



May 28, 2015

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: EB-2015-0166 - Union Gas Limited – Pre-Approval of the Cost Consequences of NEXUS Long Term Contract

Please find attached Union Gas Limited's ("Union") application and evidence seeking pre-approval of the cost consequences of a long-term transportation contract that supports the development of new natural gas infrastructure. This application is made pursuant to section 36 of the *Ontario Energy Board Act, 1998* and is filed in accordance with filing guidelines for Pre-Approval of Long-term Natural Gas Supply and/or Upstream Transportation Contracts issued by the Ontario Energy Board (the "Board") in EB-2008-0280. The application and evidence have been filed through the Board's RESS and will be available on Union's website at: www.uniongas.com.

Union intends execute this transportation contract to increase security of supply through diversification, maintain liquidity at Dawn, ensure competitive energy prices for its customers and create supply competition and opportunities for all Ontario consumers. It will provide Ontario with a direct connection to the Appalachian region of the U.S. Northeast which has emerged as the single largest and fastest growing production region of natural gas in North America.

Union signed a Precedent Agreement with the intention of entering into a long-term (15-year) contract with NEXUS for 150,000 Dth/d (158,258 GJ/d) of transportation capacity with an expected total cost of approximately \$715 million. Based on landed cost analysis Union estimates potential gas cost savings of over \$700 million over the term of the contract. As noted in the attached evidence, Union must waive or satisfy the condition precedent of obtaining Board approval by October 1, 2015. If approval is not received, Union will not commit to the NEXUS capacity.

Please contact me at (519) 436-5473 if you have any questions or wish to discuss this submission in more detail.

Yours truly,

[Original signed by]

Karen Hockin
Manager, Regulatory Initiatives

c.c.: Charles Keizer, Torys
Mark Kitchen, Union Gas
EB-2014-0271 Intervenors

ONTARIO ENERGY BOARD

IN THE MATTER OF the Ontario Energy Board
Act, 1998, S.O. 1998, c.15 (Schedule B) s.36;

AND IN THE MATTER OF an Application by
Union Gas Limited for an order or orders pre-
approving the cost consequences associated with
one long-term natural gas transportation contract.

APPLICATION

1. Union Gas Limited (“Union”) is a business corporation incorporated under the laws of the province of Ontario, with its head office in the Municipality of Chatham-Kent.
2. Union conducts both an integrated natural gas utility business that combines the operations of distributing, transmitting and storing natural gas, and non-utility storage and Liquefied Natural Gas business within the meaning of the *Ontario Energy Board Act, 1998*.
3. In accordance with the Filing Guidelines for Pre-Approval of Long-Term Natural Gas Supply and/or Upstream Transportation Contracts, issued by the Ontario Energy Board (the “Board”) in EB-2008-0280, Union is seeking pre-approval of the cost consequences associated with one long-term gas transportation contract.
4. Union has entered into an agreement, subject to certain conditions precedent, to contract for long-term transportation capacity with the NEXUS Gas Transmission (“NEXUS”) pipeline commencing November 1, 2017.
5. To support development of the NEXUS project, Union signed a Precedent Agreement (“PA”) with the intention of entering into a long-term (15-year) contract with NEXUS for 150,000 Dth/d (158,258 GJ/d) of transportation capacity with an expected total cost of approximately \$715 million. Based on assumed values for the landed cost analysis and

displaced volumes on Alliance/Vector and TransCanada paths, Union estimates potential gas cost savings of over \$700 million over the term of the contract compared to current contracted supplies.

6. The NEXUS project will transport growing supplies of Appalachian shale gas, including Marcellus and Utica shale gas production, to consumers in Ohio, Michigan, and ultimately the Dawn Hub in Ontario, Canada.
7. Union's obligations under the PA include supporting the project timelines by receiving required approvals in a timely fashion, including this application for contract pre-approval. The date by which Union must waive or satisfy this condition precedent is October 1, 2015.
8. Union hereby applies for an order or orders, pursuant to section 36 of the Act, pre-approving the costs associated with the NEXUS contract. Without such pre-approval, Union will not commit to the NEXUS capacity.
9. Union also applies to the Board for such interim orders or orders approving interim rates or other charges and accounting orders as may from time to time appear appropriate or necessary.
10. Union further applies to the Board for all necessary orders and directions concerning pre-hearing and hearing procedures for the determination of this application.
11. This application is supported by written evidence. This evidence may be amended from time to time as required by the Board, or as circumstances may require.

12. The persons affected by this application are the customers resident or located in the municipalities, police villages and Indian reserves served by Union, together with those to whom Union sells gas, or on whose behalf Union distributes, transmits or stores gas. It is impractical to set out in this application the names and addresses of such persons because they are too numerous.

13. The address of service for Union is:

Union Gas Limited
P.O. Box 2001
50 Keil Drive North
Chatham, Ontario
N7M 5M1

Attention: Karen Hockin
Manager, Regulatory Initiatives

Telephone: (519) 436-5473

Fax: (519) 436-4641

NEXUS CONTRACT PRE-APPROVAL DRAFT EVIDENCE

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1. EXECUTIVE SUMMARY

The purpose of this evidence is to request pre-approval of the cost consequences of a long-term transportation contract in accordance with the filing guidelines for Pre-Approval of Long-term Natural Gas Supply and/or Upstream Transportation Contracts (the “Guidelines”), issued by the Board in EB 2008-0280¹.

Union Gas Limited (“Union”) has entered into an agreement to contract, subject to certain conditions precedent, for long-term transportation capacity with the NEXUS Gas Transmission (“NEXUS”) Pipeline commencing November 1, 2017. This contract will increase security of supply through diversification, maintain liquidity² at Dawn, ensure competitive energy prices for its customers and create supply competition and opportunities for all Ontario consumers. The NEXUS project is designed to transport supplies of Appalachian shale gas production, including Marcellus and Utica shale gas production, from the single largest and fastest growing supply basin in North America to customers in Ohio, Michigan, and ultimately the Dawn Hub in Ontario, Canada; creating a direct connection from the largest source of natural gas on the continent to Ontario.

DTE Energy and Spectra Energy Corp. are jointly developing the NEXUS project. To support the development of this project, Union has signed a Precedent Agreement (“PA”) and obtained

¹ See Schedule 2 for OEB prescribed filing guidelines

² The liquidity of a hub such as Dawn is defined by the ease with which parties can physically buy or sell natural gas in the market. The most liquid hubs have the most significant competition, natural gas infrastructure (pipeline interconnects, and storage), and transparent pricing mechanisms.

1 anchor shipper status with the intention of entering into a long-term (15-year) contract with
2 NEXUS. Anchor shipper is a common term referring to large shippers that participate in pipeline
3 infrastructure projects, such as NEXUS, to allow them to proceed. The large volume, long term
4 commitments made by the anchor shipper ensure that significant demands exist for the capacity
5 and revenues will be guaranteed for the period of time required to justify the project. The
6 Affiliate Relationship Code (“ARC”) does not apply to the relationship between Union Gas and
7 NEXUS because NEXUS is a 50-50 partnership between DTE Energy and Spectra Energy Corp
8 where neither DTE nor Spectra have control.

9
10 Union has reviewed Filing Guidelines for the Pre-Approval of Long-Term Natural Gas Supply
11 and/or Upstream Transportation Contracts, EB-2008-0280, and it is Union’s view that the
12 Guidelines apply to the NEXUS contract. The contract is significant in that it ties new supply
13 basins to Ontario, is long term in nature, does not represent day-to-day contracting in Union’s
14 portfolio, and provides significant benefits to Union’s customers and all of Ontario. This is the
15 first time since the Alliance and Vector pipeline project in 2000 that Union has made a
16 comparable commitment to a major pipeline project that would ultimately bring substantial new
17 supplies to Dawn.

Specifically, the Guidelines apply because:

- The contract is a long-term commitment that is required to support the development of new greenfield natural gas infrastructure that will directly link Ontario and more specifically, Dawn, to new natural gas supply basins in the Appalachian region.
- The long-term contract requires a substantial financial commitment by Union Gas. The contracted volume of 150,000 Dth/d (158,258 GJ/d) of transportation capacity for 15 years will result in a total cost commitment estimated to be approximately \$715 million.

As a major natural gas utility in Ontario, Union must encourage and support new infrastructure projects such as NEXUS to connect and bring new supplies to Ontario. The Board has previously recognized the role that an LDC plays in encouraging these new, large-scale infrastructure projects:

“The Board recognized that the enrolment of regulated utilities for such long term arrangements would be a necessary and desirable element in new infrastructure development.”³

Union has entered into a long-term commitment (subject to certain conditions precedent in Schedule 1 Precedent Agreement) with NEXUS for a significant volume. Given the financial obligations resulting from the commitment, Union is requesting contract pre-approval. The

³ EB-2010-0300/EB-2010-0333 Decision and Order, page 7

1 Board has recognized the need for utilities to obtain contract pre-approval in this situation,
2 stating that:

3
4 “...regulated utilities whose sourcing decisions are typically and conventionally subject
5 to ex post facto prudence review would be reluctant or unwilling to accept very
6 significant long-term commitments without assurances of costs recovery. The result
7 would be a frustration of demonstrably needed new natural gas infrastructure.”⁴
8

9 Without the assurance provided by contract pre-approval, Union will not commit to a contract of
10 this magnitude. In a scenario where Union was unable to obtain contract pre-approval and not
11 commit as an anchor shipper to the contract as proposed, there is significant risk that producers,
12 who are also anchor shippers on the NEXUS project, may interpret Union’s action as a lack of
13 endorsement of Dawn as an important market hub and an indication of a weak market for their
14 supplies at Dawn. If these producers were to reconsider their participation on the project, or their
15 plans to bring supplies to Dawn, there is significant risk that the NEXUS project would not
16 proceed as planned.
17

18 Attracting more supplies to Dawn is critical to maintain Dawn’s liquidity and overall
19 competitiveness in the surrounding market. Given declining Vector volumes and the decrease in

⁴ EB-2010-0300/EB-2010-0333 Decision and Order, page 7

1 natural gas flowing from the WCSB to the Ontario market⁵ as well as the increasing take away
2 capacity from Dawn, Ontario needs supply projects from the growing Appalachian Basin, such
3 as NEXUS, to maintain supply and liquidity. Were these NEXUS supplies not to arrive at
4 Dawn, this would eliminate the benefits that the pipeline would bring to Union's customers, the
5 Dawn Hub, and the rest of Ontario.

6
7 Union's obligations under the PA include supporting the project timelines by receiving required
8 approvals in a timely fashion, including this application for contract pre-approval. The date by
9 which Union must waive or satisfy this condition precedent is October 1, 2015.

⁵ Schedule 3 - NEXUS Market Study Report, Sussex Economic Advisors, LLC, page 3

1 Union has taken considerable steps to meet market demands and create the ability to transport
2 new and more affordable incremental natural gas volumes from Dawn to points east and north.
3 This has included the necessary facilities required to allow for supply diversification for Union's
4 customers in Union North as well as those of Enbridge and Gaz Metro through access to supplies
5 at or upstream of the Dawn Hub. It is essential that, as takeaway capacity from Dawn is
6 increased, the supply coming into Dawn is also enhanced. Through NEXUS, this goal will be
7 achieved. Expansions planned for 2015 and 2016 will increase the Dawn Parkway system
8 capacity by 875 TJ/d (433 TJ/d in 2015¹⁰, 443 TJ/d in 2016¹¹) and further growth is planned for
9 2017. This incremental throughput capacity drives the need for additional supply at Dawn.

10
11 The Appalachian region of the U.S. Northeast as shown in Figure 2-1 is home to the Utica and
12 Marcellus shale formations in Ohio, Pennsylvania, and West Virginia which have emerged as the
13 single largest and fastest growing production region of natural gas in North America.

¹⁰ EB-2013-0074 Exhibit A, Tab 8, page 6, Figure 8-3

¹¹ EB-2016-0261 Exhibit A, Tab 8, page 10, Table 8-2

**Figure 2-1
The Appalachian Shale Region**

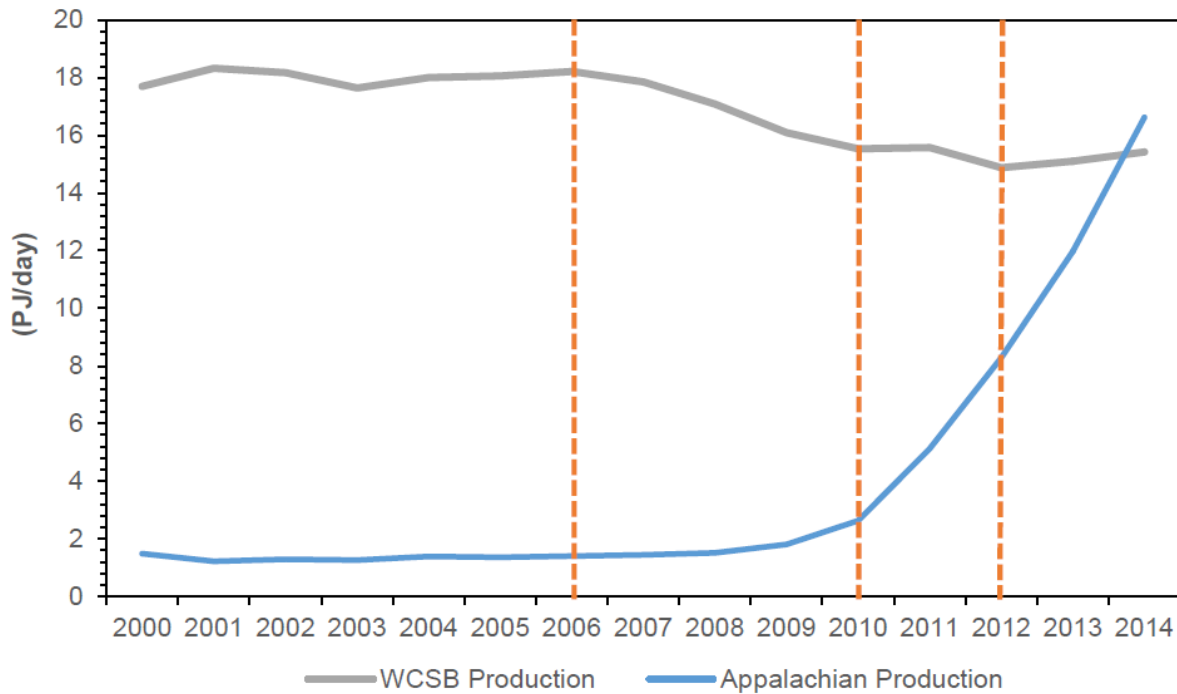


(Source: Schedule 3 - Sussex Economic Advisors Market Study Report)

1 This basin, although still in its infancy, has grown from essentially producing almost no supply
2 as recent as 2008 to exceeding the Western Canadian Sedimentary Basin (“WCSB”) production
3 levels by the end of 2014 as shown in Figure 2-2. This region is expected to continue to grow
4 and produce almost 40 PJ/d by 2035¹² Ontario is very fortunate to be in close proximity to this
5 supply basin, and yet Ontario does not currently have access to a direct pipeline route from this
6 basin to Dawn.

¹² Schedule 3 - NEXUS Market Study Report, Sussex Economic Advisors, LLC, page 32

Figure 2-2
Growth of Appalachian Shale Production vs. WCSB Production



(Source: Schedule 3 - Sussex Economic Advisors Market Study Report)

The majority of Ontario's natural gas supply needs for the past five decades have been met through the large resources of the WCSB. Natural gas from the WCSB was supplied to Ontario on the TransCanada Mainline either from Empress across northern Ontario or from pipelines passing through the northern US and eventually back into Canada to Dawn. In parallel with the emergence of shale gas supplies, there has been a pattern of declining flows from conventional western supply sources, including the WCSB, and corresponding de-contracting of long-haul

1 transportation from these sources¹³. Directionally, these changes result in less supply arriving at
2 Dawn through existing pipeline infrastructure and have impacted the diversity and liquidity of
3 the Dawn Hub. The continuation of these flow changes represents a significant risk to all natural
4 gas consumers and market participants in Ontario.

5
6 Without access to the abundant and affordable supplies in the Utica and Marcellus shale basins,
7 gas prices at Dawn, and therefore energy prices in Ontario, would be disconnected from the
8 continent-wide lower costs resulting from these emerging supplies. In other words, the cost of
9 energy in Ontario would not benefit from the moderating effect of the low-priced natural gas in
10 the Appalachian Basin available to neighbouring areas.

11
12 By Union entering into a firm transportation contract, and therefore supporting the NEXUS
13 project and its ability to connect and deliver incremental supplies into Ontario, Union customers
14 and all of Ontario will see multiple significant benefits including:

- 15
- 16 • Providing a direct pipeline route between Appalachian shale basins and Ontario that will
17 benefit Union's sales service customers by significantly increasing the security and
18 diversity of Union's transportation and supply portfolio. Access to these basins will
19 greatly reduce Union's reliance on WCSB supplies, and will offset the declining volumes

¹³ The financial impact of various parties de-contracting TransCanada long-haul transportation has already been contemplated in the NEB RH-001-2014 settlement agreement. The NEXUS project will not have an incremental impact to the TransCanada Mainline.

1 arriving at Dawn from these traditional western sources. The NEXUS capacity will allow
2 Union to displace WCSB supplies that are becoming less economic over time. WCSB
3 basis differentials, once they are combined with the cost of transportation to Ontario,
4 have become less favourable than Appalachian supplies due to rise in demands in
5 Western Canada and the abundance of natural gas supplies located in the Appalachian
6 shale region. Additional diversity will allow Union to have options as to where it sources
7 natural gas supplies in future market shifts or as prices between supply basins change.

8
9 Specifically, the NEXUS capacity will;

10 a) Replace an Alliance Pipelines contract that is expiring in the portfolio for
11 Union South customers, and

12 b) Replace TransCanada long-haul transportation contracts serving the Union
13 North and South.

14 These changes to Union's contracted capacity were contemplated and approved in the
15 TransCanada Settlement Agreement RH-001-2014.

- 16
- 17 • Introducing new pipeline infrastructure and enhancing supply at Dawn will also benefit
18 Ontario and other market participants at Dawn, such as Quebec and U.S. northeast, by
19 adding another transportation option and supporting the liquidity of the Dawn Hub.
20 Dawn liquidity is supported by adding additional physical supplies, as well as additional
21 active market participants. The Board has previously concluded that it "...is in the public

1 interest to maintain and enhance the depth and liquidity of the market at the Dawn Hub as
2 a means of facilitating competition”¹⁴. This will be of benefit to not only Union’s sales
3 service customers as noted above, but all direct purchase customers, including large
4 industrial and power customers who rely on arranging their natural gas supply at the
5 Dawn Hub.

- 6
7 • Connecting Ontario to growing, affordably priced Appalachian shale gas will help to
8 lower natural gas prices and enhance energy pricing stability in Ontario. Reduced price
9 and reduced long term price volatility is a major benefit to all market participants,
10 including power generation customers who rely on supply arrangements made at the
11 Dawn Hub.

12
13 As part of considering a contractual commitment to the NEXUS project, Union considered the
14 needs of both its sales service and direct purchase customers, as well as the rest of Ontario’s
15 natural gas market participants. This evidence will outline the fact that the increased security
16 and diversity of supply that the NEXUS pipeline would bring to Dawn is critical to shaping
17 Ontario’s energy future.

18
19 Union has been negotiating a contractual commitment to the NEXUS project since the initial
20 open season in 2012. This evidence will outline the contract analysis and risk mitigation
21 activities that have been performed to date. In addition to activities related to the transportation

¹⁴ EB-2005-0551 NGEIR Decision with Reasons, page 45

1 contract, Union has started working on gas supply arrangements with producers in the
2 Appalachian shale region. This has included participating in ongoing discussions with potential
3 suppliers, educating them on the Ontario market dynamics, negotiating North American Energy
4 Standards Board (“NAESB”) base agreements, and investigating supply options through an
5 Expression of Interest and subsequent Request for Proposal (“RFP”) process.

6
7 In summary, the resulting benefits of NEXUS are extensive, and will not only apply to Union’s
8 customers for which it is responsible to procure supply and transportation, but to all natural gas
9 market participants in Ontario including Direct Purchase and Power Generation customers, and
10 other LDCs.

3. THE NEXUS PROJECT

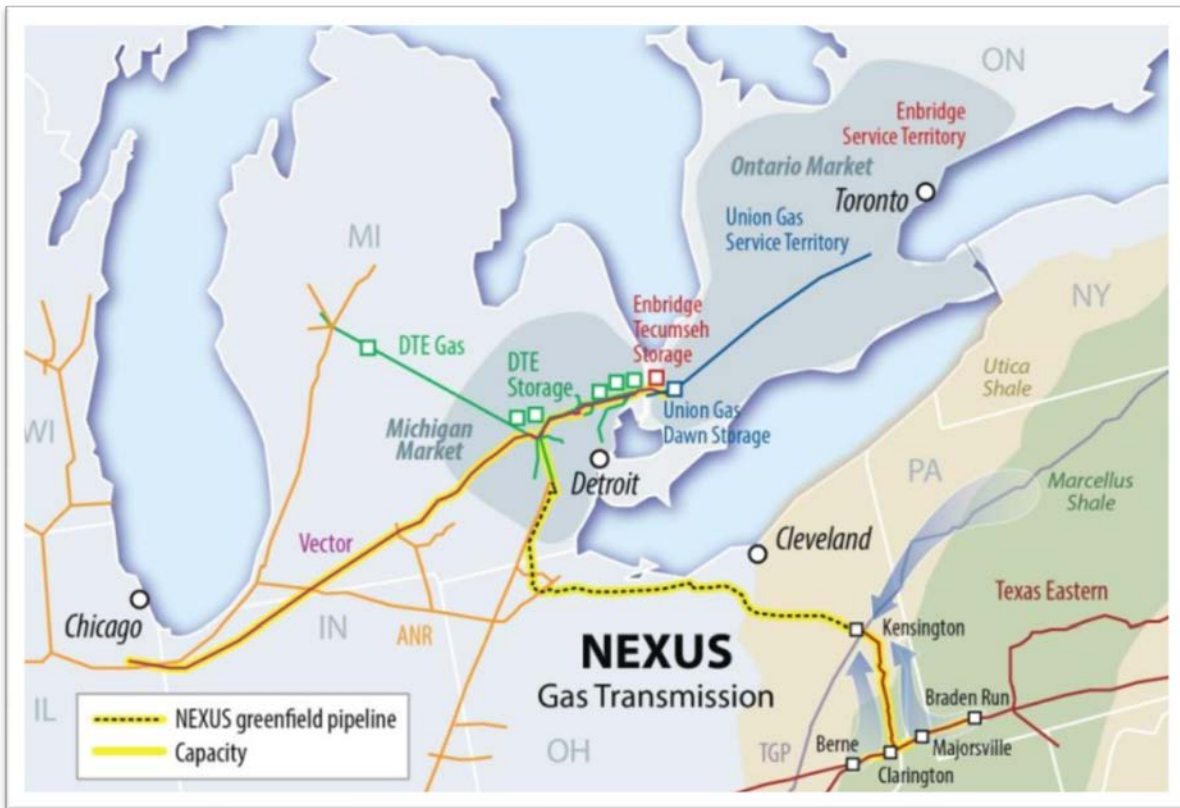
Project Description

The NEXUS project will transport growing supplies of Appalachian shale gas including Marcellus and Utica shale gas production to customers in the U.S. Midwest, including Ohio and Michigan, and to customers in Ontario, Canada including the Dawn Hub. DTE Energy and Spectra Energy Corp. are jointly developing the NEXUS project.

The proposed path for the NEXUS project will consist of two components, the first being a newly-constructed greenfield pipeline and the second being the use of existing infrastructure in Ontario and Michigan. The greenfield portion of the pipeline will extend approximately 250 miles (400 kilometers) from the Utica/Marcellus receipt points in eastern Ohio to interconnects with the existing DTE/Michcon (“DTE”) pipeline grid at Willow Run in southeastern Michigan.

For most shippers, the NEXUS path will then utilize capacity on the DTE and Vector pipeline systems from Willow Run to the Dawn Hub in Ontario, as outlined in Figure 3-1. The DTE and Vector facilities that NEXUS will utilize will likely require reinforcement, but will allow NEXUS to connect supplies to Dawn without the need for greenfield infrastructure to be constructed in these areas. The result is an efficient use of existing pipeline infrastructure.

Figure 3-1
Proposed Path of the NEXUS Pipeline



(Source: NEXUS Gas Transmission)

Although most of the capacity held by shippers will flow on the greenfield portion of NEXUS to the facilities of DTE, Vector, and then to Dawn, Union's arrangement will take a slightly different path as shown in Figure 3-2. For Union, the contracted volumes will still flow on the same greenfield portion of NEXUS from Ohio to DTE at Willow Run. However, instead of supplies then flowing on DTE facilities to Vector, they will flow on the DTE system to the International Border and St. Clair Pipelines to reach the Union Gas facilities. This path offers an advantage as it will allow the use of St. Clair to Dawn facilities that already exist and reduce the requirement for NEXUS to construct new pipeline infrastructure in Ontario.

Figure 3-2
NEXUS Pipeline Paths to Ontario/Dawn



(Source: Union Gas)

The NEXUS project will be capable of transporting approximately 1.5 billion cubic feet per day (Bcf/d) of natural gas away from the Utica/Marcellus to markets in Ohio, Michigan and Ontario.

The anticipated in-service date for the NEXUS pipeline project is November 1, 2017.

1 The shipper support of the NEXUS project is a combination of demand-pull¹⁵ market
2 participants such as end-use LDCs (i.e. Union, Enbridge and DTE), and supply-push¹⁶ market
3 participants such as the Appalachian suppliers (i.e. Chesapeake, Consol and Noble). Having both
4 types of entities supporting the project is a significant advantage as it enhances the likelihood
5 that the project will succeed.

6
7 There is significant market competition for the supply available from the growing Utica and
8 Marcellus shale basins. Numerous projects are already in progress to take these supplies to other
9 markets, including the Gulf Coast, U.S. Midwest, U.S. Northeast, and the U.S. Southeast. It is
10 critical for Union and Ontario consumers that contractual commitments to the NEXUS project be
11 made and supported to ensure Ontario and those market participants that access supplies at
12 Dawn, gain access to these supplies in a similar fashion to the other markets in the eastern half of
13 North America. This will ensure Ontario and Dawn stay well connected to new affordable and
14 competitively priced North American supplies.

15
16 The Kensington receipt point will be the outlet of a major gas processing plant in the Utica basin
17 in South East Ohio and is the starting point for the greenfield portion of the NEXUS project.
18 Given the immediate supply available, as well as the multiple additional upstream connections
19 into the NEXUS pipeline in that area, there will be sufficient supply and liquidity at this point.

¹⁵ “Demand Pull” entities located within a market area (i.e. LDCs, end use marketers, large customers) attract natural gas to a market by procuring transportation from a supply producing area in order to access suppliers.

¹⁶ “Supply Push” entities located within a supply producing region (i.e. natural gas producers, marketers, traders) seek out markets to sell their supply by procuring pipeline access to a market area in order to sell gas to market participants.

4. THE NEED FOR THE NEXUS PROJECT

When the NEXUS project was announced in 2012, it was the first greenfield infrastructure project proposed to bring significant, incremental supplies to Ontario since the Alliance and Vector pipelines in 2000. Union has limited room within its upstream transportation portfolio to make major commitments to a pipeline project. As a result, Union needs to carefully evaluate and assess its ability to make a contractual commitment for new pipeline capacity in situations where support is required to ensure new pipeline capacity gets built to connect new supplies to Ontario and the Dawn Hub. Some projects require the collective support of numerous LDCs while others may be supported by producers located in the respective supply basin.

At the time of the project announcement, Union recognized NEXUS as an opportunity to benefit from the changing North American supply dynamics and to:

- a) replace declining flows from the WCSB by gaining access to abundant, economic Appalachian shale supplies,
- b) increase the diversity and security of supply for Union's customers,
- c) reduce price volatility of the Dawn Hub, and
- d) bring major benefits to the rest of Ontario.

This fundamental shift toward Appalachian shale supplies in the U.S. northeast is supported by the Sussex Report provided in Schedule 3. As it states at page 2, "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) serving eastern markets in the U.S. and Canada”.

The Needs of Union’s Customers

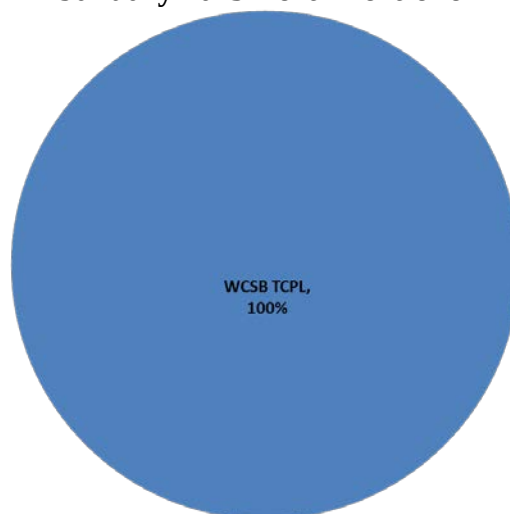
When managing its transportation portfolio and analyzing potential pipeline paths and supply sources, including the NEXUS project, Union does so in the context of the Gas Supply Planning Principles¹⁷. These principles ensure customers consistently receive secure, diverse natural gas supply at a prudently incurred cost and minimal risk. They also help Union to determine whether changes are required to the current transportation and supply portfolios. The principles are as follows:

1. Ensure secure and reliable natural gas supply to Union’s service territory;
2. Minimize risk by diversifying contract terms, supply basins and upstream pipelines;
3. Encourage new sources of supply as well as new infrastructure to Union’s service territory;
4. Meet planned design day and seasonal gas delivery requirements; and,
5. Deliver natural gas to various receipt points on Union’s system to maintain system integrity.

¹⁷ The Gas Supply Planning Principles have been presented to and accepted by the Board on many occasions. Most recently these principles were presented to the Board in Union’s 2013 Rate Case (EB-2011-0210), the 2012 Deferral Disposition Proceeding (EB-2013-0109), and the Parkway Projects Proceeding (EB-2012-0433/EB-2013-0074).

As demonstrated in Figure 4-1 below, there is currently a lack of pipeline and supply diversity in the 2015 Union North sales service and bundled direct purchase portfolio due to its 100% reliance on WCSB supplies delivered to Ontario via TransCanada long-haul transportation. This lack of diversity introduces risks around security of supply, and leaves customers in Union North exposed to the pricing characteristics and potential volatility of a single basin. With the declining flows from traditional WCSB sources, Union recognized the need to introduce new, secure, and affordable supplies that are in close proximity into the northern portfolio.

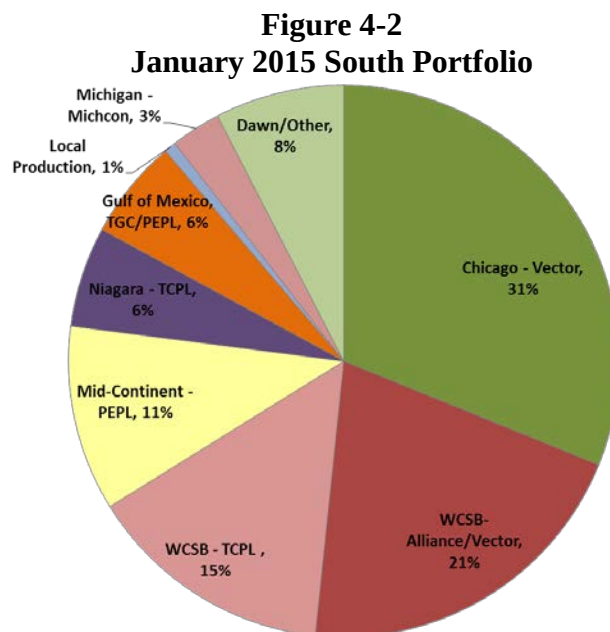
Figure 4-1
January 2015 North Portfolio



In order to address this lack of diversity in the north, Union has worked to facilitate an increased diversity of supply options for these customers in future years through the TransCanada Settlement Agreement by converting TransCanada long-haul transportation from Empress into short-haul transportation from Dawn. Once these conversions are completed, customers in Union North will have the ability to access supplies at Dawn, including those from upstream transportation projects such as NEXUS. These changes are contingent upon significant

1 infrastructure investments by TransCanada, Enbridge, and Union in the Dawn to Maple corridor
2 as discussed in recent regulatory forums including Union's Dawn Parkway 2016 Expansion
3 evidence EB-2014-0261. To facilitate and take advantage of Union North having access to
4 Dawn, Union recognized the importance of supporting the NEXUS project to introduce growing
5 Appalachian supplies into Dawn and ultimately into the northern portfolio.

6
7 As can be seen in Figure 4-2, the Union South portfolio is currently much more diverse than
8 Union North; however there is still a significant reliance on supplies directly from the WCSB.
9 Approximately 36% of Union South is sourced from the WCSB, with an additional 31% sourced
10 from Chicago. As the supplies arriving from these traditional western sources decline, Union
11 needs to find replacement capacity upstream of Dawn to deliver new gas supplies and ensure the
12 continued liquidity and diversity at the Dawn Hub.



1
2 To further enhance diversity, Union determined the need for a direct pipeline path that would
3 connect Dawn to the growing Appalachian shale supplies. This would allow the Union South
4 portfolio to further diversify and introduce additional security and exposure to more stable
5 pricing in the Appalachian shale region.

6 ***The Needs of Ontario***

7 As mentioned previously, North American natural gas markets are undergoing a dramatic change
8 in supply dynamics. This is supported by the Sussex Market Study Report in Schedule 3, and
9 has been discussed in numerous previous filings by Union including EB-2012-0433¹⁸ and EB-
10 2013-0074¹⁹, EB-2014-0145²⁰, as well as EB-2014-0261²¹.

11 The Appalachian region of the U.S. Northeast has emerged as the single largest producing region
12 of natural gas in North America. The basin is estimated to grow to production levels of 40 PJ/d
13 by 2035, and will exceed the entire WCSB at its peak production of 18 PJ/d by the end of 2015.
14 Unfortunately, there is currently no direct pipeline route into Dawn from the Appalachian shale
15 region. The NEXUS project, once completed, will provide that connection and help to enhance
16 security of supply through diversification, for all Ontario market participants.

¹⁸ EB-2012-0433, Parkway West Project, Exhibit A, Tab 4.

¹⁹ EB-2013-0074, Brantford to Kirkwall Pipeline/Parkway D Compressor, Exhibit A, Tab 4.

²⁰ EB-2014-0145, 2013 Deferral Disposition, Exhibit A, Tab 4, Appendix B and Appendix C.

²¹ EB-2014-0261, Dawn Parkway 2016 Expansion Project, Exhibit A, Tab 5.

1 The Board has previously recognized the importance of maintaining the liquidity of Dawn,
2 stating that “The development of the Dawn Hub has brought substantial benefits to consumers in
3 Ontario and to other market participants” and also that “it is in the public interest to maintain and
4 enhance the depth and liquidity of the market at the Dawn Hub as a means of facilitating
5 competition”.²²

6 In its Decision regarding Union’s Parkway Projects and Enbridge’s GTA Project, the Board
7 reiterated this position: “It is the Board’s view that while uncertainties exist for all supply
8 sources in terms of future cost and availability, it is widely acknowledged, including by this
9 Board in prior decisions, that supply diversification enhances reliability and brings cost benefits
10 through enhanced competition”²³

11
12 Ontario gas-fired generation has increased demand for natural gas. As Ontario is projected to
13 rely more heavily on natural gas-fired power generation while Ontario undergoes the
14 refurbishment of its nuclear facilities²⁴, it is important for Ontario to have access to affordably-
15 priced natural gas supplies in order to secure its energy future. Having new greenfield supply
16 options available will enhance and help maintain diversity and security of supplies to the Dawn
17 Hub, reduce natural gas prices and volatility and bring benefits to all of Ontario.

²² EB-2005-0551, Decision November 7, 2006, page 44, 45

²³ EB -2012-0451/EB-2012-0433/EB-2013-0074 Decision January 30, 2014 pp. 23-24

²⁴ Schedule 3 – NEXUS Market Study Report, Sussex Economic Advisors, LLC, page 38, 39

1 ***Analysis of Alternative Pipeline Projects***

2 When Union bid into the NEXUS Open Season in 2012, it was the only project at the time that
3 was planning to build a greenfield, direct pipeline path from the Marcellus and Utica shale basins
4 to bring significant incremental supplies directly into Dawn and Ontario. As this was the first
5 such project since the Alliance/Vector pipeline projects in 2000, Union believed it was critical to
6 encourage, support, and commit to the NEXUS project to ensure this incremental supply and
7 diversity was connected to the Dawn Hub.

8 In June 2014, Energy Transfer Partners (“ETP”) announced the Rover Pipeline (“Rover”) project
9 and held their first open season. In conjunction with the open season, ETP announced it had
10 signed long-term agreements with multiple shippers to support the construction of the pipeline.
11 These commitments were from three large producers who were operating in the Appalachian
12 shale region. Union is not aware of any commitments on Rover from end users in Ontario.

13
14 The toll being offered to shippers on Rover was very similar to that of NEXUS. However, the
15 contracted volumes required to obtain a Most Favored Nations (“MFN”) clause were much
16 higher than NEXUS. As Rover offered no incentives beyond what Union had already obtained
17 with NEXUS, and the upstream portfolio could not absorb another significant long-term
18 commitment, Union determined that it would not participate in the Rover Open Season. The
19 existence of both NEXUS and Rover pipeline projects highlights the requirement for additional

1 infrastructure connecting Appalachian shale basins to Dawn and is positive for Ontario to the
2 extent that both projects proceed as planned.

3
4 Over time, numerous other pipeline projects have been proposed that are expansions and
5 reversals of existing, mature pipeline infrastructure. These include TransCanada's Niagara to
6 Kirkwall pipeline, ANR pipelines, and Tallgrass Energy's REX pipeline. Union did in fact
7 commit to TransCanada's Niagara to Kirkwall capacity and commenced flow from Niagara in
8 2012.

9 In its role as an LDC, Union believed it to be both prudent and required to ensure the ability to
10 make large, long-term commitments within its portfolio for a project that would result in new
11 infrastructure that would make a significant difference to the future of Ontario and all natural gas
12 consumers. Union will consider these additional upstream transportation contracting options
13 whenever Union is looking for incremental supply within its portfolio in the future.

1 These benefits are further supported by the Sussex Report in Schedule 3. As it states, “The
2 NEXUS benefits (e.g., reliability, diversity, and price stability) increase the flexibility of the
3 Union and Enbridge natural gas supply portfolios; thus providing additional options to the
4 Ontario LDCs to manage natural gas supply and transportation costs, improve overall reliability,
5 and provide increased priced stability.”²⁶

6
7 With the increased diversity of these new supplies and the replacement of the WCSB supplies
8 within the Union portfolio, there may also be expected gas cost savings. These potential savings,
9 which are described in the landed cost section, will help to make Ontario more competitive with
10 neighbouring jurisdictions. Exposure to the Appalachian basin will also provide benefits to the
11 overall stability of natural gas prices in Ontario. As stated in the Sussex Report, “direct access to
12 the Marcellus and Utica supply basins will provide the Ontario LDCs with increased price
13 diversity. Specifically, the Marcellus/Utica gas supply basins will have certain price signals and
14 price indices not previously accessed by the Ontario LDCs, thus increasing overall price
15 diversity and providing more stability with respect to natural gas costs for Ontario LDC
16 customers.”²⁷

17
18 Union participated in a NEXUS non-binding open season which was held between October 15,
19 2012 and November 30, 2012. Union analyzed its future transportation requirements and chose

²⁶ Schedule 3 – NEXUS Market Study Report, Sussex Economic Advisors, LLC, page 4

²⁷ Schedule 3 – NEXUS Market Study Report, Sussex Economic Advisors, LLC, page 37

1 to bid for an amount of 150,000 Dth/d (158,258 GJ/d). This is the minimum volume required for
2 a party to qualify as an anchor shipper on the project. The project developers have offered
3 anchor shippers appropriate rate and rate-related incentives, including lower transportation rates
4 as compared to non-anchor shippers. Anchor shippers generally receive a rate that is \$.015 to
5 \$.03 US/Dth lower than other shippers.

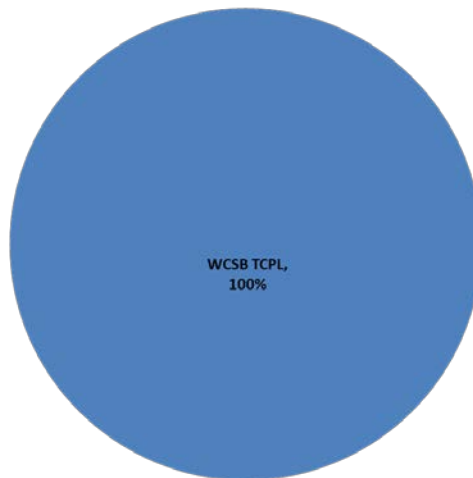
6
7 Union negotiated a unique path for the NEXUS pipeline with supplies being transported to St.
8 Clair Pipelines at the International Border. Union will then utilize its own, existing facilities to
9 transport supplies to Dawn.

10
11 This capacity is intended to serve both the needs of customers in Union North and Union South,
12 and will replace long-term WCSB-sourced transportation contracts on Alliance and TransCanada
13 that are expiring within the portfolio. The transportation capacity will be allocated based on a
14 split of approximately 2/3 for Union South and 1/3 for Union North.

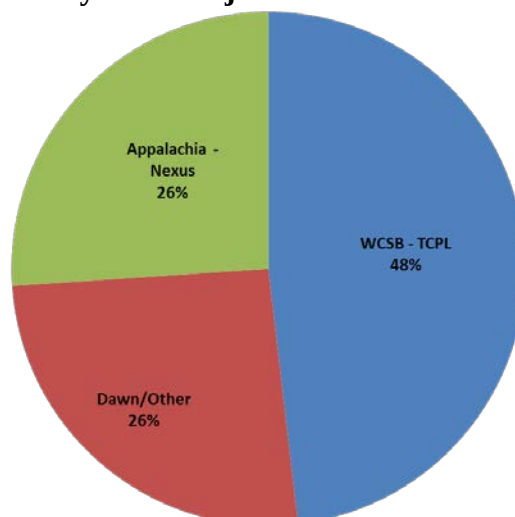
15
16 Once the TransCanada settlement facilities within the Parkway to Maple corridor are in service,
17 Union North will have direct access to Dawn for the very first time and will have the ability to
18 further enhance diversity through access to the NEXUS upstream transportation capacity. This
19 greatly diversifies the North's reliance on WCSB supplies, and will allow Union North
20 customers to benefit from enhanced supply access and diversity of Dawn and the basins
21 connected to Dawn

- 1 The results of the added diversity can be seen in Figure 5-1 as reliance on WCSB supplies in the
- 2 Union North drops from 100% (as seen earlier in Figure 4-1) down to 48%. Increased diversity
- 3 includes the addition of 26% of the portfolio from Appalachian supplies facilitated through the
- 4 NEXUS pipeline.

Figure 5-1
January 2015 North Portfolio

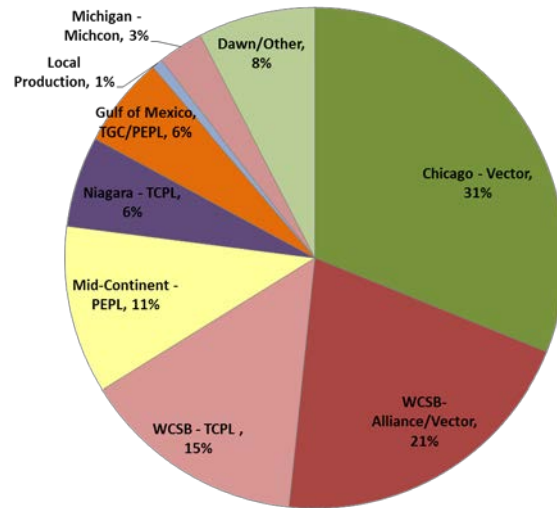


January 2018 Projected North Portfolio

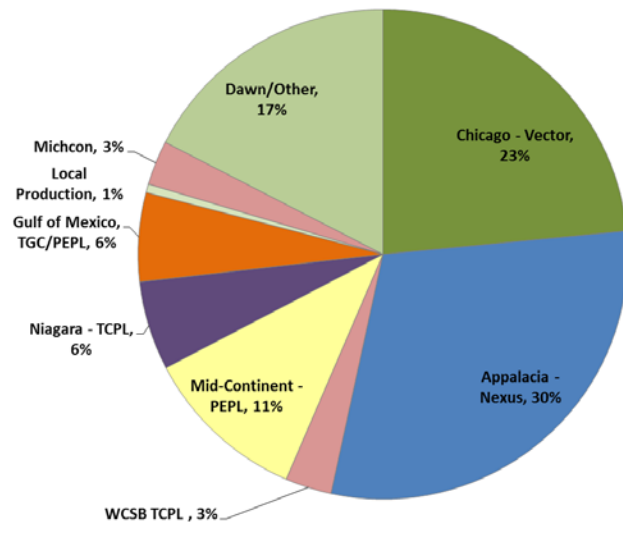


1 The Union South portfolio will benefit from NEXUS capacity as upstream transportation
2 reductions on Alliance/Vector and TransCanada take place. By accessing a portion of the
3 NEXUS capacity, the Union South portfolio will benefit from additional diversity and the
4 potential for cost savings by introducing an abundant, affordably priced source of natural gas in
5 close proximity to Ontario. This increased diversity can be seen in Figure 5-2 below as
6 TransCanada WCSB supplies drop from 21% (as seen earlier in Figure 4-2) down to 3%, and the
7 portfolio would then source 30% from Appalachian shale basins. The diverse Union South
8 portfolio still has 23% sourced from Chicago, as well as 17% from Dawn, both of which would
9 include a level of supplies from the WCSB.

Figure 5-2
January 2015 South Portfolio



November 2017 Projected South Portfolio



- 1 Looking at the entire Union transportation portfolio together (i.e. Union North and Union South),
- 2 the NEXUS capacity will add Appalachian shale supplies and will reduce the overall reliance on

- 1 WCSB from 53% in January 2015 as shown in Figure 5-3, down to 19% in January 2018 as
- 2 shown in Figure 5-4.

Figure 5-3
January 2015 North/South Combined Portfolio

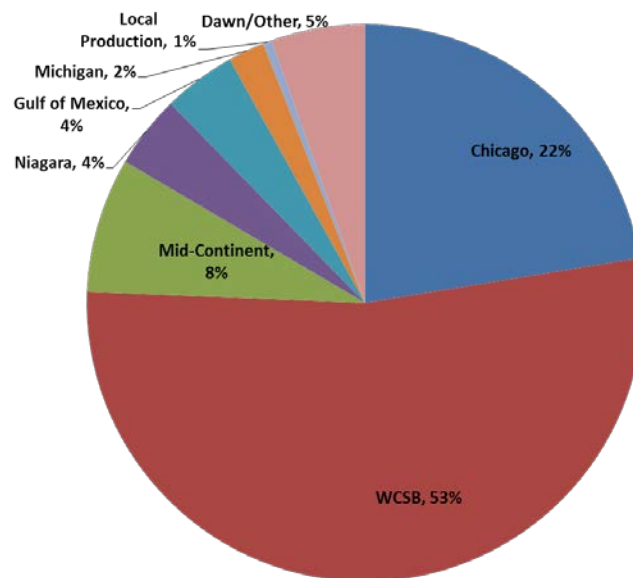
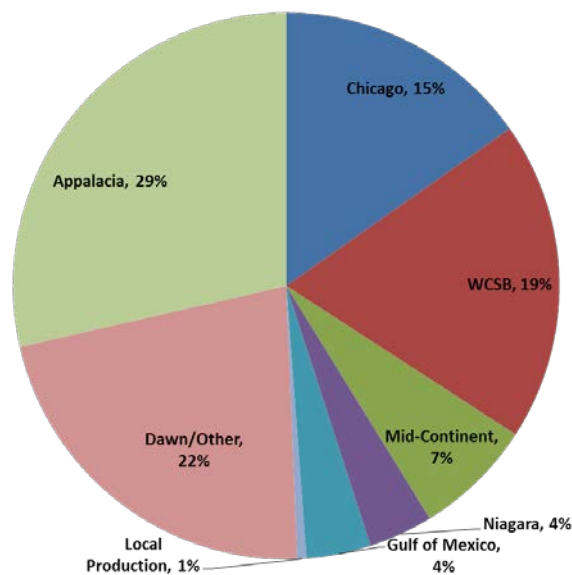


Figure 5-4
Projected January 2018 North/South Combined Portfolio



1 The goal of achieving supply diversity has been supported in previous Board decisions.
2 Specifically, the Board has stated that “Supply diversity enhances security and has the tendency
3 to lower gas prices from what they would otherwise be if the market continued to rely on fewer
4 sources of supply.”²⁸ Utica and Marcellus supplies will be transported through the new and
5 existing infrastructure and will have direct access to Dawn via a single pipeline provider.

6 ***Cost Recovery of St. Clair to Dawn Transportation from Sales Service Customers***

7 Union is proposing to charge Union North and Union South sales service customers the Board-
8 approved C1 St. Clair to Dawn transportation rate for the volumes transported from St. Clair to
9 Dawn.

10
11 In Union’s 2013 Board-approved cost allocation study, the cost associated with St. Clair to Dawn
12 transportation capacity are allocated to Union South in-franchise rate classes and ex-franchise
13 rate classes based on the design day demands of the Ojibway/St. Clair transmission system. The
14 costs allocated to Union South in-franchise rate classes are recovered from all customers in
15 delivery rates, while the costs allocated to ex-franchise rate classes (C1 and M16) are recovered
16 in transportation rates.

²⁸ EB-2012-0433/EB-2013-0074 Decision January 30, 2014, page 29

1 Union's 2013 Board-approved revenue forecast includes approximately \$2.8 million in Storage
2 and Transportation (S&T) revenue associated with St. Clair to Dawn transportation service. This
3 revenue (less allocated costs) is included in revenue for ratemaking purposes. Delivery rates for
4 all customers are lower as a result of forecasted S&T revenue from St. Clair to Dawn. S&T
5 transportation revenue also forms part of utility earnings, which are subject to sharing with
6 ratepayers during Union's 2014 to 2018 IRM term.

7
8 With Union North and Union South sales service customers utilizing the majority of the St. Clair
9 to Dawn transportation capacity effective November 1, 2017, Union will have less opportunity to
10 generate S&T revenue on this path. To offset the revenue already included in rates, and to
11 ensure there is no cross-subsidy between sales service customers and other customers, Union is
12 proposing to charge sales service customers for St. Clair to Dawn transportation service in a
13 manner consistent with how Union would charge other customers. Further, this results in the
14 same impact to sales service and bundled direct purchase customers under a scenario where
15 NEXUS would contract to St. Clair transportation service and then charge Union for the full
16 path.

17
18 Specifically, Union is proposing to charge Union North and Union South sales service customers
19 the Board-approved C1 St. Clair to Dawn transportation rate (approximately \$0.035/GJ/day
20 currently). These charges will be treated as gas supply costs and recorded in the Union North
21 and Union South Purchased Gas Variance Accounts ("PGVA"'s). The costs will be recovered in

gas supply commodity rates, from sales service customers only, as part of Union's QRAM process.

Union estimates that the annual gas supply costs for sales service customers in 2018 associated with St. Clair to Dawn transportation will be approximately \$2.0 million (158,258 GJ/d x \$0.035/GJ x 365 days). St. Clair to Dawn transportation costs have also been included in the landed cost analysis described in Schedule 4.

In summary, by executing a firm transportation agreement, and therefore supporting the NEXUS project, Union will satisfy all of its Gas Supply Planning principles as follows:

1. Ensuring secure and reliable supply by accessing the most prolific supply basin in North America at a prudently-incurred cost
2. Committing to the NEXUS pipeline, and working with Appalachian suppliers to understand the Ontario market and the benefits of Dawn, will help to ensure the new supply is attracted to Ontario and the required infrastructure gets constructed
3. Replacing existing firm transportation capacity with NEXUS capacity and accessing new secure supplies will assist Union in meeting design day and seasonal gas needs

Benefits to Ontario/Market Participants accessing supply at Dawn

The depth of liquidity of the Dawn Hub provides value to all Ontario customers by way of competitive natural gas commodity prices and attracting natural gas supply to Ontario. Union secures the supply and upstream transportation capacity required for approximately 35% of the volume of its total in-franchise distribution system, while the remaining 65% is supplied by direct purchase market participants. This includes most large, medium and small industrial plants, large commercial operations and natural gas electricity generators. From a competitiveness perspective, it is critical for these customers to have access to a robust and liquid Dawn Hub with many sellers from which to access supply. Accessing this new supply will be essential in providing diversity of supply, enhancing liquidity at Dawn and creating the opportunity for affordable energy prices to fuel Ontario's economic competitiveness. By providing access to Appalachian shale gas, it will also introduce additional stability to natural gas prices in Ontario and present an additional, economic supply option to the benefit of all Ontario natural gas customers.

As mentioned previously, a subset of the end-use customers that purchase their natural gas supply at Dawn include the natural gas fired power generators. This market relies on a healthy and liquid Dawn Hub. Most power generation contracts are commercially structured based on the price of natural gas at Dawn for a large portion of Ontario's electricity production capacity. These generators have access to unique services at Dawn that provide the necessary flexibility to

effectively operate their facilities in the hourly priced electricity market that is dispatched every five minutes.

The NEXUS project provides the opportunity to introduce new infrastructure that will provide much-needed access to Appalachian shale supplies and will deliver these supplies into Dawn, helping to maintain and grow the diversity and liquidity of the Dawn Hub. This will also allow Ontario to diversify its current reliance on WCSB as a source of natural gas, which is a significant benefit to all natural gas consumers in Ontario. As indicated above, and in the Sussex Market Study in Schedule 3, the additional transportation infrastructure and supply diversity will benefit all market participants in Ontario, including Direct Purchase and Power Generation customers.

Sussex Economic Advisors Market Report

Union Gas and Enbridge Gas Distribution, Inc. (“Enbridge”) retained Sussex Economic Advisors, LLC (“Sussex”) to perform an independent evaluation of the NEXUS project and its benefits to Ontario natural gas consumers found at Schedule 3.

The main conclusions of the Sussex report are:

- The NEXUS project will provide reliability and price stability benefits to Ontario LDCs by introducing transportation and supply diversity and access to low-priced natural gas.

- 1 • Other Ontario natural gas market participants (e.g. power generation and direct purchase
2 customers) will also benefit from the increased diversity and resulting liquidity at Dawn.
- 3 • Sussex reviewed the landed costs analysis performed by Union and, given their
4 experience and expertise, believe that although it will be subject to change over time, it is
5 a reasonable analysis that complements the many other benefits described.
- 6 • As a result, Sussex concludes that the NEXUS project is a reasonable contracting
7 decision and will result in numerous qualitative and quantitative benefits to Ontario.

8 ***Landed Costs***

9 Union has performed two distinct landed cost analyses – one in January 2014 prior to signing the
10 initial PA with NEXUS, and a second in January 2015 prior to signing a renegotiated PA with
11 updated terms. Each of the landed cost analyses were performed with different assumptions
12 based on the information known at the time.

13 As indicated above, the first landed cost was performed in January 2014, prior to signing the
14 initial PA with NEXUS. The analysis was performed using the range of tolls provided in the
15 agreement as the final rate and capital cost tracker specifics had not yet been negotiated. At that
16 point in time, the Rover project had not yet been announced and there were no other large,
17 greenfield infrastructure projects that would connect Dawn directly to the Appalachian region.
18 As such, Union's analysis was performed to determine whether the landed cost of supplies

1 transported through the NEXUS pipeline were competitive with existing transportation paths in
2 Union's portfolio.

3
4 As of January 2014, NEXUS was contemplating two phases to the project. The first phase
5 would have NEXUS providing Union with 75,000 Dth/d (79,125 GJ/d) of transportation capacity
6 for two years commencing November 1, 2015 by using existing pipeline infrastructure in
7 Michigan and Ontario. As discussed later in this section of the evidence, this phase was
8 subsequently removed from the project scope. Phase 2 was similar to how the NEXUS project is
9 now structured, providing Union with 150,000 Dth/d (158,258 GJ/d) of transportation capacity
10 from Kensington, Ohio commencing November 1, 2017. The Phase 2 path, as contemplated in
11 January 2014, would go all the way to the Dawn Hub in Ontario, however, rather than the current
12 plan of Union receiving the supplies at St. Clair. As such, the 2014 landed cost includes both
13 phases with supplies in Michigan as well as the Appalachian basin. In this landed cost analysis,
14 NEXUS would have contracted for St. Clair to Dawn to facilitate the service.

15
16 The analysis demonstrated that Appalachian shale gas transported via NEXUS was competitive
17 with other alternative upstream transportation paths available at the time, in addition to the
18 numerous other major benefits of the project. This analysis is provided in Schedule 4.

19
20 The second landed cost analysis was performed in January, 2015 using a number of assumptions
21 that had changed since the initial landed cost in 2014. Union received an updated PA with a

1 number of changes that were the result of ongoing negotiation and the MFN clause within the
2 PA. The NEXUS project scope no longer included Phase 1 as described above, and the
3 transportation path for Union would stop at the St. Clair river crossing. As the negotiated rate
4 was now included in the rate agreement, Union was able to perform the landed cost analysis to
5 validate that NEXUS was still competitive with existing pipeline paths in Union's portfolio. To
6 allow for easy comparison between NEXUS and other existing transportation paths in Union's
7 portfolio, the currently posted St. Clair to Dawn C1 toll of \$0.035 GJ/d was added to the
8 negotiated NEXUS rate. The analysis also showed that it was almost identical to the Rover
9 pipeline project that was announced in 2014. A summary of this landed cost analysis is provided
10 in Figure 5-5. For the detailed landed cost analysis, please see Schedule 5.

Figure 5-5
Summary of January 2015 Landed Cost Analysis

Rank	Path	Landed Cost (\$CDN/GJ)
1	TCPL Niagara to Kirkwall	\$8.10
2	Rover	\$8.36
3	NEXUS / St. Clair	\$8.38
4	NEXUS/St. Clair (Increase Upper end of toll by 15%)	\$8.49
5	Vector (2014 - 2017)	\$8.54
6	Dawn	\$8.56
7	Michcon (2014-2015)	\$8.62
8	Vector (2012 - 2016)	\$8.72
9	Trunkline / Panhandle	\$8.87
10	Panhandle (2012-2017)	\$8.91
11	Alliance / Vector	\$9.00
12	Panhandle (2014-2015)	\$9.02
13	Panhandle (2010-2017)	\$9.02
14	TCPL Empress to Dawn	\$9.67
15	TCPL Empress to Union CDA	\$9.83

1 In Figure 5-5, there is a significant difference between the landed cost of the NEXUS supply
2 compared to the Alliance and TransCanada long-haul supplies that it replaces within Union's
3 supply portfolio. For example, when you consider the upper-end of the NEXUS landed cost
4 (assuming the full 15% increase of the capital cost tracker) vs. the Alliance supplies, there is a
5 savings of \$0.51/GJ over the entire 15 year term. For the TransCanada-based supplies, the
6 savings on the NEXUS path are \$1.18/GJ over the term. Based on the landed cost analysis, and
7 assuming NEXUS supplies replace volumes on the discussed paths, Union estimates potential
8 cost savings of over \$700 million²⁹ over the term of the contract to sales service customers
9 compared to current contracted supplies. Overall, the landed cost of NEXUS supplies is very
10 similar to Rover, and is competitive or lower cost than other paths available in Union's portfolio.

²⁹ (Alliance/Vector vs. NEXUS plus 15%) times by Alliance/Vector volume being reduced plus (TCPL long haul vs. NEXUS plus 15%) times by volume being shifted over 15 years = $((\$9.00 - \$8.49) * 85,000 \text{ GJ/day})) + ((\$9.67 - \$8.49) * 73,000 \text{ GJ./day})) * 365 * 15 \text{ years} = (\$43,000/\text{day} * 365 * 15) + (\$86,000/\text{day} * 365 * 15) = \sim \708 million

- 1 • Primary Term : November 1, 2017 through October 31, 2032 (15 Years)
- 2 • Volume: 150,000 Dth/d (158,258 GJ/d)
- 3 • Rate: \$0.77 US/Dth (subject to a capital cost tracker adjustment)
- 4 • Fuel: 2% - 3% (estimated)
- 5 • Receipt Point: Kensington, Ohio
- 6 • Delivery Point: Union St. Clair
- 7 • Renewal rights: Right of First Refusal (“ROFR”) after the Primary Term.

8

9 As an anchor shipper, Union has negotiated a rate of \$0.77 US/Dth plus fuel, which is between
10 \$0.015 US/Dth to \$0.03 US/Dth lower than the rate offered to non-anchor shippers. The \$0.77
11 US/Dth rate consists of \$0.635 US/Dth for the greenfield portion of the pipeline and \$0.135
12 US/Dth for transportation on the DTE system. This rate is subject to a capital cost tracker
13 adjustment that will be calculated based on a capital budget of \$2.019 billion, outlined in the rate
14 agreement in Schedule 1, as compared to the actual costs upon completion of the project. This
15 will result in a maximum adjustment of +/- 15% applied only to the portion of the rate (\$0.635
16 US/Dth) related to the greenfield pipeline construction or related expansion facilities. This will
17 cap the range of the final NEXUS negotiated rate between Kensington and Union St. Clair to be
18 between approximately \$.67 US/Dth³⁰ and \$.87 US/Dth³¹ (plus fuel). These clauses are common

³⁰ The lower end of the toll is calculated by reducing the greenfield toll of \$0.635 US/Dth by 15%, and then adding the \$0.135 US/Dth to transport supplies on the DTE system ($\$0.635 * 0.85 + \$0.135 = \$0.67$)

³¹ The upper end of the toll is calculated by increasing the greenfield toll of \$0.635 US/Dth by 15%, and then adding the \$0.135 US/Dth to transport supplies on the DTE system ($\$0.635 * 1.15 + \$0.135 = \$0.87$)

1 with U.S. pipelines and help to provide certainty to the parties should costs be higher than
2 expected, and to share the benefit should the actual costs will be lower than expected.

3
4 The PA contains a number of conditions precedent for both the pipeline and the shipper. These
5 include various approvals necessary to carry out the obligations of the agreement including
6 FERC and State approvals to build the greenfield pipeline, and the Ontario Energy Board pre-
7 approval of the cost consequences of the NEXUS agreement. The date by which Union must
8 waive or satisfy this condition precedent is October 1, 2015.

9
10 The PA also contains cancellation provisions that would allow Union to terminate the PA and, in
11 most cases, not be subject to any project cancellation costs. Project cancellation cost clauses
12 traditionally protect the project proponents from shippers who terminate their participation after
13 construction has started and before the pipeline goes into service. Union has negotiated prudent
14 and fair provisions related to when it could terminate the agreement and not be subject to these
15 types of costs. This includes a right to terminate should the in service date be delayed past
16 November 1, 2018, excluding a material breach on the account of Union.

17
18 Union has also obtained an MFN clause which provides Union the ability to amend the PA
19 should another similar shipper negotiate more favourable terms than what Union has received.
20 This ensures Union will be treated fairly and equitably, and that Union is guaranteed the best
21 possible contracting terms available to similar shippers.

Union Relationship with Project Proponents

DTE Energy and Spectra Energy Corporation are lead developers of the NEXUS project and each have 50% ownership. Union is a wholly owned subsidiary of Spectra Energy Corporation. The NEXUS pipeline will be a standalone entity and does not have any relationship with Union other than through the common parent of Spectra Energy and the transportation contract between Union and NEXUS. As noted, the Affiliate Relationship Code does not apply because NEXUS is a 50-50 partnership between DTE Energy and Spectra Energy Corp. and neither party has control.

Union participated in the 2012 NEXUS Open Season. As was noted above, to ensure Union is treated in a fair and equitable manner, Union has negotiated an MFN clause within the PA which provides Union the ability to amend the PA should another similar shipper negotiate more favourable terms than what Union has received. Union negotiated with NEXUS on an arm's-length basis and in the same manner and with the same individuals as other potential shippers. As a result, Union has negotiated a rate that is discounted to that of non-anchor shippers, and is competitive with other anchor shippers on the project. Further, Union notes that the pricing Union will pay to NEXUS for the transportation contract service will be less than regulated posted tolls (which will be approved by FERC). Union's MFN clause also ensures Union will receive the best possible contracting terms of similarly situated shippers.

1 **7. RISK MITIGATION OF THE NEXUS AGREEMENT**

2
3 Union has considered the following risks as they related to the NEXUS project, and has included
4 appropriate analysis and mitigation steps. Further independent analysis can be found in the
5 included Sussex Market Study report at Schedule 3.

6 ***Project Capital Costs***

7 Risk Identification

8 Any major pipeline infrastructure project may experience capital cost variances due to a number
9 of factors. If not considered as part of negotiating a rate, there is risk that these cost overruns
10 will result in a toll that may no longer be economical for the shipper.

11
12 Risk Mitigation

13 Union has negotiated a fixed rate with NEXUS that includes a known capital cost tracker
14 adjustment mechanism. Union's rate of \$0.77 US/Dth will be adjusted to take into account
15 either higher or lower costs than anticipated. Union, and other similarly situated shippers,
16 negotiated a limit of +/-15% on the capital cost tracker adjustment that will only be applied to
17 \$0.635 US/Dth of the total rate of \$0.77 US/Dth (i.e. the greenfield and expansion portion of the
18 rate). The baseline capital budget used to calculate the tracker is \$2.019 billion as outlined in
19 Schedule 1. Having a capital cost tracker allows Union to participate in any cost savings realized
20 while limiting any cost overrun potential. This tracker defines the range of final rates of the

service and allows for a landed cost analysis to be performed with certainty. For Union, this tracker will limit the final rate to be within the range of \$0.67US/Dth to \$0.87 US/Dth.

Project Delays or Cancellation

Risk Identification

Any major pipeline infrastructure project may experience delays, or, in extreme cases, cancellation, due to a number of factors. If this were to occur, the shipper would experience a shortfall of transportation capacity in their portfolio.

Risk Mitigation

Union will mitigate any delays in construction by leveraging the diverse upstream transportation and supply options that exist at Dawn. By entering into short-term transportation and/or supply commitments, Union is able to address any gaps in the portfolio that are due to a delayed in-service date for NEXUS for a short period of time.

Should the NEXUS project be delayed beyond November 1, 2018 or cancelled, Union can withdraw from the project and will not be subject to any pre-service project costs. Union would analyze its portfolio and replace the anticipated NEXUS transportation capacity with other upstream transportation options that are available at the time.

1 ***Demand Risks***

2 Risk Identification

3 Entering into a transportation contract requires certain assumptions around the demands that will
4 support the requirements for the contracted capacity. This is especially true of long-term
5 commitments required to support a new infrastructure project such as NEXUS. If forecasted
6 demands do not materialize, the shipper is at risk of holding excess capacity within its portfolio.

7
8 Risk Mitigation

9 To ensure that any unplanned changes in demands do not jeopardize the decision to support
10 NEXUS, Union has not deviated from its normal gas supply planning practices that have been
11 validated by the Board in past proceedings.

12
13 As such, entering into a long-term contract with NEXUS does not increase Union's exposure to
14 decreases in demand. Union's current Gas Supply Plan has identified the need for upstream
15 transportation capacity in excess of 150,000 Dth/d for November 1, 2017. The contracted
16 capacity on the NEXUS pipeline will address this need, while still leaving appropriate flexibility
17 within Union's upstream portfolio should there be any fluctuations in customer demand. Should
18 natural gas demands decline in the Union franchise area, there are multiple opportunities to
19 leverage existing flexibility embedded within the portfolio to rebalance the upstream
20 transportation and gas supply portfolios.

Supply Risks

Risk Identification

In order to support an infrastructure build, pipeline projects require customers to contract for significant volumes for a long period of time. In the case of NEXUS, the requirement for anchor shippers was a 15-year commitment. There is risk that supplies available to be transported through the newly-constructed infrastructure would not be available for the entire length of the term.

Risk Mitigation

When evaluating the long-term commitment required to support the NEXUS project, Union also evaluated its ability to access adequate supplies for the duration of the contract. Union has accessed various resources including the Sussex Report (see Schedule 3) to gauge the level of supply available in the Appalachian basin and available to the NEXUS Project.

The production estimates for the Appalachian shale region are forecasted to exceed 18 PJ/d in 2015 and will continue to increase steadily for the duration of the 15-year NEXUS contract period referenced in Schedule 3. These production levels represent sufficient supply production for the duration of the NEXUS contract's primary term.

1 The abundance of shale production has also been supported previously by the Board, stating that
2 “Further, the evidence in the proceeding is that shale production is expected to remain strong and
3 there are no regulatory impediments to ongoing production where it is currently taking place.”³²
4

5 The receipt point of the NEXUS pipeline is located at Kensington, Ohio, which is an area that
6 will be well-connected to the Utica and Marcellus shale basins. In addition to the various
7 producers in the area, Kensington is also located near a number of major pipeline interconnects
8 and previously-announced expansion projects. These additional transportation and supply
9 interconnects help enhance diversity and security of supply for the duration of the NEXUS
10 contract. Up to this point, Union had not worked with many of the major suppliers that are
11 currently operating in the Appalachian shale basins. Union has been in discussions with these
12 potential suppliers since early 2013 and has conducted numerous supplier meetings and attended
13 relevant industry conferences. Many of these suppliers are new to Union as they are
14 predominantly sourcing their supply from the Appalachian shale region. These suppliers are
15 seeking a balanced portfolio of customers, and as a result have been eager to work with Union
16 and to better understand Dawn and the Ontario market dynamics. These discussions have
17 included talks regarding multiple supply alternatives ranging from standard monthly indexed
18 supply arrangements to long-term indexed netback arrangements. Union has also begun
19 negotiating NAESB base agreements with these suppliers so they can become part of the supplier

³² EB-2012-0433/EB-2013-0074 Decision January 30, 2014, pages 23-24

1 pool that Union can draw upon when the NEXUS contract becomes effective. No supply
2 contracts have been executed at this time.

3
4 Union has also issued an Expression of Interest for a portion of the supply necessary once the
5 NEXUS project is completed and in service. The goal of this Expression of Interest and
6 subsequent RFP is to understand and potentially secure up to 50,000 Dth/d (52,753 GJ/d) of
7 supply at Kensington starting November 1, 2017 (or the date when NEXUS is in service,
8 whichever is later). This supply commitment could be a term of 5 years or longer depending on
9 market terms and conditions and will be subject to Union's standard credit and other NAESB
10 requirements. Union will be open to any combination of pricing arrangements (except for fixed
11 prices) that suppliers are willing to offer. Union will evaluate each and every bid on its own
12 merits and determine the successful bidders within the prescribed timelines that accompany the
13 RFP.

14
15 To gain experience working with these new suppliers prior to the in-service date for NEXUS,
16 Union is also investigating potential firm services that will allow it to purchase gas, on an interim
17 basis, in the Appalachian basin. This will allow Union to form relationships and gain experience
18 with suppliers in that region in preparation for purchasing the supplies required once NEXUS is
19 in service.

1 ***TransCanada Mainline Risk***

2 Risk Identification

3 As mentioned previously, natural gas transported to Dawn via NEXUS will replace supplies that
4 will no longer be transported using TransCanada long-haul transportation from the WCSB.
5 Historically, the trend of shippers de-contracting TransCanada long-haul transportation resulted
6 in concerns as to the economic viability of the Mainline system, which was the subject of the
7 NEB RH-001-2014 settlement hearing.

8

9 Risk Mitigation

10 All impacts resulting from Union (and the other eastern LDCs) turning back TransCanada long-
11 haul transportation have already been contemplated in the RH-001-2014 settlement agreement
12 that was approved by the NEB in December, 2014. The financial impacts of those decisions
13 have been incorporated into TransCanada's approved tolls. The NEXUS capacity will simply
14 replace these supplies that would have otherwise been purchased at Dawn, and have no
15 incremental impact to the TransCanada Mainline system.

8. SUMMARY

As discussed in the Sussex Report at Schedule 3, North American transportation and supply dynamics are changing dramatically due to the emergence of abundant, affordably-priced natural gas in the Appalachian shale basins. At the same time, conventional supplies arriving in Ontario from the WCSB are in decline, leading to the need to explore other transportation options. To replace these declining supplies arriving from traditional western sources, Ontario requires NEXUS as a direct pipeline from the Utica and Marcellus basins to increase diversity, enhance reliability, strengthen the liquidity of the Dawn Hub, decrease price volatility and create the opportunity of affordable energy prices to fuel Ontario's economic competitiveness.

In its role as an LDC, Union and other similarly sized LDCs are the only market participants who are able to support new infrastructure projects such as NEXUS. Virtually all other natural gas market participants (i.e. large industrial direct purchase or power customers who rely more on the day-to-day market) do not have the ability to make these types of long term contract commitments. As such, in order to support new pipeline infrastructure upstream of Ontario, Union has moved forward and has advanced a significant long-term commitment to a 15-year transportation contract, with a commitment in excess of \$715 million. The Board's process for Pre-Approval of Long-Term Natural Gas Supply and/or Upstream Transportation Contracts was created to allow the utilities to make these significant commitments that will ultimately benefit all of Ontario, while receiving the assurance of recovery of the associated costs based on the market conditions that exist at the time the commitment is being considered and made. This

- 1 process applies to the NEXUS contract as it is supporting the development of new greenfield
- 2 pipeline infrastructure that will allow access to a new supply basin that will provide incremental
- 3 supplies and numerous benefits to Ontario.

RESTATED PRECEDENT AGREEMENT

This RESTATED PRECEDENT AGREEMENT (“Restated Precedent Agreement”) is made and entered into this 28th day of May, 2015 (“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 Union Gas Limited, 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 project that will ultimately provide up to approximately one and one half (1.5) billion cubic feet per day 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”). 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 Customer’s Canadian pipeline systems, and/or construction of greenfield pipeline facilities (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 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 August 11, 2014 (“the Original Precedent Agreement”);

WHEREAS, in lieu of the service contemplated in the Original Precedent Agreement, Customer now desires firm natural gas transportation service in respect of the Project from a point expected to be located at or near Kensington, OH, to a point at or near the International Border;

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

WHEREAS, the Parties contemplate that NEXUS Gas Transmission, LLC 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 Project service for Customer described herein and other customers subscribing for capacity as part of the 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 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: (i) 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 herein commencing on the 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, (including, without limitation, to provide firm transportation service contemplated herein and set forth in the applicable Pipeline tariff approved by the FERC). 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 the Project and to otherwise perform its obligations as contemplated by this Restated Precedent Agreement.
- c) The reservation rates payable by Customer for transportation service (as set forth in the applicable Pipeline tariffs approved by the FERC, the "Reservation Rates") will be set and applied for on a commercially reasonable basis.

2) Customer Obligations.

- a) Prior to the Effective Date, Customer shall have advised Pipeline in writing of: (i) any facilities which Customer must construct, or cause to be constructed, in order for Customer to utilize the firm transportation 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 Service Agreement (as 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 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 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 transportation service and to otherwise perform its obligations as contemplated by this Restated Precedent Agreement.

3) Service Agreements.

a) [RESERVED].

b) Firm Service Agreement. To effectuate the firm transportation service contemplated herein for transportation service, Customer and Pipeline agree that 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 Project transportation service have all issued the necessary authorizations to Pipeline or other pipelines to construct the greenfield and expansion facilities necessary to provide the Project service, Pipeline and Customer will execute a firm transportation service agreement governing the service (the “Service Agreement”). The 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 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 Project have all issued the necessary authorizations to Pipeline or other pipelines proposing to construct and/or provide the facilities necessary to provide the Canadian portion of the Project. For clarity, the Canadian portion of the Project service shall have no application to the transportation service that Customer is contracting for hereunder, but receipt of the Governmental Authorizations and the Customer’s Authorizations for the Canadian portion of the Project are a condition precedent to the Service Agreement between Pipeline and Customer becoming effective as reflected in Section 7(b)(ii), 7(c)(ii) and 7(c)(iii). The Parties agree to consider in good faith executing the 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 Project construction from any governmental agency or authority having jurisdiction. The Service Agreement will specify: (i) an MDQ of 150,000 Dth/d (“Customer’s MDQ”), exclusive of fuel requirements, effective on the Service Commencement Date; (ii) a primary term of fifteen (15) years commencing on the 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 Service Agreement) at the head of the 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) (MDRO of 150,000 Dth/d); (iv) a Primary Point of Delivery (as such term will be defined in the Service Agreement) at the International Border (MDDO of 150,000 Dth/d); 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 Project service, Customer shall have the right under the 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 the Project services. Prior to the Effective Date, the Parties acknowledge that Pipeline has provided to Customer copies of the Rate Agreement and a table of the expected contents of general terms and conditions that will be incorporated by reference into the transportation service agreement to form the applicable FERC gas tariff, as well as 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; 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 to the substantive detriment of Customer, 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 Service Commencement Date. On a quarterly basis, Pipeline will notify Customer regarding Pipeline's progress regarding the Project, and whether the 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 Service Commencement Date (the "Estimated Commencement Date"). In the event that Pipeline's *bona fide* estimate of the Estimated 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 Project service and Customer shall have the right to terminate this Restated Precedent

Agreement without liability between the Parties including in respect of the Customer being required to pay any Pre-Service Costs.

d) Rates.

i) [RESERVED].

ii) The rates that will apply to the 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 Service Agreement. Pipeline and Customer have agreed to the following with regard to the rates for service under the Service Agreement:

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

(2) 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.

(3) Contemporaneously with the execution of 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.

e) Most Favored Nations.

- i) Except as provided in Section 3(e)(ii) below, in the event that Pipeline enters 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 this 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 Rate Agreement, Pipeline shall offer Customer, within ten (10) business days of entering into the rate agreements with such other customer, those same rate provisions and other terms of service. If Customer is willing to accept the offer on the 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 Rate Agreement and the Service Agreement, if applicable, and the Parties will enter into an amended agreement 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 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 Service Agreement, be granted a contractual Right of First Refusal ("ROFR") in accordance with the applicable Pipeline tariff approved by the FERC. Further, the Service Agreement will be considered a ROFR Agreement in accordance with, and as that term is used in, the applicable tariff.

4) Commencement of Service.

(a) [RESERVED].

(b) 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 Service Agreement, which date shall be the beginning of a calendar month and cannot be earlier than the date upon which all of the conditions precedent set out in Section 7 have been satisfied, or waived by the Party having such waiver right, provided that the actual service commencement date for purposes of the Service Agreement (the "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 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 Service Commencement Date, Pipeline shall provide firm transportation service for Customer pursuant to the terms of the Service Agreement and Customer will pay Pipeline for all applicable charges required by the Service Agreement and the 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 Project Facilities and any other preparatory actions necessary for Pipeline, or Pipeline's designee(s), to complete and file application(s) related to the Project Facilities with the FERC 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 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 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(a), 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 Project Facilities and to implement the firm transportation service contemplated in this Restated Precedent Agreement for Project 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 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 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

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 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); 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 in Section 7(c):

a) [RESERVED].

b) Pipeline's Conditions Precedent for Project Service.

- i) Pipeline filing by April 1, 2016 the necessary requests with the FERC for approval to provide service as contemplated herein and in the 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 Project facilities, all as described in Pipeline's applications as they may be amended from time to time, necessary to provide the service contemplated herein and in the 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 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 Project facilities, all as described in their applications as they may be

amended from time to time, necessary to provide the service contemplated herein and in the 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 Project facilities and to proceed with the Project-related firm pipeline transportation arrangements with other pipelines for service on the Project facilities;
- vi) Pipeline's receipt no later than four (4) months prior to the Service Commencement Date of all necessary authorizations required to construct the Project facilities necessary to provide the firm transportation service contemplated herein and in the Service Agreement, other than those specified in Section 7(b)(ii);
- vii) Pipeline's procurement, no later than four (4) months prior to the 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 Project facilities;
- viii) Pipeline's completion of construction of the Project facilities and all other facilities required to render the Project service for Customer and for other customers subscribing Project service pursuant to the Service Agreement 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 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) Customer's confirmation to Pipeline, no later than 90 days following receipt of the Estimated 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 Service Agreement;
- ii) Subject to Section 7(d), Customer's receipt and acceptance of the approvals from the OEB for its application related to the Project no later than October 1, 2015; and
- iii) Subject to Section 7(d), Customer's receipt and acceptance no later than 30 days following satisfaction of the condition in Section 7(c)(ii), of any necessary Customer's Authorizations identified in accordance with Section 2 of this Restated Precedent Agreement.
- iv) 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), and 7(c)(ii) and subject to Section 21, 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's Authorizations, 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 its 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 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 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 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 applicable service agreement and 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's 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's 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's 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 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 applicable service agreement and 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 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)(iii), and Section 10 will be changed to a later date by the same amount of time as such change to the Estimated Commencement Date.

8) Pre-Service Costs. If: (a) Customer is in material breach of any of its material obligations arising pursuant to this Restated Precedent Agreement; and (b) such material breach is not cured within 30 days of notice to Customer by Pipeline of such material breach, or if such material breach is not capable of being cured within 30 days; and (c) Customer is not continuing thereafter in good faith and with diligence to cure such breach; and (d) as a direct result of the occurrence and continuation of Sections 8(a), 8(b) and (8c) taken collectively, the 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 transportation service to total contracted MDQ for transportation service by all customers with executed 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 Service Commencement Date to not occur. In no event shall Customer's exposure to Pre-Service Costs exceed \$219 million U.S. dollars. 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. Customer shall make reasonable efforts to minimize and if possible eliminate the withholding tax related to the Pre-Service Costs paid to Pipeline, including but not limited to requesting 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 deduct or withhold such amount from the Pre-Service Costs and remit such withheld taxes to the applicable taxing authority and 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. 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 the Project and to satisfy its obligations under this Restated Precedent Agreement and all other precedent agreements for service on 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 the Project and to satisfy its

obligations under this Restated Precedent Agreement and all other precedent agreements for service on 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 RESTATED 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 Service 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 the Service Agreement, as applicable) 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 Service Agreement, as applicable) 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 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 from 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 11, 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 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 Service Agreement and 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 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 agreement 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 Service Agreement, (b) remain in effect until all payment obligations under this Restated Precedent Agreement, and the 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 or the 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 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

charges based on the MDQ and reservation rates under the Service Agreement(s). 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 and/or the Service Agreement, nor shall it affect Pipeline's right to seek damages or performance under this Restated Precedent Agreement and/or the Service Agreement(s). Further, if, prior to the 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 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 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 Service Agreement, if applicable, have been satisfied in full.

- f) Replacement Customer Creditworthiness. In the event Customer assigns this Restated Precedent Agreement and/or the 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 Service Agreement in accordance with Pipeline's FERC 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 NEXUS Gas Transmission, LLC;; (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; 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 Service Agreement, and/or the 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: Manager Transportation Acquisition
50 Keil Dr N, Chatham, Ontario, Canada
thodgson@uniongas.com
Phone - (519) 436-4606
Fax - (519) 436-4643

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 embodies the complete agreement and understanding among the Parties with respect to the subject matter hereof and supersedes and pre-empts 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.

DEERFIELD COMPANY

By: Ward J. H.

Title: President

UNION GAS LIMITED

By: M. J. Isherwood

Title: Mark J. Isherwood

Vice-President, Business Development, Storage & Transmission

By: _____

Title: _____

SPECTRA ENERGY TRANSMISSION, LLC

By: Bill Wardley

Title: President

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.

Issued On:

Effective On: /

- 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:

Issued On:

Effective On:

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.

Issued On:

Effective On: .

- 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. Nonotiable Terms

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.

Issued On:

Effective On:

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: _____

Issued On: .

Effective On: .

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): _____

Issued On: .

Effective On:

EXHIBIT B

[RESERVED]

EXHIBIT C

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 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”**.

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 Final Capital Cost Estimate, then the Project Facilities Rate Portion of the Final Reservation Rate will be adjusted upward by multiplying it 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 Final Capital Cost Estimate, then the Project Facilities Rate Portion of the Final Reservation Rate will be adjusted downward by multiplying it 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).

In the event that the adjusted Reservation Rate decreases because the Final Capital Cost is less than the Final 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 higher rate and the revenue that Pipeline would receive for such time period had Customer paid the adjusted rate. In the event that the adjusted Reservation Rate increases because the Final Capital Cost is more than the Final Capital Cost Estimate, 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 lower rate and the revenue that Pipeline would have received for the time period had Customer paid the adjusted 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.

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: _____

EXHIBIT E

Form of Letter of Credit

See Attached.

IRREVOCABLE STANDBY LETTER OF CREDIT

Letter of Credit No: _____

Date: _____, 20__

Date of Expiry: _____, 20__

Beneficiary:

Account Party:
(Complete Legal Name)
(Address)
(City, State, Zip)

Attn: Credit Director

[Name of Bank] ("Issuing Bank") hereby establishes this Irrevocable and Transferable Standby Letter of Credit No. _____ in favor of [Spectra entity name] ("Beneficiary") for the account of [Account Party Name] ("Account Party") for the aggregate amount of up to (dollar amount) available to Beneficiary by presenting sight draft(s) to Issuing Bank when accompanied by a signed and dated statement by an authorized representative of Beneficiary certifying one or more of the following, as applicable:

1. "The amount drawn herein is to satisfy obligations of Account Party between Beneficiary and Account Party. Wherefore, the undersigned Beneficiary does hereby demand payment of \$_____. Beneficiary further certifies that supporting documents when required were presented to Account Party and that Account Party has not satisfied its obligations." And / or
2. "This Letter of Credit will expire in less than thirty (30) days and Beneficiary has not received an extension of said Letter of Credit or other acceptable replacement collateral from Account Party. Wherefore, the undersigned Beneficiary does hereby demand payment of \$_____. Upon timely receipt of an amendment extending this Letter of Credit, this drawing is to be considered automatically rescinded." And / or
3. "Issuing Bank's lowest long-term senior unsecured debt rating no longer meets or exceeds "A-" by Standard & Poor's Rating Group and "A3" by Moody's Investor Services, Inc., and Account Party has not caused a replacement Letter of Credit from an alternate financial institution acceptable to Beneficiary to be issued to Beneficiary. Wherefore, the undersigned Beneficiary does hereby demand payment of \$_____."

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

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) **“Creditworthy”** has the meaning ascribed to that term in Section 12(a).
- c) **“Customer”** has the meaning ascribed to that term in the recitals.
- d) **“Customer’s Authorizations”** has the meaning ascribed to that term in Section 2(a).
- e) **“Customer’s MDQ”** has the meaning ascribed to that term in Section 2(d).
- f) **“Dawn”** has the meaning ascribed to that term in the recitals.
- g) **“Default”** has the meaning ascribed to that term in Section 10.
- h) **“Default Notice”** has the meaning ascribed to that term in Section 10.
- i) **“DTE”** has the meaning ascribed to that term in the recitals.
- j) **“Effective Date”** has the meaning ascribed to that term in the recitals.
- k) **“Union”** has the meaning ascribed to that term in the recitals.
- l) **“Estimated Commencement Date”** has the meaning ascribed to that term in Section 3(c).
- m) **“FERC”** has the meaning ascribed to that term in Section 1(a).
- n) **“FERC Interest Rate”** has the meaning ascribed to that term in Exhibit C.
- o) **“Final Capital Cost”** has the meaning ascribed to that term in Exhibit C.
- p) **“Final Capital Cost Estimate”** has the meaning ascribed to that term in Section 3(d)(ii)(3).
- q) **“Final Estimated Reservation Rate”** has the meaning ascribed to that term in Section

3(d)(ii)(3).

- r) “**Final Reservation Rate**” has the meaning ascribed to that term in Exhibit C.
- s) “**Force Majeure**” has the meaning ascribed to that term in Section 9(c).
- t) “**Forms of Commercial Agreements**” has the meaning ascribed to that term in Section 3(b).
- u) “**Governmental Authorizations**” has the meaning ascribed to that term in Section 1(a).
- v) “**Guarantor**” has the meaning ascribed to that term in Section 13(b)(i).
- w) “**Guaranty**” has the meaning ascribed to that term in Section 13(b)(i).
- x) “**In-Service Date Notice**” has the meaning ascribed to that term in Section 4(b).
- 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**” means maximum daily delivery obligation.
- bb) “**MDRO**” means maximum daily receipt obligation.
- cc) “**MDQ**” means maximum daily quantity.
- 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) “**Open Season**” has the meaning ascribed to that term in the recitals.
- gg) “**Party**” or “**Parties**” has the meaning ascribed to that term in the recitals.
- hh) “**Pipeline**” has the meaning ascribed to that term in the recitals.
- ii) “**Pre-Service Costs**” has the meaning ascribed to that term in Section 8.
- jj) “**Project**” has the meaning ascribed to that term in the recitals.
- kk) “**Project Facilities**” has the meaning ascribed to that term in Section 3(d)(ii)(2).
- ll) “**Project Facilities Rate Portion**” has the meaning ascribed to that term in Exhibit C.

mm) “**Qualified Institution**” has the meaning ascribed to that term in Section 13(b)(ii).

nn) “**Rate Agreement**” has the meaning ascribed to that term in Section 3(d)(ii)(3).

oo) “**Rate Breakdown**” has the meaning ascribed to that term in Section 3(d)(ii)(3)

pp) “**Reservation Rate**” has the meaning ascribed to that term in Section 1(c).

qq) “**ROFR**” has the meaning ascribed to that term in Section 3(f).

rr) “**S&P**” has the meaning ascribed to that term in Section 13(a).

ss) “**Service Agreement**” has the meaning ascribed to that term in Section 3(b).

tt) “**Service Commencement Date**” has the meaning ascribed to that term in Section 4(b).

uu) “**Spectra**” has the meaning ascribed to that term in the recitals.

vv) “**Updated Capital Cost**” has the meaning ascribed to that term in Exhibit C.

ww) “**Willow Run**” has the meaning ascribed to that term in the recitals.



May 28, 2015

Mark J. Isherwood
Vice President, Business Development
Union Gas Limited
50 Keil Dr. N.
Chatham, Ontario

Re: NEXUS-US Negotiated Rate Letter Agreement for Service Agreement No. 00004

Dear Mark:

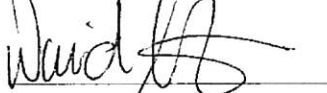
DTE Pipeline Company ("DTE") and Spectra Energy Transmission, LLC ("Spectra") (where DTE and Spectra are collectively referred to herein as "Pipeline") and Union Gas Limited ("Customer") have entered into a Restated Precedent Agreement dated May 28, 2015 (the "Precedent Agreement") to contract for firm transportation service as part of the NEXUS Gas Transmission Project. 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)



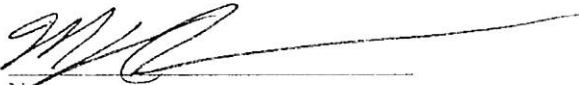
Name: David Slater
~~Executive Vice President~~
DTE Pipeline Company



Name: Bill Yardley
Title: President
Spectra Energy Transmission, LLC

ACCEPTED AND AGREED TO
THIS 28 DAY OF May, 2015

UNION GAS LIMITED (CUSTOMER)



Name:
Title: Mark J. Isherwood
Vice-President, Business Development, Storage & Transmission

STATEMENT OF NEGOTIATED RATES 1/ 8/

Customer Name: Union Gas Limited

Service Agreement: Service Agreement No. 00004 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: 150,000 Dth/d

Customer shall pay the following Reservation Rate, Commodity Rate, Fuel and Other Charges for service provided pursuant to Service Agreement 00004:

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. 00004, equal to US\$0.77, subject to further adjustment as set forth herein and in the Restated Precedent Agreement dated May 28, 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. 00004. 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 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 Customer's MDQ, plus the applicable Fuel Rate 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 2 - 3%, and all other FERC approved usage charges and usage surcharges applicable to Customer's Contract No. 0004. 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: Near a meter at an exact location to be determined at the international border between the United States and Canada, near St. Clair, 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.

FOOTNOTES:

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. 00004, 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 greater than or equal to 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 less than 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. 00004 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 greater than or equal to 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 less than 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. 00004, unless and until otherwise mutually agreed in writing between Customer and Pipeline.

3/ Pipeline and Customer acknowledge that the 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 an estimate provided by Pipeline to Customer in accordance with the Precedent Agreement ("Final Capital Cost Estimate").

4/ Pipeline and Customer agree that Service Agreement No. 00004 is a ROFR Agreement.

5/ The Reservation Charge described in the Reservation Rate section above 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, as reflected by Pipeline in an updated cost report for the Project, substantially in the form of an Exhibit K ("Updated Capital Cost"). Pipeline will provide the Updated Capital Cost report to the Customer at least thirty (30) days, but no more than sixty (60) days, prior to the in-service date of the Project, as such in-service date is estimated to occur by Pipeline at the time.

Pipeline will adjust the portion of the Reservation Rate attributable to the Project Facilities (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 will be adjusted upward by multiplying it by the ratio of the Updated Capital Cost to the Final Capital Cost Estimate; provided that, notwithstanding any other provisions 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 shall be capped at 1.15 of what was set forth as the Project Facilities Rate Portion of the Final Reservation Rate in the Rate Breakdown provided to Customer by Pipeline in accordance with the Precedent Agreement. In the event that the Updated Capital Cost is less than the Final Capital Cost Estimate, the Project Facilities Rate Portion will be adjusted downward by multiplying it by the ratio of the Updated Capital Cost to the Final Capital Cost Estimate; provided that, notwithstanding any other provisions 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 0.85. For the avoidance of doubt, in any event, the maximum downward adjustment shall be capped at 0.85 of what was set forth as the Project Facilities Rate Portion of the Final Reservation Rate in the Rate Breakdown provided to Customer by Pipeline in accordance with the Precedent Agreement.

No later than 210 days after the Service Commencement Date, Pipeline will provide to Customer a final cost report, and will file with the Commission an adjustment to Customer's

then-effective adjusted Reservation Rate to reflect any increase or decrease between the Final Capital Cost Estimate and the final capital costs ("Final 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, prepared in accordance with Section 157.14(a)(13). Such report will reflect Pipeline's final actual capital costs attributable to the Project Facilities. In the event that the Final Capital Costs are less than the Final Capital Cost Estimate, Pipeline will adjust downward the Project Facilities Rate Portion by multiplying it by the ratio of the Final Capital Costs to the Final Capital Cost Estimate; provided however that, notwithstanding any other provisions contained herein, the maximum downward adjustment shall be capped at 0.85 of what was set forth as the Project Facilities Rate Portion of the Final Reservation Rate in the Rate Breakdown provided to Customer by Pipeline in accordance with the Precedent Agreement. In such event, Pipeline will refund via an invoice credit to 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 Final Capital Costs are more than the Final Capital Cost Estimate, Pipeline will adjust upward the Project Facilities Rate Portion by multiplying it by the ratio of the Final Capital Costs to the Final Capital Cost Estimate; provided however that, notwithstanding any other provisions contained herein, the maximum upward adjustment shall be capped at 1.15 of what was set forth as the Project Facilities Rate Portion of the Final Reservation Rate in the Rate Breakdown provided to Customer by Pipeline in accordance with the Precedent Agreement. In such event, 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.

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 adjusted 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.



May 28, 2015

Mark J. Isherwood
Vice President, Business Development
Union Gas Limited
50 Keil Dr. N.
Chatham, Ontario

Re: Rate Breakdown and Final Capital Cost Estimate Under Restated Precedent Agreement
Dated May 28, 2015

Dear Mark:

DTE Pipeline Company ("DTE") and Spectra Energy Transmission, LLC ("Spectra") (where DTE and Spectra are collectively referred to herein as "Pipeline") and Union Gas Limited ("Customer") have entered into a Restated Precedent Agreement dated May 28, 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 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: \$0.635 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.

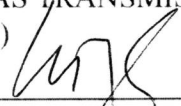
Final Capital Cost Estimate

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)



Name: *Bill Yandley*
Title: *President*
Spectra Energy Transmission, LLC

ACCEPTED AND AGREED TO
THIS 27 DAY OF May, 2015

UNION GAS LIMITED (CUSTOMER)



Name: **Mark J. Isherwood**
Title: **Vice-President, Business Development, Storage & Transportation**

OEB TEMPLATE FOR CONTRACT PRE-APPROVAL

Part I – Identification of Applicant	
Name of Applicant: Union Gas Limited	File No: (OEB Use Only)
Address of Head Office: 50 Keil Drive North, Chatham, ON N7M 5M1	Telephone Number: (519)-436-4600 Facsimile Number: (519) 436-5461 Email Address: cshorts@uniongas.com
Name of Individual to Contact: Chris Shorts Director, Gas Supply	Telephone Number: (519) 436-4668 Facsimile Number: (519) 436-5461 Email Address: cshorts@uniongas.com
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.
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.
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.
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.
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.
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.
5.2	An assessment of retail competition impacts and potential impacts on existing transportation pipeline facilities in the market (in terms of Ontario customers).
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 <i>Practice Direction on Confidential Filings</i> .



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

May 2015

Prepared by
Sussex Economic Advisors, LLC

Sussex Economic Advisors, LLC ("Sussex") has relied upon certain public sources of information consistent with standard consulting practices. Sussex makes no warranties or guarantees regarding the accuracy of any estimates, projections or analyses contained herein. Those reviewing the information contained herein waive any claim against Sussex, its partners, employees, and subcontractors. Sussex shall not be liable to any party reviewing this information.

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 price 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) alternative⁴ 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>i.e.</i> , 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>i.e.</i> , 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>i.e.</i> , 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>i.e.</i> , 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>i.e.</i> , 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 Schedule²⁵

Activity	Anticipated Timeline
Initial Project Evaluation	2013 – 2 nd Quarter 2014
Initial Information Meetings	3 rd & 4 th Quarter 2014
FERC Pre-Filing Process Initiated	4 th Quarter 2014
FERC Issue Scoping	2015
FERC CPCN Application Filing	4 th Quarter 2015
FERC Review; Stakeholder Engagement	2016
FERC Approval	4 th Quarter 2016
FERC Notice to Proceed with Construction	1 st Quarter 2017
Major Construction Initiated	Early 2017
Proposed In-Service Date	4 th 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. NATURAL GAS SUPPLY TRENDS AND IMPACT ON THE ONTARIO MARKET

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.

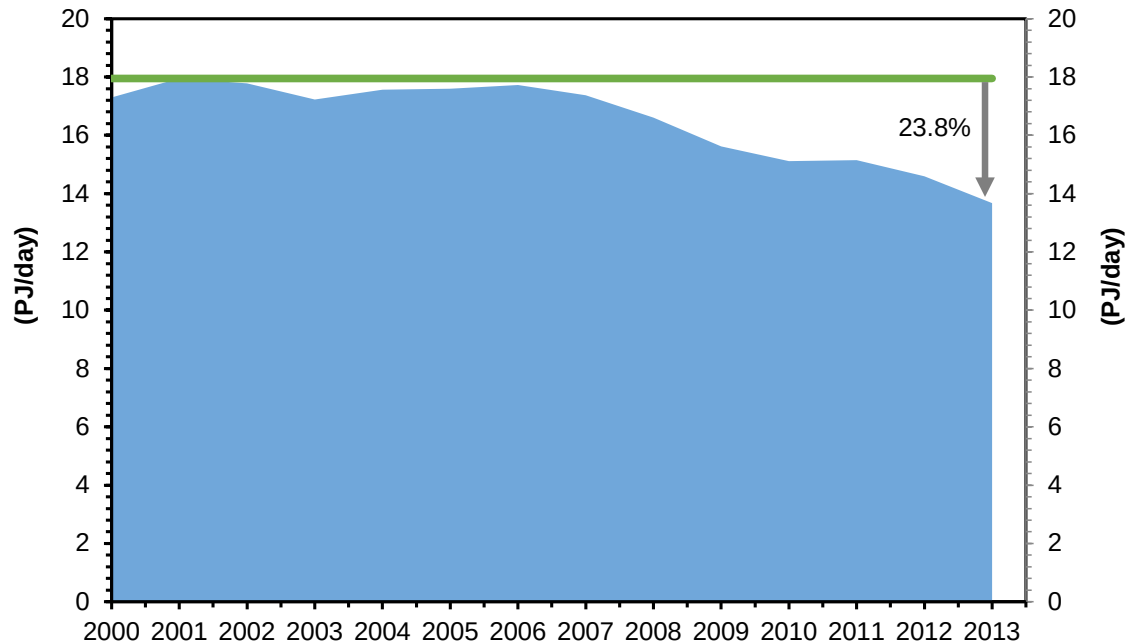
Figure 3.1: Map of WCSB²⁶



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.

Figure 3.2: WCSB Production²⁷



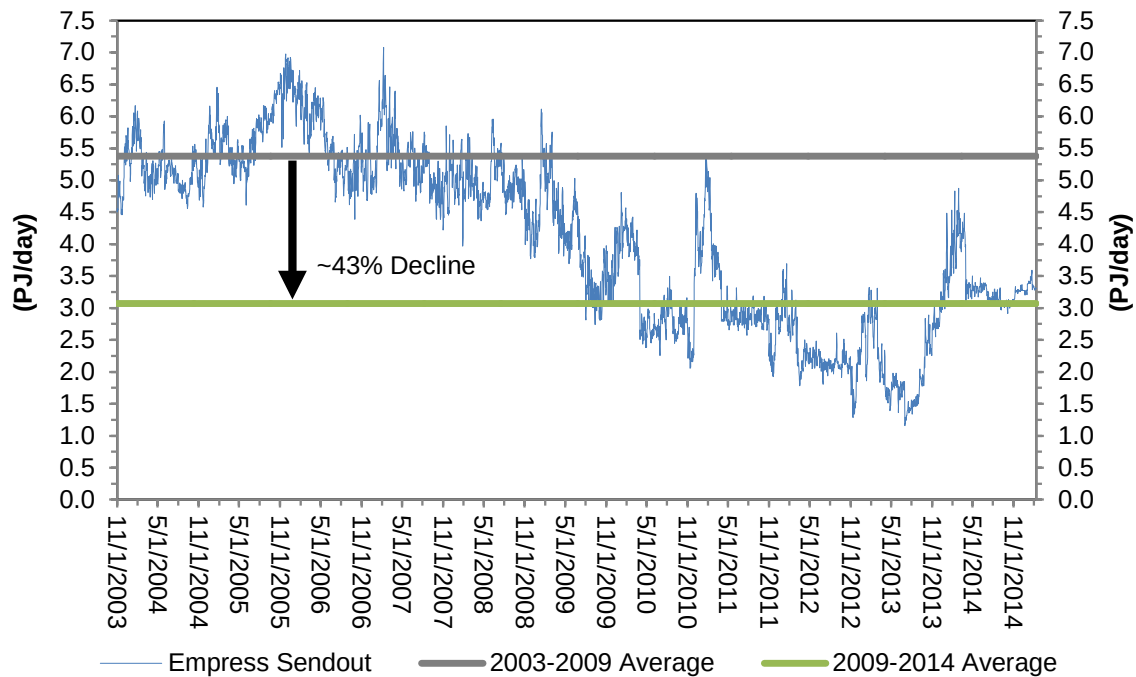
As shown by Figure 3.2, the WCSB produced approximately 17.3 PJ/day of natural gas in 2000, however, by 2006 natural gas production began to decline and averaged 13.6 PJ/day by 2013, a decline of approximately 24% from its 2001 level.²⁸

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 10⁶m³/day to PJ/day at a rate of 0.0374 10⁶m³/day per PJ/day.

²⁸ Ibid.

Figure 3.3: TransCanada Canadian Mainline Nominated Deliveries (2007-January 2015)²⁹



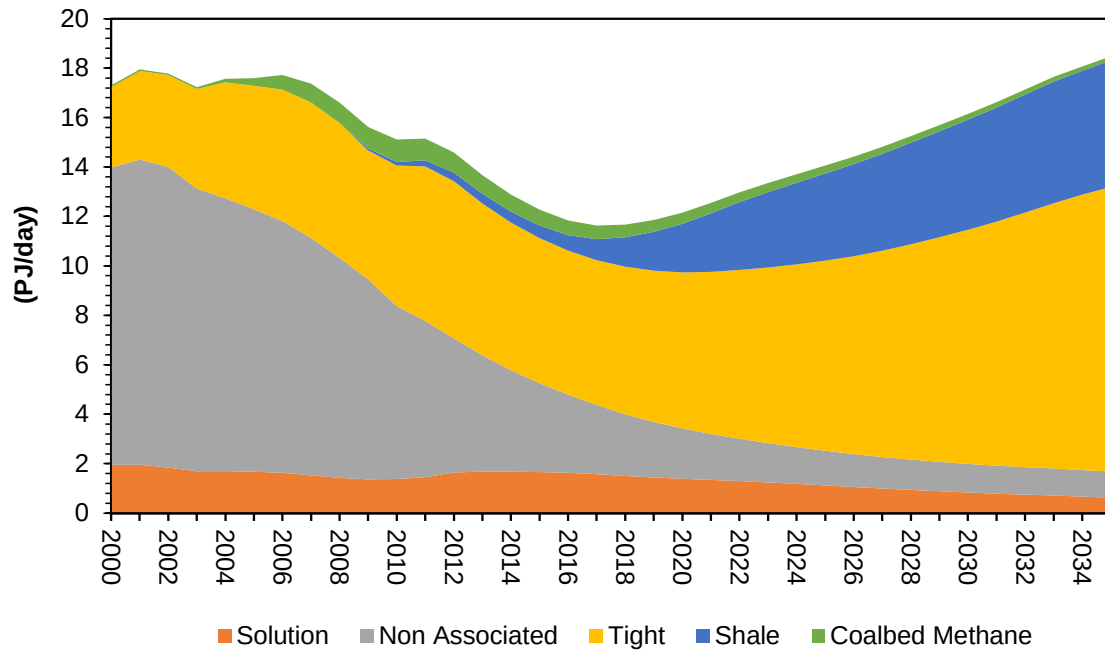
As shown in Figure 3.3, from November 2003 to October 2008, the daily volume at Empress ranged between 4.0 PJ/day and 7.0 PJ/day. In 2006, shipments from Empress began to decline, since 2009 daily volumes at Empress have been well below 4.0 PJ/day, and by 2013 daily volumes were below 2.0 PJ/day. This 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 Forecast³¹



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%.

Increasing Intra-regional Demand

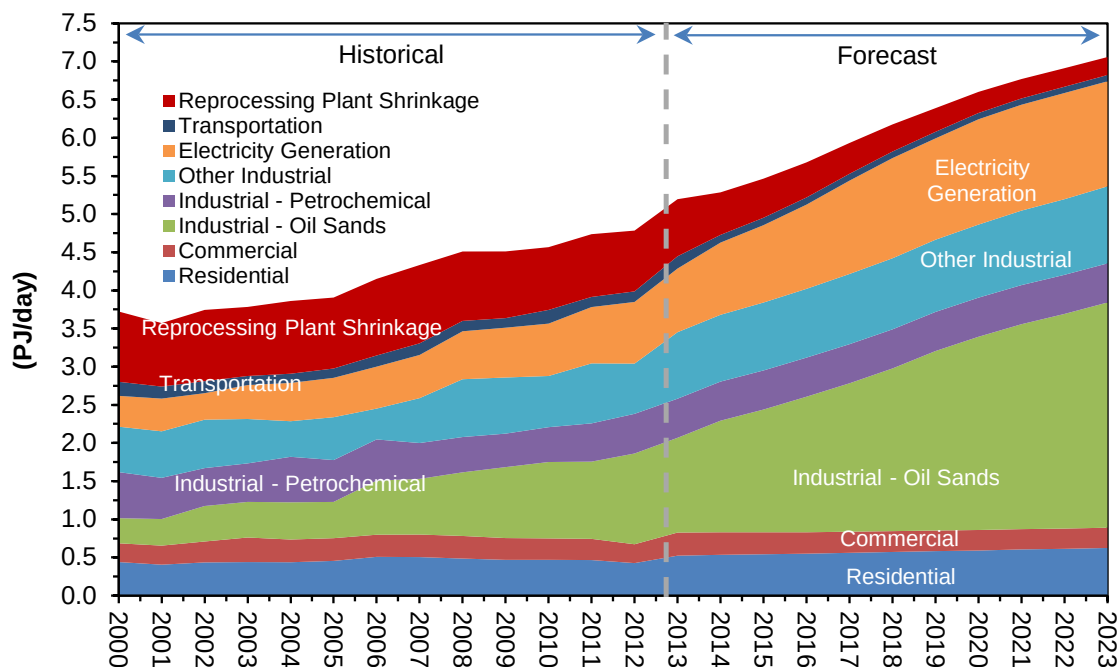
With respect to the second factor influencing the reduction in WCSB volumes shipped eastward (*i.e.*, increasing demand for natural gas from the industrial-oil sands and power generation segments), the NEB noted that intra-regional demand in the WCSB increased by approximately 25% between 2006 (4.8 PJ/day) 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.

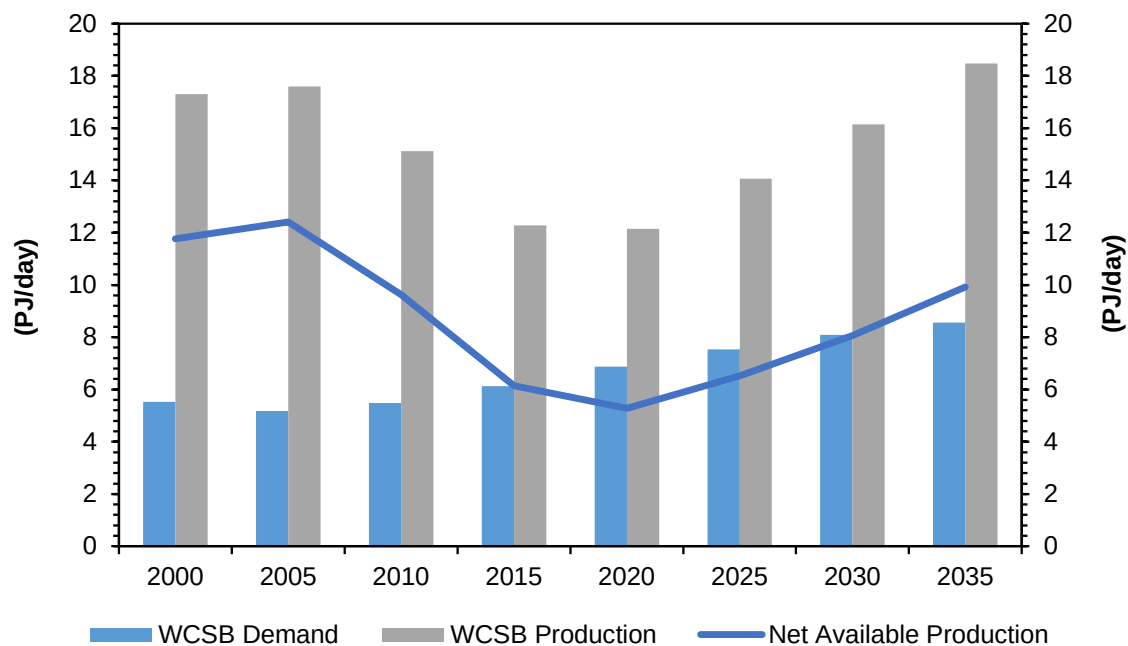
³⁷ *Ibid.*

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 Consumption⁴¹



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.

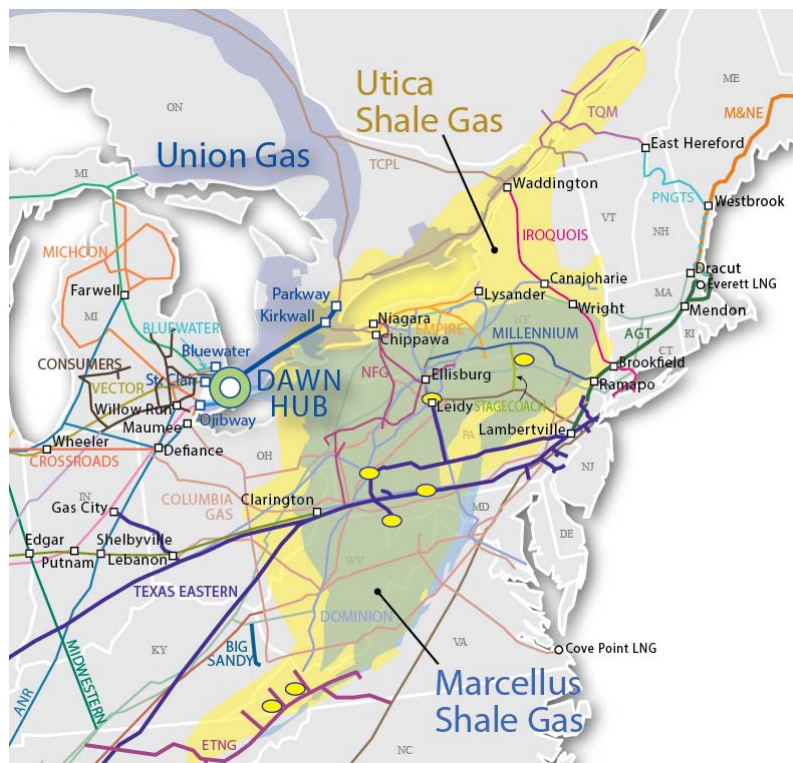
⁴¹ National Energy Board of Canada, *Canada's Energy Future 2013 – Energy Supply & Demand Projections to 2035*, November 2013, Appendix 2: Energy Demand, Appendix 4: Natural Gas.

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 Basins⁴³



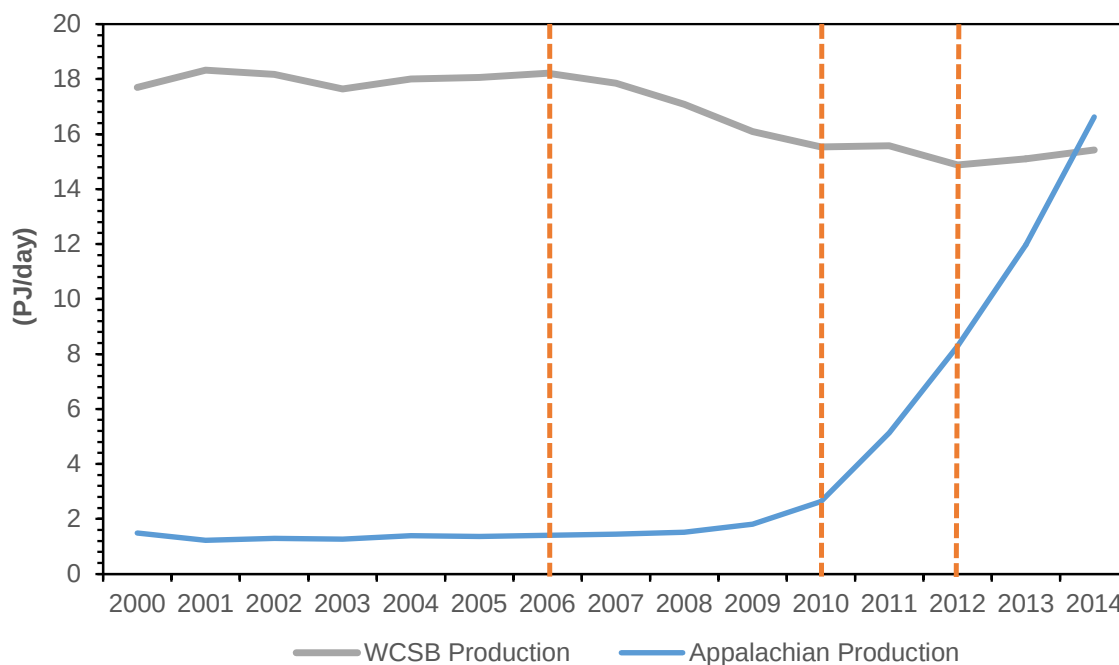
⁴² WCSB natural gas producers and project sponsors are considering the export of LNG from the Canadian and U.S. West Coast in response to the changing natural gas market dynamics. The NEB has received 30 applications for natural gas export licenses, encompassing 21 export facilities, and approved nine 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/lnngxprtclnc/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_dc_u_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/mrktblntrlgsprdcn-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

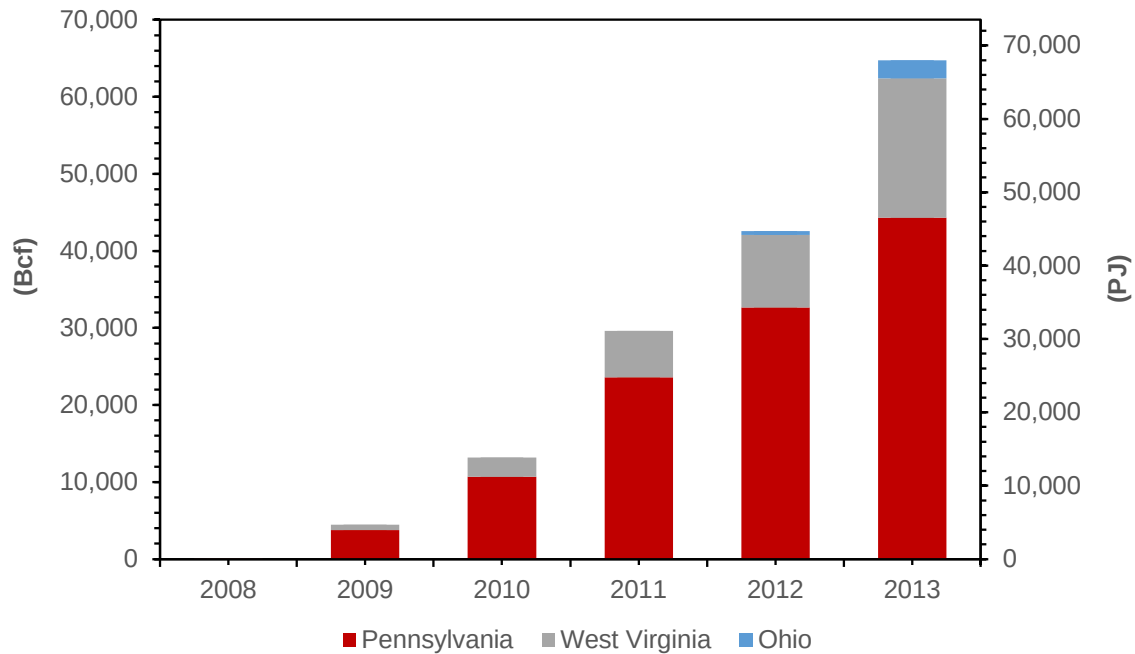
The EIA's estimate of proved reserves depicts an overall increase in U.S. proved reserves in 2013 of 9.7% (to 371,694 PJ or 353,994 Bcf) due to an improvement in natural gas prices and additional development in certain shale basins, including the Marcellus Shale. The EIA's estimate of proved reserves 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 Virginia⁴⁸



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

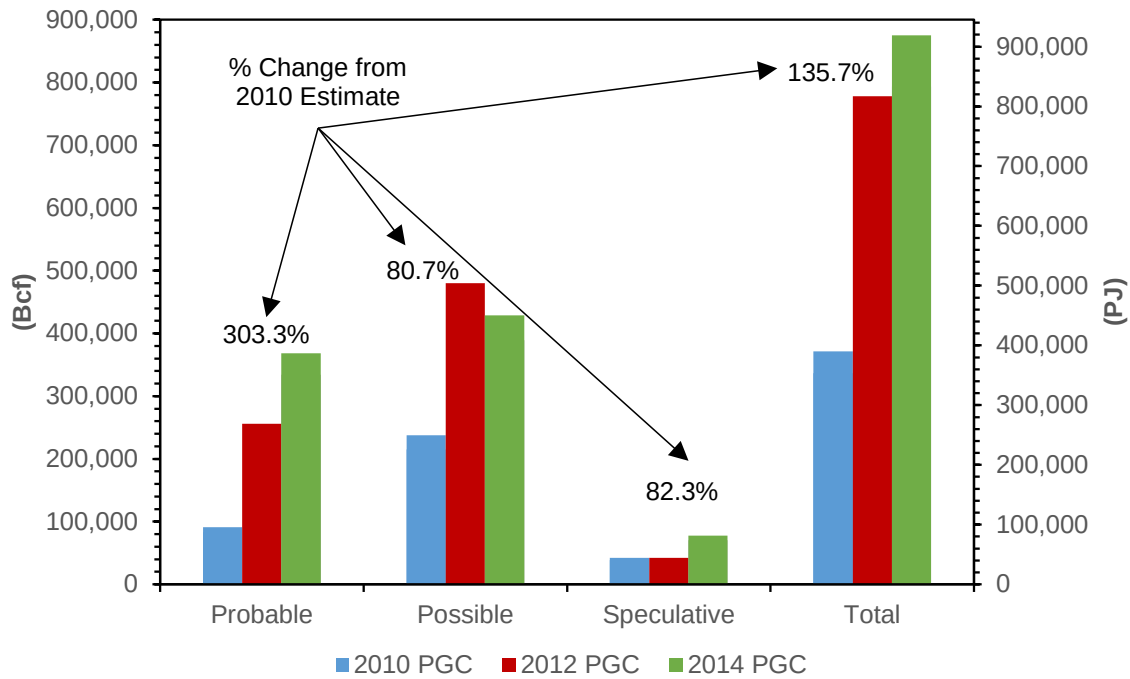
The PGC's most recent estimate of potential natural gas resources was completed in spring 2015 based on data from 2014,⁵¹ while the prior PGC estimate of potential natural gas resources was completed in 2013 utilizing data from 2012. The 2014 PGC estimate of potential natural gas resources shows significant 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.

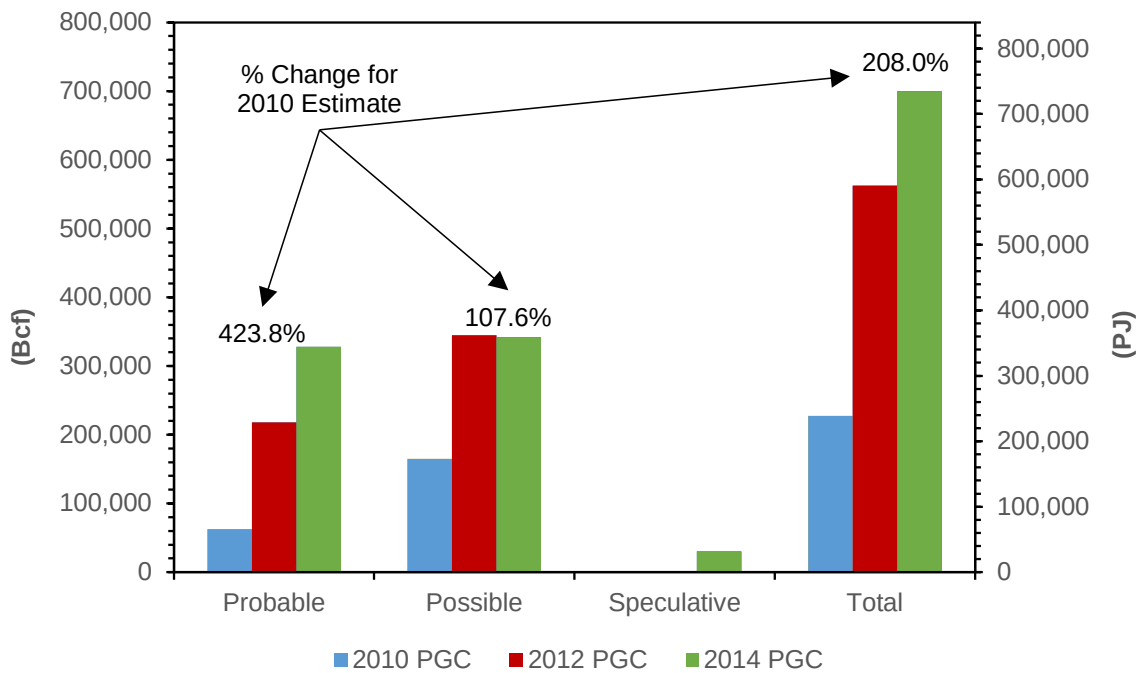
Figure 3.10: Atlantic Region Projected Gas Resources (2010-2014)⁵²



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



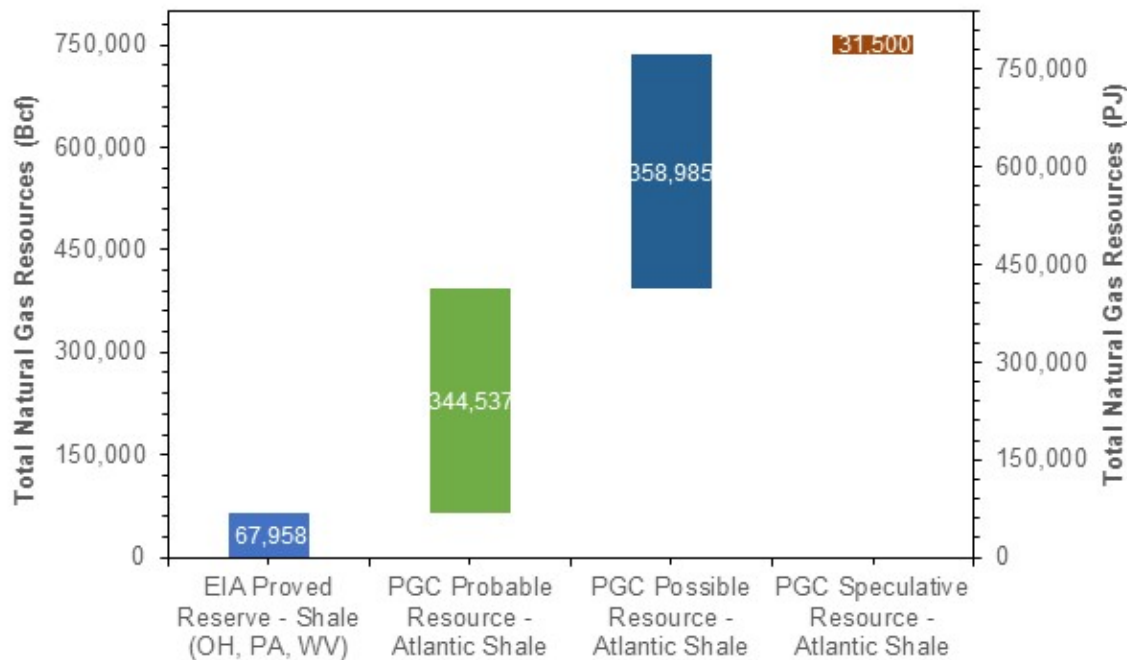
As illustrated in Figure 3.11, the 2012 PGC forecast of Atlantic Region shale natural gas is more than double the 2010 PGC forecast. In 2014, the PGC forecast of Atlantic Region shale natural gas has continued to increase with largest increase in the resources classified as probable resources. Between 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 Shale⁵⁷



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.

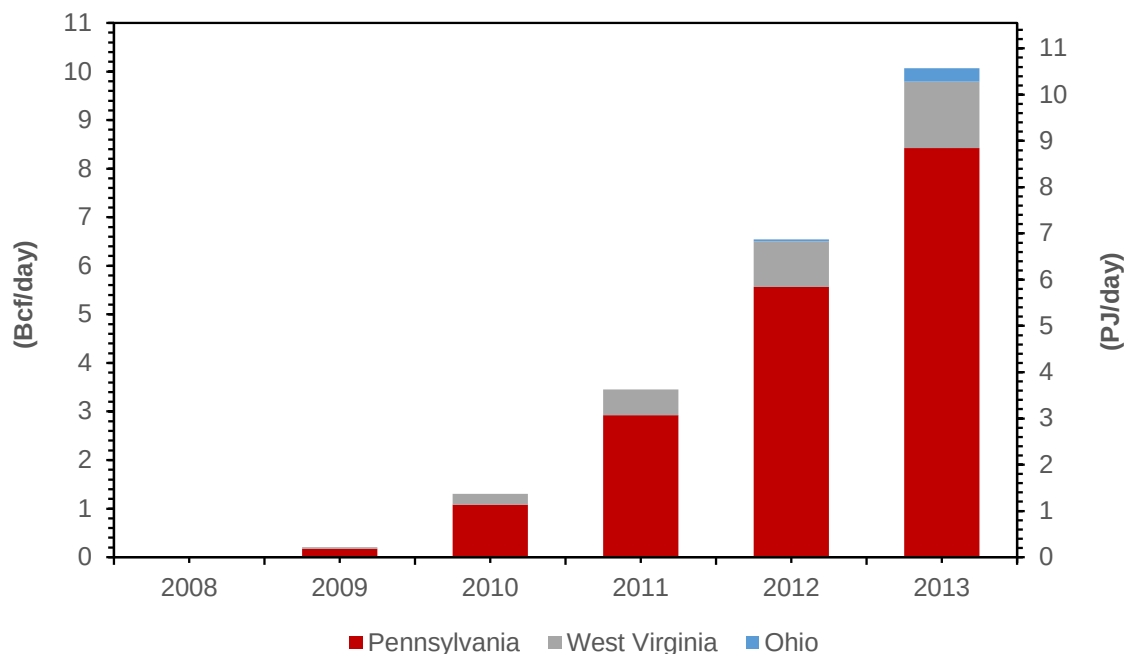
⁵⁸ The EIA notes that the 2013 annual consumption of natural gas in the U.S. was 26,131 Bcf or 27,438 PJ, which converts to approximately 71.5 Bcf/day or 75.1 PJ/day. See, U.S. Energy Information Administration, *Natural Gas Consumption by End Use*, http://www.eia.gov/dnav/ng/ng_cons_sum_dcunusm.htm, 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 Virginia⁶⁰



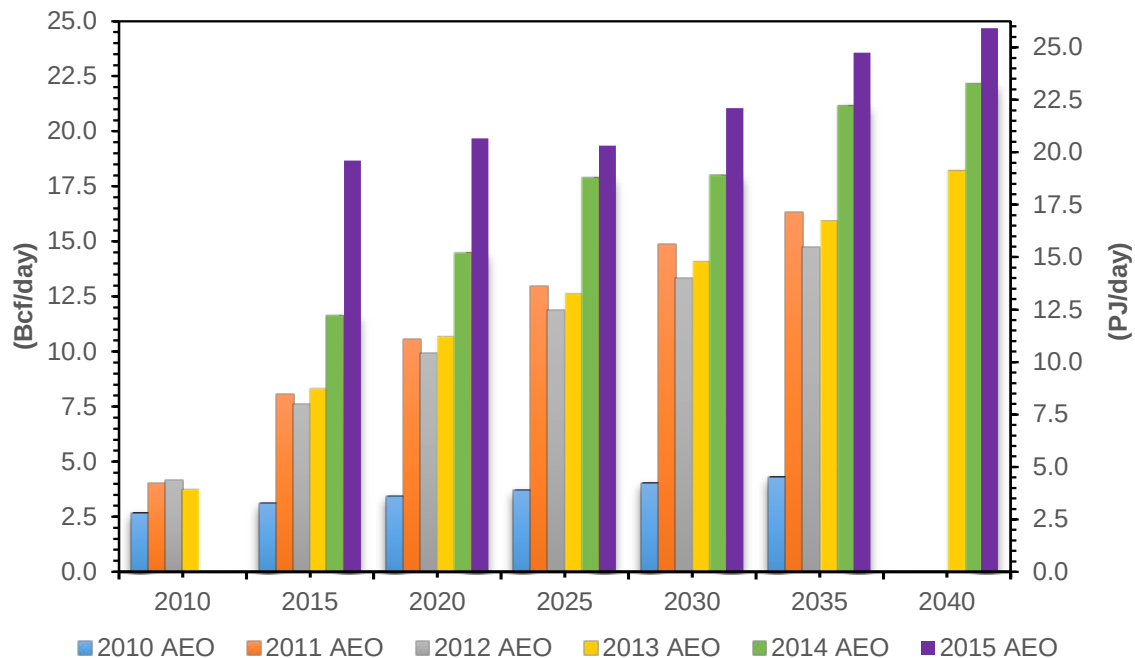
The EIA also produces a forecast of natural gas production in its AEO. Specifically, the AEO, which covers a 30 to 35 year forecast horizon, includes a forecast of natural gas production in the Northeast region (*i.e.*, Marcellus and Utica shale basins). As illustrated in Figure 3.14, for the 2010 and 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 Forecast⁶¹



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

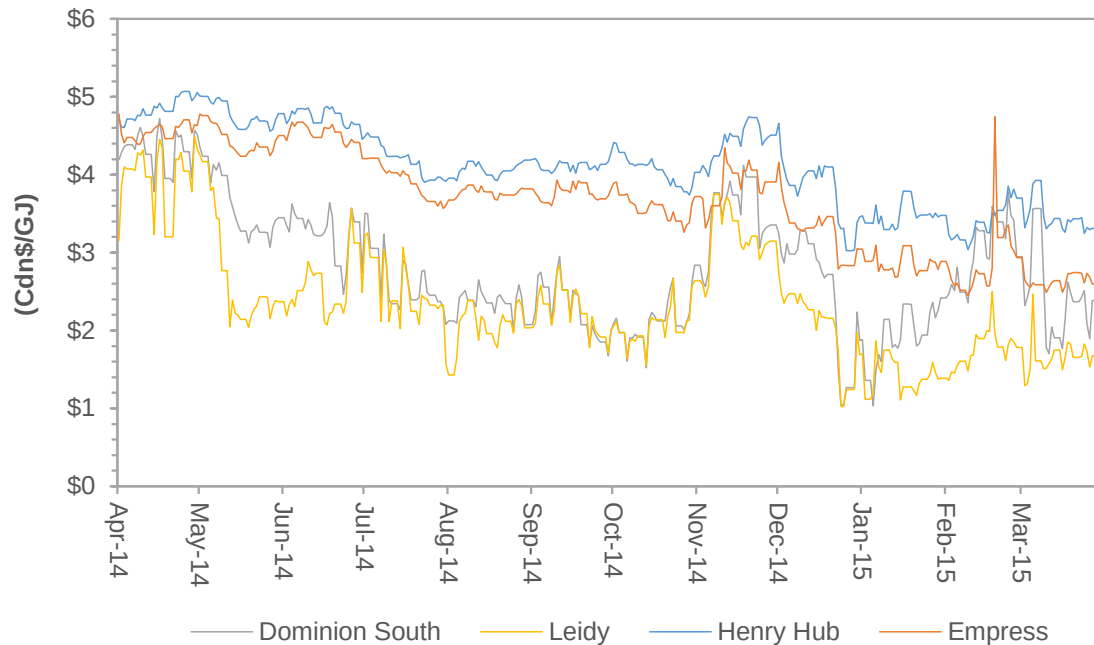
The benefits of NEXUS to the Ontario LDCs include: (1) access to proximate and competitive natural gas supply; (2) natural gas supply basin diversity; (3) enhanced liquidity for natural gas purchases made at the Dawn Hub; (4) transportation path diversity; (5) transportation cost stability; (6) natural 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

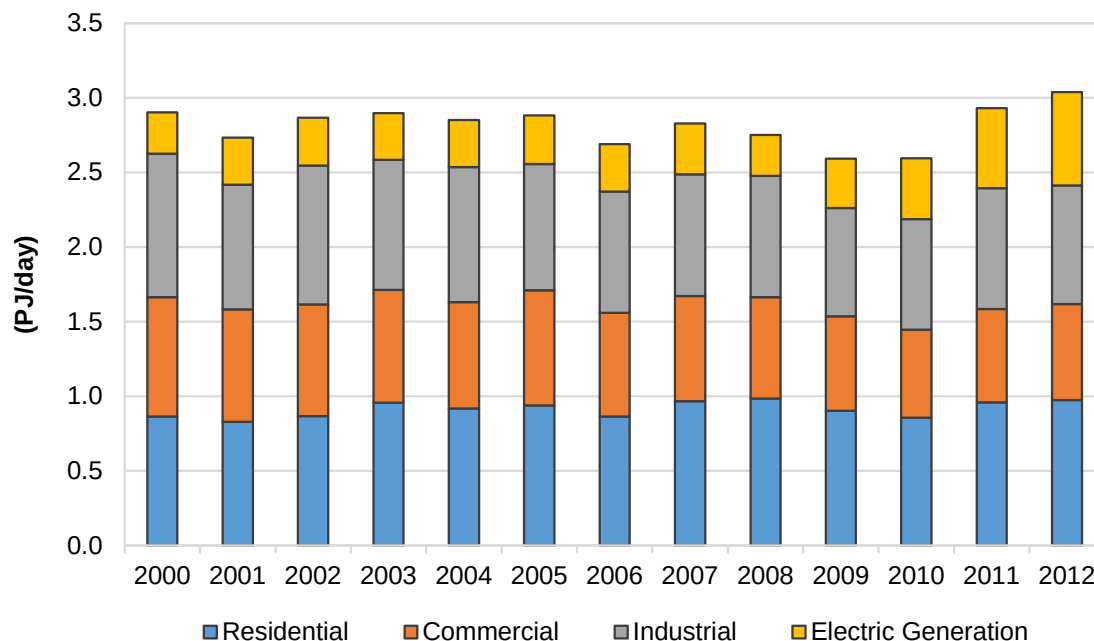
NEXUS will be a FERC regulated pipeline and, as such, will provide certain service flexibility to the portfolio of the Ontario LDCs, which may augment existing contracts on other pipelines (e.g., the TransCanada Canadian Mainline). For example, NEXUS will likely provide various terms and conditions that 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 Segment⁷¹

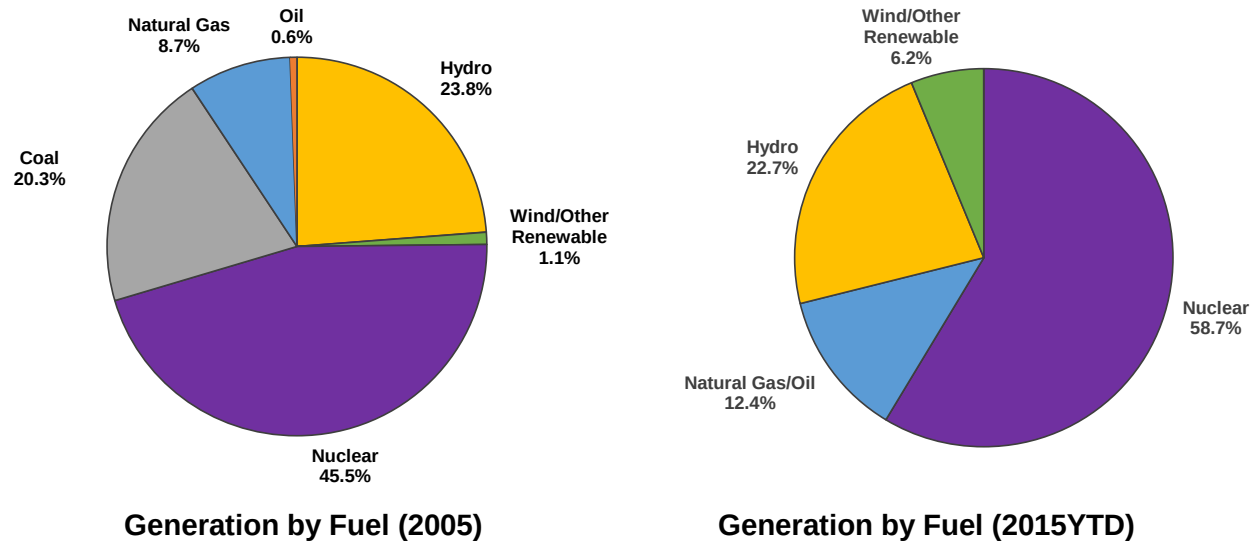


⁷⁰ National Energy Board of Canada, *Canada's Energy Future 2013 – Energy Supply & Demand Projections to 2035*, November 2013, Appendix 2.7.

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 Fuel⁷³



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 path⁸⁰ 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 Openlink⁸¹ 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.

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>i.e.</i> , 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>i.e.</i> , 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>i.e.</i> , 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>i.e.</i> , 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>i.e.</i> , 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.

January 2014 Landed Cost Analysis (Nov 2014 to Oct 2032 Transportation Contracting Analysis)

	Route	Point of Supply	Basis Differential \$US/mmBtu	Supply Cost \$US/mmBtu	Unitized Demand Charge \$US/mmBtu ⁽¹⁾	Commodity Charge \$US/mmBtu ⁽¹⁾	Fuel Charge \$US/mmBtu ⁽¹⁾	100% LF Transportation Inclusive of Fuel \$US/mmBtu	Landed Cost \$US/mmBtu	Landed Cost \$Cdn/G	Point of Delivery	Comment
	(A)	(B)	(C)	(D) = Nymex + C	(E)	(F)	(G)	I) = E + F + G	(J) = D + I	(K)	(L)	
(6)	Trunkline / Panhandle	Trunkline Field Zone 1A	-0.127	7.0325	0.1926	0.0275	0.2633	0.4833	\$7.52	\$7.43	Dawn	Includes Ojibway to Dawn costs
(6)	Panhandle (2013-2014)	Panhandle Field Zone	-0.282	6.8776	0.2671	0.0443	0.3587	0.6700	\$7.55	\$7.46	Dawn	Includes Ojibway to Dawn costs
(6)	Vector (2012 - 2016)	Chicago	0.108	7.2670	0.2500	0.0018	0.0698	0.3216	\$7.59	\$7.50	Dawn	
(6)	Panhandle (2012-2017)	Panhandle Field Zone	-0.282	6.8776	0.3524	0.0443	0.3587	0.7554	\$7.63	\$7.54	Dawn	Includes Ojibway to Dawn costs
(2)	Dawn	Dawn	0.509	7.6681	0.0000	0.0000	0.0000	0.0000	\$7.67	\$7.58	Dawn	
(6)	Panhandle (2010-2017)	Panhandle Field Zone	-0.282	6.8776	0.4579	0.0443	0.3587	0.8609	\$7.74	\$7.65	Dawn	Includes Ojibway to Dawn costs
(6)	Niagara to Kirkwall	Niagara	0.558	7.7167	0.1441	0.0000	0.0000	0.1441	\$7.86	\$7.77	Kirkwall	
(6)	Alliance / Vector	CREC	-0.832	6.3270	1.7393	-0.4152	0.3513	1.6754	\$8.00	\$7.91	Dawn	
(3)*	NEXUS	Michcon Generic/Southwest PA	0.057	7.2165	0.7500	0.0000	0.1739	0.9239	\$8.14	\$8.05	Dawn	Michcon Generic for 3 years, Southwest PA as Nexus project impacting other node
(2)	TCPL Empress to Dawn	Empress	-0.469	6.6899	1.4368	0.0000	0.1552	1.5920	\$8.28	\$8.18	Dawn	
(5)*	NEXUS (Increase Upper end of toll by 15%)	Michcon Generic/Southwest PA	0.057	7.2165	0.9660	0.0000	0.1739	1.1399	\$8.36	\$8.26	Dawn	Michcon Generic for 3 years, Southwest PA as Nexus project impacting other node
(2)	TCPL Empress to Union CDA	Empress	-0.469	6.6899	1.5588	0.0000	0.1820	1.7407	\$8.43	\$8.33	Union CDA	

- (1) Unitized Demand Charges, Commodity Charges and Fuel Charges per Maximum Applicable Tariff and include capacity required to flow fuel for downstream pipeline segments
(2) For Reference Only
(3) Toll Estimates used in lieu of official toll for portion of path
(4) Assumes \$0.15 USD/MMBTU charge to get from producing region to beginning of path
(5) Sensitivity Analysis - TCPL Niagara path
(6) Existing Union Contract
(7) No assumptions made for incremental tolling or cost recovery for infrastructure changes required.

Assumptions used in Developing Transportation Contracting Analysis:

	Annual Gas Supply & Fuel Ratio Forecasts	Point of Supply Col (B) above	Nov 2014 Oct 2015	Nov 2015 - Oct 2016	Nov 2016 Oct 2017	Nov 2017 Oct 2018	Nov 2018 Oct 2019	Nov 2019 Oct 2020	Nov 2020 Oct 2021	Nov 2021 Oct 2022	Nov 2022 Oct 2023	Nov 2023 Oct 2024	Nov 2024 Oct 2025	Nov 2025 Oct 2026	Nov 2026 Oct 2027	Nov 2027 Oct 2028	Nov 2028 Oct 2029	Nov 2029 Oct 2030	Nov 2030 Oct 2031	Nov 2031 - Oct 2032	Average Annual Gas Supply Cost \$US/mmBtu Col (D) above	Fuel Ratio Forecasts Col (G) above
	Henry Hub (NYMEX)	Henry Hub	\$4.16	\$4.46	\$5.20	\$5.33	\$5.90	\$6.84	\$6.48	\$6.68	\$6.88	\$7.15	\$7.30	\$7.63	\$8.46	\$8.51	\$8.96	\$9.43	\$9.65	\$9.84	\$7.16	
	Trunkline / Panhandle	Trunkline Field Zone 1A	\$4.12	\$4.41	\$5.14	\$5.26	\$5.81	\$6.73	\$6.37	\$6.56	\$6.76	\$7.03	\$7.17	\$7.49	\$8.30	\$8.34	\$8.78	\$9.24	\$9.45	\$9.64	\$7.03	3.74%
	Panhandle (2013-2014)	Panhandle Field Zone	\$4.10	\$4.38	\$5.07	\$5.16	\$5.70	\$6.59	\$6.23	\$6.42	\$6.60	\$6.86	\$6.99	\$7.32	\$8.12	\$8.15	\$8.58	\$9.01	\$9.18	\$9.34	\$6.88	5.21%
	Vector (2012 - 2016)	Chicago	\$4.45	\$4.72	\$5.42	\$5.49	\$6.03	\$6.92	\$6.55	\$6.74	\$6.96	\$7.23	\$7.37	\$7.71	\$8.53	\$8.59	\$9.02	\$9.49	\$9.70	\$9.89	\$7.27	0.96%
	Panhandle (2012-2017)	Panhandle Field Zone	\$4.10	\$4.38	\$5.07	\$5.16	\$5.70	\$6.59	\$6.23	\$6.42	\$6.60	\$6.86	\$6.99	\$7.32	\$8.12	\$8.15	\$8.58	\$9.01	\$9.18	\$9.34	\$6.88	5.21%
	Dawn	Dawn	\$4.97	\$5.24	\$5.84	\$5.88	\$6.36	\$7.29	\$6.93	\$7.07	\$7.30	\$7.57	\$7.73	\$8.07	\$8.91	\$8.98	\$9.44	\$9.92	\$10.15	\$10.37	\$7.67	0.00%
	Panhandle (2010-2017)	Panhandle Field Zone	\$4.10	\$4.38	\$5.07	\$5.16	\$5.70	\$6.59	\$6.23	\$6.42	\$6.60	\$6.86	\$6.99	\$7.32	\$8.12	\$8.15	\$8.58	\$9.01	\$9.18	\$9.34	\$6.88	5.21%
	Niagara to Kirkwall	Niagara	\$4.46	\$4.73	\$5.48	\$5.88	\$6.41	\$7.34	\$7.06	\$7.24	\$7.47	\$7.76	\$7.89	\$8.24	\$9.09	\$9.17	\$9.66	\$10.12	\$10.35	\$10.56	\$7.72	0.00%
	Alliance / Vector	CREC	\$3.59	\$3.84	\$4.42	\$4.51	\$4.96	\$5.89	\$5.63	\$5.83	\$6.08	\$6.33	\$6.47	\$6.86	\$7.62	\$7.67	\$8.11	\$8.57	\$8.68	\$8.81	\$6.33	5.55%
	NEXUS	Michcon Generic/Southwest PA	\$4.72	\$4.99	\$5.59	\$5.44	\$5.97	\$6.89	\$6.51	\$6.66	\$6.84	\$7.09	\$7.24	\$7.56	\$8.38	\$8.45	\$8.87	\$9.34	\$9.58	\$9.77	\$7.22	2.41%
	TCPL Empress to Dawn	Empress	\$3.80	\$4.07	\$4.70	\$4.82	\$5.29	\$6.28	\$6.00	\$6.20	\$6.42	\$6.70	\$6.86	\$7.22	\$8.01	\$8.10	\$8.55	\$8.99	\$9.13	\$9.29	\$6.69	2.32%
	NEXUS (Increase Upper end of toll by 15%)	Michcon Generic/Southwest PA	\$4.72	\$4.99	\$5.59	\$5.44	\$5.97	\$6.89	\$6.51	\$6.66	\$6.84	\$7.09	\$7.24	\$7.56	\$8.38	\$8.45	\$8.87	\$9.34	\$9.58	\$9.77	\$7.22	2.41%
	TCPL Empress to Union CDA	Empress	\$3.80	\$4.07	\$4.70	\$4.82	\$5.29	\$6.28	\$6.00	\$6.20	\$6.42	\$6.70	\$6.86	\$7.22	\$8.01	\$8.10	\$8.55	\$8.99	\$9.13	\$9.29	\$6.69	2.72%

Sources for Assumptions:

Gas Supply Prices (Col D): ICF Base Case Jan 2014
Fuel Ratios (Col G): Average ratio over the previous 12 months or Pipeline Forecast
Transportation Tolls (Cols E & F): TCPL 2013 Approved Tolls, Union Tolls in Effect Oct 2013
Foreign Exchange (Col K): \$1 US = 1.0427 CDN Source: Oct 1, 2013 Bank of Canada Closing
Energy Conversions (Col K): 1 dth = 1 mmBtu = 1.055056
Union's Analysis Completed: January 2014

* indicates path referenced in evidence for this analysis

January 2015 Landed Cost Analysis (Nov 2017 to Oct 2032 Transportation Contracting Analysis)

	<u>Route</u>	<u>Point of Supply</u>	<u>Basis Differential</u> \$US/mmBtu	<u>Supply Cost</u> \$US/mmBtu	<u>Unitized Demand Charge</u> \$US/mmBtu (1)(7)	<u>Commodity Charge</u> \$US/mmBtu (1)	<u>Fuel Charge</u> \$US/mmBtu (1)	<u>100% LF Transportation Inclusive of Fuel</u> \$US/mmBtu (1)	<u>Landed Cost</u> \$US/mmBtu (J) = D + I	<u>Landed Cost</u> \$Cdn/G (K)	<u>Point of Delivery</u> (L)	<u>Comment</u>
	(A)	(B)	(C)	(D) = Nymex + C	(E)	(F)	(G)	(I) = E + F + G	(J) = D + I	(K)	(L)	
(6)	TCPL Niagara to Kirkwall	Niagara	-0.449	7.0511	0.2008	0.0000	0.0103	0.2111	\$7.26	\$8.10	Kirkwall	
(3)	Rover	Southwest PA	-0.954	6.5455	0.8000	0.0000	0.1577	0.9577	\$7.50	\$8.36	Dawn	
*	NEXUS / St. Clair	Southwest PA	-0.954	6.5455	0.8030	0.0000	0.1728	0.9758	\$7.52	\$8.38	Dawn	Includes St. Clair to Dawn costs
(5)	NEXUS/St. Clair (Increase Upper end of toll by 15%)	Southwest PA	-0.954	6.5455	0.8984	0.0000	0.1728	1.0712	\$7.62	\$8.49	Dawn	Toll is \$ 0.77+ \$ 0.635*15%. Includes St. Clair to Dawn costs
(6)	Vector (2014 - 2017)	Chicago	-0.103	7.3972	0.1893	0.0018	0.0732	0.2643	\$7.66	\$8.54	Dawn	
(2)	Dawn	Dawn	0.177	7.6769	0.0000	0.0000	0.0000	0.0000	\$7.68	\$8.56	Dawn	
(6)	Michcon (2014-2015)	Michcon Generic	0.023	7.5229	0.0663	0.0000	0.1398	0.2061	\$7.73	\$8.62	Dawn	Includes St. Clair to Dawn costs
(6)	Vector (2012 - 2016)	Chicago	-0.103	7.3972	0.2500	0.0990	0.0732	0.4222	\$7.82	\$8.72	Dawn	
(6)	Trunkline / Panhandle	Trunkline Field Zone 1A	-0.092	7.4075	0.2245	0.0268	0.2995	0.5508	\$7.96	\$8.87	Dawn	Includes Ojibway to Dawn costs
(6)	Panhandle (2012-2017)	Panhandle Field Zone	-0.377	7.1230	0.3524	0.0439	0.4687	0.8650	\$7.99	\$8.91	Dawn	Includes Ojibway to Dawn costs
(6)	Alliance / Vector	CREC	-1.067	6.4335	1.6460	-0.3643	0.3593	1.6409	\$8.07	\$9.00	Dawn	
(6)	Panhandle (2014-2015)	Panhandle Field Zone	-0.377	7.1230	0.4579	0.0439	0.4687	0.9705	\$8.09	\$9.02	Dawn	Includes Ojibway to Dawn costs
(6)	Panhandle (2010-2017)	Panhandle Field Zone	-0.377	7.1230	0.4579	0.0439	0.4687	0.9705	\$8.09	\$9.02	Dawn	Includes Ojibway to Dawn costs
(2)	TCPL Empress to Dawn	Empress	-0.722	6.7782	1.6246	0.0000	0.2745	1.8992	\$8.68	\$9.67	Dawn	
(6)	TCPL Empress to Union CDA	Empress	-0.722	6.7782	1.7631	0.0000	0.2793	2.0423	\$8.82	\$9.83	Union CDA	

(1) Unitized Demand Charges, Commodity Charges and Fuel Charges per Maximum Applicable Tariff and include capacity required to flow fuel for downstream pipeline segments

(2) For Reference Only

(3) Toll Estimates used in lieu of official toll for portion of path

(5) Sensitivity Analysis

(6) Existing Union Contract

* indicates path referenced in evidence for this analysis

Assumptions used in Developing Transportation Contracting Analysis:

	<u>Annual Gas Supply & Fuel Ratio Forecasts</u>	<u>Point of Supply</u> Col (B) above	<u>Nov 2017 - Oct 2018</u>	<u>Nov 2018 - Oct 2019</u>	<u>Nov 2019 - Oct 2020</u>	<u>Nov 2020 - Oct 2021</u>	<u>Nov 2021 - Oct 2022</u>	<u>Nov 2022 - Oct 2023</u>	<u>Nov 2023 - Oct 2024</u>	<u>Nov 2024 - Oct 2025</u>	<u>Nov 2025 - Oct 2026</u>	<u>Nov 2026 - Oct 2027</u>	<u>Nov 2027 - Oct 2028</u>	<u>Nov 2028 - Oct 2029</u>	<u>Nov 2029 - Oct 2030</u>	<u>Nov 2030 - Oct 2031</u>	<u>Nov 2031 - Oct 2032</u>	<u>Average Annual Gas Supply Cost</u> \$US/mmBtu Col (D) above	<u>Fuel Ratio Forecasts</u> Col (G) above
	Henry Hub (NYMEX)	Henry Hub	\$4.62	\$5.43	\$6.12	\$6.59	\$6.81	\$6.89	\$7.06	\$7.23	\$7.56	\$8.03	\$8.44	\$8.90	\$9.26	\$9.62	\$9.96	\$7.50	
	TCPL Niagara to Kirkwall	Niagara	\$4.62	\$5.35	\$5.96	\$6.37	\$6.54	\$6.59	\$6.71	\$6.78	\$7.00	\$7.33	\$7.71	\$8.13	\$8.56	\$8.86	\$9.26	\$7.05	0.15%
	Rover	Southwest PA	\$4.09	\$4.88	\$5.50	\$5.89	\$6.06	\$6.12	\$6.25	\$6.32	\$6.53	\$6.85	\$7.19	\$7.58	\$7.98	\$8.28	\$8.66	\$6.55	2.41%
	NEXUS / St. Clair	Southwest PA	\$4.09	\$4.88	\$5.50	\$5.89	\$6.06	\$6.12	\$6.25	\$6.32	\$6.53	\$6.85	\$7.19	\$7.58	\$7.98	\$8.28	\$8.66	\$6.55	2.64%
	NEXUS/St. Clair (Increase Upper end of toll by 15%)	Southwest PA	\$4.09	\$4.88	\$5.50	\$5.89	\$6.06	\$6.12	\$6.25	\$6.32	\$6.53	\$6.85	\$7.19	\$7.58	\$7.98	\$8.28	\$8.66	\$6.55	2.64%
	Vector (2014 - 2017)	Chicago	\$4.63	\$5.41	\$6.07	\$6.52	\$6.73	\$6.81	\$6.97	\$7.14	\$7.46	\$7.91	\$8.31	\$8.75	\$9.09	\$9.42	\$9.73	\$7.40	0.99%
	Dawn	Dawn	\$4.82	\$5.62	\$6.29	\$6.76	\$6.98	\$7.07	\$7.24	\$7.42	\$7.75	\$8.21	\$8.63	\$9.08	\$9.43	\$9.77	\$10.09	\$7.68	0.00%
	Michcon (2014-2015)	Michcon Generic	\$4.70	\$5.49	\$6.16	\$6.62	\$6.84	\$6.92	\$7.09	\$7.26	\$7.59	\$8.05	\$8.46	\$8.91	\$9.25	\$9.59	\$9.90	\$7.52	1.86%
	Vector (2012 - 2016)	Chicago	\$4.63	\$5.41	\$6.07	\$6.52	\$6.73	\$6.81	\$6.97	\$7.14	\$7.46	\$7.91	\$8.31	\$8.75	\$9.09	\$9.42	\$9.73	\$7.40	0.99%
	Trunkline / Panhandle	Trunkline Field Zone 1A	\$4.56	\$5.37	\$6.05	\$6.51	\$6.72	\$6.80	\$6.97	\$7.14	\$7.46	\$7.93	\$8.33	\$8.79	\$9.14	\$9.49	\$9.83	\$7.41	4.04%
	Panhandle (2012-2017)	Panhandle Field Zone	\$4.42	\$5.20	\$5.84	\$6.29	\$6.48	\$6.56	\$6.71	\$6.88	\$7.19	\$7.63	\$8.02	\$8.44	\$8.76	\$9.07	\$9.36	\$7.12	6.58%
	Alliance / Vector	CREC	\$3.69	\$4.44	\$5.08	\$5.54	\$5.77	\$5.87	\$6.04	\$6.23	\$6.55	\$6.99	\$7.36	\$7.78	\$8.09	\$8.39	\$8.67	\$6.43	5.58%
	Panhandle (2014-2015)	Panhandle Field Zone	\$4.42	\$5.20	\$5.84	\$6.29	\$6.48	\$6.56	\$6.71	\$6.88	\$7.19	\$7.63	\$8.02	\$8.44	\$8.76	\$9.07	\$9.36	\$7.12	6.58%
	Panhandle (2010-2017)	Panhandle Field Zone	\$4.42	\$5.20	\$5.84	\$6.29	\$6.48	\$6.56	\$6.71	\$6.88	\$7.19	\$7.63	\$8.02	\$8.44	\$8.76	\$9.07	\$9.36	\$7.12	6.58%
	TCPL Empress to Dawn	Empress	\$4.03	\$4.78	\$5.42	\$5.87	\$6.09	\$6.18	\$6.36	\$6.55	\$6.88	\$7.33	\$7.72	\$8.15	\$8.47	\$8.78	\$9.07	\$6.78	4.05%
	TCPL Empress to Union CDA	Empress	\$4.03	\$4.78	\$5.42	\$5.87	\$6.09	\$6.18	\$6.36	\$6.55	\$6.88	\$7.33	\$7.72	\$8.15	\$8.47	\$8.78	\$9.07	\$6.78	4.12%

Sources for Assumptions:

Gas Supply Prices (Col D):

Fuel Ratios (Col G):

Transportation Tolls (Cols E & F):

Foreign Exchange (Col K)

Energy Conversions (Col K)

Union's Analysis Completed:

ICF Base Case Jan 2015

Average ratio over the previous 12 months or Pipeline Forecast

Union Tolls in Effect Jan 2015

\$1 US =

1.1762

CDN

Source: Jan 2, 2015 Bank of Canada Closing

1 dth = 1 mmBtu =

1.055056

January 2015

* indicates path referenced in evidence for this analysis

UNION GAS SYSTEM OVERVIEW

The purpose of this Schedule is to provide an overview of Union's system, including the Dawn Parkway System and the Dawn Hub, and its importance to energy supply in Ontario, Québec and the U.S. Northeast.¹

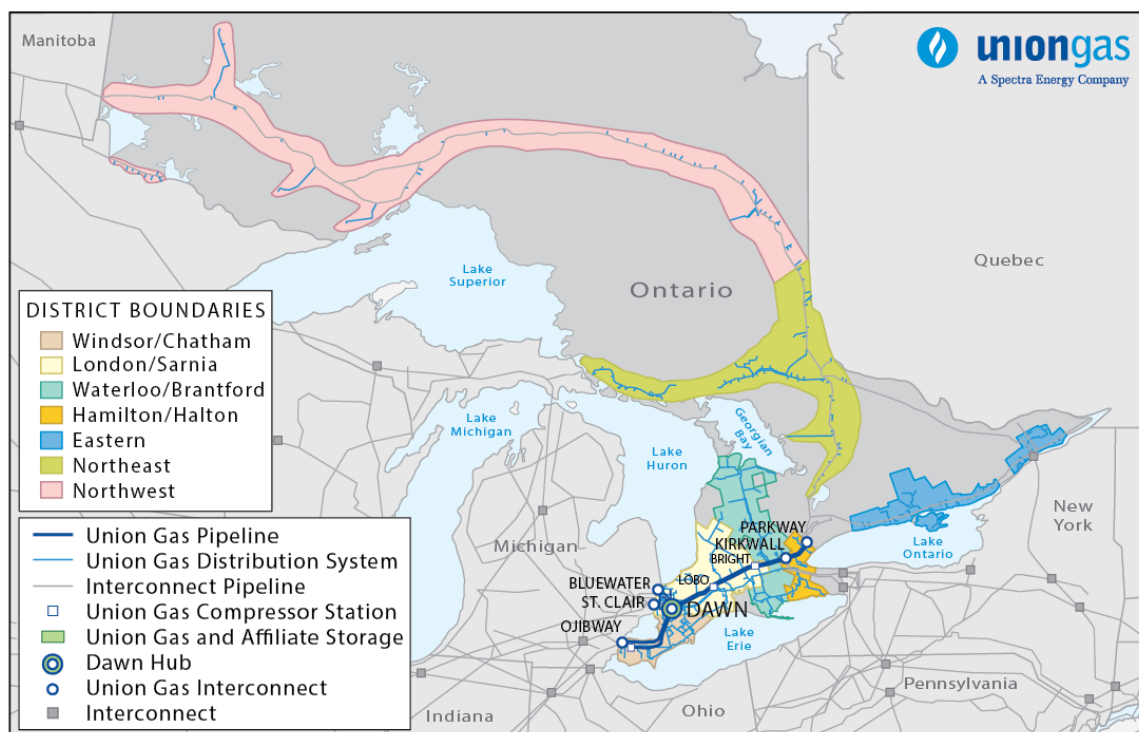
Union serves approximately 1.4 million customers in northern, eastern and southern Ontario through an integrated network of over 68,000 kilometres of natural gas pipelines. Union operates storage and transmission assets that include 166 Bcf of underground natural gas storage at the Dawn Hub as well as the Dawn Parkway System, which connects the Dawn Hub to consuming markets in Ontario, Québec and the U.S. Northeast. Throughput serving Union's in-franchise customers during 2013 was over 500 Bcf. Throughput serving Union's ex-franchise storage and transmission customers during 2013 was 890 Bcf. In total, Union transported approximately 1.4 Tcf of natural gas in 2013, which is slightly greater than all of the natural gas consumed in Ontario and Québec or approximately 5% of North American demand.

Union divides its service territory areas into Union North and Union South. Union South includes customers located west of Mississauga and south of Georgian Bay (Windsor/Chatham, London/Sarnia, Waterloo/Brantford and Hamilton/Halton Districts). Union North includes customers located north of Barrie and north and west of North Bay (Northeast and Northwest Districts). Union North also includes customers located east of Bowmanville and west of the

¹As per EB-2014-0261, Exhibit A, Tab 4.

Québec border (Eastern District). A map of Union's service districts as well as Union's system is provided as Figure 4-1.

Figure 4-1
Union Gas System and Service Districts



Union North is almost exclusively supplied from the TransCanada PipeLines Inc.

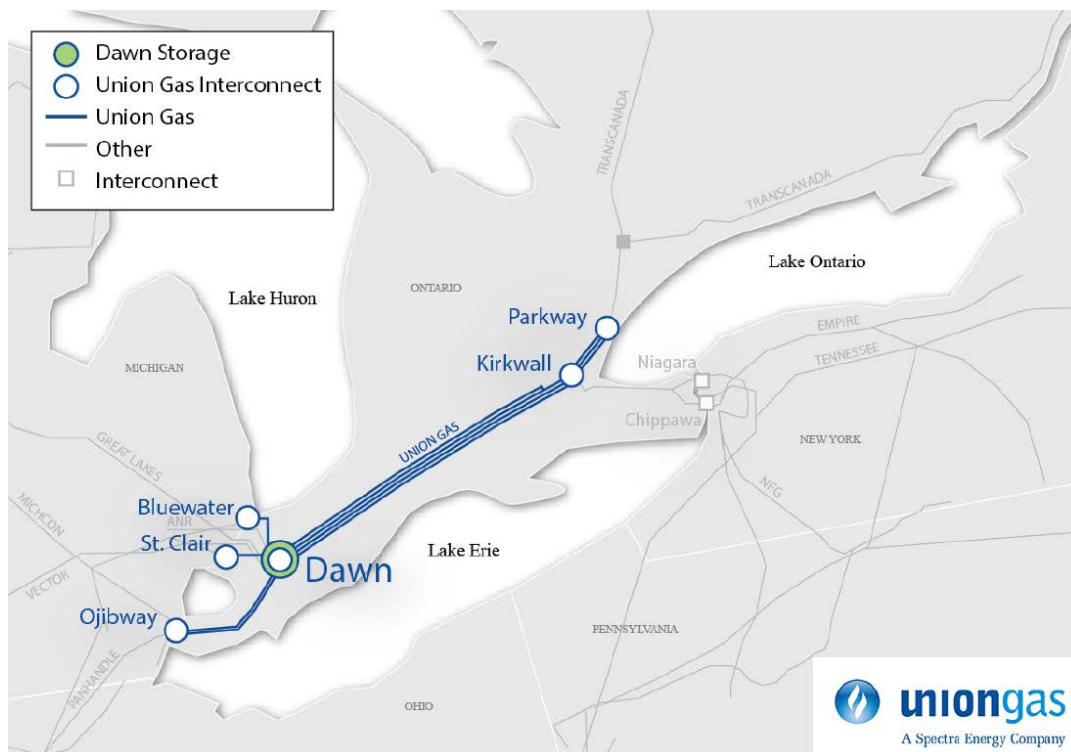
("TransCanada") Mainline system, with no other option for the transportation or physical delivery of natural gas to the laterals serving Union's districts. Therefore, these customers are reliant upon the TransCanada Mainline.

Dawn Parkway System

In Union South, Union operates the Dawn Parkway System which includes an integrated network of natural gas transmission pipelines and compressors. The Dawn Parkway System transports natural gas between the Dawn Compressor Station (“Dawn”), near Sarnia at the west end of Union South, and the Parkway Compressor Station (“Parkway”), located in Mississauga at the east end of Union South. Union operates two additional compressor stations on the Dawn Parkway System: i) the Lobo Compressor Station (“Lobo”) located near London; and ii) the Bright Compressor Station (“Bright”) located between Woodstock and Kitchener. A map of Union’s Dawn Parkway System is provided in Figure 4-2.

Figure 4-2

The Dawn Parkway System



Additionally, in January 2014, the Board approved the Parkway West Compressor Station (“Parkway West”) development². Two compressors and related facilities are currently under construction at Parkway West. The Parkway West facilities will be placed into service in stages over 2014 and 2015. Parkway West is located on a new site directly west of Parkway.

The Dawn Parkway System connects with other pipeline systems at three locations:

- 1) At Parkway, the Dawn Parkway System connects to the TransCanada Mainline and to the Enbridge Gas Distribution Inc. (“Enbridge”) system. Union connects to the TransCanada Mainline within the existing Parkway site at a delivery point referred to as Parkway (TransCanada). Union also connects to the Enbridge system within the existing Parkway site at a delivery point referred to as Parkway (Consumers), and at a second location two kilometres east of Parkway at a delivery point referred to as the Lisgar Custody Transfer Station (“Lisgar”).

At Parkway West, once construction is complete, the Dawn Parkway System will connect to the Board-approved Enbridge GTA Project Segment A (also known as the Enbridge Albion Line), targeted for November 2015, and will also connect to the existing Enbridge system, targeted for December 2014, and TransCanada Mainline, targeted for December 2015.

² EB-2012-0451/EB-2012-0433/EB-2013-0074 Decision January 30, 2014.

- 2) Near Hamilton, the Dawn Parkway System connects to the TransCanada Mainline at Union's Kirkwall Custody Transfer Station ("Kirkwall"). This portion of the TransCanada Mainline, known as the Niagara Export Line, connects to the import/export points at Niagara and Chippawa at the Ontario/New York border.
- 3) At Dawn, near Sarnia, the Dawn Parkway System connects to a number of pipelines: Vector Pipeline; Panhandle Eastern Pipeline via the Union Panhandle system; Great Lakes Gas Transmission via TransCanada; Michigan Consolidated; Bluewater Gas Storage; and ANR via Niagara Gas Transmission (NiagaraLink) and the Enbridge (Tecumseh) system.

As described above, Union receives natural gas at Dawn from a number of interconnecting pipelines which connect the Dawn Hub to most of North America's major supply basins. Dawn is also indirectly connected to Tennessee Gas Pipeline, Dominion Transmission, National Fuel Gas Supply Corporation, and Empire State Pipeline via TransCanada's Niagara Export Line (from the Niagara/Chippawa import/export points to Kirkwall) and Union's Dawn Parkway System (Kirkwall to Dawn). In its Decision regarding Union's Parkway Projects and Enbridge's GTA Project, the Board concluded that "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 supply³".

³ EB-2012-0451/EB-2012-0433/EB-2013-0074 Decision January 30, 2014, p. 29.

The majority of Union South customers located east of Dawn are served via the Dawn Parkway System. Some of Union's customers in the Hamilton/Haldimand-Norfolk and Burlington/Oakville areas are served from the TransCanada Mainline via TransCanada's Niagara Export Line and, TransCanada's Domestic Line.

Union provides transportation services on the Dawn Parkway System to ex-franchise customers, including Enbridge, TransCanada, Gaz Métro Limited Partnership and U.S. Northeast natural gas utilities. Union also uses its Dawn Parkway System (and also TransCanada services from Parkway) to ship natural gas from Dawn to Union North. Union is accountable to its in-franchise customers and its ex-franchise firm transportation customers for the reliable delivery of natural gas.

The Dawn HUB

Union operates one of the largest and most important North American market hubs, the Dawn Hub. The Dawn Hub consists of a combination of interconnecting pipelines and underground natural gas storage, and is the main source of supply for the Dawn Parkway System. The Board recognized in its November 7, 2006 Natural Gas Electricity Interface Review Decision EB-2005-0551, ("NGEIR Decision"), that "The development of the Dawn Hub has brought substantial benefits to consumers in Ontario and to other market participants⁴".

⁴ EB-2005-0551 Decision, November 7, 2006, p. 44.

The Dawn Hub is also connected to the most significant amount of underground natural gas storage within the Great Lakes region. In Ontario, Union operates 166 Bcf of natural gas storage in 24 pools that are all connected to the Dawn Hub. All of this storage is either owned by Union or contracted from other Ontario storage operators. In addition, Enbridge operates 103 Bcf of natural gas storage (Tecumseh facilities) that is connected to Dawn. Dawn is also connected through various upstream pipelines to approximately 675 Bcf of underground natural gas storage in Michigan.

Dawn is one of the most physically traded, liquid hubs in North America. The liquidity of Dawn is the result of the combination of:

- 1) access to underground storage;
- 2) interconnections with upstream pipelines;
- 3) take away capacity to growth markets;
- 4) a large number of buyers and sellers of natural gas; and,
- 5) price transparency.

In its NGEIR Decision, the Board concluded that: “it is in the public interest to maintain and enhance the depth and liquidity of the market at the Dawn Hub as a means of facilitating competition⁵”. In its Decision regarding Union’s Parkway Projects and Enbridge’s GTA Project, the Board reiterated this position: “It is the Board’s view that while uncertainties exist for all

⁵ EB-2005-0551 Decision November 7, 2006, p. 45.

supply sources in terms of future cost and availability, it is widely acknowledged, including by this Board in prior decisions, that supply diversification enhances reliability and brings cost benefits through enhanced competition⁶”.

The depth and liquidity of the market at Dawn provides value to all Ontario customers by way of competitive natural gas commodity prices, attracting natural gas supply to Ontario.

Ontario’s natural gas-fired generation market relies on a healthy, liquid Dawn Hub. Power generation contracts are commercially structured based on the price of natural gas at Dawn for approximately 5,500 MW of Ontario’s electricity production capacity. Natural gas-fired generators have access to unique services at the Dawn Hub that provide operational flexibility through firm all day storage and transportation services that allow natural gas-fired generators to match natural gas supply needs to the electricity market that is priced hourly and dispatched every five minutes.

The Board further identified the importance of the Dawn Hub in its NGEIR Decision:

“The storage facilities are an integral part of what is commonly referred to as the Dawn Hub, which is widely recognized as one of the more important market centres in North America for the trading, transfer and storage of natural gas. In its Natural Gas Forum Report, the Board stated “The large amount of nearby storage, combined with the

⁶ EB-2012-0451/EB-2012-0433/EB-2013-0074 Decision January 30, 2014, pp. 23-24.

convergence of pipelines linking the U.S. and Ontario gas markets, have made Dawn the most liquid trading location in Ontario. The Federal Energy Regulatory Commission, in its assessment of energy markets in the United States in 2004, made similar comments about the significance of Dawn:

The Dawn Hub is an increasingly important link that integrates gas produced from multiple basins for delivery to customers in the Midwest and Northeast...Dawn has many of the attributes that customers seek as they structure gas transactions at the Chicago Hub: access to diverse sources of gas production; interconnection to multiple pipelines; proximity to market area storage; choice of seasonal and daily peak and load services; liquid trade markets; and opportunities to reduce long haul pipeline capacity ownership by purchasing gas at downstream liquid hubs.⁷”

Summary

Union’s Dawn Parkway System is an integral part of the natural gas delivery system for Ontario, Québec and U.S. Northeast residents, businesses and industry. The Dawn Parkway System connects these consuming markets to most of North America’s major supply basins, to the largest region of underground natural gas storage in North America and to the liquid Dawn Hub.

⁷ EB-2005-0551 Decision November 7, 2006, pp. 7-8.