy Future 2013 – Energy Supply & Demand Projections to 2035*, November 2013, Appendix 2.7, Appendix 5.1; and Independent Electricity System Operator, *2015 Generator Output by Fuel Type Monthly Year-to-Date*, http://www.ieso.ca/Pages/Power-Data/Supply.aspx, accessed May 2015. The last coal-fired generation station in Ontario (*i.e.*, the Thunder Bay Generating Station) ceased burning coal in April 2014, and was converted to an advanced biomass generating station in 2015. *See*, Ontario Power Generation, *Thunder Bay Generating Station*, http://www.opg.com/generating-power/thermal/stations/thunder-bay-station/Pages/thunder-bay-station.aspx, accessed May 2015.

74 Ontario Power Authority, *Generation and Conservation Tabulations and Supply/Demand Balance– 2013 LTEP: Module 3*, January 2014, at 7.

The planned refurbishments of Bruce Power's Bruce B generating station and Ontario Power Generation's Darlington nuclear station are expected to be completed by 2032.[75] If completed on schedule, the refurbishment of the ten nuclear units is expected to reduce the long-term demand for natural gas by displacing natural gas-fired electric generation. However, should the refurbishment of the Bruce B and Darlington nuclear complexes be extended or cancelled, Ontario's reliance on natural gas fueled power generation could be expected to increase.

Access to New Natural Gas Supply Basins

The Ontario market primarily depends on the same natural gas supply basins as the Ontario LDCs, specifically, natural gas supplies from the WCSB, Gulf of Mexico, U.S. Mid-continent, and Chicago Hub. NEXUS will provide a direct connection between the Marcellus and Utica supply basins and the Dawn Hub. By providing access to new sources of natural gas supply at the Dawn Hub, power generators and direct purchase customers will have additional market liquidity and greater security of supply. Finally, given the various pipeline expansion projects to increase takeaway capacity from Dawn on the Dawn-Parkway system, additional deliverability to Dawn may be needed. The evidence of Union provides more detail regarding the Dawn-Parkway expansions.

Pipeline Diversity

The Ontario market is dependent on deliveries from the TransCanada Canadian Mainline and its affiliated pipelines, as well as the Alliance/Vector and Chicago Hub/Vector transportation paths. NEXUS will provide a new entrant to supply the Ontario market with natural gas sourced from a different natural gas supply basin. Ontario's direct purchase customers and those relying on the natural gas supply and price signals at the Dawn Hub can expect to benefit from a new competing pipeline and route for providing natural gas to the Dawn Hub and Ontario. In particular, the existing pipelines will see additional competitive pressures to control costs and develop new services that would better serve the long-term needs of the Ontario market. In addition, the Ontario market participants would be less dependent on any one pipeline or route

75 Ontario Ministry of Energy, *Achieving Balance – Ontario's Long-Term Energy Plan*, December 2013, at 29-30. Ontario's Long-Term Energy Plan notes that both the Bruce B and Darlington nuclear complexes will commence refurbishment of one unit each in 2016. Decisions on completing subsequent refurbishments will be made following the completion of each initial unit. Bruce Power and Ontario Power Generation will require at least 16 years to complete the refurbishment of all ten units.

to supply natural gas to the Ontario market, thus reducing Ontario's exposure to the risk of pipeline service interruptions or long-term changes in natural gas flow patterns.

Improved Liquidity at the Dawn Hub

The OEB has historically recognized the benefits of developing and improving the liquidity of the Dawn Hub.[76] Those benefits include offering natural gas supply and pricing service near the Ontario market, which provides access to counterparties, supply options, and price discovery for customers. NEXUS will provide natural gas supplies from the Marcellus and Utica basins to the Ontario/Michigan region, which will increase the volume of natural gas available for purchase at the Dawn Hub, thus directly benefiting customers that purchase at the Dawn Hub natural gas price index (*e.g.*, power generation and direct purchase customers). The NEXUS transportation capacity held by the Ontario LDCs (*i.e.*, to serve customers), will provide a greater likelihood that certain volumes will flow to Ontario and provide benefits to other market participants (*e.g.*, direct purchase customers).

Improved Economic Competitiveness in Ontario

Access to the Marcellus and Utica natural gas supply basins can be expected to help preserve the economic competitiveness of the Province of Ontario with respect to industries that are energy intensive (*i.e.*, significant reliance on natural gas and/or electricity). Specifically, many of the regions with which Ontario competes (*i.e.*, Michigan, Ohio, Pennsylvania, and New York) are either located within the Marcellus and Utica basins or have direct pipeline transportation paths to access that natural gas supply. Those regions (*i.e.*, Michigan, Ohio, Pennsylvania, and New York) are able to benefit from that direct access to abundant and lower cost natural gas supplies. Ontario would similarly benefit from lower cost natural gas supplies since the Marcellus and Utica basins are geographically proximate to Ontario, thus increasing the diversity of natural gas supplies and introducing more price stability to the Province. As a fuel source for electrical energy and manufacturing processes, lower and more stable natural gas costs would maintain Ontario's competitiveness with surrounding regions.

76 *See*, for example, *Decision with Reasons – Natural Gas Electricity Interface Review*, OEB Board File No. EB-2005-0551, November 7, 2006, at 44.

V. LANDED COST ANALYSIS

As part of their decision process regarding the contracting for pipeline capacity, the Ontario LDCs use a landed cost analysis to evaluate the delivered cost of various natural gas supply paths to a specific delivery point. Specifically, the Ontario LDCs' landed cost analysis, with respect to a capacity contract on NEXUS, compares the delivered cost of natural gas supply to the Dawn Hub from various alternative pipeline transportation routes.[77]

Sussex Review

Sussex reviewed the landed cost analysis prepared by the Ontario LDCs to verify that: (1) the approach was reasonable and consistent with typical landed cost approaches; (2) alternative options had been identified and modeled; and (3) the decision process and analysis was documented.

With respect to the first Sussex review item listed above (*i.e.*, the reasonableness of the Ontario LDCs approach), a typical landed cost analysis approach is illustrated in Table 5.1 (below). In general, a landed cost analysis assumes the pipeline demand charges are priced at a 100% load factor (*i.e.*, the transportation path is used every day at full volume) and variable and/or fuel charges are based on full contracted volumes. This approach allows multiple paths to be compared in a transparent manner.

Table 5.1: Illustrative Landed Cost Analysis Approach

1	2	3	4		3+4
Path	**Gas Supply Basin**	**Gas Supply Cost**	**Pipeline 1**	**Pipeline 2**	**Total**
A	WCSB	Henry Hub + x	$D	N/A	Henry Hub + x + $D = A Total
B	Rockies	Henry Hub + y	$E	$F	Henry Hub + y + $E + $F = B Total

As shown in Table 5.1, a landed cost analysis usually consists of four components:

1. Alternative paths to transport natural gas supply to a specific delivery point are identified;
2. The natural gas supply basin associated with each transportation path is identified;

[77] For purposes of the Sussex report, the term "alternative" with respect to the Union and Enbridge landed cost analyses includes both existing transportation routes (*i.e.*, paths from the Ontario LDCs' existing supply portfolio), as well as certain proposed transportation routes (*e.g.*, Rover Pipeline).

3. The natural gas supply cost is developed for each path, which is generally calculated relative to Henry Hub (*i.e.*, plus or minus a basis differential); and
4. The transportation cost (*i.e.*, demand, variable, and fuel charges) for all pipelines within the path is calculated.

Finally, the landed cost for each path is totaled (*i.e.*, the gas supply cost plus the total transport costs).

For example, as demonstrated in Table 5.1 (above), Path A consists of a WCSB gas supply, which is priced at Henry Hub plus (or minus) a basis differential of "x" and is transported on Pipeline 1 for a total landed cost comprised of the gas supply cost (*i.e.*, "Henry Hub + x") and the transportation cost for Pipeline 1 (*i.e.*, "$D").[78] Similarly, Path B consists of a Rockies gas supply transported on both Pipeline 1 and Pipeline 2 for a landed cost comprised of the gas supply cost (*i.e.*, "Henry Hub + y") plus total transport cost on Pipeline 1 and Pipeline 2 (*i.e.*, "$E + $F").

Union Landed Cost Analysis

The Sussex review of the Union landed cost analysis is based on the evidence submitted by Union with respect to the NEXUS capacity contract. To perform the landed cost analysis, Union identified and modeled fifteen transportation paths, which access various Canadian and U.S. gas supply basins, as well as different transportation routes to the Dawn Hub. Specifically, the alternative paths modeled by Union include access to nine natural gas production basins and/or supply hubs (*e.g.*, Marcellus/Utica shale basins, Chicago Hub, or WCSB). Therefore, with respect to the second Sussex review item (*i.e.*, range of options), the Union landed cost analysis identified and modeled a reasonable range of alternative options regarding various natural gas supply paths to the Dawn Hub.

Next, for each of the transportation routes, Union calculated the natural gas supply cost as the Henry Hub price index plus (or minus) a basis differential, as provided by ICF. Specifically, Union relied upon ICF and the associated natural gas price projections developed by ICF in their Base Case dated January 2014 and January 2015. The ICF Base Case dated January 2014 was used by Union in their January 2014 landed cost analysis as summarized in Schedule

78 The basis differential of "x" may be positive or negative depending on the available supply and demand for natural gas at a particular pricing point.

4 of the Union evidence. Similarly, the ICF Base Case dated January 2015 was used by Union in their January 2015 landed cost analysis as summarized in Schedule 5 of the Union evidence.

For both the January 2014 and January 2015 landed cost analysis, Union calculated a simple average of the natural gas prices at specific gas supply basins as that data was listed in the ICF Base Cases. This calculation was used as the gas supply cost assumption in the Union landed cost analysis.

Sussex understands that the use of ICF natural gas price projections is consistent with Union past practices regarding landed cost analyses. In addition, this approach is reasonable and consistent with a typical landed cost analysis.

Finally, consistent with the typical landed cost approach, Union calculated the total transport cost (*i.e.*, demand, variable,[79] and fuel charges) for each alternative path, assuming a 100% load factor (*i.e.*, the transportation path is used every day at full volume). Specifically, Union developed toll/rate values for the various identified paths by using current, approved tolls/rates. The use of current tolls/rates, as adjusted by tolls/rates approved in recent regulatory proceedings, is reasonable and consistent with a typical landed cost analysis. In addition, an appropriate estimate of fuel charges was included. The landed cost for each path was calculated as the sum of the total transport cost and estimated gas supply cost.

With respect to the third Sussex review item (*i.e.*, decision documentation), Union conducted a landed cost analysis prior to signing the NEXUS Precedent Agreement in January 2014 in order to assess the NEXUS capacity contract against Union's existing transportation paths. The results of the January 2014 analysis demonstrated that the total landed cost for the NEXUS path was within the range of the existing portfolio options as documented in Schedule 4 of the Union evidence. In January 2015 (*i.e.*, after executing the NEXUS Precedent Agreement), Union updated the landed cost analysis to reflect revised natural gas prices and updated tolls/rates on certain pipelines (*e.g.*, NEXUS). In addition to analyzing the delivered cost associated with NEXUS relative to Union's existing transportation paths, Union also reviewed the total landed cost of alternative paths (*e.g.*, Rover Pipeline). The results of the updated

79 The variable charges may include the NEB Abandonment Surcharges and the FERC Annual Charge Adjustment, as applicable.

landed cost analysis indicate that the NEXUS path was a competitive option relative to the existing paths and the Rover Pipeline as documented in Schedule 5 of the Union evidence.

Enbridge Landed Cost Analysis

Sussex reviewed the Enbridge landed cost analysis based on the evidence submitted by Enbridge with respect to their NEXUS Precedent Agreement. To perform the landed cost analysis, Enbridge evaluated four options for the NEXUS path[80] and seven alternative transportation paths. The paths reviewed by Enbridge include access to various Canadian and U.S. gas supply basins, as well as different transportation routes to the Dawn Hub. Specifically, the alternative paths modeled by Enbridge include access to six natural gas production basins and/or supply hubs (*e.g.*, Marcellus/Utica shale basins, Chicago Hub, or WCSB). Therefore, with respect to the second Sussex review item (*i.e.*, range of options), the Enbridge landed cost analysis identified and modeled a reasonable range of alternative options regarding various natural gas supply paths to the Dawn Hub.

Next, for each of the transportation routes evaluated, Enbridge relied upon commodity prices sourced from Openlink[81] to calculate the natural gas supply cost for each transportation path over the 15-year time period from 2017 to 2032 (*i.e.*, the term of the capacity contract as outlined in the NEXUS Precedent Agreement). Specifically, Enbridge obtained from Openlink the 21-day average settlement price for each forward contract month from November 2017 through November 2032, which was used as the natural gas supply cost assumption for each month of the analysis.

Sussex understands that the use of price projections from Openlink is consistent with Enbridge's past practices regarding gas commodity price assumptions. In addition, this approach is reasonable and consistent with a typical landed cost analysis.

80 The four NEXUS options reflect certain provisions of the NEXUS Precedent Agreement, which provides Enbridge with a capital cost tracking adjustment and preferred rights to increase its contracted capacity.

81 Openlink is the risk management software utilized by Enbridge for energy and financial risk management. The prices contained in Openlink are provided by independent third parties (*e.g.*, NGX and Kiodex) who specialize in generating and developing market information, including forward curves. *See*, *Enbridge Gas Distribution Inc. Response to TCPL Interrogatory #2, Issue A1*, OEB EB-2012-0451/EB-2012-0433/EB-2013-0074, August 12, 2013.

Finally, Enbridge calculated the total monthly transport cost (*i.e.*, demand, variable,[82] and fuel charges) for each alternative path, assuming a 100% load factor (*i.e.*, the transportation path is used every day at full volume), which is consistent with the typical landed cost approach. Specifically, Enbridge developed toll/rate values for the various identified paths based on currently approved tolls/rates except for certain paths where the tolls/rates utilized in the landed cost analysis reflect proposed tolls/rates (*e.g.*, Vector, Rover Pipeline, and ANR East).[83] The use of approved tolls/rates for existing transportation paths, and proposed tolls/rates to reflect expected tolls/rates on proposed pipeline projects/expansions, is reasonable and consistent with a typical landed cost analysis. In addition, an appropriate estimate of fuel charges was included. For each year of the analysis period (*i.e.*, 2017 through 2032), the total costs for each path was then calculated as the sum of the total monthly transport cost and estimated gas supply cost. Next, the total costs are divided by the annual quantity to calculate the landed cost. The simple average of the landed cost over the 15-year time period was used to evaluate the cost of the NEXUS capacity relative to alternative transportation paths.

With respect to the third Sussex review item (*i.e.*, decision documentation), Enbridge conducted a landed cost analysis in November 2014 (as part of the process to obtain the necessary internal approvals to proceed with the NEXUS Precedent Agreement) in order to assess the NEXUS capacity contract against various alternative transportation paths. The results of the November 2014 analysis demonstrated that the total landed cost for the NEXUS path was within the range of the options reviewed as documented in Appendix B of the Enbridge evidence. In May 2015, Enbridge updated its landed cost analysis to reflect revised commodity prices and tolls/rates for certain pipelines (*e.g.*, Vector). The results of the updated landed cost analysis indicated that the NEXUS path is a competitive option as documented in Appendix C of the Enbridge evidence.

Sussex Findings

Based on a review of the landed cost analyses performed by Union and Enbridge, Sussex has the following findings:

- The process utilized by both Union and Enbridge is reasonable and consistent with the typical landed cost analysis approach as described above (*i.e.*, alternative paths to

82 The variable charges may include the NEB Abandonment Surcharges and the FERC Annual Charge Adjustment, as applicable.

83 Based on the proposed tolls/rates in the recent open seasons on the various pipelines.

transport natural gas supply to a specific delivery point are identified, the natural gas supply basin associated with each transportation path is identified, the natural gas supply cost is developed for each path, and the transportation cost for all pipelines within the path is calculated).

- Union's landed cost analysis identified and modeled fifteen transportation paths, which include access to nine natural gas production basins and/or supply hubs in the U.S. and Canada, as well as different transportation routes to the Dawn Hub. The paths reviewed by Union represent a reasonable range of alternative options to NEXUS.
- The Enbridge landed cost analysis reviewed four options associated with the NEXUS capacity and seven alternative transportation paths to the Dawn Hub, which include access to six U.S. and Canadian natural gas production basins and/or supply hubs. The transportation paths reflect a reasonable range of alternative options regarding various natural gas supply paths to the Dawn Hub.
- Although the data sources used by Union and Enbridge to calculate the natural gas supply cost are different, both are reasonable. Specifically, the Union landed cost analysis calculated the gas supply cost for each of the transportation routes based on a price projection forecast from ICF, which is consistent with Union's past practices regarding the evaluation of pipeline contracts. Enbridge relied on commodity price projections sourced from Openlink as the gas supply cost assumption, which is consistent with Enbridge's past practices regarding gas commodity price assumptions.
- Union and Enbridge used similar approaches to calculate the transportation cost (*i.e.*, demand, variable, and fuel charges) for the various identified paths. Specifically, the Ontario LDCs relied on current or proposed tolls/rates to reflect expected tolls/rates on proposed pipeline projects/expansions. In addition, both the Union and Enbridge landed cost analyses covered the full contract term (*i.e.*, 15 years) of the capacity obligation as outlined in the NEXUS Precedent Agreements.
- As illustrated by the results of the Ontario LDCs' landed cost analyses, the NEXUS transportation path is competitive with the alternatives evaluated.
- Finally, Union's decision process and analysis are documented in Schedules 4 and 5 of the Union evidence. Similarly, the Enbridge decision process and analysis are documented in Appendices B and C of the Enbridge evidence.

VI. RISK ASSESSMENT

As part of the assessment of NEXUS, Sussex reviewed and considered certain risks related to the Project, including:

- Construction,
- Demand Forecasting,
- Supply,
- Regulatory,
- Project Development, and
- Operational.

The Sussex review includes a description of the risk and the potential impact on the Ontario LDCs as shippers on NEXUS. As noted below, in many instances, the risks faced by the Ontario LDCs are mitigated by the negotiated rate agreements executed by the Ontario LDCs. These agreements include terms and conditions, which cap the cost of transportation, provide capacity mitigation options, and provide termination rights to mitigate certain of the risks described below.

Construction Risk

As with any major pipeline infrastructure project, NEXUS will face the risk of cost increases and schedule extensions during the construction phase. Cost increases and schedule extensions may be due to route changes, unforeseen subsurface conditions, permit requirements, construction quality, labor productivity and availability, and material cost and availability. Generally, a negotiated rate agreement apportions the risk of schedule extensions and construction cost overruns to the party that is best positioned to manage that risk (*i.e.*, the project developer). Specifically, under a negotiated rate agreement, the shipper in a typical pipeline project subject to the jurisdiction of the FERC may be obligated to contribute to construction cost overruns, but that contribution is limited by the contractual terms (*e.g.*, capped limit to the transportation rate). Similarly, the Ontario LDCs, in their negotiated rate agreement, have capped the risk of construction cost overruns, thus limiting the exposure to this risk. In addition, shippers on pipeline infrastructure projects may have certain termination rights that could also facilitate management of this risk. Lastly, precedent agreements often include a date certain for commencing service. Specifically, if NEXUS is not placed in-service by November 1, 2018, then the Ontario LDCs may terminate their Precedent Agreements. In addition, should the project be delayed, the Ontario LDCs can potentially contract for short-term market purchases to fill potential gaps in their respective supply portfolios.

Demand Forecasting Risk

The Ontario LDCs may face certain risks related to whether the demand for natural gas will meet the Ontario LDCs' expectations that underpin the decision to enter into the NEXUS Precedent Agreements. Demand forecasting risks include potential demand forecast model errors, changes in economic conditions, and changes in social or political conditions. The primary mitigation factor regarding demand forecasting risks is that the Ontario LDCs are entering into the Precedent Agreements with NEXUS as replacement capacity for existing contracts within their respective supply portfolios. As such, the decision to enter into the NEXUS Precedent Agreements are not premised on future demand growth, and are instead premised on existing demand.

Although the Ontario LDCs face the risk that natural gas demand could decline, the consistent historical natural gas consumption by the Ontario LDCs' customers and the current cost competitiveness of natural gas minimizes the likelihood of this risk materializing. In addition, the Ontario LDCs have the ability to manage their respective supply portfolios through the termination of other transportation/supply contracts. Also, the term (*i.e.*, 15 years) of the firm transportation agreement outlined in the Ontario LDCs' Precedent Agreements with NEXUS is on the shorter end of the range, thus mitigating the risk of long-term demand erosion.

Further, given the substantial undertakings with respect to the refurbishment of certain nuclear generating facilities in Ontario and the expectation that natural gas-fired power generation capacity would be the likely backstop should those projects require additional time, Ontario may require additional natural gas transportation capacity.

Lastly, NEXUS, as a FERC jurisdictional pipeline, will be required to provide shippers with measures to mitigate any un-utilized capacity, such as capacity release and segmentation. The NEXUS pipeline will access various markets in Ohio and Michigan (*i.e.*, within the NEXUS transportation path of the Ontario LDCs), which should provide the Ontario LDCs with counterparties to structure deals regarding un-utilized capacity. These services (*e.g.*, capacity release and segmentation) and access to markets will enhance the ability of the Ontario LDCs to manage un-utilized capacity and potentially provide revenues to offset the NEXUS pipeline demand charges.

Supply Risk

Supply risk incorporates several subcategories of potential risks related to NEXUS, including:

- The cost competitiveness of natural gas relative to alternative fuels;
- The cost of alternative transportation paths;
- The cost of alternative supply basins; and
- The overall availability of natural gas to supply NEXUS.

With regard to the cost competitiveness of natural gas relative to alternative fuels, the substantial increase in natural gas production from shale basins has fundamentally re-shaped the projections of the cost of natural gas and the availability of natural gas supply. As such, natural gas will continue to effectively compete for various market segments (*e.g.*, residential, commercial, industrial, and power generation), thus encouraging natural gas exploration and production.

The cost effectiveness of the NEXUS transportation path is described in the evidence of Union and Enbridge. Based on that analysis, NEXUS is expected to be a competitively priced option. Nonetheless, it is important to recognize that NEXUS has the additional benefits described in Section IV (*e.g.*, diversity in natural gas supply basins, pipelines, and price) that further enhance the value of NEXUS capacity to the Ontario LDCs. Additionally, NEXUS will provide access to alternative supply basins through connections with the TETCO and TGP systems.

The availability of natural gas to serve NEXUS is discussed in Section III; and, based on those discussions, sufficient natural gas supply is forecasted to be available for the term of the NEXUS Precedent Agreements. Finally, should natural gas availability from the Marcellus and Utica basins become an issue, NEXUS will have access to other natural gas supply basins through the NEXUS interconnections with upstream pipelines.

Regulatory Risk

Sussex considered several areas of regulatory risk related to delays or failure to secure regulatory permits and approvals that are necessary to construct and operate NEXUS. Overall, the regulatory processes for securing these approvals are initiated and managed by the lead developers of NEXUS (*i.e.*, DTE and Spectra). The lead developers initiated the pre-filing process with FERC in late December 2014, and have outlined a detailed plan for securing the necessary permits in their pre-filing application. More notably, both DTE and Spectra have an extensive record of developing, constructing, and owning natural gas transmission pipelines, particularly in the relevant market area, which is likely to mitigate the potential for regulatory approval delays. Spectra, for instance, operates more than 22,000 miles of interstate pipelines and approximately 300 Bcf of storage in the U.S. and Canada.[84] DTE, in addition to owning a regulated natural gas distribution utility, intrastate pipeline, and storage facilities in Michigan, has ownership interest in the Vector and Millennium pipelines and the Bluestone Gathering System. Given this combined experience, if NEXUS should encounter significant permitting or regulatory approval delays, the lead developers have the experience to manage and mitigate this risk.

In general, shippers who participate in open seasons for pipeline capacity manage regulatory risk by including conditions or terms in the precedent agreement that provide opportunities for shippers to re-assess their position if certain milestones and schedule deadlines are not met. To that end, shippers may be permitted to terminate the precedent agreements should the shippers not receive their required regulatory approvals. By way of example, the NEXUS Precedent Agreements have as a condition precedent approval of the agreement by the OEB by October 1, 2015.

Project Development Risk

NEXUS faces three subcategories of project development risk. First, a major interstate natural gas transportation pipeline, such as NEXUS, faces the risk of potential opposition from landowners along the proposed route. Second, a major pipeline, such as NEXUS, could experience a lack of shipper interest and insufficient firm capacity contracts to underpin the project. Third, the potential risk that the contractual counterparties fail to perform pursuant to the agreements.

84 *See*, Spectra Energy, About Us: At a Glance, http://www.spectraenergy.com/About-Us/At-a-Glance/, accessed January 2015.

To mitigate the risk of landowner opposition, NEXUS has identified a 600-foot corridor along the proposed route of NEXUS for study and review.[85] The lead developers have also identified approximately 3,500 land parcels that fall within that corridor and have already begun outreach to those landowners.[86]

The risk of insufficient demand has been mitigated by the three open seasons held by the lead developers of NEXUS, which have resulted in various shipper commitments, including precedent agreements with "supply push" and "demand pull" entities. Specifically, certain natural gas producers (*e.g.*, Chesapeake, CONSOL Energy, and Noble Energy) or "supply push" parties have expressed interest in long-term transportation contracts on NEXUS. Similarly, certain LDCs (*e.g.*, Union and Enbridge) or "demand pull" parties have expressed interest in long-term transportation contracts.[87] The experience of the NEXUS lead developers coupled with the diverse shipper base provides mitigation with respect to project development risk.

In terms of failure to perform risk, the lead developers (*i.e.*, DTE and Spectra) have been involved in the development, construction, and operation of numerous pipeline projects.[88] From a creditworthiness perspective, both lead developers are rated investment grade by the major credit ratings agencies and have market capitalizations of approximately $15 billion or more. Both Spectra and DTE have also been involved in the development, construction, and operation of numerous pipeline projects. Therefore, the counterparty or credit risks associated with the lead developers of the NEXUS Project are likely mitigated.

Operational Risk

The Ontario LDCs face two primary subcategories of operational risks: (1) operational costs, and (2) operational performance risks. The risk of operational costs exceeding the current expectations is mitigated by the negotiated rate agreement, which defines levels of rates. In addition, any operating costs not covered by the negotiated rate agreement would be subject to

85 *In Re: Request for Approval to Use the Pre-Filing Process NEXUS Gas Transmission, LLC – NEXUS Gas Transmission Project*, FERC Docket No. PF15-10-000, December 30, 2014, at 5.

86 Ibid, at 7. The lead developers were granted survey permission for approximately 72% of the proposed NEXUS route.

87 PRN Newswire, *Spectra Energy Reports Third Quarter 2014 Results,* November 5, 2014.

88 In December, 2014, Spectra was recognized as the 2014 Premier Construction Project by Platts Global Energy Awards. This award is provided to an entity to recognize, "excellence in project execution and management."

review and approval by the FERC, thus providing the Ontario LDCs with an opportunity to participate in a regulatory process regarding operating costs. Similarly, FERC approved tariff requirements and the complaint/review process at the FERC limit the risk of operational performance shortfalls. Both risks are further mitigated by the substantial project development and operational records of the NEXUS lead developers (*i.e.*, Spectra and DTE).

VII. REVIEW OF STATE PROCESSES FOR PRE-APPROVAL

In addition to the Ontario market review, the qualitative and quantitative discussion of NEXUS, and the analysis of benefits and risks associated with the Project, Sussex also reviewed various regulatory approaches regarding pre-approval of pipeline capacity contracts. Specifically, Sussex reviewed the pre-approval processes in certain jurisdictions, including Massachusetts, Connecticut, Florida, and North Carolina.

Massachusetts

In Massachusetts, the Department of Public Utilities ("DPU") reviews the actions of the LDC (*i.e.*, contracting for pipeline capacity) to determine if it is "consistent with the public interest". Among other considerations, the primary requirements for the LDC to meet this guideline are:

1. Consistency with the company's portfolio objectives; and
2. Favorable comparison to the range of alternative options reasonably available to the LDC at the time of the acquisition or contract renegotiation.

To establish consistency with portfolio objectives, the LDC may reference "portfolio objectives established in a recently approved forecast and requirements plan or in a recent review of supply contracts under Section 94A, or may describe its objectives in the filing accompanying the proposed resource."[89] Additionally, the DPU process requires a review of "relevant price and non-price attributes of each contract to ensure a contribution to the strength of the overall supply portfolio."[90]

The DPU requires an LDC to review alternative natural gas supply options by evaluating "whether the pricing terms are competitive with those for the broad range of capacity, storage, and commodity options that were available to the LDC at the time of the acquisition, as well as with those opportunities that were available to other LDCs in the region".[91] Other considerations include non-price objectives, such as supply reliability and diversity.

89 *Order in Re: Petition of Boston Gas Company and Colonial Gas Company each d/b/a National Grid, pursuant to G.L. c. 164, § 94A, for Approval of Two Precedent Agreements for Firm Transportation Service with Algonquin Gas Transmission, LLC*, Docket No. D.P.U 13-157, January 31, 2014, at 3.

90 Ibid, at 4.

91 Ibid.

The Massachusetts LDCs have received pre-approval of pipeline capacity contracts from the DPU on several occasions, including in recent filings involving precedent agreements between affiliates of National Grid, Columbia Gas, and Northeast Utilities, as shippers, and Spectra, as developer and owner of the Algonquin Incremental Market ("AIM") Project.[92] The AIM Project will provide certain New England LDCs with more access to natural gas supplies from the Marcellus and Utica basins. In their DPU filing, National Grid provided support with respect to the consistency of the 15-year AIM precedent agreements with their portfolio objectives (as illustrated by National Grid's Forecast and Supply Plan) and requirements (*i.e.*, existing customer loads and future load growth). In addition, National Grid evaluated "how the AIM Project would affect the reliability, flexibility, and diversity of the Company's portfolio."[93] The applications by the affiliates of Columbia Gas and Northeast Utilities were generally similar to that submitted by National Grid.

The DPU approved the AIM precedent agreements, finding that the contracts were in the public interest. The DPU noted that the AIM capacity compared favorably (*e.g.*, competitive delivered cost) with the alternatives that were considered by the LDCs.[94] In addition, the DPU stated in its order approving the AIM precedent agreement with an affiliate of Northeast Utilities, that:

> Moreover, the AIM Project will significantly enhance the Company's ability to access a new supply source [Marcellus Shale] located in close proximity to New England…Because the Company's access to eastern Canadian supplies and imported LNG has declined notably in recent years, and western Canadian supplies will be more expensive, the AIM Project provides the Company with an opportunity to replace these supplies with a more reliable source [Marcellus Shale].[95]

Connecticut

Connecticut is implementing its Comprehensive Energy Strategy ("CES"), which established significant customer-growth objectives, requiring Connecticut Natural Gas Corporation, The Southern Connecticut Gas Company, and Yankee Gas Services Company (the "Connecticut LDCs") to update their capacity requirements, calculate shortfalls, and identify sources of

92 *See,* Docket Nos. D.P.U. 13-157, D.P.U. 13-158, and D.P.U. 13-159.

93 *Order in Re: Petition of Boston Gas Company and Colonial Gas Company each d/b/a National Grid, pursuant to G.L. c. 164, § 94A, for Approval of Two Precedent Agreements for Firm Transportation Service with Algonquin Gas Transmission, LLC*, Docket No. D.P.U 13-157, January 31, 2014, at 16.

94 Ibid, at 22.

95 *Order in Re: Petition of NSTAR Gas Company, pursuant to G.L. c. 164, § 94A, for Approval of a Precedent Agreement for Firm Transportation Service with Algonquin Gas Transmission, LLC*, Docket No. D.P.U. 13-159, January 31, 2014, at 20 [clarification added].

additional capacity. In a proceeding related to the implementation of the Connecticut CES, the Connecticut LDCs filed for pre-approval of their precedent agreements associated with the AIM Project and the TGP Connecticut Expansion, which will increase their access to natural gas supplies from the Marcellus and Utica shale basins. As part of the pre-approval process, the LDCs were required to file the following information with the Public Utilities Regulatory Authority ("PURA"):

1. Peak-Day Demand Forecast;
2. Forecasted Requirement for Additional Capacity;
3. Fit with LDC's Existing Portfolios;
4. Comparison with Alternative Sources; and
5. Other Considerations.[96]

The Connecticut LDCs received pre-approval for their precedent agreements from the PURA.[97] However, the PURA noted that, although it does not usually pre-approve pipeline capacity contracts, based on the information provided by the Connecticut LDCs, and acknowledging that the CES legislation would require significant load growth, PURA approved the precedent agreements in order "to make the expansion plan viable."[98]

Florida

In Florida, Florida Power & Light ("FPL") filed for pre-approval of the precedent agreements with Sabal Trail and the Florida Southeast Connection ("FSC") with the Florida Public Service Commission ("FPSC").[99] The FPSC noted that FPL was not legally required to obtain their approval since the pipelines fall under the jurisdiction of the FERC. However, the precedent agreements would require FPSC action "at the time FPL seeks recovery of costs in the fuel clause proceeding."[100] Due to the magnitude of costs associated with the precedent agreements, FPL requested a determination from the FPSC that the "decision to enter into long-

96 *Decision in Re: PURA Investigation of Connecticut's Local Distribution Companies' Proposed Expansion Plans to Comply with Connecticut's Comprehensive Energy Strategy*, Docket No. 13-06-02, November 22, 2013, at 17-23.

97 Ibid, at 64-65.

98 Ibid, at 23.

99 *Proposed Agency Action Order on Florida Power & Light Company's Proposed Sabal Trail Transmission, LLC and Florida Southeast Connection Pipelines*, Docket No. 130198-EI, Order No. PSC-13-0505-PAA-EI, October 28, 2013, at 4.

100 Ibid, at 2.

term gas transportation contracts is prudent and that the associated costs are eligible for recovery through the fuel clause."[101]

The FPSC's evaluation of FPL's precedent agreements involved several steps, including a review of the Company's need for additional capacity. As a vertically integrated electric utility, FPL's need for incremental capacity is tied to its projection of increased electricity load. The FPSC reviewed FPL's customer load forecast and proposed generation resource portfolios, comparing the requirements resulting from these projects to the Company's existing contracted capacity. Following this review, the FPSC concluded, "FPL has adequately demonstrated a need for an additional 400 MMcf/day of firm natural gas transmission capacity by 2017."[102]

The FPSC next evaluated the alternative options to determine if the Sabal Trail and FSC precedent agreements represented the most cost-effective solutions to meet this capacity need. The FPSC found that the Sabal Trail and FSC precedent agreements provided cost savings and offered additional benefits related to supply diversity and opportunities for further expansion.[103]

North Carolina

In North Carolina, Duke Energy, a vertically integrated electric utility, and Piedmont Natural Gas Company, Inc. ("Piedmont"), a natural gas utility, received pre-approval from the North Carolina Utilities Commission ("NCUC") related to a precedent agreement with the Atlantic Coast Pipeline, LLC ("ACP") for the transport of natural gas from the Marcellus Shale supply region.[104] The NCUC accepted Piedmont's demonstration of the reasonableness of the precedent agreement.[105] Piedmont emphasized, among other benefits, that the ACP project would provide:

- Additional natural gas supplies from highly liquid trading points in the Marcellus and Utica basins;
- New transportation infrastructure at favorable and stable rates;
- Operational enhancements and additional supply deliverability; and

[101] Ibid.
[102] Ibid, at 9.
[103] Ibid, at 13-15.
[104] *Order Accepting Affiliated Agreements for Filing and Permitting Operation Thereunder Pursuant to G.S. 62-153 and Authorizing Piedmont to Enter into Related Redelivery Agreements*, Docket No. G-9, Sub 655, October 28, 2014.
[105] Ibid.

- Economic development benefits related to construction and operation of the pipeline.[106]

Summary and Conclusions of State Processes for Pre-Approval

While the specific requirements with respect to each jurisdiction's pre-approval process can vary, the information submitted in a pre-approval filing generally addresses the following:

- The need for the project;
- The competitiveness of the project;
- The quantitative and qualitative benefits associated with the project;
- The compatibility of the project with the existing portfolio; and
- The mitigation of the risks associated with the project.

Finally, the regulatory process for pre-approval of the cost consequences associated with long-term capacity agreements in the jurisdictions reviewed by Sussex is generally consistent, specifically:

- The LDC, at its discretion, may file for pre-approval of the cost consequences associated with the capacity contract;
- The capacity contracts usually represent significant investments by the project developers and shippers;
- The LDC provides evidence addressing the requirements listed above;
- The LDC requires certainty regarding the recovery of costs and, therefore, requests pre-approval; and
- The infrastructure or project may not be developed absent pre-approval of the capacity contract.

106 Ibid.

VIII. CONCLUSIONS

Sussex has completed certain research and analyses to evaluate NEXUS, and has developed the following observations and conclusions.

Natural Gas Market Trends

The North American natural gas market is evolving in response to certain large, emerging sources of natural gas in the U.S. Northeast and Mid-Atlantic (*i.e.*, Marcellus and Utica shale basins), which are displacing the traditional sources of natural gas (*e.g.*, WCSB) in Eastern Canada, including the Province of Ontario. The natural gas supply reserves and production in the Marcellus and Utica supply basins are forecasted to be more than adequate for the term of the NEXUS transportation agreements. In addition, NEXUS provides access to other pipelines and, therefore, other natural gas supply basins. The ability to access these growing and competitive sources of natural gas is premised on sufficient natural gas transportation capacity to deliver Marcellus and Utica natural gas to the Ontario market.

Benefits of NEXUS

NEXUS will provide numerous reliability and price stability benefits to the Ontario LDCs, including:

1. Access to proximate and competitive natural gas supply;
2. Natural gas supply basin diversity;
3. Enhanced liquidity for natural gas purchases made at the Dawn Hub;
4. Transportation path diversity;
5. Transportation cost stability;
6. Natural gas price index diversity; and
7. Service flexibility.

A contract for capacity on NEXUS increases the flexibility of the Union and Enbridge natural gas supply portfolios; thus, providing additional options to the Ontario LDCs to manage natural gas supply and transportation costs, improve overall reliability, and provide increased priced stability. NEXUS will also provide several benefits to other Ontario natural gas market participants (*e.g.*, the power generation segment and direct purchase customers), including: (1) access to new natural gas supply basins; (2) pipeline diversity; and (3) improved liquidity at the Dawn Hub. In addition, NEXUS will directly connect the Ontario LDCs to a growing and competitively priced natural gas supply basin, which is proximate to Ontario.

Landed Cost Analysis

The landed cost analysis prepared by Union and Enbridge regarding NEXUS consists of four components: (1) alternative paths to transport natural gas supply to a specific delivery point were identified; (2) the natural gas supply basin associated with each transportation path was identified; (3) the natural gas supply cost was developed for each path; and (4) the transportation cost (*i.e.*, demand, variable, and fuel charges) for all pipelines within the path was calculated.

The Ontario LDCs' process is reasonable and consistent with the typical approach used to conduct a landed cost analysis. The transportation paths identified and modeled by the Ontario LDCs represent a reasonable range of alternative options to NEXUS. Specifically, the Union landed cost analysis evaluated fifteen transportation paths to the Dawn Hub; and Enbridge identified and modeled four options associated with the NEXUS capacity and seven alternative transportation routes to the Dawn Hub. As illustrated by the results of the Ontario LDCs' landed cost analyses, the NEXUS transportation path is competitive with the alternatives evaluated. Finally, Union and Enbridge developed appropriate documentation of their approach, analysis and results.

Risk Assessment

As shown in Table 8.1, Sussex identified six categories of risk related to NEXUS. For each risk category, Sussex identified the potential impact on the Project, and the mitigation strategies employed by the Ontario LDCs and NEXUS.

Table 8.1: NEXUS Risk Review

Risk Category	Risk Mitigation
Construction Risk	The Ontario LDCs were able to mitigate their exposure to construction-related risks by entering into negotiated rate agreements. A negotiated rate agreement apportions the majority of the risk associated with schedule delays and construction cost overruns to the party that is best positioned to manage that risk (*i.e.*, the project developer). In addition, the Ontario LDCs have certain termination rights that can also facilitate management of this risk.

Risk Category	Risk Mitigation
Demand Forecasting Risk	The Ontario LDCs' Precedent Agreements with NEXUS are not dependent on load growth, as the NEXUS capacity will replace existing transportation capacity contracts. The term (*i.e.*, 15 years) of the firm transportation agreement outlined in the Precedent Agreements is on the shorter end of the range of typical firm transportation agreements associated with new infrastructure, thus mitigating the risk of long-term demand erosion. The Ontario LDCs also have the ability to manage their respective gas supply portfolios by terminating other transportation/supply contracts.
Supply Risk	The Marcellus/Utica shale basins (*i.e.*, the origination point for NEXUS) are the fastest growing natural gas supply basins in North America. Various third-party forecasts support the availability of sufficient natural gas supply for the duration of the NEXUS contract. In addition, NEXUS has access to other natural gas supply basins via interconnections with other pipelines. The term (*i.e.*, 15 years) of the firm transportation agreement outlined in the Precedent Agreements is on the shorter end of the range of typical firm transportation agreements associated with new infrastructure, thus mitigating the risk of a long-term reduction in natural gas supply from the Marcellus/Utica shale basins.
Regulatory Risk	The NEXUS lead developers (*i.e.*, Spectra and DTE) have significant and recent experience regarding the federal and state regulatory approval processes for pipeline infrastructure; and Spectra/DTE have initiated the FERC pre-filing process for NEXUS. The Ontario LDCs are requesting the OEB's pre-approval of the cost consequences outlined in the NEXUS Precedent Agreements to manage the provincial regulatory risks.
Project Development Risk	The NEXUS lead developers are highly experienced pipeline developers that have begun outreach to landowners and have held three open seasons to secure shipper demand. The open seasons have resulted in shipper commitments from a mix of "supply push" and "demand pull" entities, which is further evidence of the viability of the Project. Both lead developers are subsidiaries of large, creditworthy holding companies.
Operational Risk	The NEXUS lead developers have extensive experience with pipeline operations. Further, any operational issue or cost would likely be subject to the FERC review and approval process.

Based on the review of the risk categories, Sussex concludes that the overall risk to the Ontario LDCs and their customers are largely mitigated by:

1. The usual and customary terms and conditions in the NEXUS Precedent Agreements;
2. The strength of the lead developers;
3. The strategy employed by the Ontario LDCs to limit their exposure to potential construction cost overruns; and
4. The current production expectations for the Marcellus and Utica supply basins.

Pre-Approval of Cost Consequences of NEXUS

Finally, the NEXUS transportation agreements, as outlined in the Ontario LDCs' Precedent Agreements, represent a significant commitment of 15 years at approximately USD $1.0 billion of pipeline demand charges for Union and Enbridge. Pre-approval of the cost consequences outlined in the Precedent Agreements would eliminate the risk to the Ontario LDCs of an ex-post facto cost disallowance, assure an opportunity to recover the pipeline demand charges, and facilitate the development of new natural gas infrastructure. Certain state utility regulatory commissions in the U.S. have adopted pre-approval guidelines to facilitate the development of new natural gas pipeline infrastructure. In general, these regulatory guidelines provide a framework (*e.g.*, required information) for the utility to seek pre-approval from the regulatory body for the costs associated with pipeline capacity; thus, reducing the risk of a cost disallowance for the utility, while increasing the probability of the development of new infrastructure.

APPENDIX A: SUMMARY BIOGRAPHIES OF SUSSEX PROJECT TEAM

James M. Stephens, *Partner*

Mr. Stephens has 25 years of experience in the energy industry and he has held senior management positions at consulting firms, energy marketing companies and natural gas utilities. He has assisted numerous clients with regulatory policy strategy/tactics and energy market analyses/assessments including: the analysis of regional energy market dynamics and the associated drivers for new natural gas infrastructure (*e.g.*, pipeline expansions); the evaluation of new markets/opportunities (*e.g.*, distributed LNG); market entry/exit strategies (*e.g.*, service territory or product/service expansions); market implications of new energy infrastructure (*e.g.*, LNG facilities and pipelines); integrated resource plans (*e.g.*, natural gas demand forecasting and resource portfolio analysis); natural gas supply portfolio evaluation and optimization (*e.g.*, asset management agreements); and management prudence (*e.g.*, implementation of risk management/portfolio strategies). In addition to his consulting experience, Mr. Stephens served as the President of a retail energy marketing firm where he was responsible for all aspects of business unit management including front, mid and back office functions. Mr. Stephens was also responsible for the Gas Supply Procurement and Portfolio Optimization function for a local distribution company. Mr. Stephens holds a B.S. in Management and an M.B.A. with a concentration in Operations Management from Bentley College.

Samuel G. Eaton, *Managing Consultant*

Mr. Eaton has nearly ten years of consulting experience in the electric and natural gas industries. Mr. Eaton's work includes assessing the prudence of project management and internal control systems used to evaluate, select, initiate and manage major capital projects in the U.S. and Canada. In addition, Mr. Eaton has assisted utilities with regulatory policy issues, consolidated tax adjustments, rate design, and natural gas expansion projects. He has also aided in the development of expert reports ranging in topics from round-trip trades to the economic impact of storing spent nuclear fuel. Separately, Mr. Eaton has participated in approximately $10 billion of nuclear and fossil-fueled power plant divestitures, and corporate acquisitions. His experience on these transactions includes due diligence, workforce matters, the development and negotiation of purchase and sale agreements, and closing the transactions. Prior to entering consulting, Mr. Eaton was employed by the Jacksonville Economic Development Commission, where he supported several local development projects and created and managed an extensive database of local companies eligible for economic development incentive programs. Mr. Eaton graduated cum laude from Brandeis University with a Bachelor of Arts in Economics and Business (minor).

Kim Nguyen*, Managing Consultant*

Ms. Nguyen has ten years of consulting experience in the energy and utility industries. She has contributed to engagements involving regulatory strategy and market analyses including: the evaluation of regional energy market demand/supply dynamics, energy pricing and basis implications, and the associated drivers for new natural gas infrastructure; the development and evaluation of natural gas demand forecasts; and natural gas supply portfolio evaluation and optimization. Ms. Nguyen has also provided analytical support for expert witness testimony on a variety of issues including: cost of capital and capital structure, marginal costs studies, and expense and operating performance benchmarking. She has extensive experience in database development, researching regulatory and energy market issues, performing statistical analysis, and financial analysis and modeling. Ms. Nguyen holds a B.A. in Economics from Clark University, where she graduated summa cum laude and was a member of the Omicron Delta Epsilon Society.

Peter Newman*, Executive Advisor*

Mr. Newman, who is an Executive Advisor with Sussex, has over thirty-five years of experience in various natural gas supply management roles for WE Energies. Specifically, Mr. Newman was responsible for managing all the natural gas supply functions including: long term supply planning and acquisition; natural gas purchasing strategies and execution; capacity portfolio optimization; development and implementation of risk management objectives and policies; and management of the gas control function. In addition, Mr. Newman participated in numerous Federal Energy Regulatory Commission proceedings with respect to natural gas pipeline expansions, rate proceedings, new services and other regulatory issues. Mr. Newman was also a key member of the management team that developed and built the Guardian Pipeline and, in that role, Mr. Newman contributed to a variety of activities, including: market development and project management, developing and implementing the open season process, market assessment, regulatory strategy and proceedings, capacity marketing and tariff development. Mr. Newman is an engineering graduate of the University of Wisconsin-Platteville.

FORM A

Proceeding: EB-2015-0175

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is James M. Stpehens (*name)*. I live at Medon (*city)*, in Massachusetts (*province/state*) of the United States.

2. I have been engaged by or on behalf of Union Gas Limited and Enbridge Gas Distribution Inc.(*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date: June 3, 2015

(Original Signed by: James M. Stephens)

Signature

2014-2015 Gas Supply Plan Memorandum

Enbridge Gas Distribution Inc.

April 2015

Table of Contents

1. Introduction

1.1 Purpose

On July 17, 2014 the Ontario Energy Board ("Board") released its Decision with Reasons in relation to the 2014 to 2018 Custom Incentive Regulation plan ("CIR") application filed by Enbridge Gas Distribution Inc. ("Enbridge" or the "Company") under case number EB-2012-0459 ("EB-2012-0459 Decision"). Included in the EB-2012-0459 Decision were a number of reporting requirements that Enbridge had committed to provide. One of those reporting commitments was the provision of a Gas Supply Plan Memorandum. This memorandum was to be provided on an annual basis over the term of the CIR plan and would include[1]:

1. *a summary of the current natural gas market situation;*
2. *the results of the design day demand forecast with a discussion of the underpinning assumptions;*
3. *an overview of the current gas supply portfolio;*
4. *the identification of near term portfolio decisions and a description of how the Enbridge strategy for the specific portfolio decision conforms to the gas supply planning principles; and*
5. *a summary of major upstream pipeline regulatory filings and/or recent regulatory orders (e.g. RH-003-2011); physical infrastructure projects that will likely impact Enbridge; and the implications associated with gas supply basins.*

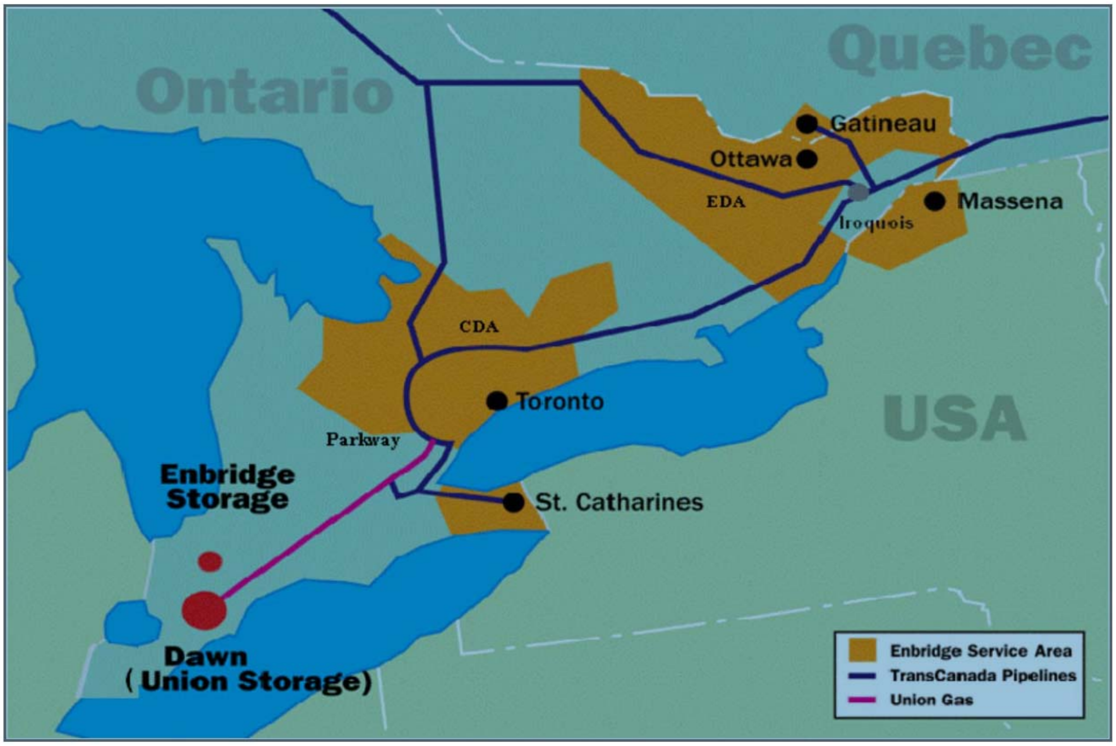
This document has been prepared in response to the reporting requirement for a Gas Supply Plan Memorandum as determined in the Board's Decision.

1.2 Company & Franchise Area Description

Enbridge is a natural gas distribution company with its head office in the City of Toronto. Enbridge is the largest natural gas distribution company in Canada and provides natural gas distribution services to over 2 million customers. It is among the fastest growing natural gas distribution companies in North America with approximately 40,000 largely temperature sensitive customers being added across its franchise each year. The Enbridge franchise area spans central and eastern Ontario and includes the Greater Toronto Area ("GTA"), the Niagara Peninsula, Barrie, Midland, Peterborough, Brockville, Ottawa, Gatineux via Gazifère Inc., and other Ontario communities (collectively the "Enbridge System") as shown in Figure 1.

[1] EB-2012-0459 Decision with Reasons dated July 14, 2014 page 80.

Figure 1 – Enbridge Franchise Map

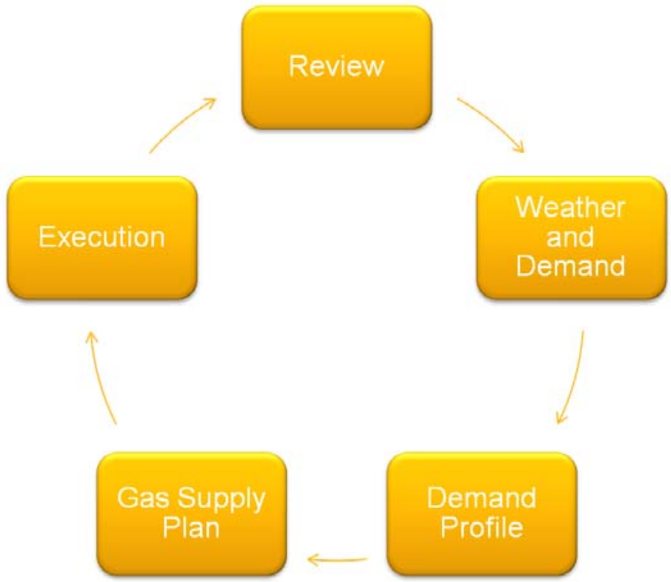


Enbridge does not have access to any significant local natural gas production within its franchise area. Less than 1% of its annual gas supply requirement is locally produced within Ontario. In order to provide safe, reliable, and cost effective delivery of natural gas to its customers, Enbridge procures supply from basins and liquid hubs within North America. These supplies are transported to the markets served by Enbridge through contracted capacity on several upstream natural gas transmission systems that ultimately connect to the Enbridge franchise area and storage facilities at Tecumseh and the Dawn hub in Ontario.

1.3 Gas Supply Planning

The objective of gas supply planning is to develop a portfolio of natural gas supply, transportation, and storage assets that provide for the safe, reliable, and cost effective delivery of natural gas to customers throughout the calendar year. A gas supply portfolio is structured first and foremost to meet demand for natural gas on peak day (i.e. the day of highest demand) along with seasonal demand for natural gas throughout the winter and summer months. The process of establishing the gas supply plan is conducted annually. The resulting gas supply plan is filed with the Board as part of Enbridge's annual rate adjustment applications. Establishment and execution of the gas supply plan is summarized in Figure 2 as a cycle of phases.

Figure 2 – Gas Supply Planning Cycle



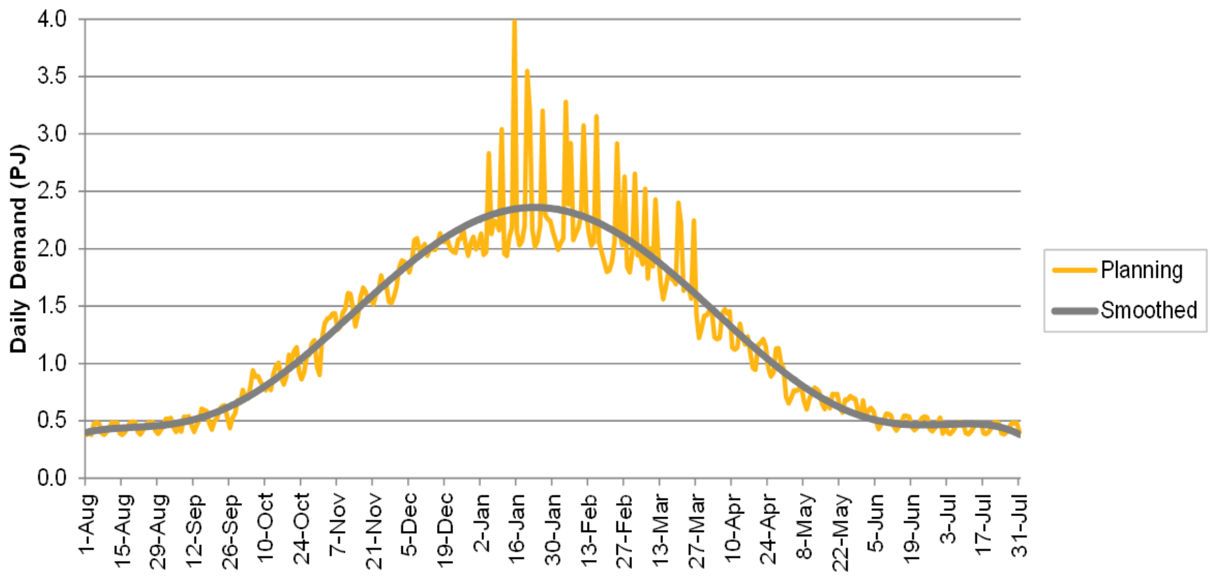
The cycle begins with a review of recent and expected future market conditions. The North American natural gas market is evolving at a very rapid pace. Natural gas production from shale formations has created new procurement opportunities and lead to the development of new and repurposed transportation pipelines across the integrated North American natural gas grid. This is especially so in the case of the Northeast United States where natural gas production is now equivalent to production from the WCSB.

The annual demand budget is developed in the weather and demand phase. Using Board approved methodologies, annual demand is forecast utilizing projected degree days, customer additions, information from large volume customers and other economic variables. Once the annual demand budget is provided to Energy Supply and Policy, development of the gas supply plan for the upcoming test year can begin.

The demand profile phase distributes the annual demand budget into a daily demand profile. When establishing the daily profile, Board approved Design Criteria[2] are used. These Design Criteria distribute annual demand according to seasonal weather patterns. Also included are peak day demand and near peak demand conditions. In Enbridge's Design Criteria the former is referred to as peak day and the latter are referred to as multi-peak days. The magnitude of the peak day and multi-peak days are determined by the weather conditions contained in the Design Criteria. These weather conditions were statistically determined using a 1 in 5 recurrence interval based on a log-normal distribution. When the Design Criteria are applied the resulting daily demand profile is used in developing the gas supply plan as illustrated in Figure 3.

[2] Current Design Criteria was approved by the Board as part of EB-2011-0354 and includes peak and 18 multi-peak heating degree days based on a 1 in 5 recurrence interval of weather conditions over a log-normal distribution.

Figure 3: Illustrative Daily Demand Profile



The level of risk, as measured by the recurrence interval, assumed in the Design Criteria has a significant impact on the development of the demand profile and subsequently the gas supply plan. A more conservative level of risk (i.e. a longer recurrence interval) will result in a gas supply plan that requires higher upfront budget costs to procure storage and transportation assets and will mitigate the need to procure incremental commodity and transportation assets should actual demand exceed budgeted demand. The converse is true when a less conservative approach (i.e. a shorter recurrence interval) is used to develop the gas supply plan. Figure 4 provides a qualitative assessment of cost impacts on a gas supply plan resulting from different levels of risk assumed in the Design Criteria.

Figure 4: Design Criteria Risk Matrix

Design Criteria	Demand Variance Above Budget	
	Minimal	High
Risky	Low Budget Cost Neutral Execution Cost	Low Budget Cost High Execution Cost
Conservative	High Budget Cost Neutral Execution Cost	High Budget Cost Low Execution Cost

Once the demand profile is established, the gas supply plan can be developed. The gas supply plan includes a portfolio of natural gas supply, transportation and storage assets used to meet demand. The gas supply plan is developed and assessed using four gas supply planning principles:

- *Reliability* – Enbridge is the "supplier of last resort" and as a result supplies are sourced from established liquid hubs and transported to the markets served by Enbridge via firm transportation contracts in order to mitigate delivery interruption;
- *Diversity* – Mitigates reliability and cost risks by procuring supplies from multiple procurement points and transporting supplies to market and/or storage through several different paths;
- *Flexibility* – Manages shifting demand requirements through differentiated supply procurement patterns and provides operational flexibility through service attributes and contract parameters; and
- *Landed Cost* – Balances gas supply costs with the other principles and ensures low cost natural gas supply for customers.

The gas supply planning principles are taken into consideration when gas supply plans are developed. The gas supply plan is evaluated through an iterative process utilizing a modeling application called SENDOUT to minimize overall supply portfolio costs. The resulting gas supply plan is evaluated using the gas supply planning principles.

Once the gas supply plan is established, the execution phase of the cycle takes place. Decisions related to the execution of the gas supply plan are made during operational planning meetings that are typically conducted on a weekly basis during the winter season and bi-weekly during the summer season. These meetings are held more frequently if required. The Company also holds bi-weekly meetings to discuss and determine how UDC is to be managed. Outcomes from these meetings are incorporated into the operational planning meetings.

The operational planning meetings are chaired by the Director of Energy Supply and Policy and include a diverse cross-functional team represented by Gas Supply Planning, Gas Supply Procurement, Gas Costs and Budgets, Gas Control Operations, Gas Storage Operations, Distribution Planning, and Key Customer Contract Management. These meetings determine how the gas supply plan is to be executed and include decisions on gas supply procurement and capacity utilization.

2. Natural Gas Market Context

2.1 2014 Natural Gas Market Review

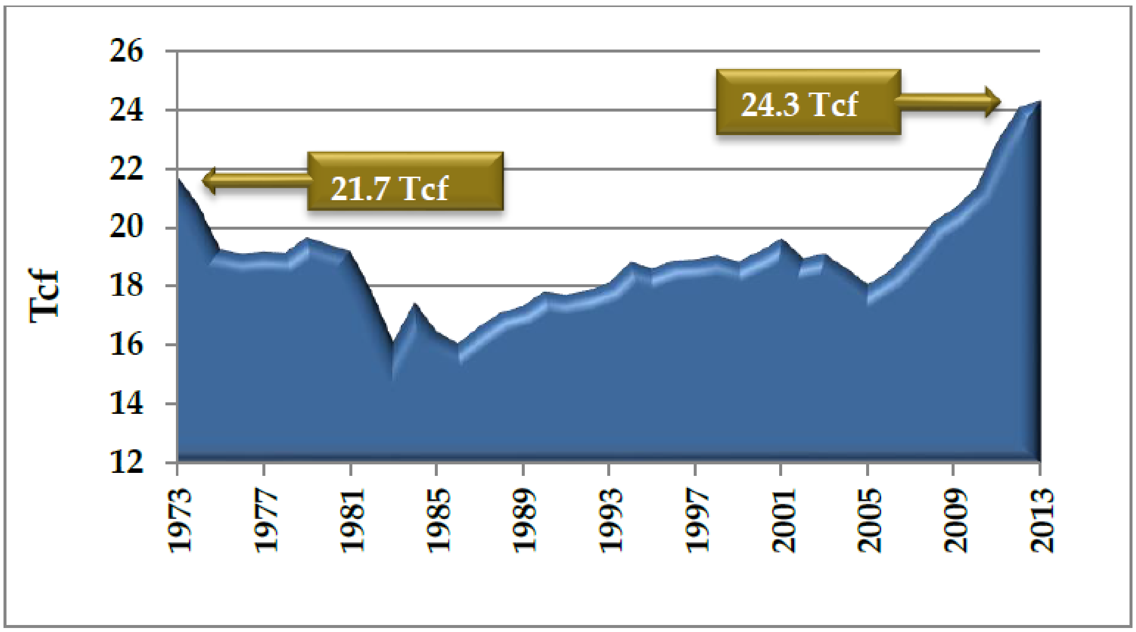
The 2014 Natural Gas Market Review[3] was conducted by the Board during the last quarter of 2014 and into the first quarter of 2015. The review provided a broad perspective of the North American natural gas market and the impacts to Ontario gas markets. The emergence of new natural gas supply basins and the decline of "conventional" natural gas supply basins underpinned discussions on market context.

[3] 2014 Natural Gas Market Review (EB-2014-0289) documentation is located on the Board website at http://www.ontarioenergyboard.ca/oeb/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/2014%20Natural%20Gas%20Market%20Review%20(EB-2014-0289).

2.2 Emerging Natural Gas Supply

The North American natural gas industry has evolved significantly since technological advances in horizontal drilling and hydraulic fracturing have facilitated the economical extraction of natural gas from shale deposits. Natural gas supply from shale has been the primary driver of United States natural gas production. United States natural gas supply has increased by approximately 30 percent over the last seven years. Recent production has exceeded prior periods of peak production experienced 40 years ago[4] as demonstrated in Figure 5.

Figure 5: United States Natural Gas Production History

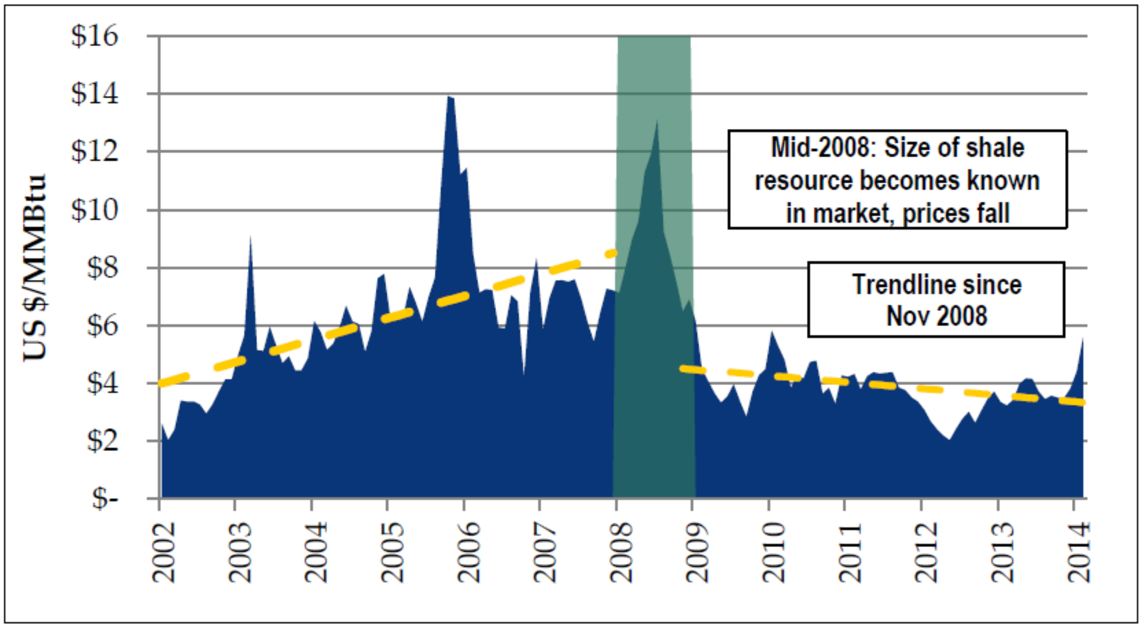


Source: Navigant / U.S. E.I.A.

The increase in natural gas production from shale basins has resulted in declines in natural gas prices. The steep increase in natural gas prices that was experienced at the turn of the century reversed as natural gas production from shale basins expanded. This contributed to a significant decrease in natural gas prices in 2009 and prices have been trending downward since that time as indicated in Figure 6.

[4] EB-2014-0289 2014 Natural Gas Market Review Final Report by Navigant, page 8.

Figure 6 – Henry Hub Price History



Source: Navigant / Platts

The location of shale supply basins has had a significant impact. Historically, gas demand had traditionally been served by a combination of conventional supply basins located in concentrated regions of North America. These supplies were transported via long haul transmission pipelines. The emergence of shale supply basins has changed these traditional pipeline flows. Unlike conventional supply basins, shale supply basins are located all across North America and, as shown in Figure 7, often in close proximity to demand centres. The broad dispersion of shale supply basins has created an opportunity for natural gas supply to be procured closer to demand centers, reducing distance of haul and therefore transportation costs if these supplies can be accessed. This has led to the reconfiguration of the North American natural gas grid and flows. Gas supplies are now flowing in directions opposite to historical flows and existing and new pipelines have been developed to facilitate these flows, particularly in and around shale basins.

Figure 7 - North American Shale Gas Basins

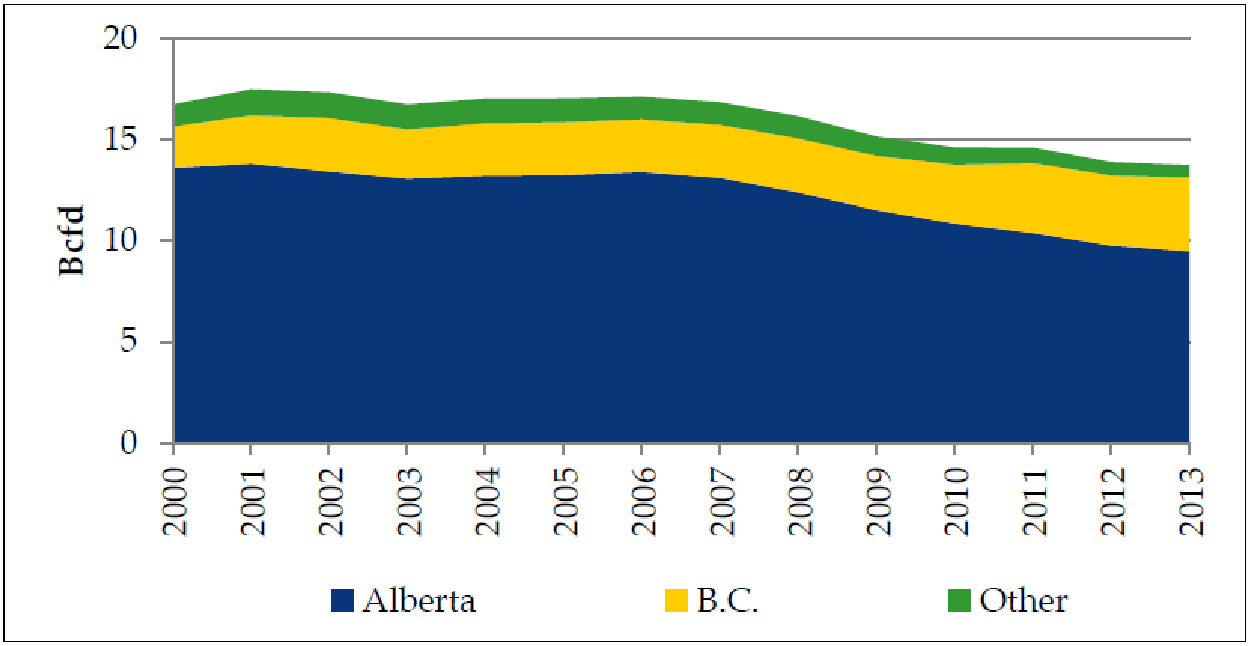
Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

2.3 Western Canadian Sedimentary Basin

Enbridge has traditionally relied on natural gas supply from the WCSB and long haul transportation on the TransCanada Mainline to supply a significant portion of its gas supply plan requirements. At the end of 2000, Enbridge increased portfolio diversity by contracting on Alliance Pipeline and Vector Pipeline which provided additional access to WCSB supply and Chicago supply.

Production in the WCSB peaked in 2001 and has steadily decreased since that time as show in Figure 8. The decline experienced in 2001 was relatively gradual but increased in magnitude around 2007 shortly after the production increases experienced in the United States began.

Figure 8 - Historical Canadian Natural Gas Production



Source: NEB

3. Provincial Regulatory Considerations

3.1 GTA and Parkway Projects

Leave to construct applications were filed with the Board in December 2012 by Enbridge for the GTA Project (EB-2012-0451), by Union Gas in April 2013 for the Brantford-Kirkwall/Parkway D Project (EB-2012-0074), and by Union Gas in July 2013 for the Parkway West Project (EB-2012-0451) (collectively the “GTA and Parkway Projects”). Although the applications were filed separately, the Board combined the proceedings, heard them together, and released a decision granting leave to construct in January 2014.

Collectively, the GTA and Parkway Projects involved the construction of new natural gas pipelines, new compressors, and associated facilities for the purpose of reinforcing the transmission and distribution systems in and around the GTA while providing the GTA with incremental access to transportation capacity from supply hubs such as Dawn and Niagara. The GTA and Parkway Projects also served as an important step in providing similar incremental market access to eastern Ontario, Quebec, and the northeast region of the United States by incorporating 1,200 GJ per day of transmission capacity into Segment A as part of the solution to address transportation capacity restrictions on TransCanada’s Mainline in Ontario. Maps that describe the GTA and Parkway Project facilities and locations are located in Appendices 8.1, 8.2, and 8.3.

The GTA and Parkway Projects will provide benefits for Enbridge’s gas supply plan and therefore customers. The facilities provide for increased security of supply and market access to supply at Dawn and Niagara Falls. Natural gas markets outside of the GTA will also benefit from the new facilities in conjunction with TransCanada's proposed King's North and related projects.

The GTA and Parkway Projects also result in landed cost benefits due to increased utilization of shorter haul paths and access to emerging supply in the United States.[5]

3.2 Dawn Access Consultative

As a result of the GTA and Parkway Projects, Enbridge is able to provide additional market access to Dawn for its direct purchase customers. Enbridge agreed during the EB-2012-0451 proceeding to consult with customers to create a new transportation service where natural gas supplies could be delivered to Enbridge at Dawn. The consultation was initiated in June 2014 and culminated with the Dawn Access Settlement Agreement which was approved by the Board.

3.3 April and October QRAMs

The level of demand experienced over the winter of 2013/2014 was significantly higher than budgeted. Low storage balances late in the winter season and the need to procure incremental supply from the spot market resulted in significant commodity price adjustments to recover the resulting increase in gas supply costs. The Board confirmed that Enbridge followed its gas supply plan[6] for the 2013/2014 winter, however the level of concern related to the magnitude of the associated QRAM adjustments caused Enbridge to evaluate the risk assumed in its gas supply plan. This evaluation led Enbridge to propose changes to the management of storage balances. These proposed changes were filed in Enbridge's 2015 Rate application in addition to the volume of forecasted demand, actual demand, and supply over this period as summarized in Appendix 8.4 from an excerpt of Exhibit I.D1.EGDI.FRPO.8, Attachment A.

3.4 2015 Rate Adjustment

Enbridge traditionally planned to maintain storage balance targets at levels that would provide maximum storage deliverability until the end of January or beginning of February after which storage balances and subsequently storage deliverability were allowed to decline. For the 2015 gas supply plan, Enbridge proposed to utilize more conservative planning assumptions with respect to the establishment of storage balance targets. The 2015 gas supply plan will maintain full deliverability from storage until the end of February and maintain sufficient storage deliverability throughout March such that a March peak day can be met as late as March 31st. The Board has approved the proposed changes to the management of storage balances for the 2015 rate year.

4. National Regulatory Considerations

4.1 Restructuring Proposal

TransCanada filed its Business and Services Restructuring Proposal and Mainline Final Tolls for 2012 and 2013 (RH-001-2011) application with the National Energy Board ("NEB") in September 2011. The application was filed largely in response to the development of new natural gas supply basins, new and

[5] EB-2012-0451 Exhibit J6.X
[6] EB-2014-0191 Decision and Order dated September 25, 2014, page 4.

repurposed transmission pipelines, and generally an increase in competition across North America's natural gas industry as discussed earlier in this memorandum. The NEB captured the essence of this situation in the opening paragraph of their decision where they stated "*[n]o major NEB regulated natural gas transmission pipeline has ever been affected by market forces to the extent that the mainline is now affected*"[7].

The NEB's decision established a new framework for how TransCanada would manage the Mainline going forward. One of the more significant aspects of the decision was the establishment of multi-year fixed tolls over the period of 2013 to 2017. As a result TransCanada was expected to manage the Mainline and through various aspects of the decision such as greater discretion in setting the bid floors for services such as Interruptible Transportation ("IT") and Short Term Firm Transportation ("STFT"). As a result of this change to discretionary pricing Enbridge determined it was not economic to continue to rely on STFT and chose to procure additional long haul FT.

4.2 Energy East and Eastern Mainline Projects

TransCanada's Energy East and Eastern Mainline Projects were filed with the NEB in October 2014 and are currently being review by the NEB. The Energy East Project is a 4,600 KM pipeline project that will transport approximately 1.1 million barrels of crude oil per day from Alberta to eastern Canada. The pipeline will include a combination of newly constructed pipelines and converted natural gas pipelines that are currently part of TransCanada's Mainline. The Eastern Mainline Project includes the construction of a new natural gas pipeline from the City of Markham to the community of Iroquois to replace required natural gas capacity that is being converted to oil service.

The full extent of the impact that these projects will have on Enbridge's gas supply plan will not be known until the Energy East and Eastern Mainline projects are considered by the NEB. But the initial impact of these projects was experienced when TransCanada initiated the March 2013 Existing Capacity Open Season ("May 2013 ECOS") that Enbridge intended to participate in to replace previously contracted STFT capacity. As part of the May 2013 ECOS, TransCanada had reserved all existing long-haul FT capacity into eastern Ontario and Quebec for the Energy East Project resulting in the capacity only being offered as non-renewable FT ("FT-NR"). As a result of no other FT capacity being offered, Enbridge was required to replace previously contracted STFT capacity to the Enbridge EDA with FT-NR capacity that had no renewal rights past November 1, 2017. This created significant concerns over Enbridge's ability to reliably provide natural gas supply for approximately 25% of the peak demand in the Ottawa area.

4.3 Tariff Proposals

TransCanada filed an application to amend the gas transportation tariff for Mainline transportation services in June 2013. The NEB decision on this application resulted in modifications to the renewal provisions that extended the notice period from 6 months to 2 years. This decision increased the planning horizon for securing FT transportation and reduced the flexibility in the gas supply plan to manage shorter term changes in demand.

[7] RH-003-2011 Reasons for Decision, dated March 2013, page 1.

4.4 Abandonment Set Aside and Collection Mechanisms

The NEB initiated the Land Matters Consultative Initiative ("LMCI") in January 2008 for the purpose of ensuring that funds are available when abandonment costs are incurred for all pipelines regulated by the NEB. An Abandonment Surcharge is now applied to all paths on the TransCanada Mainline resulting in increased the landed cost of the gas from the TransCanada system.

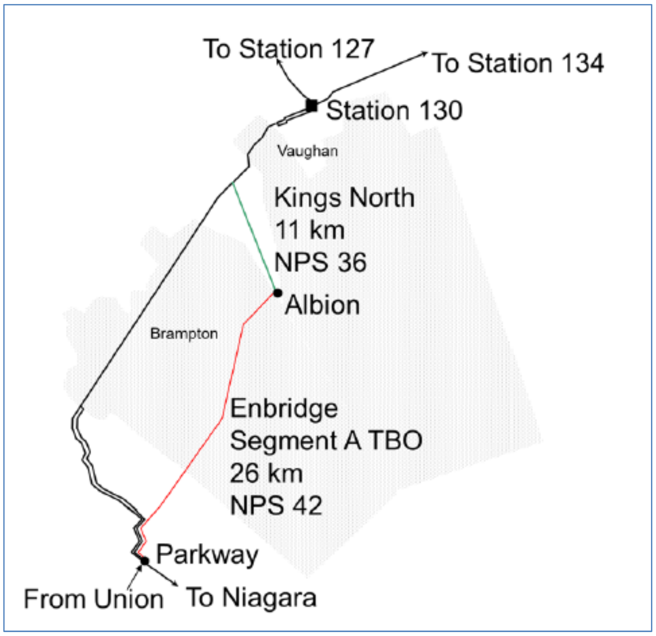
4.5 Mainline 2013-2030 Settlement

In December 2013, TransCanada filed an application for approval of the Mainline 2013-2030 Settlement that was the founded on a negotiated settlement agreement between TransCanada, Enbridge, Gaz Métro Limited Partnership, and Union Gas for the purpose of providing "*market participants with long-term certainty and stability of Mainline tolls, creating an environment that will facilitate the investment required to support the efficient development of natural gas infrastructure in Canada, while providing a reasonable opportunity for Mainline cost recovery*"[8]. The NEB's decision was released in November 2014 which generally approved the application and established a framework for much needed infrastructure development in Ontario.

As a result of the Mainline 2013-2020 Settlement, TransCanada agreed to address the capacity restrictions on the Mainline between Parkway and the Maple compressor station (Station 130) by contracting for transportation by others ("TBO") capacity on Segment A of Enbridge's GTA Project and constructing new infrastructure, for example, The King's North project. The King's North Project is illustrated in Figure 9 and consists of approximately 11 km of new natural gas pipeline that will connect Segment A of Enbridge's GTA project at the Albion station to TransCanada's Mainline near the Maple compressor station. Through coordinated open seasons on the TransCanada Mainline and Union Gas transmission system, market participants now have the opportunity to procure natural gas supply at Dawn for transportation to eastern Ontario, Quebec and the northeast region of the United States.

[8] RH-001-2014 TransCanada Pipeline Limited Application for Approval of Mainline 2013-2030 Settlement, page 1.

Figure 9 – Kings North Project[9]



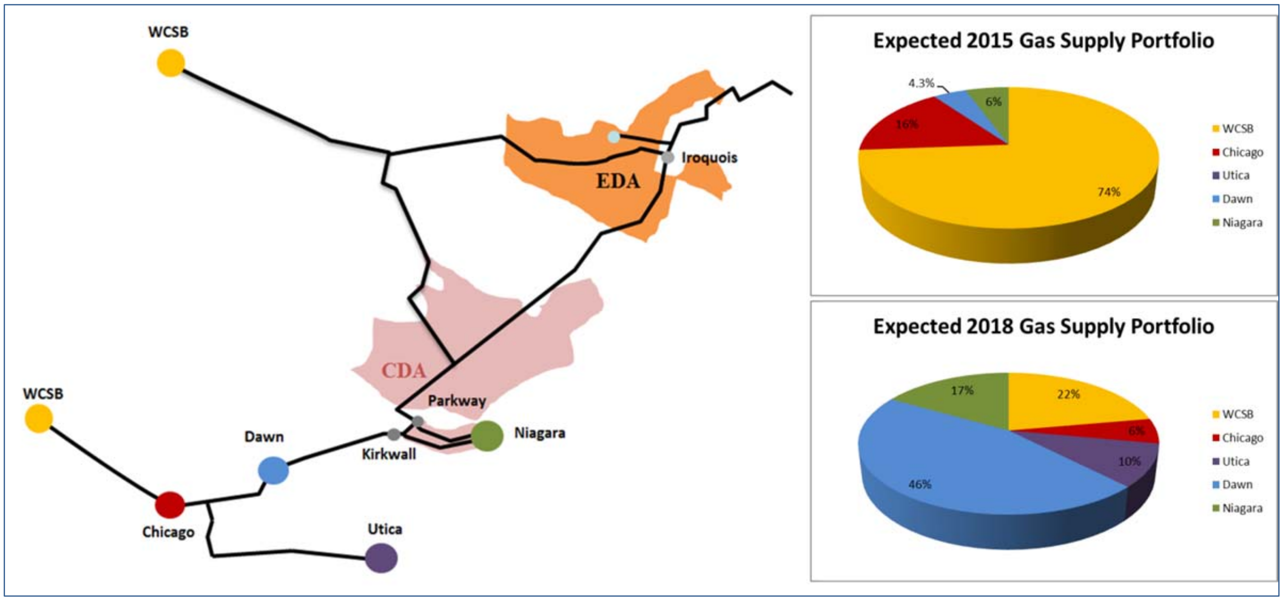
Market access to incremental FT from Dawn addresses the reliability concerns related to the lack of renewal rights inherit with the FT-NR capacity that is currently included in Enbridge's gas supply plan portfolio. Enbridge has executed precedent agreements for incremental transmission capacity on the Union Gas system and the TransCanada Mainline to align with the FT-NR capacity that will expire on November 1, 2017.

The replacement of FT-NR capacity with FT capacity from Dawn is a critical improvement to the reliability of Enbridge's gas supply plan. The open seasons offered by TransCanada and Union Gas for the incremental FT capacity required a 15 year term commitment. The 15 year term will be managed through flexibility provided by shorter term contracts already contained within Enbridge's supply portfolio.

The incremental market access to Dawn enhances the diversity of gas supply and transportation in the gas supply plan. As a result of the open seasons for new capacity that have been offered by TransCanada and Union Gas as a result of the Mainline 2015-2030 Settlement, Enbridge is expecting to more evenly distribute the amount of supply that is procured from various supply hubs across North America as shown in Figure 10. This diversity reduces significant reliance on any one supply basin, increases reliability and lowers the landed cost of gas supply into the franchise. This is accomplished by replacing more expensive long haul transportation with short haul transportation as discussed earlier in the GTA and Parkway Projects section of this memorandum.

[9] TransCanada King's North Connection Pipeline Project application dated August 2014, Page 3-9

Figure 10 – Supply Portfolio Diversification



5. 2015 Gas Supply Plan

5.1 Peak Day Coverage

A discussion on peak day coverage was provided in EB-2014-0276, Exhibit D1, Tab 2, Schedule 1 as part of the annual rate application and an excerpt is included below. The breakdown of the peak day requirement and supply forecast from EB-2014-0276, Exhibit D1, Tab 2, Schedule 6 is provided in Appendix 8.5.

> *In EB-2011-0354 Enbridge presented a new Design Criteria Study which all parties agreed to accept on a phased in approach. The Design Day Criteria is based upon a 1 in 5 recurrence interval. The new Design Criteria Study was filed inEB-2011-0354 at Exhibit D1, Tab 2, Schedule 3. The Company has prepared its 2015 Gas Cost budget assuming a peak day forecast based upon 41.4 degree days (Celsius) for the coldest peak. Enbridge is currently forecasting a design peak day level of 105 534 103m3 (3.7 Bcf) during the winter season of the 2015 Test Year.*

> *The Company has chosen to maintain the same level of Peaking Services for 2015 as was forecast for 2014. Also, similar to 2014 the Company chose to rely principally on TCPL FT service to meet the 2015 Peak Day Demand. The driver for this decision is based upon events at the National Energy Board ("NEB"). On March 27, 2013 the NEB issued its decision in TransCanada Compliance filing RH-003-2011. As discussed as part of the Settlement Agreement in EB-2012-0459 at Exhibit N1, Tab 2, Schedule 1, the ability for TCPL to charge for STFT service an amount in excess of the FT toll made contracting for STFT service inappropriate. TCPL is currently offering STFT service for the November 2014 to March 2015 period at a minimum bid floor of 1,200% of the current FT toll for each month.*

The Company intends to continue to monitor the availability of transport to the franchise area and to look for alternatives that will provide value to the customers of Enbridge while still providing safe and reliable service. If alternatives are found then any differences in the cost of those services versus those forecasted as part of the 2015 gas costs will be captured in the 2015 PGVA.

The Company's plan for meeting its peak day requirements in 2015 includes an increase in TCPL FT capacity of approximately 150,000 GJ/day driven primarily by four factors compared to 2014: 1) an increase in the overall peak day demand due to growth, 2) a decline in the level of interruptible volume largely stemming from a decline in the number of interruptible customers, 3) the migration of Ontario T-Service ("OTS") customers to either System Sales or Western T-Service ("WTS"), and 4) a decrease in available delivered service supplies. Prior to renewal of their contracts with Enbridge a number of interruptible customers including institutional customers such as schools and hospitals indicated that the curtailment costs they experienced this past winter were excessive and requested to move from an Interruptible ("IT") Rate to a Firm Rate. The Company evaluated the requests on a case by case basis and once it was determined that a switch from IT to Firm would not impact the distribution system, customers were allowed to move to a Firm Rate. As a consequence, the Company had to look for additional supplies to meet its peak day requirements. OTS customers are required, under their direct purchase agreement, to deliver a daily volume directly into the franchise area. The migration of customers from OTS to either System Sales or to WTS results in less volume being delivered directly into the franchise area by Direct Purchase customers. As a consequence, the Company had to look for additional supplies to meet its peak day requirements. A breakdown of the peak day requirement and supply forecast is shown at Exhibit D1, Tab 2, Schedule 6.

Similar to 2014, the incremental capacity required to meet forecasted 2015 peak day demand will not be utilized at a 100% load factor based upon the 2015 volumetric forecast. The Company is forecasting $166.4 million in cost consequences associated with unutilized transportation capacity. This forecast is also based upon the TCPL tolls in place at the time of the derivation of the October 2014 QRAM. As part of the Settlement Agreement in EB-2012-0459 parties agreed that, instead of including a forecasted Unabsorbed Demand Charge ("UDC") amount in gas costs for rate making purposes, any actual UDC costs incurred during the year would be captured in either the 2014 DDCTDA or the 2014 UDCDA. The Company is proposing a similar treatment be used in 2015 with one minor exception. The Company believes that any costs associated with actual UDC costs can be tracked through a single deferral account and is therefore proposing the 2015 Unabsorbed Demand Charges Deferral Account ("2015 UDCDA"). In 2015 Enbridge will use best efforts to mitigate UDC that would otherwise be recorded in the 2015 UDCDA. For example, during the summer months when the Utility is injecting gas into storage, whenever possible, the Company will use transportation capacity to displace discretionary purchases of gas at Dawn. If there still remains unutilized capacity the Company will use best efforts to make that capacity available to third parties to mitigate the UDC costs. Similar to 2014 the Company intends to *continue to provide monthly reporting of the on-going amounts in the 2015 UDCDA. The Company has provided at Appendix A, a monthly breakdown of the forecasted 2015 UDCDA.*

5.2 Transportation

A discussion on the transportation assets that were included in the 2015 Gas Supply Plan was discussed in EB-2014-0276, Exhibit D1, Tab 2, Schedule 1 as part of the annual rate filing and an excerpt is included below. The list of transportation contracts from EB-2014-0276, Exhibit D1, Tab 2, Schedule 2 is provided in Appendix 8.6.

Enbridge has a number of Firm Transportation ("FT") and other service entitlements in place for system gas sourced in Western Canada or in the United States (at the Chicago hub as well as U.S. supply area), or both, during the 2015 Test Year. These include service entitlements with TransCanada (both long haul and short haul), Alliance Pipeline and Vector Pipeline. For purposes of this forecast, contracts were priced based upon current tolls and if contracts had an expiry date during the Test Year these contacts were assumed to expire. For instance, the Company has chosen not to renew its contract with Alliance Pipeline as well as two Vector Pipeline contracts totaling 100 000 MMBTU/d. These contracts expire on November 30,, 2015 and October 31,, 2015 for each pipeline respectively. Included in the forecasted supply portfolio effective November 1, 2015 is the acquisition of 200 000 GJ/day of supply at the Niagara interconnect on TCPL. In order to transport that gas from the Niagara import point, the Company has assumed the acquisition of 200 000 GJ/day of Niagara Falls to Enbridge Parkway CDA capacity on TCPL.

For the purposes of the 2015 forecast the Company has assumed the assignment of 31,098 Gj/day of TCPL short haul capacity to Direct Purchase customers effective November 1, 2014 to October 31, 2015.

With the forecasted in service date of November 1, 2015 for the GTA Project, the Company is assuming a number of changes in its plan to meet its peak day demand. A number of TCPL FT contracts will be allowed to expire, the Company will no longer rely on peaking service in the CDA and Direct Purchase customers will be allowed to shift their deliveries to Dawn, as proposed in the Dawn Access Settlement Agreement recently approved by the Board (EB-2014-0323). Phase 1 will consist of an assignment of up to 149,818 GJ/day of TCPL Dawn to CDA short haul capacity). Replacing these, the Company will increase its reliance on M12 service entitlements with Union Gas.

M12 service entitlements on the Union system currently total 2,225,102 GJ/day (2,081 MMcf/day) and for the purposes of the 2015 gas cost budget are forecast to increase by 400,000 GJ/day (375 Mmcf/day) commensurate with the in-service date of the GTA Project. M12 provides for delivery of gas by Union at Dawn for storage injection or onward transportation, for gas withdrawn from storage at Tecumseh or Union, or both, and for gas sourced in Western Canada or the United States, or both, and delivered at Dawn for onward transportation. The Company also has M16 transportation capacity with Union to facilitate the Chatham "D" Storage pool. The *gas cost forecast assumed January 1, 2014 Union tolls. A list of the Company's transportation contracts can be found at Exhibit D1, Tab 2, Schedule 2.*

5.3 Storage

A discussion on the storage assets that were included in the 2015 Gas Supply Plan was discussed in EB-2014-0276, Exhibit D1, Tab 2, Schedule 1 as part of the annual rate filing and an excerpt is included below.

The Company has underground storage of its own at Tecumseh near Corunna in southwestern Ontario and at Crowland near Welland in the Niagara Region. Tecumseh is a large multiple-cycle facility, whereas Crowland is a small peak shaving facility.

The Company also has contracted capacity with third party providers that are valued at market based pricing. The size of the contracted capacity and the term of the contracts vary such that every year Enbridge will enter the market place via an RFP process seeking to replace the contracted capacity scheduled to expire March 31 of that year. For purposes of the 2015 gas cost forecast the Company has assumed the amount and value of storage set to be extended. Any variation between this assumed cost and the actual cost of storage acquired through an RFP process will be captured in the 2015 Storage & Transportation Deferral Account (2015 S&TDA).

In the April 2014 and October 2014 QRAM proceedings (EB-2014-0039 and EB-2014-0191 respectively) the Company discussed its utilization of storage as a part of its gas supply plan. Historically the Company would establish storage targets to maintain sufficient deliverability from storage and would maintain maximum deliverability until late January to early February in order to meet design day or near design demand requirements. As demand declined so too would storage deliverability throughout the winter. To offset the decline in deliverability, the Company would purchase additional delivered supplies if demand was above budget. Developing a gas supply plan in this fashion proved satisfactory during periods of budgeted or slightly colder than budget winters. This was not the case in the winter of 2014 and the Company was forced to purchase significantly higher volumes of gas at Dawn to serve the needs of its customers.

For purposes of preparing the 2015 gas supply plan the Company has implemented a change with respect to how it plans to manage its storage balances. The Company is forecasting storage targets such that maximum deliverability from storage can be maintained until the end of February and such that deliverability from storage is sufficient to meet March peak day as late as March 31. An advantage of maintaining higher storage balances until the end of February is that in the event of colder than budgeted demand in the month of March the Company can reduce the requirement of daily spot purchases at presumably higher prices.

Also during the April 2014 and October 2014 QRAM proceedings the Company explained its long term practice of the use of a seven day ahead forecast of degree days along with budgeted weather beyond seven days to make gas procurement decisions. The Company plans to make a change in how it uses forecasted weather to make procurement decisions next winter. The Company will continue to rely on a seven day ahead forecast of degree days as part of its *decision making process for gas procurement for the upcoming week. The Company, however, intends to look to medium term weather forecasts as a means of assessing medium term demand impacts in order to help decide whether or not it should adjust its supply plan for the upcoming month or the remainder of the winter season. The Company currently tracks several medium term weather forecasts and will look to some consensus of these forecasts as another indicator of future demand. Depending on a number of factors (such as the point in the winter when the decision is being made, where storage balances are relative to target, what is happening in the markets where the Company purchases gas) the Company may choose to adjust its month ahead and/or seasonal purchases taking into consideration not only budgeted weather but also medium term weather forecasts. The cost consequences of such decisions will be reflected within the PGVA.*

Maintaining higher storage balances later into the winter season in conjunction with using a medium term weather forecast (as described above) will allow the Company to react sooner and more effectively to make adjustments to the supply plan to meet changing demand. By reacting sooner it will provide for an ability to acquire month ahead supplies to help reduce daily spot purchases. Conversely in a warmer than normal year the longer term forecast will allow for the potential to reduce purchases sooner.

6. Future Natural Gas Transportation Considerations

6.1 2016 Open Seasons

In November 2013, TransCanada conducted a New Capacity Open Season for firm transportation effective November 1, 2016 ("2016 NCOS") including receipts from Union Parkway Belt for delivery to eastern Ontario, Quebec, and the northeast region of the United States. The 2016 NCOS was premised on NEB approval of the Mainline 2013-2030 Settlement Agreement. Union Gas coordinated an open season on their transmission system with the 2016 NCOS. Together, these open seasons provided market access to incremental transmission capacity from supply hubs such as Dawn and Niagara.

Market access to Dawn provided much needed relief to the lack of firm transportation capacity required by markets in eastern Ontario, Quebec, and the northeast region of the United States resulting from capacity restrictions on the TransCanada Mainline and the expectation of the need to replace FT-NR stemming from the development of Energy East Project. The open seasons were of particular importance to Enbridge's gas supply plan which currently includes 166,000 GJ per day of FT-NR capacity that will expire on November 1, 2017 with no option to be renewed. Enbridge has executed precedent agreements with Union Gas for replacement capacity from Dawn to Parkway and an equivalent amount with TransCanada from Union Parkway Belt to Enbridge EDA effective November 1, 2017.

6.2 2017 Open Seasons

In December 2014, TransCanada conducted a New Capacity Open Season for firm transportation effective November 1, 2017 ("2017 NCOS"). Similar to the 2016 NCOS, the 2017 NCOS was premised on the 2013-2030 Settlement Agreement but since the NEB had released its Letter Decision dated

November 29, 2014, the 2017 NCOS was subject to being withdrawn subject to Acceptable Approval of the parties to the Mainline 2013-2030 Settlement Agreement. In conjunction with the 2017 NCOS, Union Gas conducted an open season on their transmission system.

Enbridge has executed precedent agreements with TransCanada on two paths which include Union Parkway Belt to Enbridge CDA and Union Parkway Belt to Enbridge EDA. The natural gas supply for both of these paths will be provided from Dawn through existing and new transportation capacity as part of the Union Gas open season.

The new firm transportation capacity has been requested by Enbridge to facilitate:

1. New services for in-franchise customers;
2. Replacement of peaking supplies;
3. To address medium term demand growth; and
4. Gas supply portfolio improvements.

<u>New services for in-franchise customers</u>

Enbridge has received elections from the majority of its direct purchase customers requesting to migrate from their current transportation services to the new DTS that resulted from the Dawn Access Settlement. The new transportation capacity requested by Enbridge in the 2017 NCOS, including the conversion of long haul capacity for direct purchase customers who are currently delivering to Empress, will be used to provide the level of service that has been requested under phase 2 of the DTS election process. In addition to requiring the transportation capacity to support the new DTS, Enbridge has experienced a decline in the contracted capacity for interruptible distribution services that are used to manage periods of high demand. A portion of the transportation capacity requested in the 2017 NCOS will be used to offset customer migration from interruptible distribution services and ensure the distribution system demand will continue to be met in a safe, reliable, and cost effective manner.

<u>Replacement of peaking supply</u>

Enbridge has historically relied on peaking services to meet its peak day and near peak requirements in the Ottawa area. This is an on demand short term service provided by third parties who typically divert supply destined for export markets. Similar to concerns related to the interruptible service, TransCanada's plans to reduce transportation capacity in the region as a result of the Energy East Project will reduce these exports and therefore the availability and reliability of these peaking services. As a result, Enbridge is no longer comfortable relying on peaking service and will replace it with the firm transportation that has been requested in the 2017 NCOS.

Medium term demand growth

Enbridge requires incremental upstream transportation to accommodate growth in peak day demand.

Gas supply portfolio improvements

The Enbridge gas supply plan is based on balancing the principles of reliability, diversity, cost and flexibility. The gas transportation services that have been acquired and requested will improve the reliability and diversity of Enbridge's gas supply portfolio while reducing the landed cost of natural gas in the franchise through increased access to Marcellus and Utica shale supply basins through Dawn. This will be achieved in part through net new supply requirements as discussed above and by converting existing long-haul transportation contracts in a manner that is consistent with the 265 TJ per day long-haul commitment that was made as part of the Mainline Settlement Agreement that was originally executed on October 31, 2013.

7. Future Provincial Regulatory Considerations

7.1 Review of Board's Policy on Gas Procurement and Gas Supply Plans

On March 31, 2015, the Board published a Staff Report to the Board regarding the 2014 Natural Gas Market Review (the "Staff Report"). Included in the Staff Report was a recommendation for the Board to initiate a proceeding that will "examine the Board's policy in relation to gas procurement and the assessment and approval of distributor gas supply plans"[10] which the Board indicated would be conducted through a stakeholder consultation. Information related to the scope, activities, and schedule for this proceeding will be provided at a later date, and at that time Enbridge will assess what impacts that the outcomes of the proceeding will have on its gas supply planning process.

7.2 Incremental Storage

As discusses earlier in this memorandum, Enbridge has incorporated changes in how is manages storage deliverability targets in its 2015 gas supply plan through an increase in forecasted natural gas supply purchases in the winter period and a subsequent decrease in forecasted natural gas supply purchases later in the year. The shifting of supply purchases in this manner reduces forecast storage withdrawals early in the winter thereby maintaining higher forecast storage inventory, and subsequently higher storage deliverability, later into the winter season.

Enbridge expects to manage storage deliverability targets in a similar manner for the 2016 gas supply plan. Looking beyond the 2016 gas supply plan, Enbridge anticipates that other changes , such as incorporating incremental or contingency storage in the gas supply plan, could be used to manage the storage deliverability targets in a more effective manner. Preliminary analysis indicates that 16 Bcf of incremental storage would be required to maintain a similar level of risk assumed in the peak day demand forecasting. A summary of the preliminary analysis is included in Figure 11.

[10] Staff Report to the Board on the 2014 Natural Gas Market Review (EB-2014-0289) dated March 31, 2015, page 29.

Figure 11 – Incremental Storage Analysis Summary

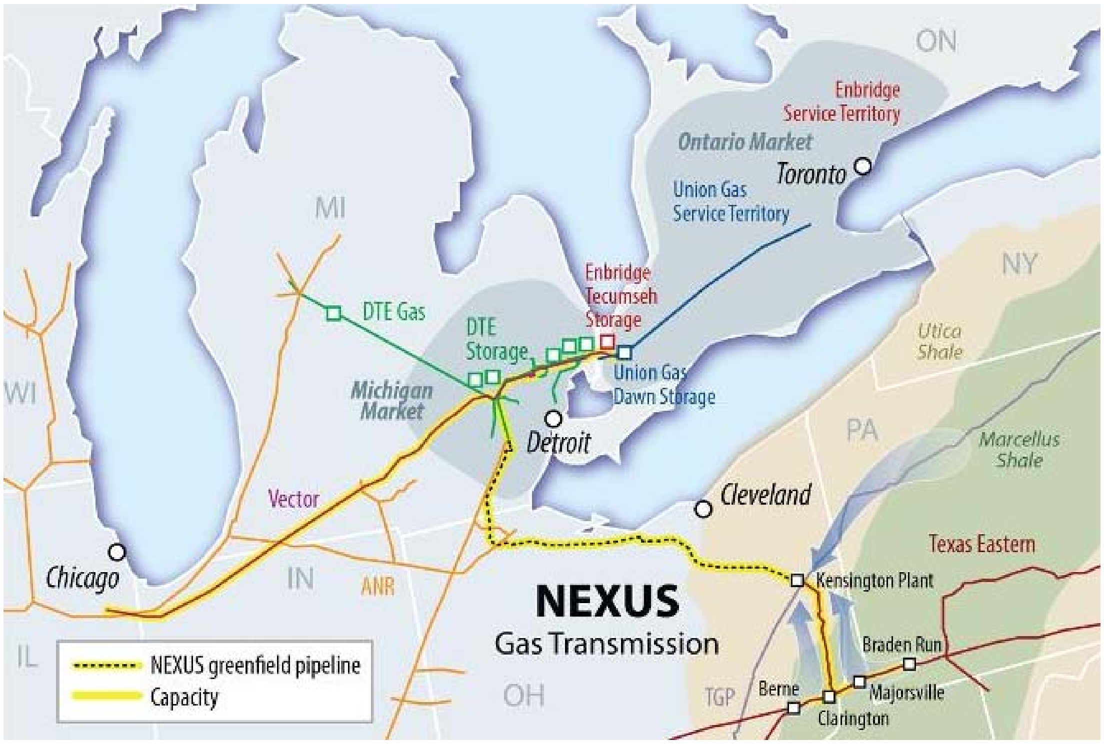
Incremental Storage Requirements*: Various Design Criteria (Normal Distribution)			
Design Criteria Recurrence Interval	Associated Probability of Being ≥	Central Weather Zone Winter HDD	Incremental Storage Requirement (Bcf)
Current 1 in 2	50%	2,945	-
1 in 5	20%	3,207	9
1 in 10	10%	3,303	14
1 in 15	≈6%	3,364	16
Peak Day Equivalent	5.7%	3,369	16
1 in 20	5%	3,384	21
* Analysis based on 2015 budget			

Enbridge is investigating how to move forward with a more thorough analysis of storage requirements and the cost and risk trade-offs associated with more storage capacity. When it has completed a more thorough analysis, Enbridge will consider when and how to bring forward the resulting recommendations to the Board and stakeholders.

7.3 Pre-approval of NEXUS costs

The NEXUS Gas Transmission Project ("NEXUS") is a proposed natural gas transmission pipeline that will deliver up to 1.5 Bcf per day of supply from the Appalachian Basin, which includes Marcellus and Utica shale gas production, to the DTE Energy Company system or the Vector Pipeline for delivery to Dawn. A map of NEXUS is included in Figure 12.

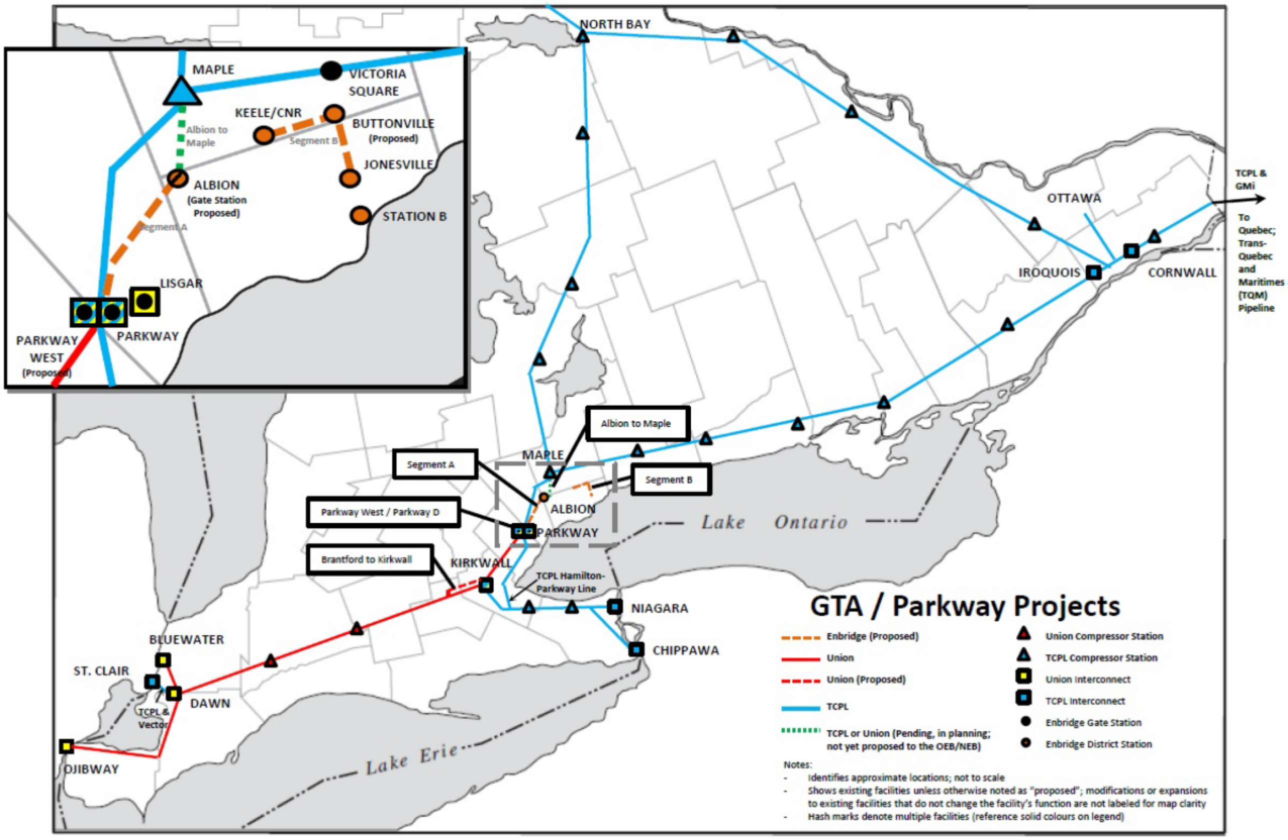
Figure 12 – NEXUS Gas Transmission



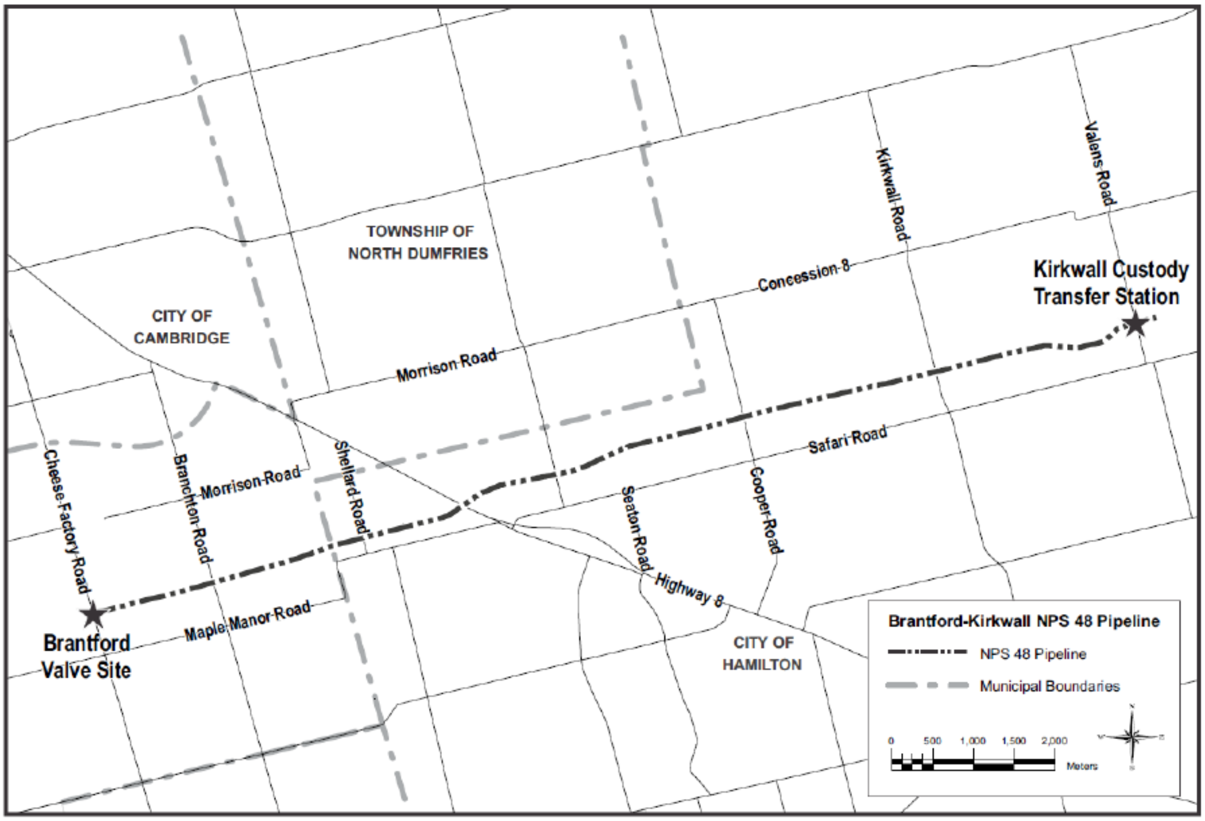
Enbridge signed a precedent agreement with NEXUS for 110,000 Dth per day for firm transportation service commencing on November 1, 2017 to diversify its gas supply plan portfolio while improving the reliability of supplies being transported to Dawn at a competitive landed cost. The precedent agreement is conditional on gaining Board pre-approval of the associated contract costs. Enbridge is expecting to file an application with the Board for pre-approval in the second quarter of 2015.

8. Appendices

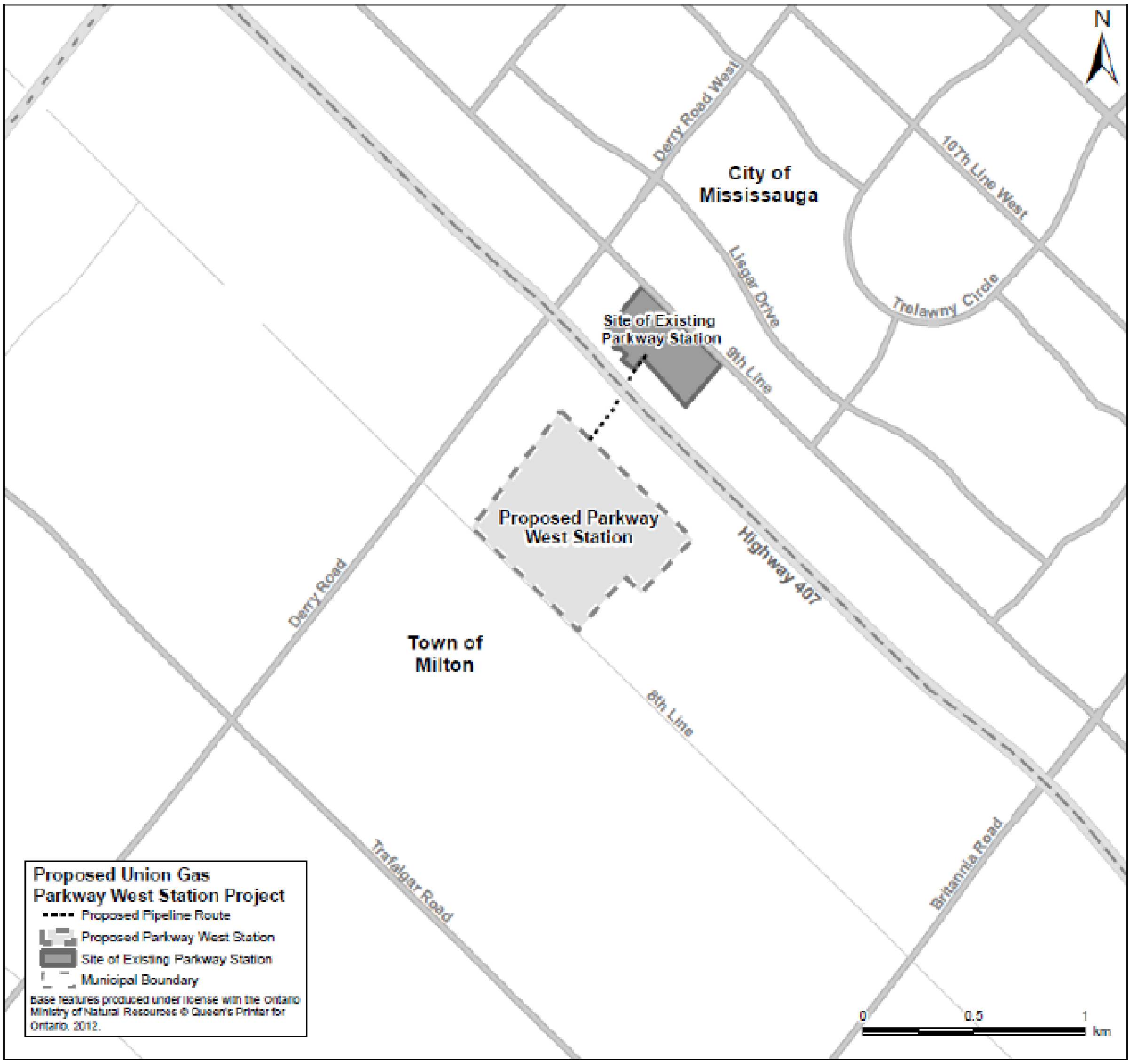
8.1 GTA Project Map



8.2 Brantford-Kirkwall/Parkway D Project



8.3 Parkway West Project Map



8.4 2013/2014 Forecasted and Actual Demand

2013 Actual		Item #		2014												
Column 1	Column 2			Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13	Column 14	Column 15
			PJ's													
November	December			January	February	March	April	May	June	July	August	September	October	November	December	
43.7	62.0	1.	Forecasted Demand	69.7	60.7	53.5	33.2	20.8	14.7	13.4	13.3	15.0	27.2	41.5	60.4	423.3
51.1	70.3		Actual Demand	85.9	73.1	70.5	40.9	22.1	15.4	15.4	14.7	16.3	27.1	51.7	61.9	495.1
			Supply													
19.3	19.9	2.	EGD Contracted Long Haul TCPL Capacity	19.5	17.6	19.2	18.9	19.8	18.9	19.5	19.6	18.9	19.5	19.1	19.7	230.1
-	-	3.	Less Unutilized Capacity	-	-	-	-	-	-	(3.1)	(6.7)	(5.2)	(5.1)	-	-	(20.1)
19.3	19.9			19.5	17.6	19.2	18.9	19.8	18.9	16.4	12.9	13.7	14.4	19.1	19.7	210.0
9.1	9.3	4.	Direct Purchase Own Transportation	9.9	8.7	9.5	9.4	10.9	10.5	10.6	10.5	9.9	9.6	8.3	8.6	116.3
8.7	8.9	5.	Alliance/Vector	8.8	8.1	10.2	8.6	9.0	8.6	6.9	6.2	6.0	6.3	7.7	9.0	95.4
2.1	11.4	6.	Dawn Discretionary	15.0	16.2	21.8	10.0	-	-	-	-	-	0.0	5.1	13.6	81.6
-	-	7.	Peaking Supplies	1.6	0.1	0.6	-	-	-	-	-	-	-	-	-	2.3
39.2	49.5		Total Supply	54.7	50.6	61.3	46.9	39.6	38.0	33.9	29.5	29.6	30.3	40.2	50.9	505.7
12.0	20.8	8.	Storage Requirement	31.2	22.5	9.2	(6.0)	(17.5)	(22.6)	(18.5)	(14.9)	(13.3)	(3.2)	11.4	11.0	(10.6)
51.2	70.3		Total Supply	85.9	73.1	70.5	40.9	22.1	15.4	15.4	14.7	16.3	27.1	51.7	61.9	495.1

8.5 2015 Budget Peak Day Demand

Item #	2014 Budget Peak Day Demand GJ's	Column 1 CDA	Column 2 EDA	Column 3 Total	2015 Budget Peak Day Demand GJ's	Column 4 CDA	Column 5 EDA	Column 6 Total
1.	Demand	3,288,088	673,262	3,961,350	Demand	3,303,548	674,042	3,977,590
2.	Less Curtailment	(133,995)	(28,705)	(162,700)	Less Curtailment	(83,874)	(33,259)	(117,133)
3.	Net Peak Day Demand	3,154,093	644,557	3,798,650	Net Peak Day Demand	3,219,674	640,783	3,860,457
4.	TCPL FT Capacity	271,468	370,627	642,095	TCPL FT Capacity	404,538	390,627	795,165
5.	TCPL STFT	-	-	-	TCPL STFT	-	-	-
6.	TCPL Short Haul	151,818	114,000	265,818	TCPL Short Haul	158,720	114,000	272,720
7.	TCPL STS	369,464	80,611	450,075	TCPL STS	369,465	80,611	450,076
8.	Ontario T-Service	300,354	26,576	326,930	Ontario T-Service	243,353	5,718	249,071
9.	Union Deliveries	1,775,027	-	1,775,027	Union Deliveries	1,775,027	-	1,775,027
10.	Delivered Service	182,738	-	182,738	Delivered Service	167,739	-	167,739
11.	Peaking Service	105,505	52,753	158,258	Peaking Service	105,506	52,754	158,260
12.	Total Supply	3,156,374	644,567	3,800,941	Total Supply	3,224,348	643,710	3,868,058
13.	Sufficency/(Deficiency)	2,281	10	2,291	Sufficency/(Deficiency)	4,674	2,927	7,601

8.6 Transportation Contract Summary

STATUS OF TRANSPORTATION CONTRACTS

Item #	Transportation	Route	Total Contracted Daily Volume		Fuel Rate	Monthly Demand Charge		Estimated Commodity Charge		Expiry Date
	Current Contracts									
1	TCPL FT - CDA	Empress to CDA	63,468	GJ	varies	47.62803	$/GJ	-	$/GJ	31-Oct-17
2	TCPL FT - CDA	Empress to CDA	201,070	GJ	varies	47.62803	$/GJ	-	$/GJ	31-Oct-15 [1]
3	TCPL FT - CDA	Empress to CDA	9,000	GJ	varies	47.62803	$/GJ	-	$/GJ	31-Oct-15
4	TCPL FT - CDA	Empress to CDA	56,000	GJ	varies	47.62803	$/GJ	-	$/GJ	31-Dec-15
5	TCPL FT - EDA	Empress to EDA	197,421	GJ	varies	49.13597	$/GJ	-	$/GJ	31-Oct-17
6	TCPL FT - EDA	Empress to EDA	50,000	GJ	varies	49.13597	$/GJ	-	$/GJ	31-Mar-15
7	TCPL FT - EDA	Empress to EDA	116,250	GJ	varies	49.13597	$/GJ	-	$/GJ	31-Oct-15
8	TCPL FT - EDA	Empress to EDA	166,000	GJ	varies	49.13597	$/GJ	-	$/GJ	31-Oct-16 [2]
9	TCPL FT - Iroquois	Empress to Iroquois	26,956	GJ	varies	49.45575	$/GJ	-	$/GJ	31-Oct-17
10	TCPL FT Dawn to CDA		149,818	GJ	varies	7.16453	$/GJ	0.01360	$/GJ	31-Oct-17 [3]
11	TCPL FT Dawn to CDA	Assignment to Direct Purchase	(31,098)	GJ	varies	7.16453	$/GJ	0.01360	$/GJ	31-Oct-16 [3]
12	TCPL FT Dawn to EDA		114,000	GJ	varies	13.28433	$/GJ	0.03229	$/GJ	31-Oct-17
13	TCPL FT Dawn to Iroquois		40,000	GJ	varies	12.76919	$/GJ	0.03038	$/GJ	31-Mar-16
14	TCPL FT Parkway to CDA		572	GJ	varies	3.14523	$/GJ	0.00350	$/GJ	31-Oct-17
15	TCPL FT-SN Parkway to CDA		85,000	GJ	varies	3.17490	$/GJ	0.00326	$/GJ	31-Oct-18
16	TCPL STS Parkway to CDA		283,892	GJ	varies	1.69730	$/GJ	0.00024	$/GJ	31-Oct-17
17	TCPL STS Parkway/Kirkwall to EDA		70,895	GJ	varies	4.84530	$/GJ	0.00757	$/GJ	31-Oct-17
18	TCPL STS Parkway to EDA		9,716	GJ	varies	4.84530	$/GJ	0.00757	$/GJ	31-Oct-17
19	Niagara to CDA		200,000	GJ	N/A					
20	Nova Transmission	AECO to Empress	166,869	GJ	N/A	5.35000	$/GJ	-	$/GJ	31-Oct-16
21	Nova Transmission	AECO to Empress	20,000	GJ	N/A	5.35000	$/GJ	-	$/GJ	31-Oct-15
22	Alliance Pipeline	Alberta to US border	2,124.6	10^3m^3	varies	981.1600	$\$/10^3m^3$	-	$\$/10^3m^3$	30-Nov-15 [4]
23		US border to Chicago	75.0	mmcf	varies	16.5000	$US/dth	-	$US/dth	30-Nov-15
24	Vector Pipeline -	Chicago to Cdn border	96,000	dth	varies	7.0140	$US/dth	-	$US/dth	30-Nov-17
25		Cdn border to Dawn	101,285	GJ	varies	0.5705	$/GJ	-	$/GJ	30-Nov-17
26	Vector Pipeline	Chicago to Cdn border	79,000	dth	varies	7.0140	$US/dth	-	$US/dth	30-Nov-17
27		Cdn border to Dawn	83,349	GJ	varies	0.5705	$/GJ	-	$/GJ	30-Nov-17
28	Vector Pipeline -	Chicago to Cdn border	50,000	dth	varies	Negotiated Toll				30-Nov-15 [5]
29		Cdn border to Dawn	52,753	GJ	varies	Negotiated Toll				30-Nov-15 [5]
30	Vector Pipeline -	Chicago to Cdn border	50,000	dth	varies	Negotiated Toll				30-Nov-15 [5]
31		Cdn border to Dawn	52,753	GJ	varies	Negotiated Toll				30-Nov-15 [5]
32	Union Gas Dawn to Parkway		1,764,678	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Mar-14 [6]
33	Union Gas Dawn to Parkway		106,000	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-18
34	Union Gas Dawn to Parkway		57,100	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-19
35	Union Gas Dawn to Parkway		18,703	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-14
36	Union Gas Dawn to Parkway		200,000	GJ	varies	2.9610	$/GJ	-	$/GJ	31-Oct-22
37	Union Gas Dawn to Lisgar		10,692	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-14
38	Union Gas Dawn to Kirkwall		35,806	GJ	varies	2.0110	$/GJ	-	$/GJ	31-Oct-14
39	Union Gas Dawn to Kirkwall		32,123	GJ	varies	2.0110	$/GJ	-	$/GJ	31-Mar-14
40	Union Gas Parkway to Dawn		236,586	GJ	varies	0.5790	$/GJ	-	$/GJ	31-Mar-14

notes:
(1) in the event of a delay in the GTA project these contracts continue beyond October 31, 2015
(2) Contract Effective November 1, 2015
(3) In addition to the toll provided above there is a monthly surcharge as well - $0.13281/GJ/month
(4) the Alliance contract will not be renewed beyond the November 30, 2015 expiry date
(5) these Vector contracts will not be renewed beyond the November 30, 2015 expiry date
(6) the Company is planning to contract for an incremental 400,000 GJ/day of M12 capacity effective November 1, 2015
(7) volume increases to 75,000 in second year of contract

Item #	Transportation	Route	Total Contracted Daily Volume		Fuel Rate	Monthly Demand Charge		Estimated Commodity Charge		Effective Date	Expiry Date
	Pending Contracts to meet Peak Day in 2015										
41	Peaking Service - CDA		105,505			varies		varies		1-Dec-14	31-Mar-15
42	Peaking Service - EDA		52,753			varies		varies		1-Dec-14	31-Mar-15
			158,258								
43	TCPL FT - CDA	Empress to CDA	75,000	GJ	varies	47.62803	$/GJ	-	$/GJ	1-Jan-15	31-Oct-18
44	Nova Transmission	AECO to Empress	75,000	GJ	N/A	5.35000	$/GJ	-	$/GJ	1-Jan-15	31-Dec-15
45	Niagara to CDA		25,000			Negotiated Toll				1-Nov-13	31-Mar-15
46	Niagara to CDA		60,000			Negotiated Toll				1-Nov-14	1-Mar-16 [7]
47	Dawn to CDA		25,000			Negotiated Toll				1-Nov-13	31-Mar-15
48	Dawn to CDA		25,000			Negotiated Toll				1-Nov-14	1-Mar-16

Witness: D. Small

CURRICULUM VITAE OF
JOEL DENOMY

Experience: Enbridge Gas Distribution Inc.

Manager, Regulatory Applications
2014-Present

Manager, Gas Supply & Strategy
2010-2014

Manager, Strategic Planning
2009-2010

Manager, Economic and Market Analysis
2007-2009

Supervisor, Economic and Market Analysis
2006-2007

Senior Market Analyst, Volumetric and Market Analysis
2003-2006

Market Analyst, Volumetric and Market Analysis
2002-2003

Education: Chartered Financial Analyst
CFA Institute, 2006

Master of Arts (Economics)
University of Waterloo, 2002

Bachelor of Arts (Honours Economics, Finance Specialization)
University of Waterloo, 1999

Memberships: Canadian Association of Business Economists (CABE)
CFA Institute & Toronto CFA Society

Appearances: (Ontario Energy Board)
EB-2012-0459
EB-2012-0451
EB-2011-0354
EB-2010-0333
EB-2008-0219
EB-2007-0615
EB-2006-0034
EB-2005-0001
RP-2003-0203

(Regie De L'Energie)
R-3587-2005
R-3665-2008

(New York State Public Service Commission)
08-G-1392

CURRICULUM VITAE OF
JAMIE LeBLANC

Experience: Enbridge Gas Distribution Inc.

Director, Energy Supply and Policy
2013

General Manager - Gazifère Inc.
2010

Manager, Finance and Control – Enbridge Gas New Brunswick Inc.
2005

Supervisor, Financial Reporting – Enbridge Gas New Brunswick Inc.
2004

Education: Chartered Accountancy Designation
Atlantic School of Chartered Accountants, 1998

Bachelor Business Administration
University of New Brunswick, Fredericton, 1996

Memberships: Chartered Professional Accountants New Brunswick

Appearances: (Ontario Energy Board)
EB-2014-0289
EB-2013-0046

(National Energy Board)
RH-001-2013

(Régie de l'énergie/Régie du gaz naturel)
R-3900-2014
R-3884-2014
R-3793-2012
R-3758-2011

(New Brunswick Energy and Utilities Board)
Cost of Capital for Enbridge Gas New Brunswick (EGNB) – 2010
EGNB Financial Results 2009 – 2010
EGNB Cost of Service Study – 2010
EGNB LFO Rate Changes – 2010
EGNB Various Rates and HFO Rates - 2010
EGNB Development Period – 2009
EGNB Financial Results 2008 – 2009
EGNB Financial Results – 2007 - 2009

CURRICULUM VITAE OF
ANDREW WELBURN

Experience:	Enbridge Gas Distribution Inc. Manager Gas Supply and Strategy 2014
	Manager Upstream Business Partners 2012
	Manager Contract Relationships 2008
	Manager Operations Performance Reporting 2006
	Manager Contract Support and Compliance 2001
	Manager Transactional Services Sales 2000
	Supervisor Gas Control 1997
	Leak Surveyor 1997
	Supervisor Pipeline Inspector 1994
	Operations Engineer 1994
	Load Research Technician 1992
Education:	Bachelor of Applied Science in Civil Engineering University of Waterloo
Memberships:	Professional Engineer Ontario Ontario Society of Professional Engineers
Appearances:	(Ontario Energy Board) EB-2014-0289
	(National Energy Board) MH-001-2013

James M. Stephens
Partner
Sussex Economic Advisors, LLC

Mr. Stephens has twenty-five years of experience in the energy industry and he has held senior management positions at consulting firms, energy marketing companies and local distribution companies. He has assisted numerous clients with regulatory policy strategy/tactics and energy market analyses/assessments including: the analysis of regional energy market dynamics and the associated drivers for new natural gas infrastructure; the evaluation of new markets/opportunities; market entry/exit strategies; market implications of new energy infrastructure; integrated resource plans; natural gas supply portfolio evaluation and optimization; and management prudence. In addition to his consulting experience, Mr. Stephens served as the President of a retail energy marketing firm where he was responsible for all aspects of business unit management including front, mid and back office functions. Mr. Stephens was also responsible for Gas Supply Procurement and Portfolio Optimization for a local distribution company. Mr. Stephens has appeared as an expert witness in several jurisdictions including the States of Massachusetts and Maine as well as Provinces of Ontario and Québec. Mr. Stephens holds a B.S. in Management and an M.B.A. with a concentration in Operations Management from Bentley College.

REPRESENTATIVE PROJECT EXPERIENCE

Energy Market Assessment

Retained by numerous leading energy companies to develop regional energy market assessments throughout the U.S. and Canada. Such assessments have included evaluation of market impacts associated with new infrastructure, assessment of natural gas transmission infrastructure, market structure and regulatory situation analysis, and assessment of competitive position. Market assessment engagements typically have been used as integral elements of business unit or asset-specific strategic plans or valuation analyses. In addition, certain market assessments have been submitted to the Federal Energy Regulatory Commission, National Energy Board of Canada and various state and provincial regulatory agencies to support the benefits of new infrastructure.

Representative engagements have included:

- For two Canadian LDCs developed a review of certain mid-Atlantic natural gas supply basins.
- For the State of Maine Public Utility Commission prepared a report that summarized the Northeast and Atlantic Canada natural gas power markets; and analyzed the potential benefits and costs associated with natural gas pipeline expansions. The independent report was filed at the Maine Public Utility Commission.
- On behalf of Spectra Corporation developed a market assessment evaluating the impact of new pipeline infrastructure into the New York City, New Jersey and New England markets. The independent reports were filed at the Federal Energy Regulatory Commission and/or presented to state public utility commissions.
- For an international energy company prepared an assessment of the market potential for distributed LNG, with a particular focus on the commercial and industrial sectors. The results of the analysis were presented to senior management.
- For a project developer, prepared a demand analysis of the current and projected natural gas market for the Southeast U.S. The independent report, which was filed at the Federal Energy Regulatory Commission, addressed the demand for natural gas in both the electric generation and traditional LDC markets.
- For an international energy company, prepared an analysis regarding LNG facility investment with a particular focus on LNG peaking facilities.
- Conducted due diligence for commercial banks regarding investments in natural gas pipelines, natural gas storage projects and LNG facilities.

- For a project developer, assisted with the evaluation of the market opportunity for an importation LNG terminal in the northeastern United States.
- For numerous clients, provided regional natural gas demand assessments to support energy infrastructure investment. The results of these studies have been submitted and supported in various jurisdictions, including the Federal Energy Regulatory Commission and the National Energy Board of Canada.
- For a natural gas producer, reviewed energy contract practices and pricing mechanisms to support a contract arbitration process.

Business Strategy and Operations

Retained by numerous leading North American energy companies to provide services relating to the development of strategic plans and planning processes for both regulated and non-regulated entities. Specific services provided include: developing market entry strategies for retail and wholesale businesses; review of management practices and procedures; and business process redesign initiatives.

Representative engagements have included:

- For Columbia of Massachusetts developed expert witness testimony in support of a contract for natural gas pipeline capacity. The testimony was submitted in the Massachusetts Department of Public Utilities.
- For Union Gas developed expert testimony regarding the gas supply planning process and associated activities. The testimony was submitted to the Ontario Energy Board.
- For Gaz Métro developed expert testimony regarding the utilization of natural gas storage. The testimony was submitted to the Régie de l'énergie.
- For an LDC reviewed the current retail choice program, certain proposed changes, and the potential impacts on the gas supply portfolio.
- For an LDC reviewed the cost and benefits of expanding into new service territories. The final work product was presented to the LDC Board of Directors.
- Reviewed the investment potential of a greenfield LDC on behalf of a regional energy distributor
- Reviewed the natural gas supply alternatives (i.e., supply basin cost, transport basis and regulatory issues) for an integrated energy company
- Developed regional market assessments and associated market entry strategies for a wholesale energy marketing company.
- Reviewed certain management practices and procedures for a wholesale energy marketing company.
- Performed due diligence on a retail electricity marketing firm in support of a third party investment.
- Prepared a competitive position analysis (i.e., SWOT analysis) for an interstate gas pipeline.
- On behalf of a wholesale energy marketing company, reviewed federal and state requirements associated with entering certain natural gas markets.
- Assessed the economic viability of gas distribution utility service expansion in Vermont.
- Developed new service offerings, including firm transportation and stand-by service, for a mid-Atlantic utility.
- Managed the re-engineering of a large Midwest LDC's gas supply procurement process.
- Managed the re-engineering of a mid-Atlantic wholesale energy marketing company's gas operations.
- On behalf of an interstate pipeline, conducted a customer outreach/survey program.

Regulatory Analysis and Support

On behalf of electric, natural gas and combination utilities and interstate natural gas pipeline companies throughout North America, provided services relating to the development of regulatory and ratemaking strategies, energy supply obligations, stranded cost assessment and recovery, rate design, and management prudence. Specific services provided include: assistance with open season process and procedures, FERC standard of conduct review, analysis of provider of last resort obligations in both electric and gas markets, develop new service offerings, and provide litigation support.

Representative engagements have included:

- On behalf of an LDC developed an integrated resource plan including demand forecasting and gas supply portfolios analysis. The final work product was submitted to the State Utility Commission.
- Retained by the Alaska Gasline Development Corporation to assist with market review and assessment, open season process development and implementation, and associated activities (e.g., tariff and service development).
- Retained by various LDCs and electric utilities to evaluate interstate pipeline open seasons including an analysis of the quantitative and qualitative aspects of the various projects.
- Retained by numerous LDCs to assist with natural gas demand forecasting
- Retained by an LDC to develop regulatory strategy associated with the funding of distribution expansion.
- Retained by a Midwest U.S. interstate gas pipeline to assist with an open season including drafting of tariffs and precedent agreements, and interaction with potential shippers.
- Retained by a Northeast energy company to review the FERC reporting requirements and standards of conduct for an interstate pipeline business unit.
- Provided regulatory and litigation support to a natural gas pipeline regarding rate impacts of new infrastructure development.
- Provided litigation support to a mid-west utility regarding proposed gas purchase disallowances for storage utilization, hedging activity, and pipeline capacity decisions.
- On behalf of a Midwest utility, developed and implemented a third party transportation program
- Assisted several LDCs evaluate and implement regulatory strategy regarding declining use per customer.
- Developed demand study to support the AES Sparrows Point LNG FERC application.
- On behalf of Emera Brunswick Pipeline, assisted with the development of the demand and supply study submitted as part of the application to the National Energy Board of Canada.
- Provided support to a Canadian LNG supplier regarding their NEB export license application.

Energy Procurement

Directed and participated in the review of various energy procurement projects including demand modeling, portfolio review/optimization, procurement strategies and associated cost structures.

Representative engagements/experience has included:

- For a municipal utility evaluated its current gas supply portfolio and the options associated with purchasing strategies.
- For a municipal utility evaluated the benefits and costs associated with quick-start generation.
- Retained by a natural gas utility to review the value achieved under an asset management agreement, including use of storage.
- Provided a private company with a review of natural gas supply and storage options and associated prices and risks.
- On behalf of a large natural gas distribution company, evaluated the benefit associated with asset management opportunities.
- On behalf of a regional combination utility, reviewed the appropriate jurisdiction for a natural gas pipeline asset.
- On behalf of a natural gas utility, conducted a detailed audit of the gas supply, marketing, and accounting functions.
- On behalf of several gas utilities, developed demand forecasts and supported those forecasts in regulatory proceedings.
- For a multi-state utility, reviewed the demand forecast planning process and procedures and recommended certain process changes.
- On behalf of a financial institution, reviewed the competitiveness of a storage project investment and quantified the impact of various new projects on the storage project financial performance.

Financial and Economic Advisory Services

Involved in the sale or evaluation of several non-regulated energy companies including wholesale and retail energy marketing companies, on-line energy brokers and energy services' companies. Assisted clients with market strategy and the identification of partnership opportunities. Specific services provided include: business unit evaluation, development of sale materials, marketing of transaction, bid evaluation and negotiation support. These engagements have resulted in completed sales or strategy changes.

Representative engagements have included:

- For a municipal utility evaluated and negotiated an asset management agreement.
- Assisted an LDC with gas supply due diligence regarding a potential acquisition.
- Assisted a private company with business/market communication material and the identification of potential partners to support the commercialization of the client's patented intellectual property.
- Performed an independent review of a retail energy marketer to value a third party investment.
- Sale of Niagara Mohawk Power Corporation's non-regulated energy marketing affiliate.
- Sale of Providence Energy Corporation's non-regulated marketing affiliate.
- Performed an independent valuation of an on-line energy broker on behalf of an investor.

PROFESSIONAL HISTORY

Sussex Economic Advisors, LLC (2012 – Present)
Partner

Concentric Energy Advisors, Inc. (2002 – 2012)
Executive Advisor
Senior Vice President
Vice President

Navigant Consulting, Inc. (2000 – 2001)
Director, Energy Market Assessment Practice Area

Providence Energy Services (1997 – 2000)
President (1998 – 2000)
President, Providence-Southern (1997 – 1998)

REED Consulting Group (1994 – 1997)
Assistant Vice President

Colonial Gas Company (1991 – 1994)
Director, Gas Supply Planning and Acquisition (1993 – 1994)
Manager, Gas Supply (1991 – 1993)

Boston Gas Company (1987 – 1991)
Senior Gas Supply Analyst (1990 – 1991)
Transportation and Exchange Analyst (1988 – 1990)
Business Analyst (1987 – 1988)

EDUCATION

M.B.A., Bentley College, 1991
B.S., Bentley College, 1987

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Member of the American Gas Association
Member of the New England Gas Association
Former Member of the American Public Gas Association

Recent Expert Witness Appearances of James M. Stephens

SPONSOR	DATE	JURISDICTION	DOCKET NO.	SUBJECT
Union Gas	April, 2013	Ontario	Docket No. 2013-0109	Gas Supply Planning
Columbia Gas of Massachusetts	September, 2013	Massachusetts	Docket No. 13-158	Pipeline Capacity Contract
Columbia Gas of Massachusetts	September, 2013	Massachusetts	Docket No. 13-161	Integrated Resource Plan
Gaz Métro	October, 2013	Québec	Cause tarifaire 2014, R-3837-2013	Storage Utilization
Maine Public Utility Commission	February, 2014	Maine	Docket No. 2014-00071	Pipeline Open Season
Gaz Métro	January, 2015	Québec	Cause tarifaire 2015, R-3879-2014	Storage Utilization