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January 16, 2015

Filed Electronically

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, Suite 2700
Toronto, Ontario M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: 2014 Natural Gas Market Review
Ontario Energy Board ("Board") File No. EB-2014-0289
TransCanada PipeLines Limited – Written Submission

In the Board's letter of September 19, 2014, participants in the 2014 Natural Gas Market Review were invited to submit written comments following the Stakeholder Conference. Enclosed with this letter is the written submission of TransCanada PipeLines Limited.

If the Board requires additional information with respect to this filing, please contact Jim Bartlett by phone at (403) 920-7165 or by email at jim_bartlett@transcanada.com.

Yours truly,
TransCanada PipeLines Limited

Original signed by

Catharine Davis
Vice President, Pipelines Law

Attachments

Assessment and Implications of Natural Gas Supply Developments for the Ontario Market

Ontario Energy Board
2014 Natural Gas Market Review (EB-2014-0289)

Submission of TransCanada PipeLines Limited

January 16, 2015

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1.0 INTRODUCTION

TransCanada welcomes the opportunity to provide input to the current Ontario Energy Board (OEB) Market Review. The intent of this submission is to provide the OEB with an understanding of how the natural gas markets in Ontario have evolved, how they will continue to evolve and the implications for natural gas infrastructure required to supply the Ontario market.

2.0 BACKGROUND

The TransCanada Mainline was built in the 1950s to transport western Canadian natural gas to the Ontario market. Since its construction, the TransCanada Mainline has been the primary source of natural gas supply for Ontario and has played a critical role in ensuring the availability and reliability of the Province's gas supplies. For many decades, Ontario, like many eastern markets, relied principally on accessing distant gas supplies through a single long-haul pipeline system.

With continued growth in the Ontario gas market, as well as growing demand in Quebec and the U.S. Northeast, TransCanada expanded the Mainline to accommodate this increased demand. While Ontario also received some gas from the U.S. Midwest via interconnected pipelines near St. Clair and Ojibway, and maintained an extensive gas storage system, WCSB supplies delivered on the TransCanada Mainline remained the dominant supply source.

The model of a single, long-haul pipeline supplying a significant majority of Ontario's natural gas needs was changed when Alliance and the downstream Vector Pipeline entered service in late 2000. These two projects directly connected Ontario to the Chicago Hub and expanded the Province's access to Gulf Coast and Midwest U.S. gas supplies, as well as to WCSB supplies. Subsequent expansions by Vector and other pipeline projects have further increased access to U.S. supply.

Within the last decade, North America witnessed a rapid growth in shale gas production, initially in Texas and the U.S. Midcontinent area and most recently in the Marcellus and other emerging shale resource plays. In 2009, the eastern leg of the Rockies Express pipeline ("REX-East") entered service. Although REX-East did not directly serve Ontario, for the first time it directly connected eastern gas markets with the large and growing Rocky Mountain supply area, thereby significantly diversifying regional gas supply. Once again, Ontario's diverse upstream pipeline interconnections favorably positioned the Province to access these new gas supplies.

With continued growth in Marcellus/Appalachian gas supplies, another alternative supply source became available to Ontario. Niagara, which had been a major export point on the Mainline system for decades, became an import point for Marcellus gas in 2012. In 2007 through 2014, due to the availability of alternative supplies in northeast U.S markets, Mainline firm contracts to U.S. export points were not renewed, declining from 2.7 PJ/d in 2007 to 1.2 PJ/d in 2014.

Figure 1 presents a timeline of significant events in the development of Ontario's current gas supply portfolio over the past 30 years.

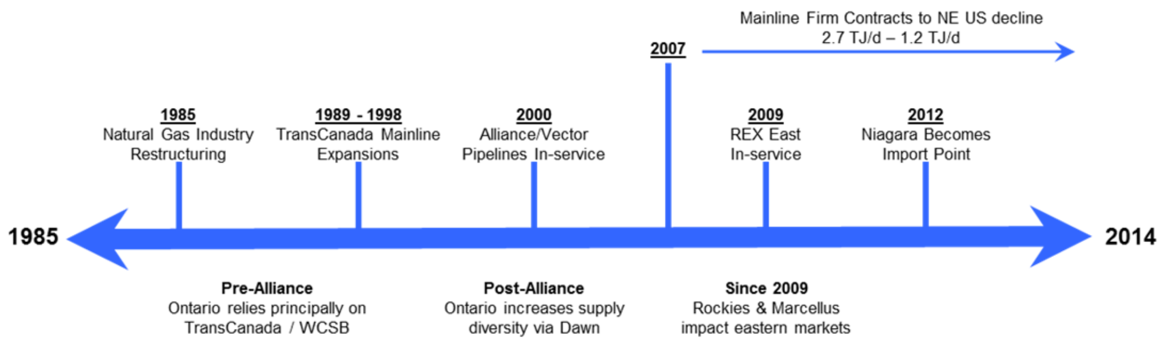


Figure 1: Ontario Gas Supply Timeline

3.0 THE ROLE OF TRANSCANADA

TransCanada has substantial pipeline infrastructure in Ontario, and its affiliates have sizeable investments in gas-fired electric generation in the Province. Throughout the past half century, TransCanada has played an integral role in ensuring that Ontario could access North America's increasingly diverse supply options.

Long haul contracts on the Mainline increased significantly from 1989 to 1998. These firm contracts underpinned Mainline expansions totalling $8.1 billion to serve both export and domestic demand. Over the past decade, shippers have increasingly utilized TransCanada's integrated pipeline system to further diversify Ontario's supply sources by contracting for short-haul transportation services in TransCanada's eastern market area.

The trend in annual contracted capacity depicted in Figure 2 clearly highlights the flexibility of TransCanada's Mainline system. Over the past decade, TransCanada's traditional long haul contracted capacity fell from 5,000 TJ/day to less than 1,500 TJ/day in 2012 and then rebounded to over 3,000 TJ/d in 2014, reflecting the new regulatory model that was implemented on the Mainline pursuant to the National Energy Board's (NEB) direction and the introduction of pricing discretion.

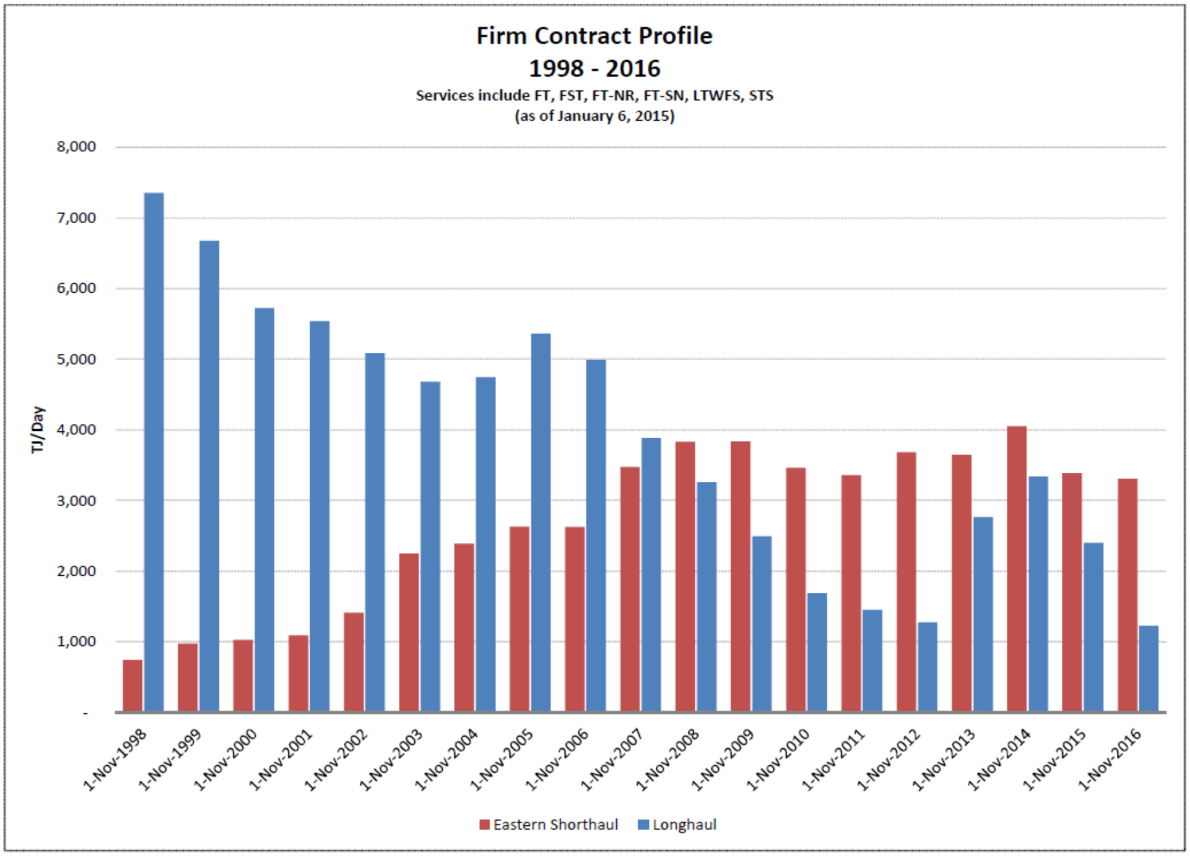


Figure 2: Changing Profile of Mainline Contract Demand

While the change in TransCanada's contracting portfolio provided a direct advantage to the Ontario market in accessing closer and growing supply sources, the decrease in long-haul contracts resulted in increasing tolls on the TransCanada Mainline. As a result, TransCanada filed an extensive restructuring proposal in the RH-3-2011 Application. The NEB, in its March 2013 Decision on the restructuring application, rejected a number of proposed changes and implemented a new Mainline tolling model which included:

- Fixed firm tolls for a 5 year period at levels below full cost recovery
- Full pricing discretion for discretionary services
- Establishment of deferral accounts to capture over or under-recovery of costs

Since the NEB's decision in early 2013, eastern gas markets have continued to evolve rapidly. In addition, the RH-3-2011 Decision created new, unanticipated issues and problems. With further growth in Marcellus/Appalachian supply, eastern Canadian shippers wanted additional access to short-haul capacity. Fixed tolls, combined with the potential loss of revenue from conversion of long-haul to short-haul contracts, prevented the Mainline from being able to accommodate the requests. The eastern Canadian LDCs proposed to bypass the Mainline between Parkway and Maple.

Litigation ensued, creating conditions that could have delayed access to additional Marcellus/Appalachian supplies for years.

As a result of collaboration between TransCanada, Gaz Métro Limited (GMi), Union Gas Limited (Union) and Enbridge Gas Distribution Inc. (EGD) (jointly, the LDCs), a settlement was reached which provided the LDCs with access to additional short-haul supplies while at the same time providing TransCanada with a reasonable opportunity to recover its costs. As part of the Settlement, TransCanada committed to build short-haul capacity in the Eastern Triangle as required. With recent NEB approval of the Mainline Tolls and Tariff Application in RH-1-2014, the Settlement was implemented, clearing the path for further enhancing Ontario's natural gas supply diversity.

Following implementation of the Settlement, long haul contracts on the Mainline are forecast to decline to approximately 1,200 TJ/d by November 2016.

4.0 KEY GAS MARKET DEVELOPMENTS IMPACTING ONTARIO

4.1 Macro Market Overview

Ontario is the second largest consumer of natural gas in Canada, with annual provincial demand in excess of 1,000 Bcf or, on average, about 2.8 Bcf/day. The Province enjoys a highly favorable position on the North American natural gas pipeline network, and serves as an important regional storage and transportation center. Ontario enjoys access to multiple sources of natural gas including those from the WCSB, the U.S. Gulf Coast, Midcontinent and Rocky Mountain regions. Marcellus shale gas has become the dominant addition to Ontario's expanding portfolio of gas supply options. Figure 3 depicts Ontario's current diversity of gas supply options.

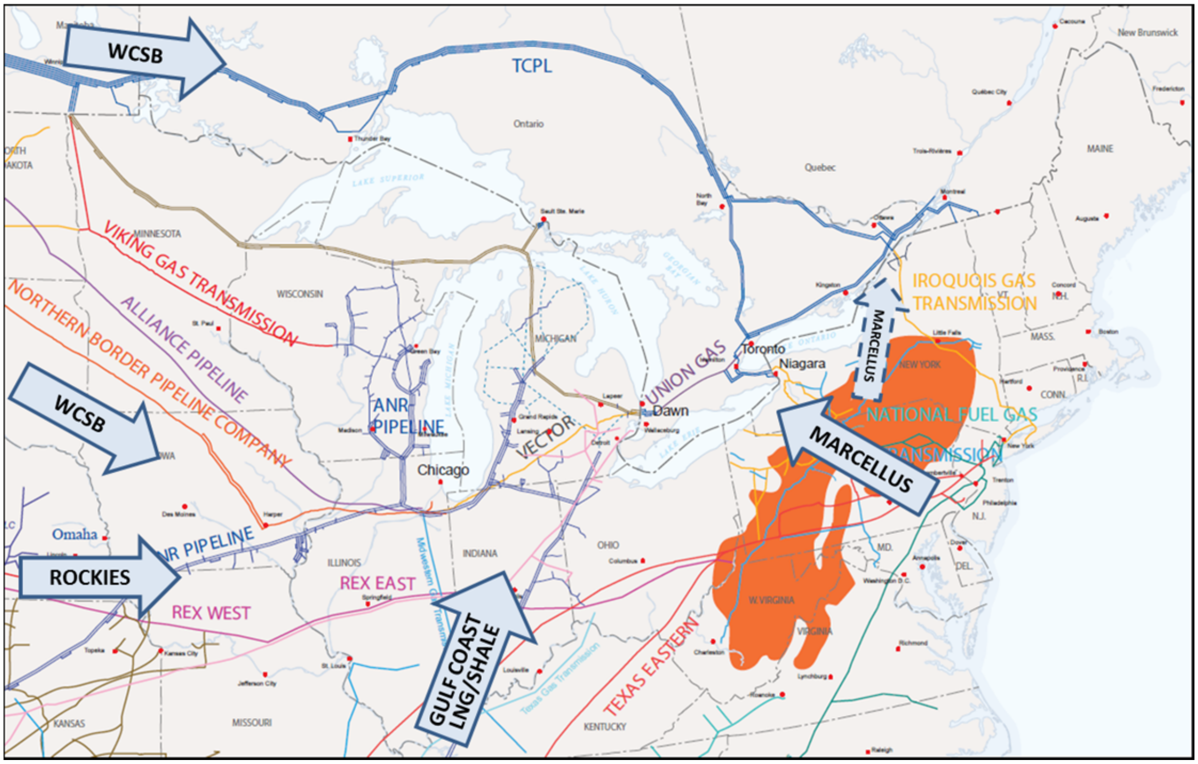


Figure 3: Ontario Gas Supply

The significant growth in Ontario's supply diversity has been driven primarily by unprecedented changes in the North American natural gas supply markets. The rapid and dramatic growth in supply has resulted from new technology combining horizontal drilling with advances in hydraulic fracturing. As a result, there is more gas supply in North America than ever imagined. To illustrate:

- In the 2010 Natural Gas Market Review (2010 Review) Marcellus production was forecast to increase to 6 Bcf/d by 2020. Actual Marcellus production reached 6 Bcf/d in 2012, and about 15 Bcf/d by late 2014 (see Figure 4) together with the more recent Utica supply.
- In the 2010 Review, total North American shale gas production was forecast to reach 29 Bcf/d in 2020. Actual production levels reached 38 Bcf/d in 2014.

The natural gas industry is being challenged to adapt the current infrastructure to this step change in supply. As noted earlier, eastern markets have traditionally been served by long-haul pipelines delivering gas from distant supply basins. Some of the new supply basins are now located much closer to these markets. One forward looking factor that must be acknowledged is that Marcellus and Appalachian supply growth is so immense that supply push will be the driver of incremental infrastructure. Figure 4 shows the forecast of Marcellus and Utica supply as compared to total northeast U.S. demand. Supply exceeded demand in 2013, with the excess supply seeking new markets including Ontario and Quebec. This supply forecast is conservative, with current actual supply represented by the red dot in Figure 4.

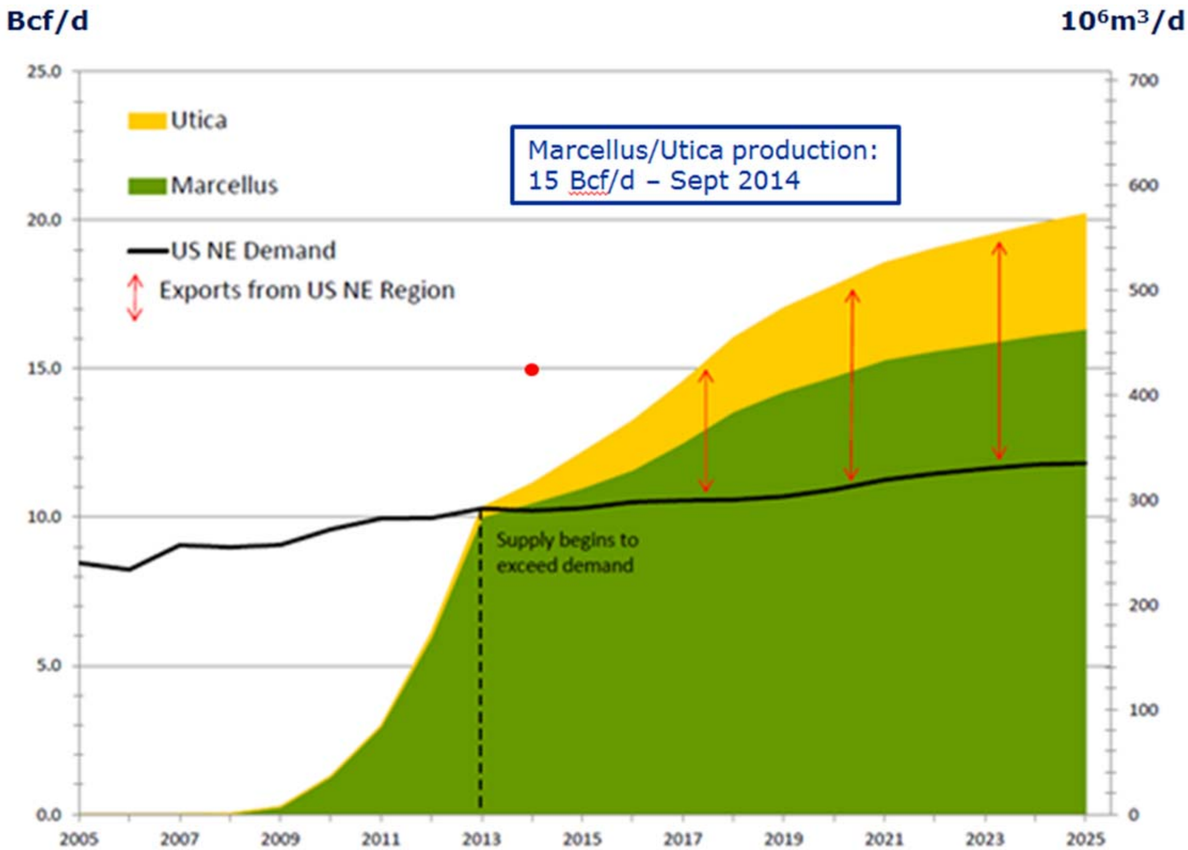


Figure 4: U.S. Northeast Supply and Demand

The supply push nature of incremental infrastructure is illustrated by the multitude of projects that have been proposed to connect Marcellus/Appalachian supplies to northeast U.S. markets (see Figure 5).

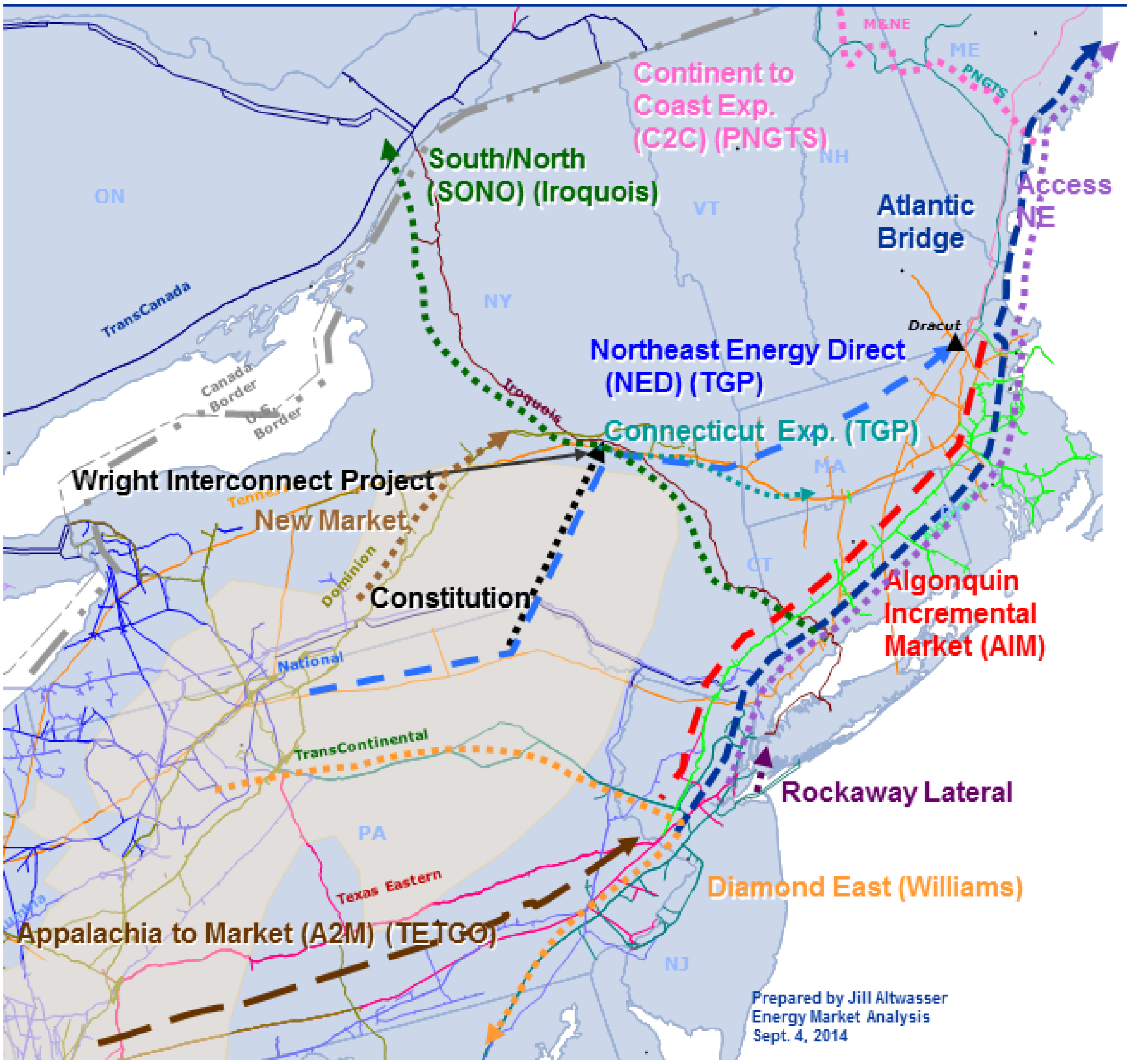


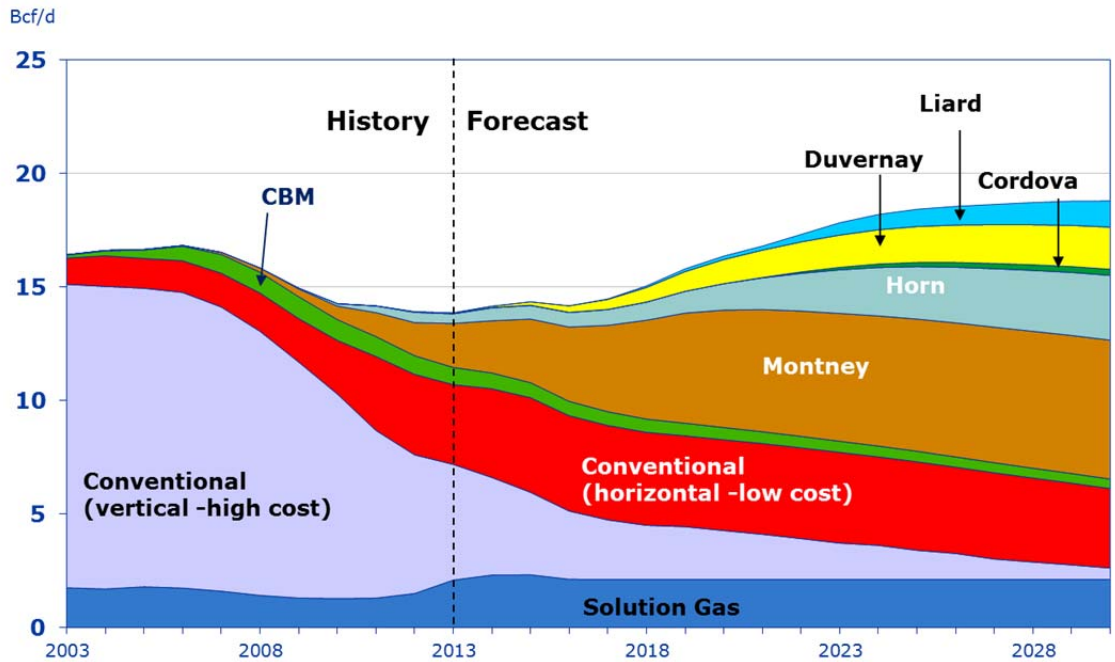
Figure 5: Incremental Natural Gas Facilities

One example of how this new infrastructure is changing market dynamics for Ontario is the Constitution project. This new pipeline, which will provide access for 650 MMcf/d of Marcellus gas to the Iroquois system at Wright, New York, was approved by the FERC in December of 2014. Constitution has the potential to alter the traditional flow pattern on the Iroquois system, allowing net imports to Canada. In fact, TransCanada already has received expressions of interest from customers for receipt service at Iroquois.

It is essential to incorporate the evolving nature of natural gas supply infrastructure in the northeast U.S. when designing Mainline capacity requirements in the future.

Failure to do so could result in construction of unnecessary capacity, the costs of which will likely be passed on to consumers in Ontario and Quebec.

One reason that eastern markets have sought further supply diversity was the view that the WCSB would not be able to supply eastern market requirements in the long term. Although conventional WCSB supply is in decline, there is a significant amount of shale gas potential to drive overall WCSB production higher. Figure 6 shows a current forecast for WCSB production through 2030. Note the growth in supply over the next 15 years is primarily driven by an increase in shale and other unconventional gas production areas.



Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Bcf/d	13.9	14.2	14.3	14.2	14.5	15.1	15.8	16.4	16.8	17.3	17.8	18.2	18.4

Figure 6: WCSB Gas Supply

TransCanada's NGTL system is the primary system for aggregating WCSB production for export from western Canada. NGTL has received 500 MMcf/d of additional supply in 2014 relative to 2013. Demand growth in western Canada was only 100 MMcf/d over the same time period, leaving 400 MMcf/d of supply looking for a market. While TransCanada has committed several billion dollars to expand the NGTL system to accommodate this growth, the WCSB is now constrained by available markets.

As a result, the WCSB remains a reliable supply option to Ontario. Long-haul pipeline capacity to access this supply already exists via the Mainline and other pipelines. However, without sufficient contracts, this capacity may be retired or repurposed over time. This needs to be considered when weighing the option of expanding the Mainline within Ontario.

4.2 Eastern Canadian Mainline Infrastructure

With NEB approval of the RH-1-2014 Settlement, a number of infrastructure projects in the Eastern Triangle are now ready to proceed. In collaboration with Union and EGD with respect to the Greater Toronto Area (GTA) reinforcement project as well as other requests for switching from long-haul to short-haul service, two Mainline expansion projects in southern Ontario have been identified: the Kings North Expansion and Vaughan Loop (see Figure 7). The combined projects will increase the takeaway capacity at Parkway by 800 TJ/d, increasing Ontario's access to Dawn and/or Marcellus/Appalachian supplies.

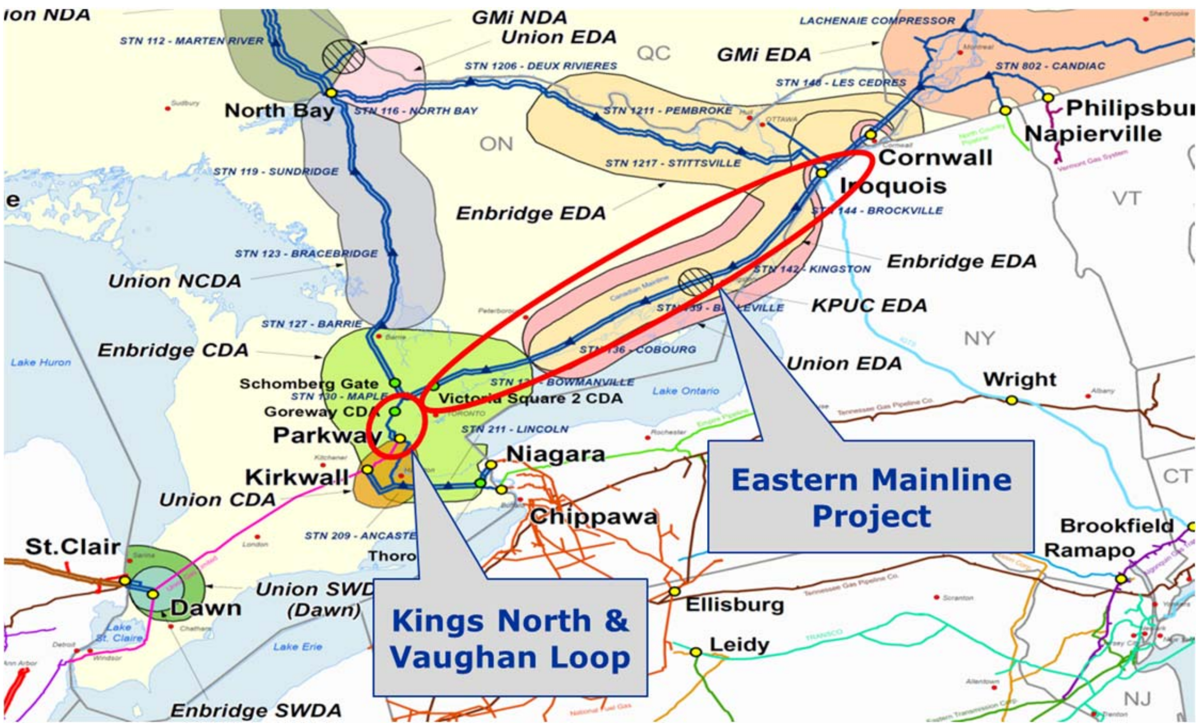


Figure 7: Mainline Planned Facilities for Ontario

Two other projects will further increase access to Marcellus/Appalachian supplies: the Niagara/Chippawa Receipt project and the Hamilton Line project. Currently over 400 TJ/d is received at the Niagara interconnect. Receipt capacity at Niagara and Chippawa will grow to over 1.1 PJ/d by 2016. In addition, the Hamilton Line project will allow 200 TJ/d to flow from Niagara and Chippawa directly into the EGD franchise area at Parkway. In aggregate, as a result of these projects, Parkway to

Maple capacity will have increased by 1.2 PJ/d between 2012 and 2016. The Eastern Mainline Project, also shown in Figure 7, is discussed in the following section.

4.3 Energy East Project

4.3.1 The Proposal

As noted earlier, the TransCanada Mainline has seen declining long-haul throughput in recent years. In addition to changes in the natural gas markets of North America, there has been an evolution in oil markets. Continued growth in oil production from western Canada, primarily driven by growth in oil sands production, as well as new production sources of oil in the U.S. leveraging the same technology that has driven shale gas production, have resulted in new oil transportation infrastructure requirements.

The Energy East Project was proposed as a way to address both the decline in long-haul contracts on the Mainline as well as the demand for additional oil transportation capacity out of the WCSB. Put another way, Energy East provided an opportunity to repurpose some of the Mainline’s assets to a higher value use. At a high level, Energy East proposes to transfer one of the Mainline’s several individual pipelines from the Alberta-Saskatchewan border to near the Quebec border from gas to oil service.

More specifically within the Eastern Triangle, the proposal includes the transfer of the North Bay Shortcut (NBSC) 42-inch line from the Mainline to Energy East (the line from North Bay Junction to the Iroquois export point in Figure 8). In conjunction with the transfer of the NBSC facilities, TransCanada has proposed construction of new facilities in the Eastern Triangle, known as the Eastern Mainline Project (EMP). The EMP will provide 575 TJ/d of additional capacity in Ontario between the City of Markham and the community of Iroquois.

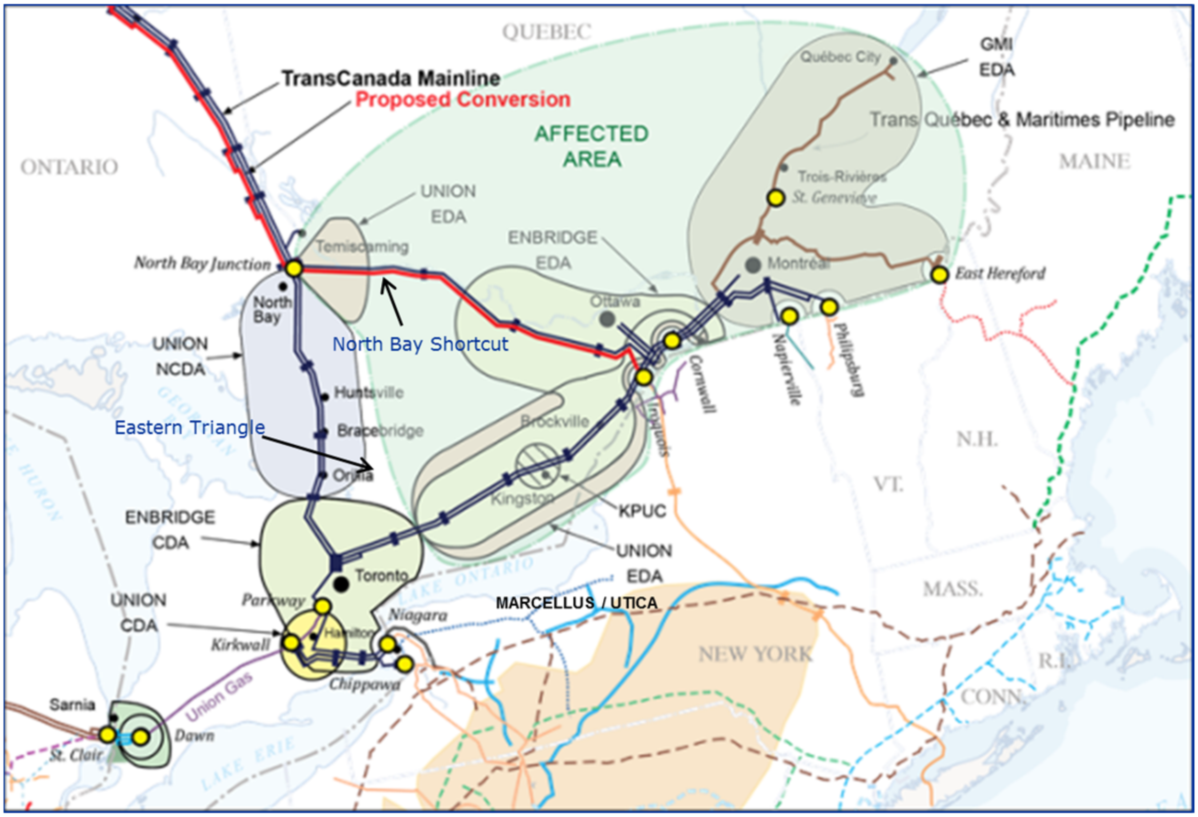


Figure 8: Energy East Affected Area

Prior to the transfer of one line of the NBSC to Energy East, the Eastern Triangle capacity into the Affected Area is approximately 3.2 PJ/d. After the transfer of one line of the NBSC and the capacity provided by the EMP, Eastern Triangle capacity into the Affected Area will be approximately 2.6 PJ/d.

4.3.2 The Benefits

TransCanada has calculated the net present value of the benefit of transferring Mainline gas facilities to Energy East and building the EMP to be approximately $900 million, of which $500 million will accrue to Eastern Triangle shippers.

4.3.3 Market Analysis

Before proceeding to market analysis with respect to the Energy East project, it is important to clearly demarcate the portion of the Mainline system impacted by the project. Only points east of Toronto and east of North Bay Junction are impacted by the proposed transfer of the NBSC, labelled "the Affected Area" in Figure 8. None of Toronto, the GTA, Sarnia or Hamilton is impacted by the transfer. The Affected Area consists of two major components: domestic markets of eastern Ontario and Quebec, and export markets to the northeast U.S.

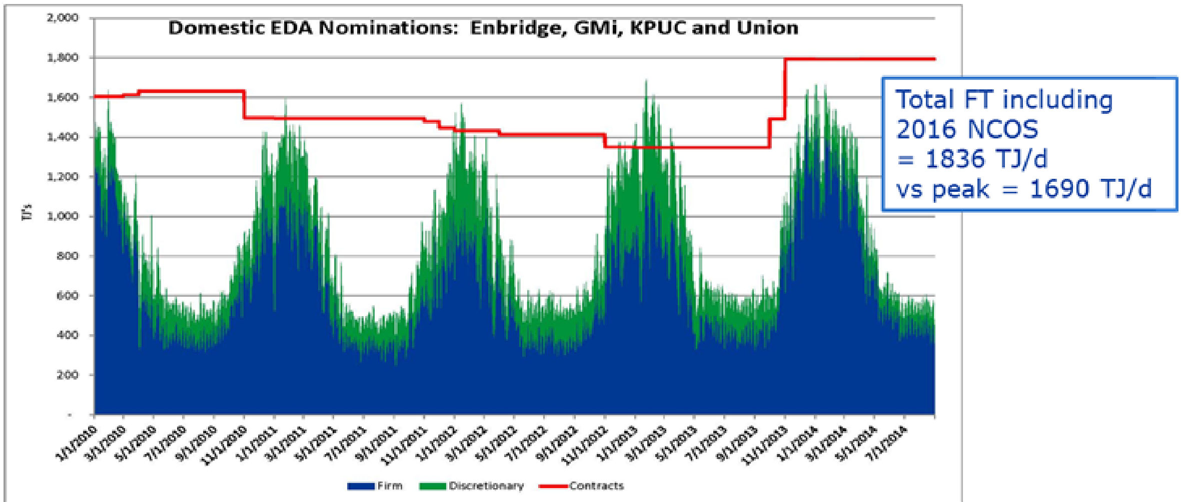
The Mainline is a contract carrier pipeline. The Mainline's capacity, as well as any subsequent capacity additions, must be underpinned by long-term firm transportation (FT) service contracts. If the Mainline has available capacity as a result of shippers using less than their firm contract levels or as a result of decontracting, this is used to provide discretionary services. The NEB has confirmed that the pipeline's obligation is to provide capacity to meet firm contract service requirements, and that shippers who require capacity should contract for firm annual capacity to meet those requirements.

Current capacity to move gas through the Eastern Triangle to Affected Area markets is approximately 3.2 PJ/d. However, firm contract levels are less than that. The domestic market currently holds 1.8 TJ/d of firm contracts in the Affected Area, although the maximum historic flow has never exceeded 1.7 PJ/d. In addition, Mainline firm contracts held to northeast U.S. EDA export markets have declined in recent years. In 2007, these markets held 1.6 PJ/d of firm contracts. By 2014 firm contracts declined to 0.7 PJ/d, leaving 0.9 PJ/d of uncontracted capacity directly associated with export markets. In recent years, shippers in these export markets have gained access to alternative sources of supply, as discussed in Section 2.1.

TransCanada is designing the post-Energy East Eastern Triangle capacity into the Affected Area to reflect the 1.8 TJ/d of domestic firm contracts, and the 0.7 PJ/d of EDA export contracts, for a total of 2.6 TJ/d. Post-Energy East, the Mainline capacity available for domestic markets will be more than adequate to meet demand.

It is helpful to review actual historical data to validate the fact that Ontario gas markets will be fully served by the Mainline capacity post-Energy East. Figure 9 shows total domestic EDA nominations vs. total EDA FT contracts. In 2014, EDA domestic firm contracts exceeded peak day nominations by 150 TJ/d.

Figure 10 shows total existing Mainline EDA, post-Energy East system capacity and actual usage of the Mainline over the past four years. Post-Energy East capacity will be sufficient to meet current domestic FT contracts (which are higher than actual flows), newly subscribed FT identified through recent new capacity open seasons, and all FT export contracts (assuming all 700 TJ/d renew).



Domestic EDA's	Year				
	2010	2011	2012	2013	2014
Yearly Avg (GJ/day)	813,739	798,421	821,450	907,126	904,599
Summer Avg (GJ/day)	590,193	561,631	580,695	643,346	639,834
Winter Avg (GJ/day)	1,130,553	1,134,005	1,160,409	1,280,960	1,354,699
Peak (GJ/day)	1,633,619	1,592,652	1,569,812	1,690,988	1,667,308

Does not include Nominations from within the 'Affected Area'. Firm is FT, FT-NR, and STS. Discretionary includes IT, STFT, FT D, FT SN D, FT-NR D, STS O

Figure 9: Domestic EDA Volumes

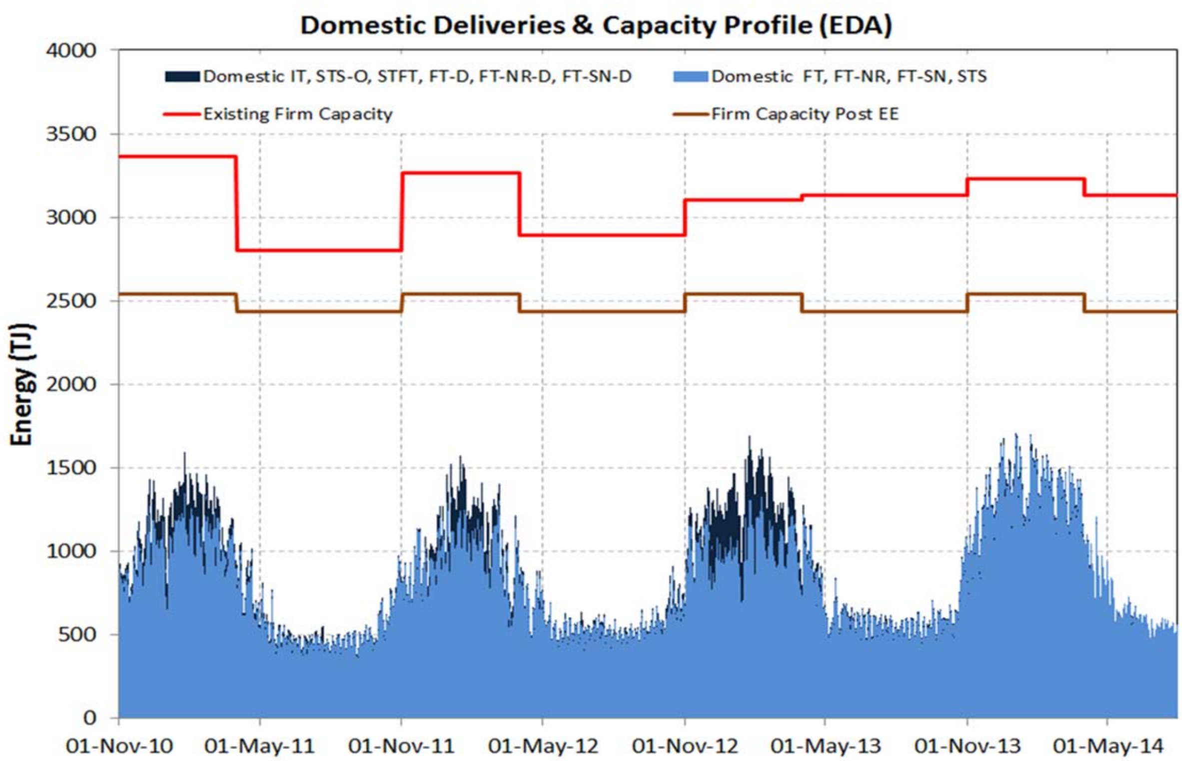


Figure 10: EDA Capacity and Domestic Market Flow

In order to validate TransCanada's market analysis, a review of recent EGD and Union regulatory filings and presentations was conducted for stated peak day demand and the adequacy of current Union and EGD firm Mainline contracts to serve that peak day demand (see Figure 11).

	GJ/d
Enbridge EDA	
Net Peak Day Demand	640,783
TCPL FT + STS Required to Meet Net Peak Day Demand	585,238
Mainline Contracts Held by EGD:	
FT + STS – Delivery to EDA	558,282
FT - Iroquois Delivery	66,956
Total	625,238
Excess Firm Contracts	40,000
Union EDA	
Peak Day Requirement	156,829
Mainline Contracts Held by Union: FT + STS - Delivery To EDA	162,621
Excess Firm Contracts	5,792

Figure 11: EGD and Union EDA Peak Day Analysis

In its 2015 Rate Application[1], EGD notes that it requires 585,238 GJ/d of Mainline firm service contracts to meet net 2015 EDA peak day demand. Actual Mainline firm contracts held by EGD that can be used to meet this requirement total 625,238 GJ/d as of January 1, 2015[2]. EGD has 40,000 GJ/d of Mainline firm contracts in excess of what is required to meet EGD's budgeted 2015 EDA net peak day requirements. EGD's rate application also shows that EDA peak day demand grew only 0.1% from 2014 to 2015[3].

[1] EB-2014-0278, Exhibit D1, Tab 2, Schedule 6
[2] TransCanada Mainline CDE Tables
[3] EB-2014-0278, Exhibit D1, Tab 2, Schedule 6

In Union's 2013-14 Gas Supply Plan Presentation to Stakeholders in April 2014, the most current publically available information, Union stated that peak day requirements in their EDA were 156,829 GJ/d. Actual Mainline firm contracts held by Union to the EDA to meet this requirement total 162,621 GJ/d[4]. Union has 5,792 GJ/d of Mainline firm contracts in excess of what is required to meet their 2013-14 peak day requirements.

Both EGD and Union's own analyses and evidence show that current levels of firm contracting on the Mainline are in excess of peak day demand forecasts, consistent with TransCanada's analysis.

Furthermore, TransCanada's analysis shows that Iroquois is forecast to become a supply point in the 2016/17 time frame (see Figure 12).

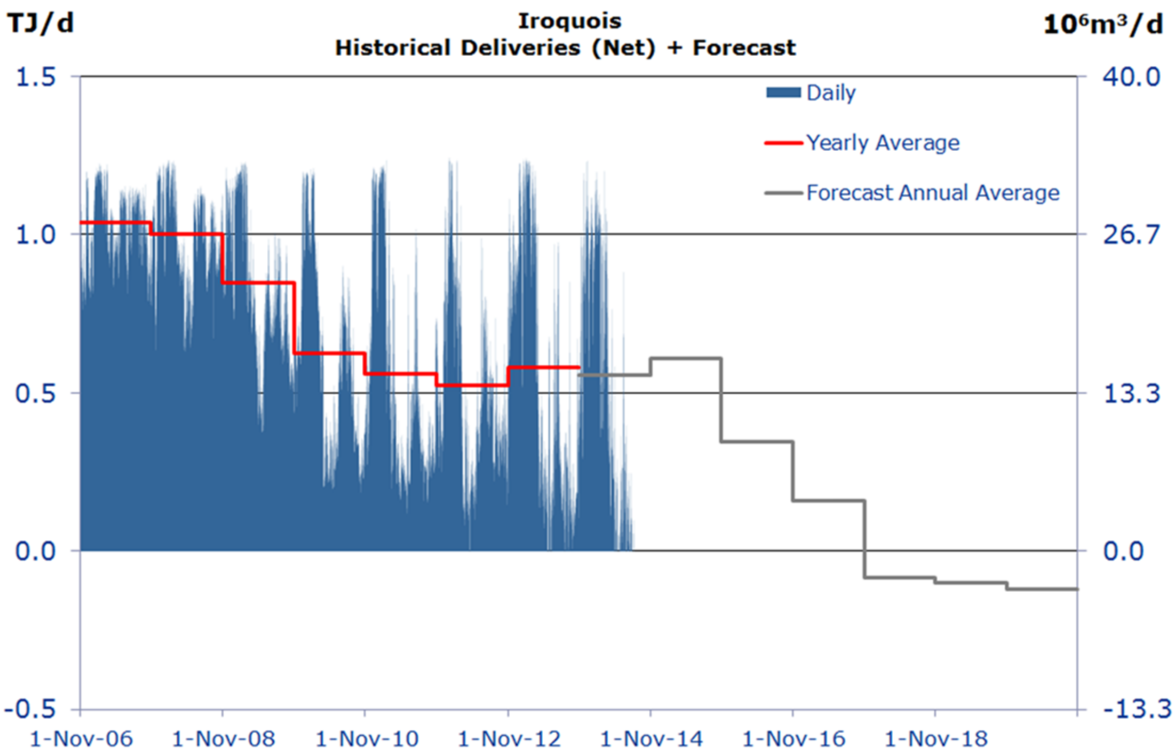


Figure 12: EDA Export Market Flow

Indeed there was zero export flow at the Iroquois point on more than 120 days during the summer of 2013, and there was gas that would have physically flowed into Canada at the Iroquois point had there been metering facilities to receive it.

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4 TransCanada Mainline CDE Tables

Beyond 2016 export flows at Iroquois are forecast to decline to zero and Iroquois will become an import point as northeast U.S. shippers obtain alternative Marcellus/Appalachian supplies through new pipeline projects such as Constitution, as discussed in Section 2.1 above. The forecasts of Rosenkranz[5], the Wood Mackenzie report filed by the Market Area Shippers in the RH-1-2014 proceeding (Attachment 1, pages 18-22), the Bentek forecast included in a June 2014 Boston LDC Forum presentation (Attachment 2), and the Iroquois Pipeline 2014 Boston LDC Forum presentation are all consistent with TransCanada's view that Iroquois will become an import point. Indeed, TransCanada has received expressions of interest for receipt service at Iroquois in the 2016 NCOS.

All of this suggests that there is a high probability that even more capacity will become available to serve Ontario and other domestic Canadian markets, and that regulators must be cautious not to require the construction of redundant Mainline capacity, the costs of which will likely be passed on to consumers in Ontario and Quebec.

5.0 TRANSCANADA COMMENT ON THE NAVIGANT REPORTS

TransCanada wishes to clarify two issues raised in the Navigant Reports.

In the report entitled "Winter 2013/14 Natural Gas Price Review" dated November 25, 2014 and filed in the 2014 Natural Gas Market Review, on page 21 and Figure 24 of the Report, Navigant infers that TransCanada's discretionary prices reduced available gas supplies to the Ontario market from Empress. This was not in fact the case. IT flows on the Mainline from Empress to Dawn from February 1 to March 15 2014 (2.1 PJ's) were significantly higher than they were in the same period in 2012 (0.25 PJ's) or 2013 (0.09 PJ's). Similarly, in this period for 2014, TransCanada sold 281,154 GJ/d more STFT than in each of 2012 and 2013. 2012 and 2013 were years in which TransCanada did not have pricing discretion for discretionary services. In addition, available capacity from NGTL to the Mainline was constrained last winter. During the period of February 1, 2014 to March 15, 2014 in which Navigant notes there were 21 days where flow was less than 1 TJ/d, NGTL was operating at capacity such that additional flows to the Mainline were not possible for a portion of this period. Therefore, pricing was not the only factor.

In the report entitled "2014 Natural Gas Market Review Final Report dated December 22, 2014 Navigant states on page 18 "The difficulty, however, over the long term is the fact that the price spread on average between AECO and Dawn, Ontario fails to cover pipeline tariff costs…" Navigant goes on to say "At these prices, holding pipeline capacity is not an economic proposition and is a disincentive to

[5] John A. Rosenkranz Presentation, "An Assessment of Dawn-Parkway Transportation Service Turn Back", 2014 Ontario Natural Gas Market Review, Stakeholder Conference September 3-4.

holding Mainline system capacity. This no doubt also contributes to the decreased utilization on the Mainline system…"

TransCanada notes that the Mainline condition of costs not being covered by the price spread (capacity is out of the money) is not unique. Essentially all North American pipelines are experiencing the same phenomena. Even though historical summer or yearly average price spreads from NIT to Dawn are "out of the money" during short periods where long term firm contract levels are insufficient to meet the total market requirements, the price spread does widen significantly in other periods of the year (example: winter 13/14) and shippers do acquire FT contracts on the Mainline. TransCanada's long-haul contracts have increased significantly over the past two years and now stand at approximately 3.3 PJ/d. We must conclude these shippers have determined that holding TransCanada Mainline capacity is economic.

6.0 TRANSCANADA COMMENT ON OEB POLICY ISSUES

TransCanada appreciates the opportunity to comment on the following items of interest on the Proposed Issues List contained in the December 23, 2014 OEB letter on next steps.

Issue 1: How can the Board's assessment of distributor natural gas supply plans be enhanced to ensure a better understanding of the various elements of the plan, the potential risks associated with those elements, and the applicant's proposals for methods of managing those risks?

TransCanada observes that the Ontario LDCs value supply diversity. The WCSB, with its abundant supply, can contribute to this diversity. An illustration of the value of WCSB supply occurred in the winter of 2013/14, which saw Dawn prices rise much higher than western Canadian prices at NIT (market within NGTL system). Firm long haul Mainline capacity held by the LDCs allowed access to the relatively inexpensive WCSB supplies during times of price spikes at Dawn. EGD stated in its EB2014-0039 QRAM application that fully utilizing its Mainline firm long haul contracts saved Ontario consumers $97.4 million as compared to buying gas at Dawn. Ontario access to WCSB supplies can help mitigate gas price volatility. However It is important to note that, as a contract carrier, TransCanada has no obligation to maintain Mainline capacity that is not underpinned by firm contracts and does have an obligation to minimize costs. As a result, without sufficient contracts, long haul Mainline capacity that allows Ontario to access WCSB supply may be retired or repurposed over time. The OEB should take this into consideration when evaluating LDC gas supply plans.

Issue 3: What is the appropriate role of the Board in relation to the efficient operation of the natural gas market in the public interest, for example, regarding the sufficiency of Ontario access to northeastern U.S. gas supplies?

TransCanada reiterates its comment in regards to Issue 1 above that the Board should give consideration to the supply diversity benefit of sourcing gas from the WCSB. In Section 2.1 of this submission it is noted that the Marcellus/Appalachian supply growth forecast is very large and, as a result, infrastructure development is being driven by this supply push. In other words, the supply growth will result in new infrastructure being built even if Ontario LDCs do not sign long term contracts on behalf of their system supply customers.

7.0 CONCLUSION

TransCanada appreciates the opportunity to contribute to the OEB's energy market review. As noted in this submission, TransCanada has been a trusted partner in supplying Ontario's energy needs for over half a century. Looking ahead, TransCanada will continue to ensure that Ontario's natural gas markets have the necessary infrastructure to access diverse and reliable supply sources. While Energy East will provide very significant benefits for the entire country, it will specifically benefit Ontario gas consumers by transferring Mainline gas assets to higher value use while concurrently ensuring that Ontario's firm contracted supply requirements are fully met.

Hearing Order RH-001-2014

TransCanada PipeLines Limited (“TransCanada”)

Application for Approval of 2013 to 2030 Settlement Agreement

NEB File OF-Tolls-Group 1-T211-2013-05 01

Appendix C

to the Joint Written Evidence of the

Market Area Shippers

Hearing Order RH-001-2014

TRANSCANADA APPLICATION
FOR APPROVAL OF 2013 TO 2030 SETTLEMENT AGREEMENT

Expert Report and Direct Testimony

Prepared By

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On behalf of

MARKET AREA SHIPPERS GROUP (MAS)

July 4, 2014

Q 1 Please state the scope of your engagement that resulted in the development of this evidence.

A1 Wood Mackenzie was requested on behalf of Union Gas Limited, Enbridge Gas Distribution Inc., and Gaz Métro Limited, to prepare a report highlighting changes in the North America natural gas industry starting as early as 2000, with emphasis on changes that have occurred since TransCanada PipeLines Limited (TransCanada) filed its ratecase (RH-003-2011) in 2011. We were also requested to include analysis of the TransCanada Application and how it might impact the landed cost of gas within eastern Canada if approved and implemented.

Q 2 How is the evidence structured?

A2 This evidence addresses: (1) North America gas production forecasts and changes since 2000, with particular focus on the period post-2011; (2) the forecast for North America gas demand and use during this same timeframe; (3) the evolution of natural gas pipeline flows throughout North America since 2000 as the markets shift from a long-haul transportation structure to a more regionally based structure; and (4) the landed cost of natural gas in Ontario and Québec should the Application be approved.

The first part of this evidence addresses the evolution of fundamental changes in North American natural gas markets that have occurred starting as early as 2000, especially as related to the gas supply picture in the U.S. and Canada since 2011 and how the supply changes are impacting the way the market functions. Since 2011 North America gas markets have been impacted by the game changing ability to develop and produce vast amounts of natural gas from shale formations, especially in the U.S. Northeast. Changes in demand, driven by the extreme oscillations of the economy, hydrocarbon prices, the use of renewables and the natural gas supply changes themselves, are then discussed as well as the impacts of the supply and demand shifts on pipeline flows, imports and exports of natural gas (both between the U.S. and Canada as well as North America and the rest of the world), and natural gas pricing. These developments provide context for an understanding of the future utilization of the TransCanada Mainline.

The final section of the evidence discusses the landed costs of gas for deliveries within Ontario and Québec under the current in force "compliance" tolls and under the currently proposed (Settlement) tolls.

Unless indicated otherwise, all analysis is based on Wood Mackenzie's past and current long term forecasts of the natural gas markets in North America. These forecasts are proprietary, developed for the benefit of our retainer service subscribers.

Evolution of the North American Natural Gas Market Since 2000

Q3 Could you provide a general review of the evolution of the natural gas markets within North America that have occurred since 2000?

A3 Yes. Following many years of abundant, inexpensive gas being available throughout North America, which encouraged significant development of gas fired generation, the traditional conventional supplies in the U.S., especially in the Gulf of Mexico, began declining. In 2000, production from the Gulf of Mexico was approximately 13.3 bcfd, peaking the next year at 13.6 bcfd. By 2006, that area was only producing 7.9 bcfd. This was also the year that production in the Western Canadian Sedimentary Basin (WCSB) reached its peak production of 16.7 bcfd.

During these same years, producers in the Barnett Shales in Texas were mastering techniques to economically extract gas from the shale formations, and others were taking those techniques and applying them to tight sands formations in the U.S. Rockies where production had grown from 5.1 bcfd in 2000 to 8.4 bcfd in 2006. Wood Mackenzie's 2006 forecast contained the following quote relative to gas supply in the U.S.: "Although conventional production for the U.S. lower 48 states onshore is in decline, unconventional production from tight gas, shale gas, and Coal Bed Methane are forecast to grow and enable mid-term supply growth." According to the 2006 Wood Mackenzie forecast, unconventional gas was expected to make up 43% of all supply by 2011 and overall U.S. production was expected to increase to approximately 54 bcfd, from a low of just under 50 bcfd in 2005. In reality, total U.S. production was 62.9 bcfd in 2011, with unconventional sources comprising 68%, 34% of which was shale gas production. The year 2005, in retrospect, was a pivotal year for natural gas production in the U.S. The Barnett, Fayetteville and Woodford shales were looked at as the key supply sources for the future. By 2008, the Marcellus and the Haynesville began development in the U.S. and the Montney in Western Canada was producing approximately 0.4 bcfd. 2008 was also the year that total U.S. and Canadian production reached approximately 70.4 bcfd, exceeding the previous high of 70.2 bcfd in 2001.

Q4 More specifically, what changes in the North America Natural Gas markets have developed since 2011, the year TransCanada made its filing in RH-003-2011 proceeding?

A4 Gas prices above $7.00 per Dth (nominal USD) from 2004 through 2008 encouraged producers to drill anywhere there was the reasonable potential to find and produce gas. The experimentation with the horizontal drilling and fracturing techniques developed in the Barnett shales and perfected in the Fayetteville were continually being refined as the potential for rich rewards attracted enthusiastic independent producers to hunt for gas. The years from 2006 through early 2011 saw an annual average 2% growth in North American gas production, but by the end of 2011, we had seen a 6% year over year increase in overall production. Much of that growth can be attributed to an increase in production in the Marcellus from 1.4 bcfd in 2010 to 3.3 bcfd in 2011. The growth rate in the Marcellus, while impressive for one year, has continued to increase with production growing in magnitude even more rapidly from 2011 to today.

Table 1 – Annual Average Daily Production from the Marcellus and Utica Shales (bcfd) *

	Marcellus	Utica	Total NE	% Change
2010	1.38	0.00	1.38	
2011	3.44	0.00	3.44	149.3%
2012	6.66	0.02	6.68	94.2%
2013	9.93	0.33	10.26	53.6%
2014	12.76	1.06	13.82	34.7%

Source: Wood Mackenzie

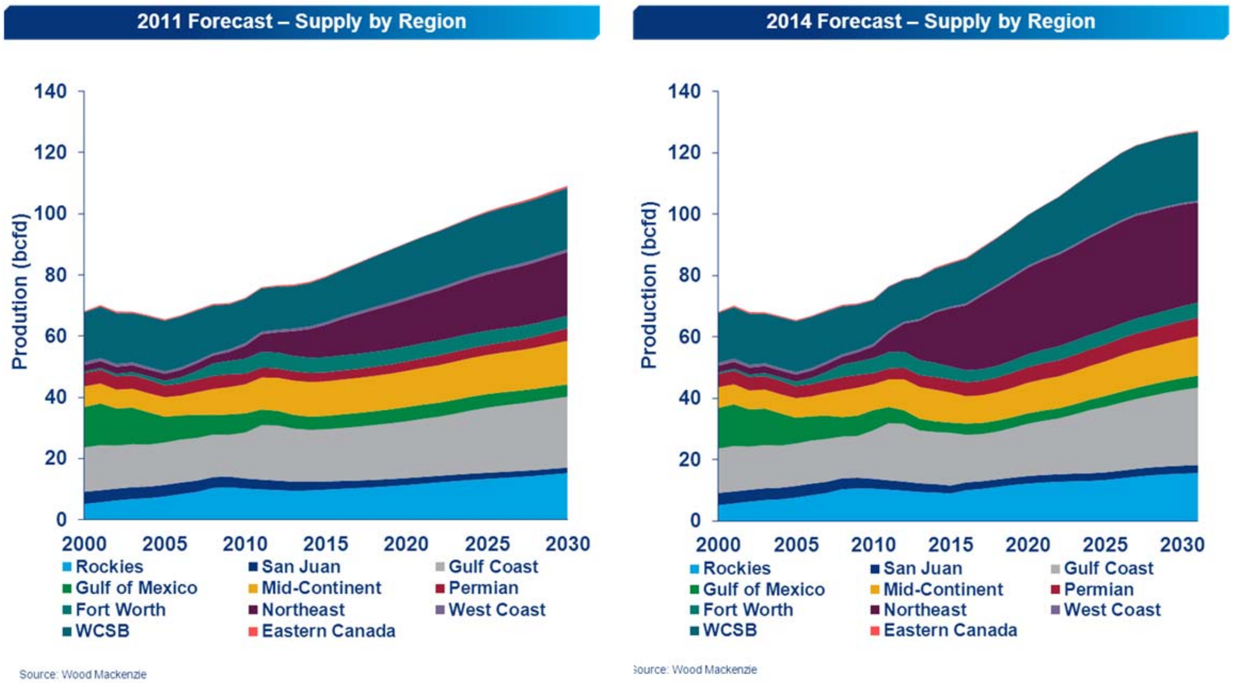
*2014 forecast

Since the RH-003-2011 application in 2011, the natural gas industry in North America has continued to evolve. Back in 2011, total U.S. and Canadian gas production was forecast to reach 76.9 bcfd by the end of 2013 and 90.5 bcfd by 2020. Actual marketable natural gas production in the U.S. and Canada reached 79.7 bcfd in 2013. This level was 2.8 bcfd greater than anticipated in 2011. Wood Mackenzie now forecasts this level to reach 99.8 bcfd by 2020.

Q5 What has been driving this significant increase in North American natural gas production, post 2011?

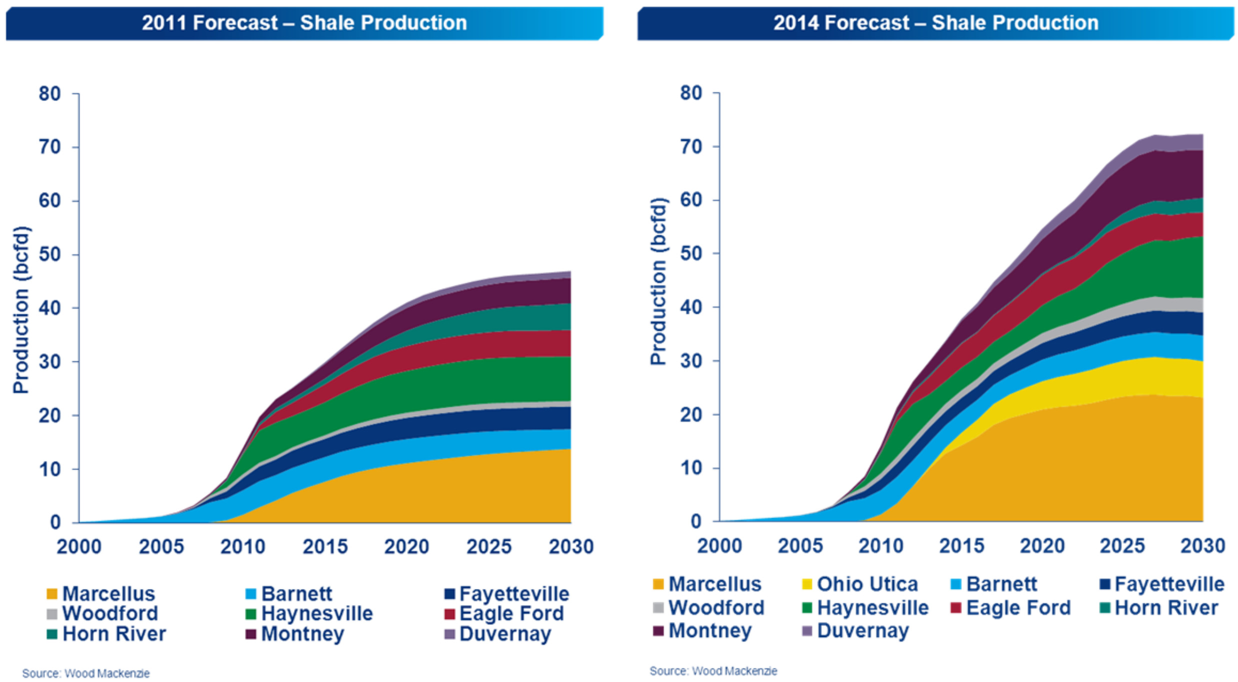
A5 Production levels beyond those forecast in 2011 in the U.S. lower 48 states shale formations, especially the Marcellus and Utica plays in the U.S. Northeast , is driving this significant increase. The Wood Mackenzie 2011 North American natural gas production forecast by geographic region is compared with its current, 2014 forecast in Figure 1.

Figure 1: Comparison of 2011 and 2014 North American Natural Gas Production by Region



In 2011, overall shale production in North America was forecast to reach 25.2 bcfd by 2013 and grow to 41.1 bcfd by 2020. The reality is that shale production has accelerated much quicker than anticipated, reaching 29.9 bcfd by 2013. Wood Mackenzie now forecasts shale production to reach 54.6 bcfd by 2020, a 33% increase over the forecast made in October, 2011. As alluded to above, much of the change in production is due to the growth in U.S. Northeast production, the fastest growing supply area in North America. The Wood Mackenzie 2011 shale production forecast by play is compared with the current 2014 Wood Mackenzie shale production forecast by play in Figure 2.

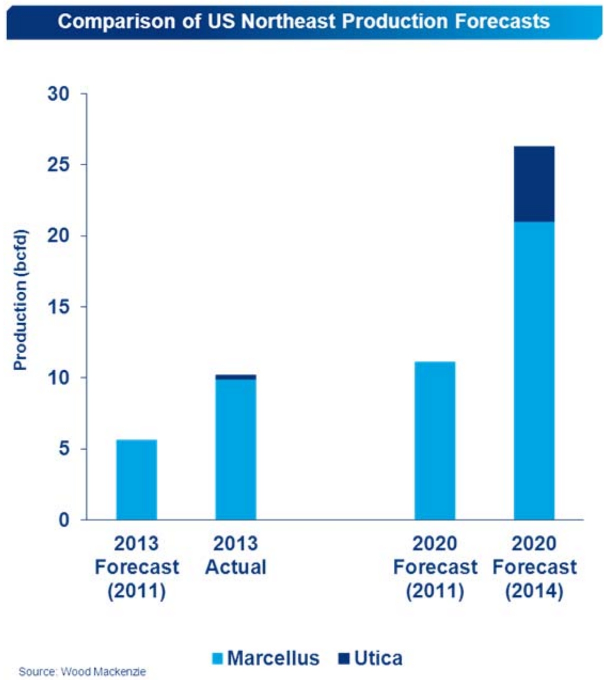
Figure 2: Comparison of 2011 and 2014 North American Shale Gas Production by Play (forecast and actual)



Q6 Please elaborate on why the U.S. Northeast is being viewed as the driver of natural gas growth in North America.

A6 Production in the Marcellus shale was approximately 3.4 bcfd by the end of 2011. The Utica, however, was not producing commercial volumes of gas at that time. By 2013, production in the Marcellus reached 9.9 bcfd and the Utica was producing 0.3 bcfd. Today, the Marcellus is producing approximately 12.8 bcfd and the Utica is providing an additional approximately 1.1 bcfd. The current forecast for production is approximately 21.0 bcfd and approximately 5.3 bcfd respectively by 2020, a total of 25.3 bcfd of gas production from these two northeast plays. This is almost 2.3 times the volumes forecasted by Wood Mackenzie in 2011. The 2011 Wood Mackenzie U.S. Northeast production forecast is compared with the current 2014 Wood Mackenzie U.S. Northeast production forecast in Figure 3.

Figure 3: Comparison of 2011 and 2014 Forecast U.S. Northeast Shale Gas Production



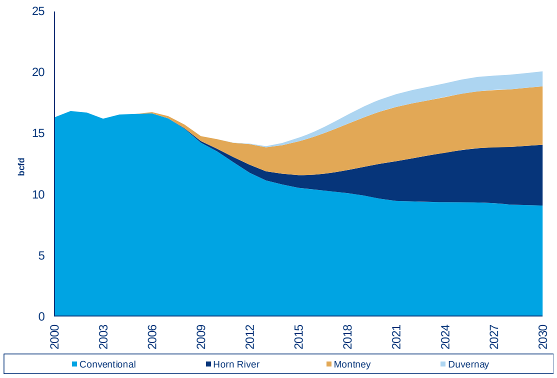
Q7 What has caused the more rapid than expected growth in production in these two U.S. Northeast plays?

A7 Changes in the cost of production in the U.S. Northeast from 2011 to today help explain much of the growth in production in the Marcellus and Utica. In 2011, the dry gas portion of the Marcellus featured a breakeven cost of supply of less than $3.50 per Dth (nominal USD). Incremental value of extracted natural gas liquids, which reduce the breakeven cost of supply in the liquids-rich sections of the southwest Marcellus and portions of the Utica shale, has brought the cost of supply in these areas even lower. Additionally, technology continues to play a significant role. Longer laterals, increased use of pad drilling, and closer fracturing zones have increased the initial production (IP) rates for the wells, allowing the costs to be spread over more units of production as well as allowing producers to recover their costs sooner. We are now seeing producers targeting “multi-zone” drilling, using the same wells to produce gas from multiple production depths and stacked plays. Today, the cost of producing supply in these basins is averaging below $3.00 per Dth (nominal USD). Some of the "wet" gas in southwest Pennsylvania is seeing costs of production after liquids credits below $2.00 per Dth (nominal USD). With natural gas prices at the Henry Hub averaging above $4.00 per Dth (nominal USD) today, there are strong incentives to increase production in these plays. Rapidly changing pipeline and processing infrastructure has also contributed to the significantly larger production numbers we are seeing today.

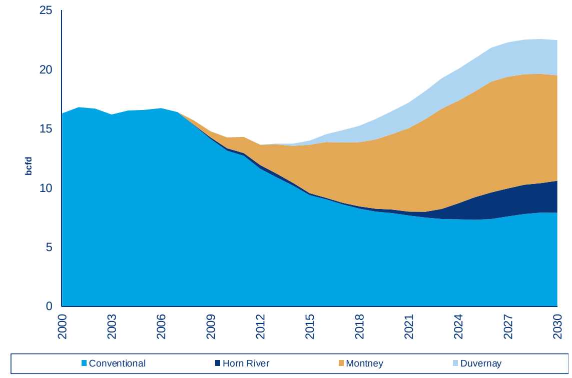
Q8 What has happened to production in the Western Canadian Sedimentary Basin (WCSB) during this time?

A8 While the U.S. lower 48 states have witnessed an overall increase in production, comparable changes in production in the WCSB have been modest during this period. The WCSB region was producing 14.3 bcfd in 2011 and from 2012 to 2014 has been averaging approximately 13.7 bcfd. Wood Mackenzie is currently forecasting a production level in the WCSB of 16.5 bcfd by 2020, driven by production in the Horn River of 0.3 bcfd, the Montney of 6.4 bcfd, and the Duvernay of 1.9 bcfd. The balance of 7.9 bcfd is expected to come from the traditional producing areas of the WCSB. This compares to a forecast of 17.7 bcfd for 2020 made in 2011 when western Canada shales were forecast to produce 2.9 bcfd in the Horn River, 4.3 bcfd in the Montney and 1.0 bcfd in the Duvernay. The balance of 9.6 bcfd was expected to come from the traditional producing areas of the WCSB. Competition from gas production in the U.S. Northeast is a key reason for the less optimistic view today, although economics in the Montney and Duvernay are improving, pushing production in the Horn River out to later in the forecast. The Wood Mackenzie 2011 WCSB production forecast by type is compared with the current 2014 Wood Mackenzie WCSB production forecast by type in Figure 4.

Figure 4: Comparison of 2011 and 2014 WCSB Natural Gas Production Forecast by Type



Source: Wood Mackenzie



Source: Wood Mackenzie

<u>North American Natural Gas Demand/Use Since 2000</u>

Q9 Have there been commensurate changes in North American natural gas demand since 2011?

A9 No. Indigenous North America demand growth has not kept pace with production capabilities. In fact, the productive capabilities of North American supply has been held back by the slower pace of demand growth and in some regions, a lack of access to markets through new pipeline facilities. New sources of demand are being developed, in the form of Liquefied Natural Gas (LNG) exports from both the U.S. and Canada, and a resurgence of industrial demand, primarily chemicals, fertilizers, and Direct Reduced Iron steel plants in the U.S., and increasing oil sands production in Canada. In 2011, U.S. industrial consumption of natural gas was forecast by Wood Mackenzie to reach 18.7 bcfd by the end of 2013 and increase to 21.4 bcfd by 2020. Actual consumption by the U.S. industrial sector was 20.5 bcfd in 2013 and is now forecast by Wood Mackenzie to increase to 24.3 bcfd by 2020. In the 2011 Wood Mackenzie forecast, Canadian industrial demand was forecast to reach 4.2 bcfd by 2013 and 5.2 bcfd by 2020. Actual industrial demand, lead primarily by the oil sands in Alberta, reached 4.0 bcfd in 2013 and is now forecast to reach 5.1 bcfd by 2020.

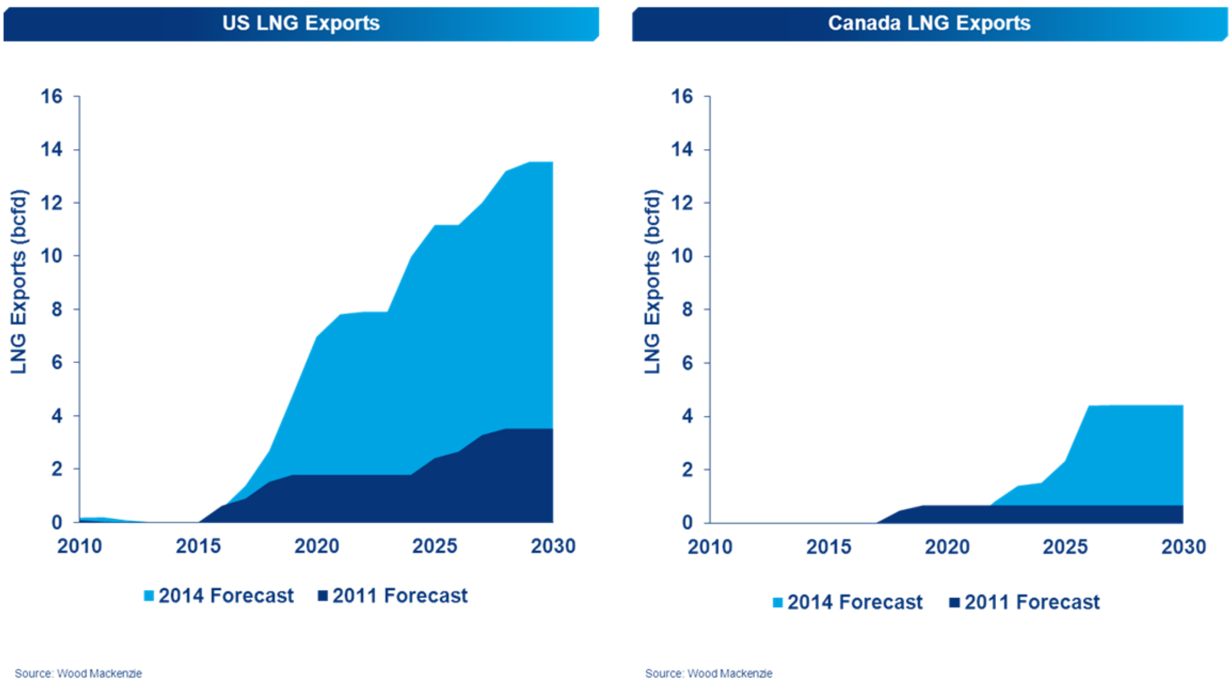
The differences in the forecasts for electric consumption are moderate in the U.S. In 2011, U.S. power sector demand was forecasted to reach 22.0 bcfd in 2013 and increase to 24.9 bcfd by 2020. Actual consumption in the power sector reached 22.3 bcfd in 2013 and Wood Mackenzie now forecasts consumption in the power sector to grow to only 24.0 bcfd by 2020 due to increased demand efficiency and increases in renewable energy sources. The Wood Mackenzie 2011 forecast for Canadian demand for gas in the power sector was 0.9 bcfd by 2013 but actual consumption reached 1.3 bcfd by 2013. The Wood Mackenzie 2011 forecast for 2020 was to reach 1.0 bcfd but is now expected to reach 1.8 bcfd, a 38% increase due to a forecast of increased coal plant retirements in Alberta.

Q10 In 2011, LNG exports from the U.S. and Canada were included in the forecast. Has anything changed in your view on this new market as a result of the increases in production discussed above?

A10 Yes, since 2011 the growth in North American natural gas production in absence of a corresponding level of demand growth has led to changes in our U.S. and Canadian LNG export expectations. In 2011, the U.S. and Canada were forecast by Wood Mackenzie to commence LNG exports in 2016 and 2018, respectively. U.S. LNG exports were expected to grow from 0.63 bcfd in 2016 to 2.4 bcfd by 2025. LNG exports from Canada were expected to grow from 0.5 bcfd in 2018 to 0.7 bcfd in 2025 and remain at that level through 2030.

Our current outlook for North American LNG exports has changed dramatically. U.S. LNG exports are forecast to commence in 2016 at 0.5 bcfd and grow to 7 bcfd by 2020 before increasing to 11.2 bcfd by 2025. LNG exports from Canada are now expected to commence in 2022 with 0.8 bcfd being exported, and increase to 4.4 bcfd by 2026. The delay in our forecast for Canadian LNG exports is primarily driven by the "Greenfield" nature of the facilities, making them more costly and time intensive than "Brownfield" repurposing of existing import facilities in the U.S. The delays are not attributable to a lack of gas supply to act as feedgas to the proposed facilities, as we believe there is more than adequate economic production that can be developed to supply these projects once constructed. The Wood Mackenzie 2011 and 2014 LNG North American export forecasts are compared in Figure 5.

Figure 5: Comparison of 2011 and 2014 North American LNG Exports



<u>**Evolution of Natural Gas Markets and Transportation Since 2000**</u>

Q11 You have discussed several changes that have occurred, and are expected to continue to occur in the supply and demand balances in North America. How are these changes impacting the overall market, especially related to pipeline flows and utilization?

A11 Changes in demand and the growth in U.S. Northeast supply especially, has led to significant reconfigurations and additions of pipeline capacity to enable growing supply to reach markets. Expansions of take-away capacity in the U.S. Northeast have enabled increasing amounts of gas production to reach both eastern Canadian and eastern U.S. markets within the immediate region and beyond, taking away markets traditionally served by other production basins located much further away. Markets within several hundred miles of the Marcellus and Utica are increasingly being served by gas production from these plays, displacing more traditional supplies from the U.S. Southwest, mid-continent, and western Canada. Regional production is serving regional demand, to the extent infrastructure and economics allow. In addition, newly approved and proposed projects are designed to increase access for U.S. Northeast production to Ontario, Québec, Maritimes, New England and the rest of the U.S. Northeast, the U.S. Midwest and the U.S. Southeast.

Current supply takeaway capacity in northeast Pennsylvania, a key producing region of the Marcellus, is approximately 7.7 bcfd. This is expected to increase by approximately 4.6 bcfd by 2017 to total over 12 bcfd, with: 60% of new volumes headed to the East and Southeast to serve new and existing U.S. markets along the Atlantic seaboard; 35% of the volumes headed to the North and Northwest towards Canada and the U.S. Midwest; and the rest serving local demand.

In the area comprised of Ohio, West Virginia and the southwest region of Pennsylvania, current takeaway capacity is approximately 6.8 bcfd into mainline pipelines. Capacity is expected to increase by approximately 8.0 bcfd to total nearly 15.0 bcfd by 2018. Approximately 5.0 bcfd of this new capacity is planned to enable southwest Pennsylvania production to reach new and existing markets in the U.S. Southeast and 2.6 bcfd of additional capacity is expected to enable Marcellus and Utica production to access the Midwest markets, including pipelines that can deliver gas directly or indirectly into Dawn and Ontario. There are several proposals, specifically Nexus, ANR and ETP Rover that, if constructed, will enable direct access for Dawn and Ontario from the Utica and Marcellus.

Wood Mackenzie has included, in its forecast models, 64 pipeline projects in the eastern U.S. and Canada to be undertaken between 2014 and 2020, with a combined capacity of approximately 25 bcfd. These include projects within the Marcellus and Utica to allow gas to reach mainline pipeline capacity, projects designed to allow mainline pipelines to reach northeast U.S. and eastern Canada markets, and projects designed to reach markets that are more remote from the Marcellus and Utica, primarily the

U.S. Midwest and Southeast. A suite of projects is planned by Union Gas, Enbridge and TransCanada in southwestern Ontario and within the Greater Toronto Area that will increase capacity in the Eastern Ontario Triangle (EOT) to accept and transport gas from eastern Canadian receipt points, including Dawn, Niagara and Chippawa, to eastern Canadian markets and beyond.

Q12 Are regions outside the U.S. Northeast and eastern Canada experiencing similar changes in pipeline flows and regional supply and demand dynamics?

A12 Yes, for instance, the U.S. Gulf Coast is increasingly being served by gas produced in the Eagle Ford, Barnett, Haynesville, Fayetteville and other shale plays, in addition to gas from Oklahoma and the Midcontinent that used to target upper Midwest markets.

Q13 Please provide examples of how the natural gas system is shifting from a long-haul system to a more regionally focused system.

A13 Massive supply growth in the U.S. Northeast, continued development of both supply and demand (power, industrial and LNG export)in the U.S. midcontinent and along the U.S. Gulf Coast, the concentration of new demand markets in the U.S. Southeast and eventually LNG exports along the Canadian west coast are reshaping pipeline flows throughout North America. In combination, changes in the sources of supply and the resulting changes in pipeline flows are driving the North American pipeline system from a long haul transportation system to a more regionally focused system.

A significant portion of market demand in the U.S. Northeast and eastern Canada has historically been met with natural gas from the U.S. Gulf Coast, offshore Gulf of Mexico and the WCSB. Today and in the future, demand in the U.S. Northeast will increasingly be met by U.S. Northeast production, primarily from the Marcellus and Utica. The market within the EOT and U.S. Northeast has replaced some WCSB supply with gas sourced from Dawn and/or from the Marcellus and Utica. The EOT region will increasingly access supplies from the U.S. Northeast, to the extent infrastructure within the EOT and to the eastern receipt points into Canada (such as Nexus and ETP Rover) are constructed to support those increases. Supplies from the U.S. Gulf Coast and off shore regions, western Canada and LNG imports into New England and the Canadian Maritimes will continue to meet seasonal and peak day demand within the EOT, as well as in the Canadian Maritimes and New England.

Notwithstanding the shift in supply source for the EOT, WCSB gas transported by the TransCanada Mainline will continue to be required to meet demand along the Prairies Line segment and Northern Ontario Line (NOL) segment. The EOT segment, especially during periods of high demand will also continue to rely on TransCanada Mainline deliveries. New WCSB production will eventually be targeting west coast Canadian LNG export projects.

Gas production in the mid-continent that has traditionally flowed north, into the Midwest, will be flowing south to supplement Gulf Coast production that will no longer be flowing north or east beyond the Georgia area. The mid-continent production will be required to meet growing demand from LNG exports, industrial demand growth along the Gulf Coast and pipeline exports into Mexico.

Many of the changes in flows in the U.S. Southeast use existing infrastructure. However, existing pipelines will need to be reconfigured to enable U.S. Northeast production to serve the growing U.S. Southeast demand. The long haul pipelines in the region are being bifurcated, with the southern portions continuing to flow eastward most of the time, and the northern portions beginning to flow to the south. The neutral point is approximately Georgia.

The growth in U.S. production is impacting other regions as well. As Marcellus and Utica production reaches Midwest markets, gas production in the U.S. Rockies, which traditionally served the Midwest, is increasingly seeking markets along the U.S. West Coast and Pacific Northwest. In turn, this is increasing gas-on-gas competition between the WCSB and U.S. Rockies gas.

The best way to illustrate how the North America pipeline system is evolving from a primarily long haul system to a more regionally focused system, is to view Figure 6 which shows Wood Mackenzie's 2014 forecasted 2020 annual average daily flows of natural gas along major pipeline corridors[1] throughout North America. These flows are average annual and do not indicate firm contract levels, or the requirement for contracted firm capacity during the winter season or on peak days to meet demand, which are significantly greater. This figure demonstrates the geographic reach of U.S. Northeast gas production. Flows from the Kentucky/Tennessee region towards the Texas/Louisiana region are expected to reach 1,277 mmcfd, as seen in the black circle. This growth in flows from the U.S Northeast to the U.S South is driven by growth in Marcellus and Utica production and is expected to significantly disrupt the traditional pattern of south to north flow with only 191 mmcfd average annual flow expected in this direction.

As a result of increasing flows from the U.S. Northeast to the west, flows from Arkansas/Oklahoma to Texas are expected to increase and flows from Texas to the Arkansas/Oklahoma region are projected to decrease. In 2020, flows towards Texas from Arkansas/Oklahoma are expected to reach 3,530 mmcfd and flows out of Texas to Arkansas/Oklahoma are expected to be minimal, at less than 200 mmcfd on average as shown in the red circle.

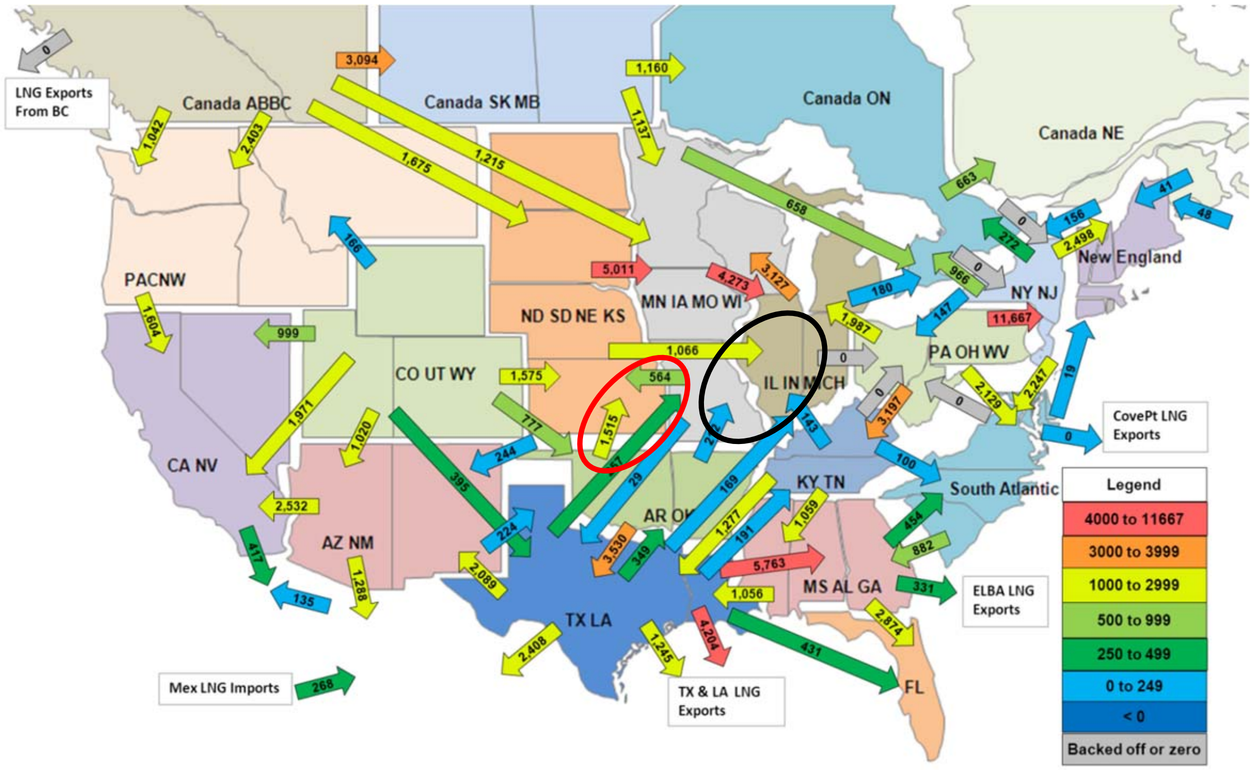
Similar to the two examples highlighted, gas entering Canada via import points throughout Ontario are projected to reach approximately 2.1 bcfd on average by 2020. Approximately 1.0 bcfd enters through the Niagara and Chippawa import points and 0.3 bcfd enters via the Iroquois pipeline (net of imports and exports) carrying gas from the Marcellus and Utica. The balance enters through Dawn via direct imports and comprises gas from the WCSB, Marcellus, Utica and other U.S. lower 48 states gas entering Dawn from Michigan, as well as gas injected and withdrawn from regional storage facilities. The level of

[1] These corridors do not in most cases, represent a specific pipeline, rather they represent general flows through many pipelines entering and exiting a region.

imports at Dawn, and supply access to Dawn will depend on appropriate infrastructure being constructed within the EOT. Average annual flows entering northern Ontario on the TransCanada Mainline are expected to be approximately 1.2 bcfd.

With additional debottlenecking of capacity within the EOT, Marcellus and Utica gas could enter Dawn and Ontario if any of the proposed projects, such as Nexus and ETP Rover, get constructed. Failure to increase capacity within the EOT and into the EOT has limited the ability of gas consumers in Ontario and Québec to take full advantage of the abundant, economic regional supplies from the U.S. lower 48 states, including the Marcellus and Utica. Without increased access to the Marcellus and Utica supplies, these forecast import numbers will not be met, requiring the EOT consumers to be more dependent on the more costly, long haul transportation connecting them with the WCSB. This is likely to increase overall costs for these consumers, particularly when load factor adjusted transportation costs to meet heat sensitive seasonal loads are taken into account.

Figure 6: 2020 Projected North America Average Annual Daily Gas Flows (from the 2014 Forecast)



Q14 Please describe changes in the U.S. Northeast that may be of particular interest to Ontario and Québec consumers?

A14 A comparison of 2011 and 2014 projections of the average annual flows of natural gas in the U.S. Northeast region from Wood Mackenzie's forecasts highlights the changes to traditional flows due to the rapid emergence of Marcellus and Utica production. Figures 7 and 8 illustrate these changes by showing average annual flows along key pipeline paths[2]. Figure 7 shows the projected annual average 2020 flows (under normal weather conditions) from the 2011 forecast and Figure 8 shows the expected2020 flows from the current 2014 forecast. Volumes of gas moving from Canada to New York via the interconnects at Niagara and Chippawa provide a good illustration of the changes in flows

[2] Again, paths do not represent a specific pipeline nor do they indicate firm contract levels or the peak flows experienced during the winter and on peak days.

brought on primarily by the development of the Marcellus Shale. In 2011, the 2020 flows were projected to be 330 mmcfd into Canada and flows from Canada into the U.S. were projected to be 43 mmcfd. In the 2014 forecast, no flows are expected from Canada to the U.S. and the expected flows into Canada have increased to 966 mmcfd at the Niagara and Chippawa interconnects. This phenomenon is occurring now and continues to be forecast even during extreme winter conditions.

Forecast 2020 imports into Dawn have not changed since the 2011 forecast, remaining at approximately 840 mmcfd. The yellow circles, however, indicate a flow change of importance to the Dawn import point and EOT consumers, as forecast flows from the Marcellus and Utica into Michigan in 2020 have increased from an anticipated 611 mmcfd from the 2011 forecast to an expected approximately 2.0 bcfd. Some of these volumes could be imported to Ontario at Dawn, for use in storage or to flow directly to serve consumers in the EOT and beyond. This gas can displace some of the WCSB gas flowing to Dawn, or with appropriate short haul pipeline capacity added within the EOT by Union Gas, Enbridge and TransCanada, this gas can add incremental volumes into the EOT and beyond from the Marcellus and Utica to allow additional load growth or to further reduce the reliance on the TransCanada Mainline, thereby reducing annual costs of landed gas within the EOT.

As can be seen in Figure 7, the 2011 projected flows from the northeast region of Pennsylvania to New York and New Jersey were 3,863 mmcfd by 2020. In the 2014 Wood Mackenzie forecast, flows on this corridor are expected to increase to 11,667 mmcfd, reflecting increased transportation capacity constructed or repurposed to accommodate significant amounts of increased gas production (reference blue circles on Figures 7 and 8).

The current projection for Marcellus and Utica gas to enter Canada via far eastern Canadian import points in 2020 is approximately 1.2 bcfd, with no flows, on an annual basis, of Canadian gas into the U.S., except those volumes that are exported into the U.S. Midwest and then imported at Dawn. Again, these flows may not reflect firm contract levels or their use during the winter and on peak days, especially relative to Iroquois Pipeline. This is contrasted by the anticipated flows from our 2011 forecast for 2020 that projected 0.33 bcfd flowing into Canada and 0.46 bcfd flowing out of Canada (exclusive of the Dawn dynamics mentioned above. These projected changes in average annual flows can be seen in the red circles on Figures 7 and 8. Much of the gas imported to Canada on the Iroquois Pipeline is expected to move further east to serve Vermont, the Canadian Maritimes and New England via the Portland Pipeline and the M & NE pipeline.

The green circles on Figures 7 and 8 show perhaps the most dramatic changes in projected flows and the changes that could ultimately impact consumers in Ontario and Québec the most. Flows along the main pipeline routes from Kentucky/Tennessee into Pennsylvania, Ohio, and West Virginia were expected to decrease to 0.27 bcfd as the Marcellus grew in size, displacing north bound flows of gas in our 2011 forecast. Today, with the significant uplift in production in the Marcellus and expected production in the Utica, the need to find markets for all that production has required pipeline modifications and construction which will allow an average of 3.2 bcfd to physically flow from the producing region towards the U.S. Southeast, in addition to the displacement that was already anticipated. This indicates that if more capacity is not made available to move U.S. Northeast production into eastern Canada, the volumes will be committed to other, more distant markets, making it contractually unavailable to consumers within the EOT region. Many of the capacity commitments being made out of the Marcellus are producers looking to sell their gas. Once they have committed to pipeline capacity that moves away from Canada, they will be unlikely to redirect their gas towards Canada until they produce more gas than can fill their committed transportation capacity. Timing is therefore important for Ontario and Québec consumers to access the abundant supply of the Marcellus and Utica shale formations. Debottlenecking of the EOT in a timely manner, combined with potential projects such as Nexus, ANR and ETP Rover, can increase the direct access to the Marcellus and Utica shales for consumers within the EOT.

Figure 7: 2020 Projected Annual Average Northeast Gas Flows from the 2011 Forecast

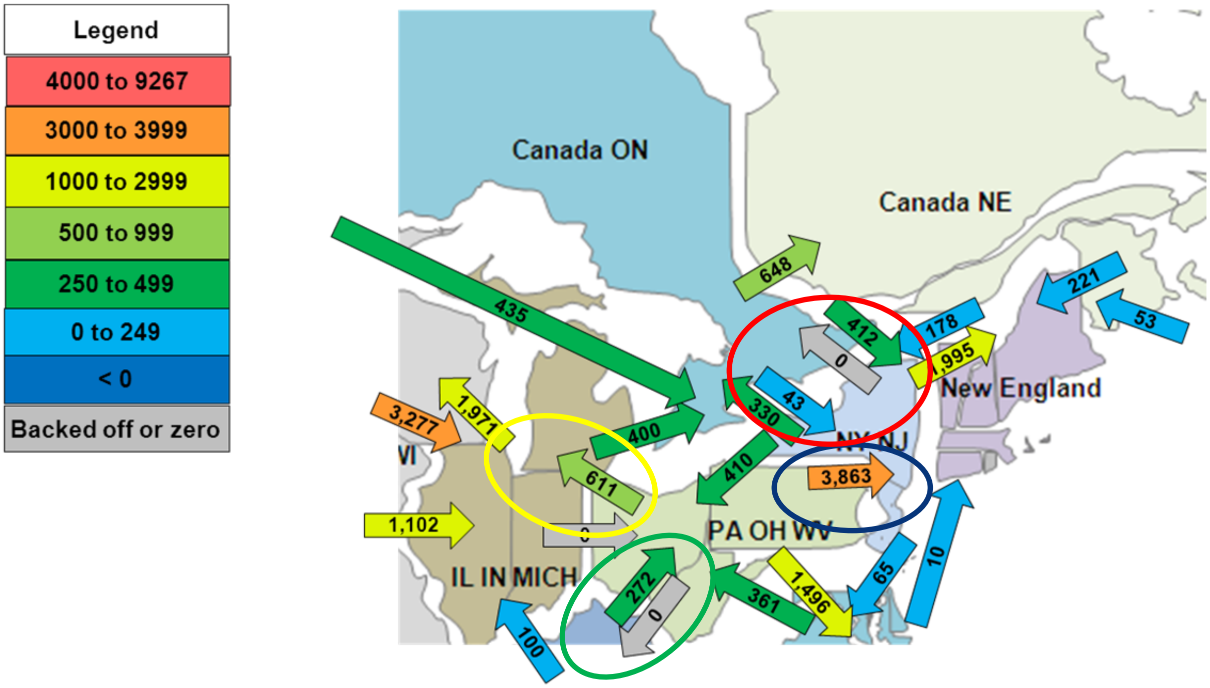
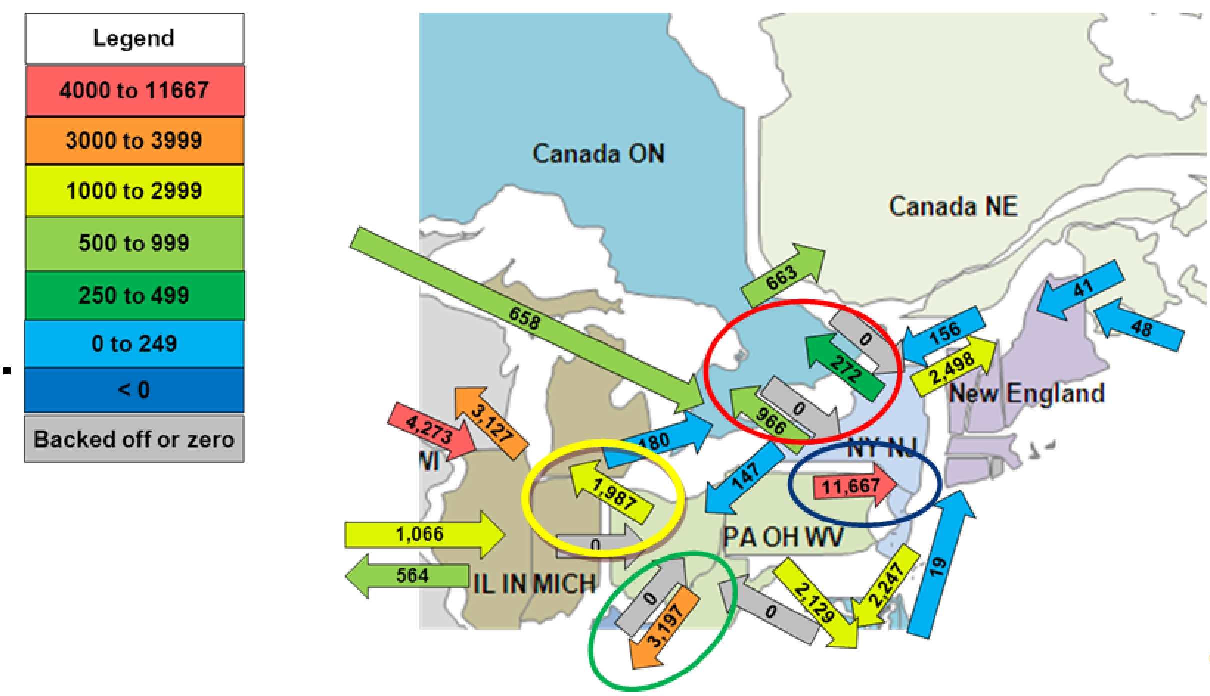


Figure 8: 2020 Projected Northeast Gas Flows from the 2014 Forecast



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Q15 What do these flow changes mean for consumers of natural gas throughout North America?

A15 A key implication of the transition from primary dependence on long haul transportation to a system that is much more regionally focused is that consumers will have access to lower cost, shorter distance transportation that can replace at least some of the more expensive long haul capacity they were reliant upon prior to the availability of more regional gas supplies. Customers with seasonal and peak day requirements will see the greatest cost savings due to the current need to pay for more expensive long haul capacity that is only used for a short period of the year. Where there is not sufficient pipeline capacity available to access regional supply or to transport that supply to market, these markets will be forced to continue their reliance on long haul. Long haul capacity will still play a key role for many consumers, particularly customers that do not have access to, or are more distant from the abundant shale gas production (such as Western Canadian markets located closer to the WCSB).

Having access to nearby gas supply, increasing diversity can increase competition among suppliers from all basins with access to a particular market, such as the EOT. Competition among suppliers, especially in an environment such as described earlier that exists within North America where gas production capability exceeds demand, generally means lower gas costs to consumers.

Other benefits that may be derived by increasing access to additional supplies include the potential for an increase in reliability due to diversity of supply, operational efficiencies due to the location of regional supplies (pressure support) and the ability to grow demand at potentially lower costs of delivered gas supply.

Landed Costs of Gas

Q16 With all of the changes that are taking place, what do you see happening to gas prices that are likely to be available to consumers in Ontario and Québec?

A16 Table 2 shows Wood Mackenzie's forecast average annual price for gas at AECO, Dawn, and Niagara/Chippawa for the years 2015 through 2020. The impact of implementing the proposed tolls on gas prices in these three supply areas are most pronounced at AECO. The appropriate average annual gas price is used in the discussion of the Landed Costs of Gas below.

Table 2: Annual Average Price of Gas

Compliance Tariff Scenario

Year	AECO	Dawn	Niagara
2015	$3.55	$4.08	$3.67
2016	$3.43	$3.99	$3.71
2017	$3.47	$4.03	$3.78
2018	$3.72	$4.35	$4.11
2019	$3.91	$4.67	$4.42
2020	$3.91	$4.82	$4.57
Average	**$3.67**	**$4.32**	**$4.04**

Proposed Tariff Scenario

Year	AECO	Dawn	Niagara
2015	$3.53	$4.10	$3.68
2016	$3.28	$4.04	$3.74
2017	$3.34	$4.08	$3.82
2018	$3.58	$4.39	$4.14
2019	$3.75	$4.73	$4.49
2020	$3.66	$4.88	$4.63
Average	**$3.52**	**$4.37**	**$4.08**

Source: Wood Mackenzie

Q17 How does the Settlement impact landed cost of gas for consumers in Ontario and Québec as well as other Mainline customers?

A17 While the Settlement tolls proposal includes toll increases over the Compliance tolls, the Settlement tolls proposal includes TransCanada's commitment to work with Union Gas, Enbridge and Gaz Métro to increase the ability to move gas from eastern Canada receipt points throughout the EOT. Incremental pipeline capacity can accommodate future growth and can move some current purchases from the WCSB via the TransCanada Mainline to eastern Canadian receipt points.

With this in mind, Wood Mackenzie has undertaken an analysis of the combined impacts of higher TransCanada transportation tolls under the Settlement Toll scenario with the benefits of being able to use lower short-haul tolls that access eastern Canadian receipt.

Wood Mackenzie's analysis indicates that access to eastern Canadian receipt points, using the Settlement tolls, will save natural gas consumers who shift their procurement from long-haul, Empress-based transportation to short-haul, eastern receipt point based transportation (assuming 75% purchased at Dawn and 25% at Niagara/Chippawa) an average of approximately CDN $0.66 per Dth per day in overall landed cost based on a 100% load factor. A consumer utilizing only 80% load factor will save an additional CDN $0.25 per Dth per day in landed cost, for a total savings under the Settlement Toll scenario of CDN $0.91 per Dth per day. These savings are compared to long haul compliance tolls in an environment without access to incremental short haul capacity.

Customers that take the majority of their gas from the TransCanada Mainline, such as customers in the Prairies or parts of the NOL, are expected to have minimal economic impacts from the Settlement being implemented, as the average annual price of gas at Empress is expected to decrease slightly under the Settlement. The increased transportation costs are offset by the decrease in gas costs at Empress. For some of these customers, such as in the NOL, with new EOT infrastructure in place, there may be opportunities to also purchase gas from the eastern receipt points, providing diversity that they do not have today. For customers located within the Union NDA for instance, supply sourced from Dawn and Empress land at similar costs under the Settlement. As customers in the EOT shift away from Empress, more gas will be available to Mainline customers at Empress which puts downward pressure on Empress gas prices.

Q18 Are the expected benefits from the Settlement anticipated to be short term?

A18 No, so long as the fundamental assumptions remain similar in the long term, the gas cost savings should endure for a longer period of time. The economics may vary over time based on actual gas costs, but it is anticipated that from the benefits provided by the Settlement will be available for the foreseeable future.

Q19 Can you summarize your conclusions to this analysis?

A19 Yes. The increased production of significant volumes of low cost shale gas, especially in the Marcellus and Utica in the U.S. Northeast, is rapidly changing the North America natural gas business, especially in the U.S. Northeast and eastern Canada. The need for expensive long haul pipeline transportation is being replaced by less expensive short haul transportation that can access these nearby reserves. Low cost production growth is expected to continue well into the next decade.

Consumers in eastern Canada have had limited access to date to these nearby reserves due to limits in pipeline capacity within the EOT to accommodate potential increases in volumes available at eastern receipt points. The Settlement tolls provide a long term tolls framework that will allow increased access to alternative supplies, especially from the Marcellus and the Utica shale formations, through new pipeline capacity in the EOT. Even with the proposed increased costs associated with these tolls, total annual costs of gas to consumers in eastern Canada will be lower than they are under the current tolls. The Settlement provides the structure that will allow the needed pipeline construction to increase access to these supplies of gas at costs that are at a significant discount to Empress purchases and TransCanada long haul capacity, especially for customers that have seasonal loads and utilize capacity at less than 100% load factor. Additionally, customers outside of the EOT will see minimal changes to their current costs, but gain diversification through access to gas delivered at eastern receipt points, an option that is not available today. The Settlement will not cause disruption to the overall Mainline market.

Put simply, a transition to short-haul transportation under the Settlement tolls, which considers transition costs, is less expensive for eastern Canadians than long haul transportation out of Empress under the Compliance tolls.

Additionally, having long term stability of tolls allows for better planning by consumers, producers and pipelines. Having stable tolls also makes the EOT a more attractive market for gas producers looking to sell their production on a long term basis.

Q20 Does this conclude your evidence at this time?

A20 Yes.

Northeast Will Begin Net-Exporting In 2017 On Annual Basis

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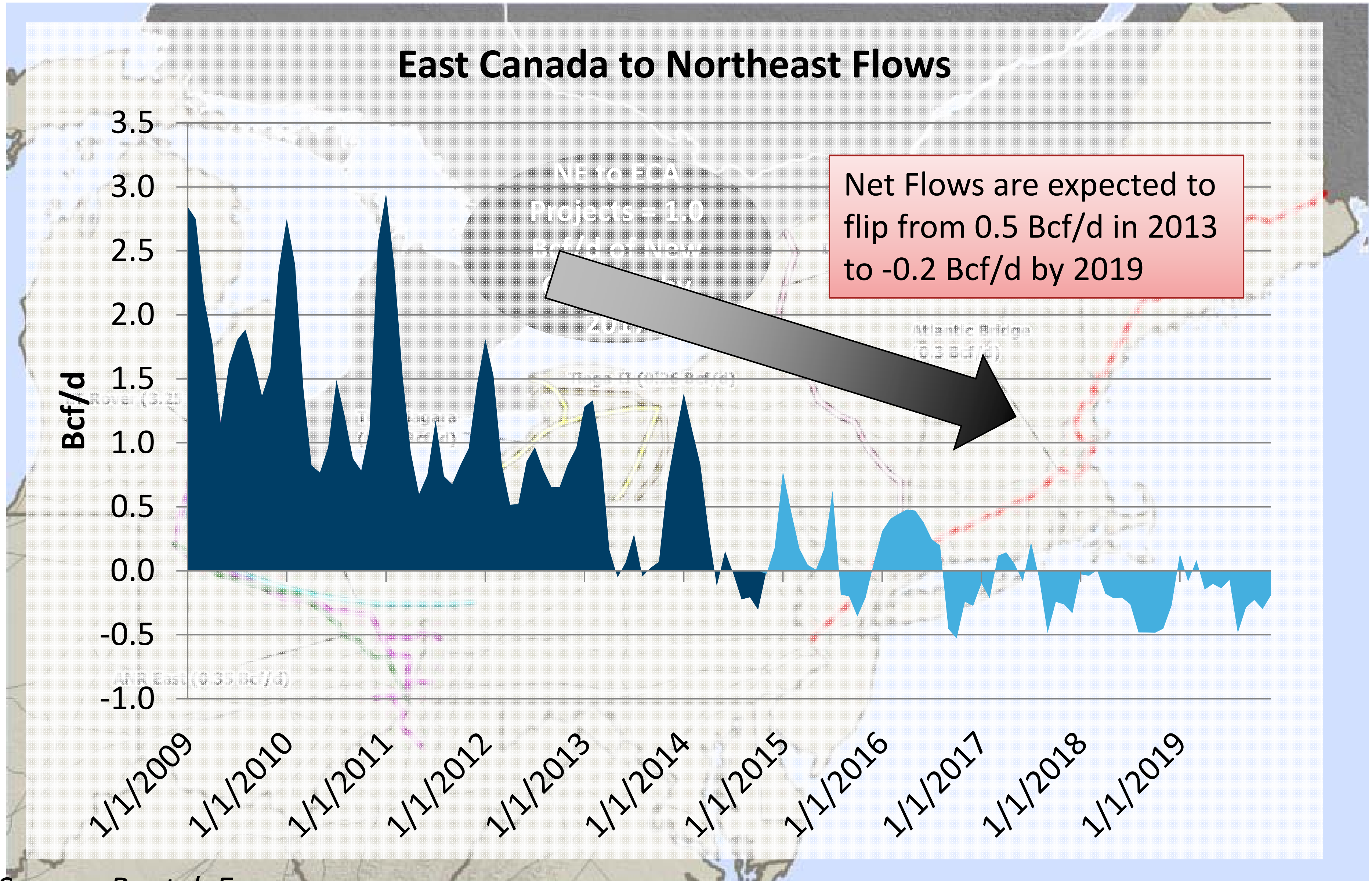

Source: Bentek Energy