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Energy East Oil Pipeline

Potential Implications on

Ontario Natural Gas Consumers

A Report Prepared by
Elenchus Research Associates Inc.

24/03/2015

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1 OVERVIEW

Elenchus was retained by the Ontario Energy Board ("OEB") to:

1) Review the TransCanada PipeLines Limited's ("TransCanada") Energy East application.
2) Consult with Ontario large volume natural gas customers to better understand their views on the impact of TransCanada's proposed Energy East Pipeline Project.
3) Prepare a report detailing these customers' feedback regarding the potential impacts of the Energy East Project.

This review and consultation focused on the natural gas pipeline impacts.

Elenchus is a leading Canadian consulting firm respected for its expertise and experience in economic regulation, focusing on the energy and the telecommunications sectors.

This report is a summary of the review and feedback that Elenchus received.

2 APPROACH

Elenchus reviewed TransCanada's proposed Energy East Pipeline Project application that was filed with the National Energy Board ("NEB") on October 30, 2014. Elenchus also met with a variety of individual large customers, customer associations and Local Distribution Companies ("LDCs") to obtain their feedback and input on how the Energy East project would affect them. Elenchus provided each customer group a summary of the natural gas components of the Energy East project along with a summary of issues (see Appendix 2) that had already been identified and which were already part of the Energy East dialogue.

Meetings included the following Ontario customers:

- Industrial Gas Users Association ("IGUA")
- Association of Power Producers of Ontario ("APPrO")
- Canadian Manufacturers and Exporters ("CME")
- Schools Energy Coalition
- Energy Retailers/Marketers
- Utilities (Union Gas Limited, Enbridge Gas Distribution Inc., Utilities Kingston, Kitchener Utilities)
- Association of Major Power Consumers of Ontario ("AMPCO")

The OEB held a meeting and WebEx with the large volume customers and associations stakeholders on March 12, 2015. This meeting covered the Elenchus report as well as the ICF report.

3 POTENTIAL IMPACTS OF THE ENERGY EAST PIPELINE

3.1 INTRODUCTION

TransCanada's Energy East Pipeline Project ("Project" or "Energy East") includes the conversion of one 42 inch nominal pipe size ("NPS") pipeline loop of the TransCanada Mainline (further discussion of the Mainline in Section 4) between the Alberta/Saskatchewan border (Burstall) and Iroquois Junction (near Cornwall) from natural gas to oil service. Energy East will also build new oil pipeline facilities upstream of Burstall and east of Iroquois Junction, pump stations and other facilities to complete the Project. In addition, TransCanada is proposing to expand one of its existing pipelines in southern Ontario (Eastern Mainline Expansion Project) to offset a portion of the loss of capacity when TransCanada transfers and converts one of its Mainline pipelines between North Bay and Cornwall from gas service to oil service. This proposed expansion line is a 36" pipeline between Markham and Iroquois.

TransCanada expects to transfer the following segments of NPS 42" to Energy East[1]:

- Prairies Section – Line 100-4
- Northern Ontario Line – Line 100-4 and portions of Line 100-3
- North Bay Shortcut – Line 1200-2.

The impacts of the transfer of these assets can be examined in three discrete sections:

- The Prairies (from Empress to the Manitoba/Ontario border),
- The Northern Ontario Line ("NOL") (from the Manitoba/Ontario border to North Bay), and
- The Eastern Triangle ("ET") (the remaining Mainline facilities in Ontario and Quebec south of North Bay, and east of the St. Clair River).

3.2 POTENTIAL IMPACTS

From the discussions with the large volume customers, Elenchus has generally categorized the impacts to Ontario natural gas customers from the proposed conversion as:

- The impacts to pipeline capacity, both now and in the future
- The implications to future natural gas tolls both initially and in the future

[1] Energy East Pipeline Ltd., Project Description Volume 1 page 1-4 March 2014 and RH-001-2014 Centra 9

- The implications to the Ontario natural gas commodity market
- The implications to service offerings.

4 DESCRIPTION OF THE TRANSCANADA MAINLINE

The TransCanada Mainline (“Mainline”) is an existing natural gas transmission corridor that consists of a number of parallel pipelines or loops, as shown in **Figure 1** below. Compressor stations are also situated approximately 80 kilometres (“km”) apart along the pipeline. These compressor stations serve to increase the pressure to account for friction losses along the pipeline. The Mainline serves markets in the Prairies, as well as Ontario, Quebec and various export markets in the Mid-West and Northeast United States.

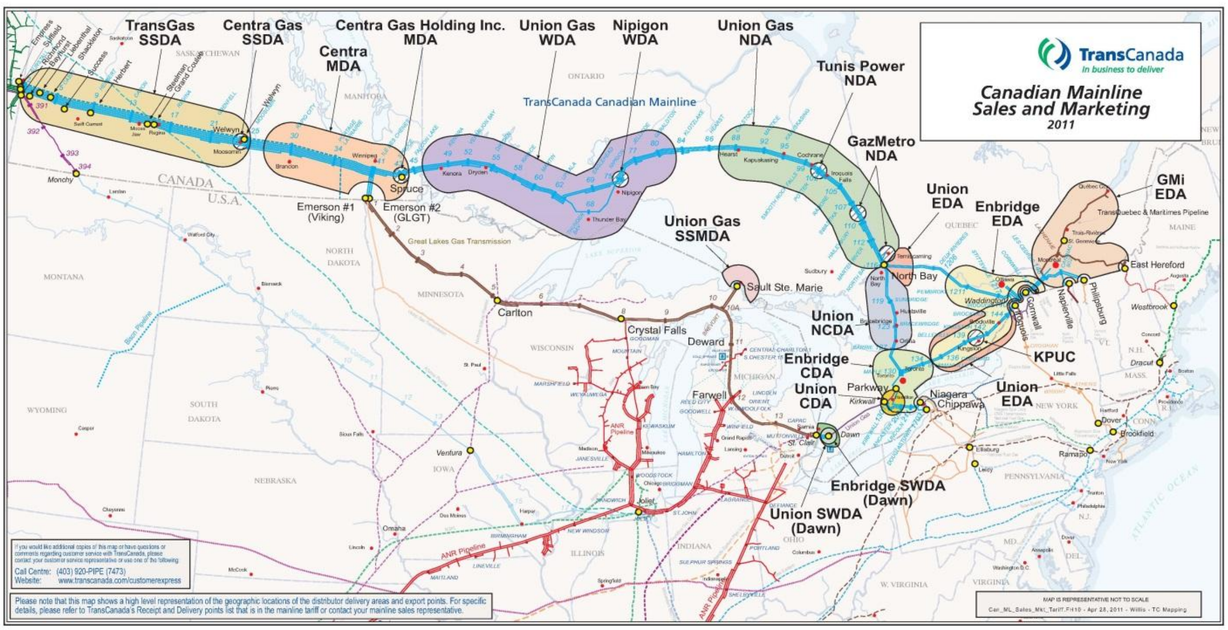

Figure 1: TransCanada Mainline Facilities

5 ONTARIO NATURAL GAS MARKET

Ontario is a significant Canadian natural gas market and Ontario’s storage and transportation facilities are critical to the Canadian and United States Northeast markets. In 2013, Ontario customers consumed 878 PJ (about 34% of all natural gas consumed in Canada). There are 3.5 million residential customers, 264,670 commercial customers and 12,176 industrial customers. **Figure 2** shows Ontario’s historical customer growth (note the two scales in the graph).

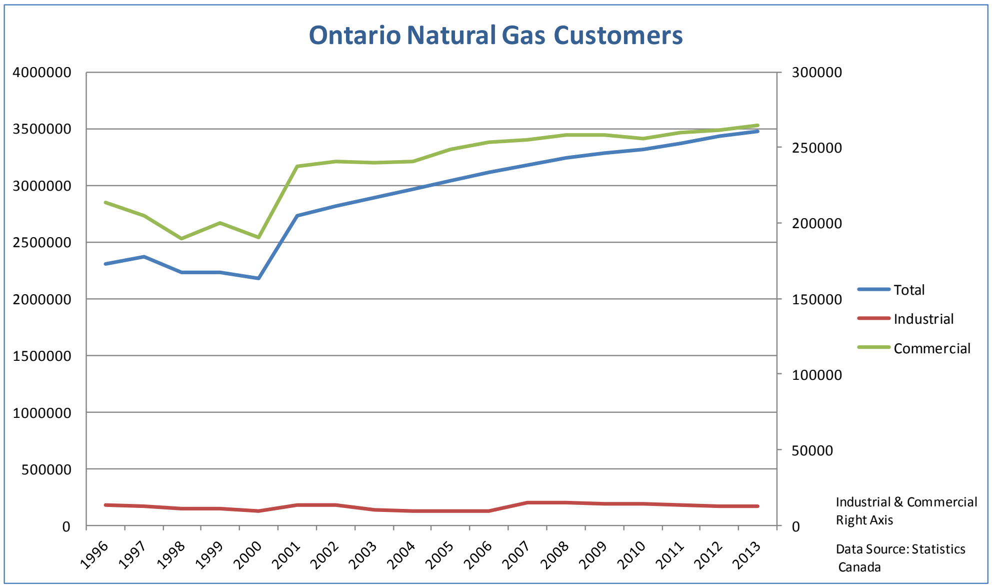

Figure 2: Ontario Natural Gas Customers

Figure 3 shows the historical and projected growth of natural gas power generation capacity in Ontario. Projections of increased natural gas use and demand include continued growth of natural gas power generation through to 2017. The Ontario Power Authority ("OPA") has projected about 10,000 MW of natural gas power generation capacity.

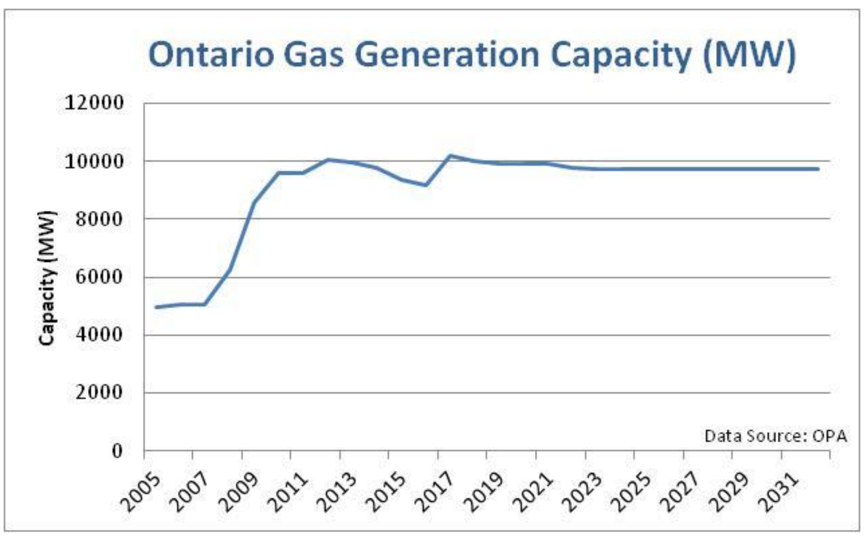

Figure 3: Ontario Natural Gas Power Generation Capacity

As shown in **Figure 4** the OPA is projecting natural gas generation to increase to over 30 TWh/year by 2020.

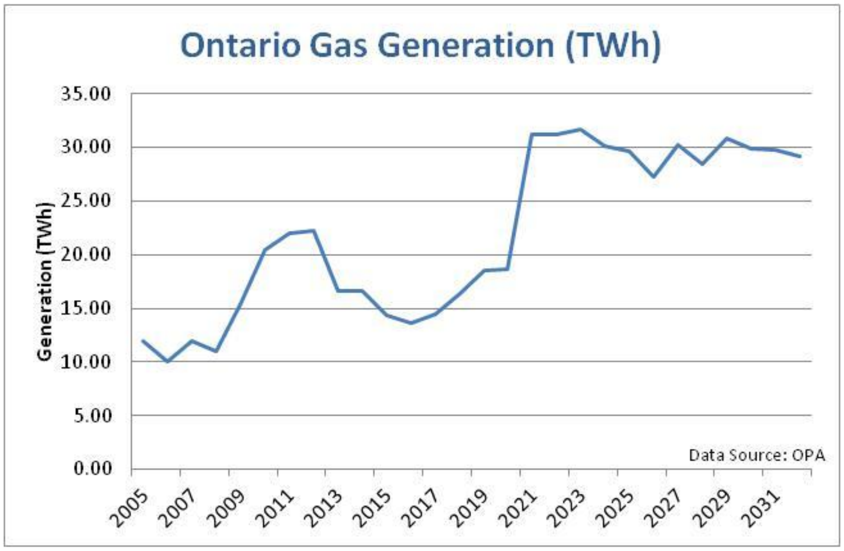

Figure 4: Ontario Natural Gas Power Generation

Access to reliable natural gas supplies will be important to meet the organic growth from the residential, commerical and industrial markets. It will also be important to meet the growth from power generation in order to help ensure an adequate and reliable power grid in Ontario. Gas-fired power generation in Ontario has increased to partially replace the capacity from Ontario's shuttered coal-fired generation fleet. The operation of the gas-fired generation is expected to increase as nuclear power plants are retired or while they are being refurbished.

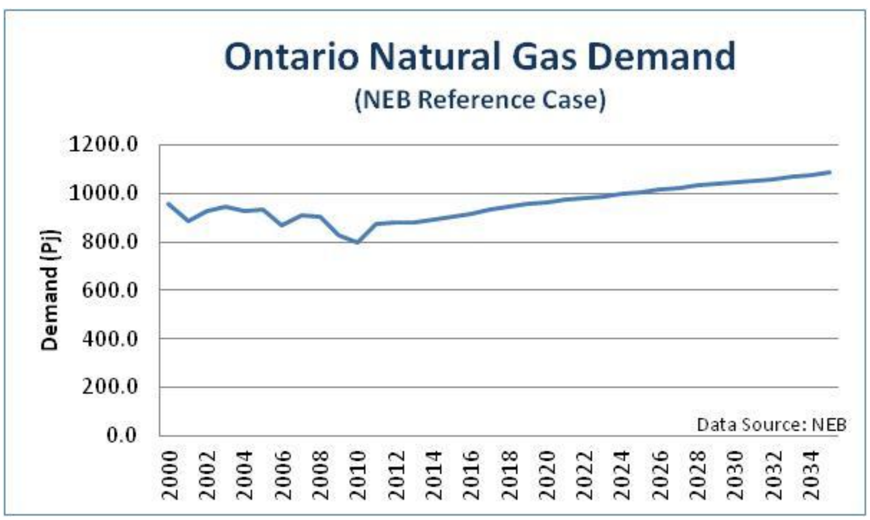

Figure 5: Ontario Natural Gas Forecast

The National Energy Board's ("NEB") Ontario reference case forecasts Ontario's natural gas consumption to grow from 878 PJ to 1085 PJ by 2035 as illustrated in **Figure 5**.

The NEB reference forecast does not include: 1) the potential impacts on gas prices and price volatility of Energy East, 2) the conversion of a portion of TransCanada's Mainline and 3) Union Gas's preliminary estimate of the Ontario Liquefied Natural Gas ("LNG") market opportunity (see Section 8).

The most current forecast of supply and demand for Ontario markets has been developed for the OEB by ICF[2]. ICF's 30 year forecast projects more than sufficient gas supplies will be available for Ontario markets of over 4.6 TJ/d in 2035.

Ontario natural gas prices fell from 2006 through 2012. There have been recent price increases and regional price volatility related to extreme weather and locational based capacity constraints. The NEB has projected a gradual rise in natural gas prices through 2034. **Figures 6** and **7** show the residential and industrial historical and projected end use prices. Regional price differences and price volatility could develop in the future due to extreme weather conditions and capacity constraints during peak periods as occurred in the winter of 2013 -14. Customers are of the view that maintaining sufficient infrastructure will assist in reducing the locational constraints and its related price volatility.

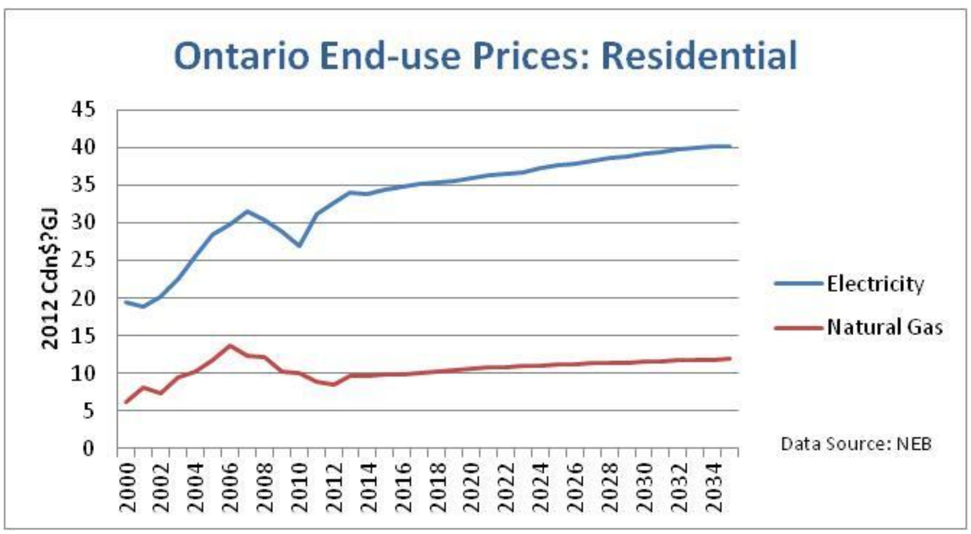

Figure 6: Residential End Use Gas Prices

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[2] Impact of Energy East on Ontario Natural Gas Prices; Prepared for: Ontario Energy Board; Prepared by: ICF International March 6, 2015

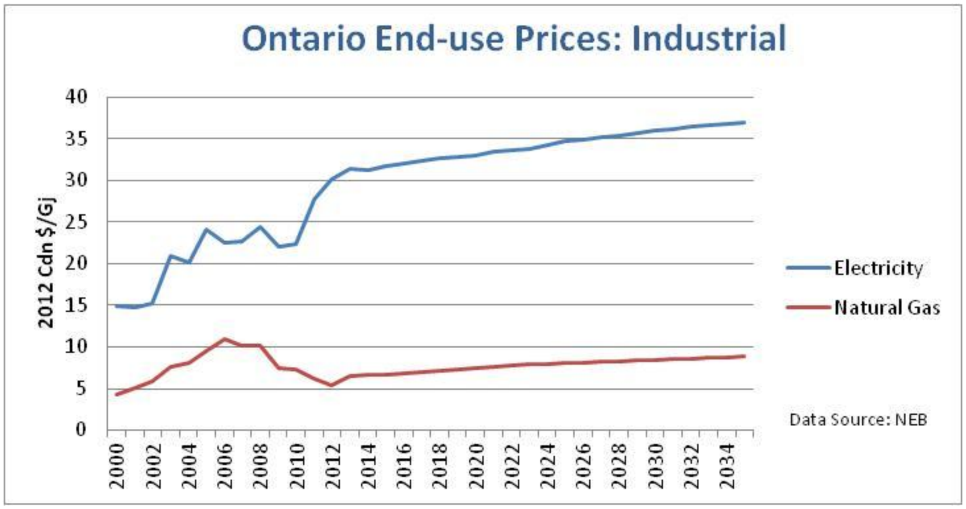

Figure 7: Industrial End Use Gas Prices

Most large Ontario industrial customers purchase their gas directly under contract from suppliers rather than from their local utility. Direct purchase customers manage their own gas commodity, transportation and balancing risks. Due to pipeline toll and tariff changes and upstream transportation contracting risks, many Ontario large direct purchase customers have switched from purchasing their natural gas in Alberta to sourcing it in Ontario.

6 ENERGY EAST AND EASTERN MAINLINE PROJECTS

Figure 8 shows the proposed Energy East project and the Eastern Mainline project.

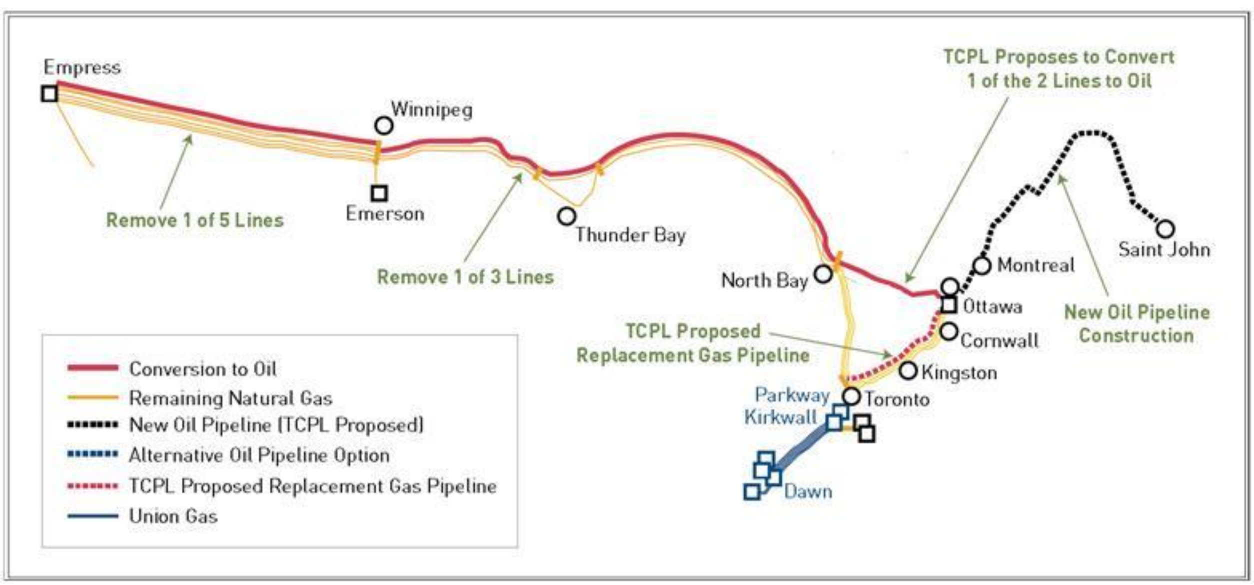

Figure 8: Energy East and Eastern Mainline Projects

6.1 ENERGY EAST PROJECT

The Energy East Project includes a transfer of 3,000 km of one of TransCanada's 42 inch Mainline natural gas pipelines to Energy East and the transfer and conversion of it to deliver oil to Quebec and New Brunswick. The transfer of the gas pipeline includes:

- 940 km in the prairie provinces
- 1,640 km of Northern Ontario Line ("NOL")
- 420 km between North Bay and Cornwall

TransCanada, in its application, has stated that these assets have a net book value ("NBV") of $1.5 billion[3]. In addition, TransCanada would build new oil facilities. These include:

- 72 new oil pump stations
- 1,500 km of new oil pipeline in Alberta, Eastern Ontario, Quebec and New Brunswick
- 2 marine oil terminals

TransCanada has estimated the total project costs of $14.393 billion[4] (excluding interest during construction) as shown in the table below:

Table 2-3: Estimated Capital Costs

Component	Capital Cost ($ million)
Pipeline:	
New Pipelines	4,707
Conversion Pipelines	685
Pump Stations	3,329
Tank Terminals and Delivery Meter Stations	1,928
Marine Terminals	635
Sub-total	**11,284**
Transfer Price for Gas Assets	1,509
AFUDC	1,600
Total	**14,393**

The Energy East pipeline is proposed to be in-service in the fourth quarter of 2018[5].

[3] Energy East Pipeline Ltd. TransCanada PipeLines Limited Volume 2 Section 4.4.1

[4] Energy East Pipeline Ltd. TransCanada PipeLines Limited Volume 1: Energy East Project and Asset Transfer Applications, Section 2 Project Overview; pg 24

6.2 EASTERN MAINLINE PROJECT[6]

TransCanada in its application has proposed building the Eastern Mainline Project ("EMP") from Markham to Cornwall (mostly along the existing TransCanada Montreal right of way) parallel to the north shore of Lake Ontario. This is necessary to facilitate the transfer of the natural gas Mainline from North Bay to Cornwall (the North Bay Shortcut ("NBS")) and to replace part of the lost capacity resulting from taking part of the NBS out of service.

The EMP would consist of 245 km of 36 inch new pipe (looping the existing system) and 5 new compressor stations. The EMP would have a capacity of 575 TJ/d to replace part of the 1,200 TJ/d of capacity removed from the NBS. The proposed replacement capacity is based on the combination of the existing firm capacity requirements plus customer responses to TransCanada's 2016 new capacity open season ("2016 NCOS") (further discussed in Section7.2). TransCanada estimates that the EMP would have a Capital Cost of $1.5 billion consisting of $1.1 billion for the new pipeline and $0.4 billion for the new compression. TransCanada has a projected in-service date for the EMP of the first half of 2017, concurrent with the transfer of NBS.

7 CUSTOMERS' KEY MESSAGES

The key messages customers (see Section 2) described during these consultations include:

1. Transferring the sections of natural gas pipeline west of North Bay **does not** create capacity shortfall concerns
2. Transferring the section of pipeline from North Bay to Cornwall **will result in** a capacity shortfall concern
3. The price of the natural gas assets being transferred to Energy East **should be fair** to gas customers.
4. Energy East increases the risk of higher ET tolls
5. Reduction of ET Capacity will result in:
    - Higher gas commodity price, and increased price volatility in ET, and
    - Higher cost of electricity when gas-fired generation is on the margin in Eastern Ontario
6. Commercial terms to access transportation capacity on the Mainline will be more onerous

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[5] http://www.energyeastpipeline.com/facts/oil-and-pipelines-101-2/
[6] TransCanada Certificate of Public Convenience and Necessity NEB Application filed October 2014

7. The newest line on the Mainline system is being transferred to Energy East. The remaining older lines may be susceptible to future integrity issues resulting in:
   - Risk of higher operating and maintenance costs, and
   - System reliability concerns

8. Additional information is required to better understand the application and the implications of the Energy East Project and the Eastern Mainline Project on gas customers. This additional information includes:
   - The long term tolling implications
   - Flow forecasts in the ET under various growth scenarios and the impact on tolls

9. Some customers would like new services to recognize that discretionary capacity in the ET will be reduced or eliminated

10. LDCs would like OEB clarity on the policy implications of contracting for additional capacity in the ET to meet direct purchase and future growth requirements

Each of these key messages is discussed below.

7.1 TRANSFERRING THE SECTION OF PIPELINE WEST OF NORTH BAY DOES NOT CREATE A CAPACITY SHORTFALL

This portion includes the Prairies and NOL sections. **Figure 9** below illustrates the capacity implications in each section as filed by TransCanada[7]

- Customers do not have capacity concerns with transferring 2,600 km of the proposed 3,000 km. Consequently, customers support the transfer of underutilized assets upstream of North Bay.

- Customers believe that transferring this section will reduce rates through a lower rate base, a reduction in the abandonment charges, and a reduction in operations and maintenance costs.

- Customers have some concerns regarding the additional costs that may be incurred by TransCanada's Mainline in NOL to facilitate the asset transfer. Some of these costs include:
  - Current capacity that has been idled for integrity reasons will need to be refurbished because of the Energy East conversion. The remaining pipelines that have been derated will be required to meet peak day requirements.

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[7] Application Vol 4 page 4-7

- Customers believe that the transferred assets should be transferred at a fair price.

Capacity Implications of Asset Transfer

(TJ/d)	Prairies	Northern Ontario	Eastern Triangle (EDA)
Existing Capacity	6,462	3,600[2]	3,180
Capacity Lost Upon Transfer	1,131	1,474	1,210
Capacity Post Transfer	5,331	2,126[2]	1,970[4]
FT Contracts	769[1]	1,109[3]	2,545
Comments	Sufficient	Sufficient s.t. integrity work	Shortfall of 575 TJ/d

Notes
1. As of November 2016.
2. Includes capacity currently idled for integrity reasons. Integrity work underway to restore capacity. Integrity costs on line being transferred is being paid for by Energy East, other integrity work paid for by Mainline and included in rates.
3. Includes GLGT.
4. Based on existing firm contracts plus 2016 new capacity open season (NCOS).

Figure 9: Capacity Implications of the Asset Transfer

7.2 TRANSFERRING THE NORTH BAY SHORTCUT LINE WILL RESULT IN A CAPACITY SHORTFALL

Customers are concerned that the existing capacity of 1,200 TJ/d in the North Bay Shortcut ("NBS") will be replaced with only 575 TJ/d as proposed by TransCanada under the EMP. Further customers are concerned about the methodology that TransCanada used to determine the replacement capacity (i.e., Existing Firm Transportation ("FT") + 2016 NCOS)[8,9]. These customers feel that this could result in insufficient capacity to serve the Eastern Ontario Triangle existing and future markets, and could result in existing markets supply shortages and price spikes. For example, a study prepared by Wood Mackenzie[10] for Union and Enbridge projects that Energy East will lead to a capacity shortfall in the NBS (see **Figure 10**) and will contribute to higher winter prices and even higher peak day gas prices for markets east of Toronto.

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[8] Energy East Pipeline Ltd. TransCanada PipeLines Limited Energy East Project Application Volume 2: Sale and Purchase of Mainline Assets, Section 4; October 2014; pgs 1-2

[9] TransCanada Certificate of Public Convenience and Necessity NEB Application filed October 2014, Section 1.2

[10] Energy East Pipeline Project: Impacts to Ontario's Natural Gas Market; PRESENTATION TO THE ONTARIO ENERGY BOARD, Slide 11, January 29, 2015

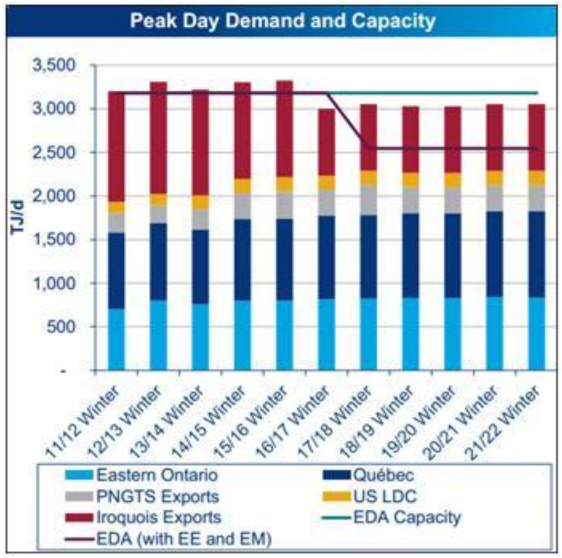


Figure 10: Capacity Shortfall

Customers are also concerned that they will have to pay for future expansion costs of the EMP. These customers project near term growth and believe that this growth should be included in TransCanada's 2017 NCOS to appropriately size the EMP. Further these customers propose that the costs related to adding this capacity should be borne by Energy East.

Customers believe that current system flexibility will be reduced or eliminated and that this will negatively impact the Ontario secondary market.

A number of gas customers are unable to contract for new long term capacity as would be required in a NCOS. Long term contracts require customers to provide long term financial guarantees. These customers are currently relying on the existing short term firm capacity contracts supplemented by discretionary purchases in the secondary markets to meet their gas requirements. These customers are concerned that firm capacity will be reduced after the Energy East and EMP Projects have been completed. These customers are concerned that a reduction in available firm capacity will increase the demand for shorter term firm and interruptible transportation services and could detrimentally impact the secondary markets in Eastern Ontario. These customers are concerned that this would result in an increase in their delivered gas costs.

Customers believe that leaving the NBS in gas service eliminates the above concerns. Alternatively if the NBS is transferred to Energy East these customers recommended that sufficient replacement capacity should be constructed in ET. The full costs and risks of this replacement capacity (up to 1,200 TJ/d) should be paid for by Energy East. However, there was a range of views on the level of replacement capacity that should be built. Some suggestions included: 2016 and 2017 NCOS, known growth plus a reasonable growth projection. There was also a range of views on the level of interruptible capacity that was needed after the transfer of the NBS to Energy East, but most customers believed that a reasonable amount of interruptible capacity was required in the ET.

The timing of the NBS transfer should be consistent with the timing of the capacity replacement (i.e., the EMP project). The EMP, as currently designed, is proposed to be in service prior to the transfer. Customers commented that this timing is essential.

- There were questions about how the Marcellus shale gas developments could impact future demand for ET Mainline capacity (in Northeast United States and Eastern Canada)
- Enbridge will submit bids in 2017 NCOS for their in-franchise direct purchase customers' transportation requirements as well as growth needs
- Union will submit bids in 2017 NCOS for their in-franchise direct purchase customers' requirements and growth.
- Utilities Kingston plans to submit a bid in the 2017 NCOS for its growth requirements.

7.3 THE PRICE OF THE ASSETS BEING TRANSFERRED TO ENERGY EAST SHOULD BE FAIR TO GAS CUSTOMERS

There was no single view on what was "fair", but customers proposed that the price should recognize:

- That NBV does not reflect the significant and timely benefits of transferring a 2,600 km pipeline to Energy East. Some customers think fair would be the market value of the assets being transferred.
- The new additional induced costs (increased tolls and fuel costs) resulting from the transfer of the NPS 42 pipeline to Energy East and risks to gas shippers, especially the cost and risks of building the EMP, and risks of having to build near term additional Mainline capacity for the projected capacity differential between NCOS 2016 and near term growth requirements.
- These customers believe that TransCanada should build to meet the long term requirements of the market (up to 1,200 TJ/d) and the cost of this capacity be borne by Energy East.
- Potentially higher commodity costs in Eastern Ontario due to reduced capacity.
- The existing NOL line is currently being depreciated on an accelerated basis. The accelerated depreciation is due to the lack of perceived economic life of the asset. If the asset is to be transferred it should be re-evaluated for

economic life and the transfer price should take this into account. Any delays in the transfer date will result in a lower NBV[11].

- Customers prefer cost and commodity price neutrality once sufficient replacement capacity is provided. Customers believe that the current system provides flexibility to purchase gas at market prices in the secondary market but that with the removal of capacity to a point where there is insufficient peak day capacity that the secondary market could be detrimentally impacted.
- Customers also preferred rate neutrality. The rate base of the required replacement capacity being added should be no more that the transfer price of the NBS.
- It should be noted that TransCanada in its application is proposing a $500[12] million contribution to offset part of the cost of EMP. This will have the effect of lowering the effective rate base over the amortization period (to 2030).

7.4 ENERGY EAST INCREASES RISK OF HIGHER ET TOLLS

Customers are concerned that the rate base and tolls in the ET will increase due to:

- Additional costs of the EMP ($1.5 billion compared to the rate base of the EMP offset by the $0.4 billion transfer price of the NBS). This cost is offset by Energy East's partial contribution of $500 million
- The net rate base, at the planned capacity level will increase by $0.66 billion[13]
- Planned market growth will require a Mainline expansion which will increase rate base and increase tolls
- Costs to refurbish idled capacity in the NOL
- Increased fuel required due to greater future reliance on use of compression due to reduced pipe capacity that has been transferred to Energy East
- EMP has been estimated in 2014 dollars not the estimated installed cost
- All cost overruns of the EMP will be at gas shippers' risk
    - The LDCs have estimated that a $1 billion cost overrun on the EMP and/or future growth costs would eliminate all Mainline benefits on an NPV basis

[11] Note that Energy East has not filed for a specific depreciation period,(Vol 3 page 2-12) but the oil shippers have signed contracts up to 20 years in length (Vol 3 page 2-4)
[12] Energy East Pipeline Ltd. TransCanada PipeLines Limited Energy East Project Application Volume 2: Sale and Purchase of Mainline Assets, October 2014, pg 6
[13] Energy East Application Volume 2 Table 4-7

- Future expansion costs could be exacerbated through the use of a 36 inch versus a 42 inch for EMP. Customers believe that a 42 inch line would be a more appropriate long term approach to planning for the EMP.

7.5 ONTARIO COMMODITY PRICE RISK AND RESULTING PRICE IMPACT ON ONTARIO ELECTRICITY

ICF on behalf of the OEB reviewed the commodity price issues and has projected potential commodity price increases at Iroquois/Waddington (With EE- Without EE) of between 0.18 – 3.75 US$/MMBtu as shown in **Figure 13**. These commodity price impacts would apply to those volumes transacted at Waddington as opposed to all volumes consumed in the ET. While most gas consumed in Eastern Ontario is not purchased at the Iroquois/Waddington price, this price represents a proxy for the value of natural gas and the impact of pipeline constraints on the ET downstream of Maple.

Tabular Price Results from the Cases – Price Comparison at Iroquois/Waddington

(2014 US$/MMBtu)

		2016	2017	2018	2019	2020	2021	2025	2030	2035	Avg. 2016-35
Annual	Without EE	4.47	4.76	4.83	5.04	5.18	5.37	5.64	6.49	6.96	5.82
	With EE	4.47	4.80	4.92	5.14	5.31	5.49	5.79	6.72	7.29	6.00
	Difference	*0.00*	*0.04*	*0.09*	*0.10*	*0.13*	*0.12*	*0.15*	*0.23*	*0.33*	*0.18*
	% Diff.	***0.1%***	***0.9%***	***1.9%***	***2.2%***	***2.5%***	***2.1%***	***2.7%***	***3.6%***	***4.7%***	***3.0%***
Winter* (Dec-Feb)	Without EE	5.56	5.36	5.52	5.64	5.75	5.85	6.28	7.24	8.09	6.57
	With EE	5.56	5.57	5.88	6.10	6.26	6.31	6.90	8.17	9.32	7.26
	Difference	*0.00*	*0.21*	*0.36*	*0.46*	*0.51*	*0.46*	*0.62*	*0.93*	*1.23*	*0.69*
	% Diff.	***0.0%***	***3.9%***	***6.6%***	***8.1%***	***8.9%***	***7.8%***	***9.9%***	***12.9%***	***15.3%***	***10.5%***
Summer (May-Sep)	Without EE	3.94	4.34	4.41	4.63	4.81	5.04	5.19	6.04	6.41	5.38
	With EE	3.94	4.33	4.41	4.61	4.80	5.03	5.19	6.04	6.41	5.38
	Difference	*0.00*	*-0.01*	*0.00*	*-0.02*	*-0.01*	*-0.01*	*0.00*	*0.00*	*0.00*	*0.00*
	% Diff.	***-0.1%***	***-0.3%***	***-0.1%***	***-0.3%***	***0.0%***	***-0.1%***	***0.0%***	***0.0%***	***0.0%***	***0.0%***
Design Day (January)	Without EE	30.13	29.04	29.91	30.58	31.14	31.71	34.04	39.26	43.83	35.60
	With EE	30.13	30.18	31.89	33.06	33.91	34.19	37.40	44.30	50.53	39.35
	Difference	*0.00*	*1.14*	*1.98*	*2.48*	*2.77*	*2.48*	*3.36*	*5.04*	*6.70*	*3.75*
	% Diff.	***0.0%***	***3.9%***	***6.6%***	***8.1%***	***8.9%***	***7.8%***	***9.9%***	***12.9%***	***15.3%***	***10.5%***

*The Average Winter price in a year includes the December price of the prior year; for example, the 2020 Winter price is an average of the December 2019, January 2020, and February 2020 prices. Annual prices run from November to October. The design day price provides an "indicative value" for a design day, estimated by applying the ratio of the observed peak day price to the average winter price from the 2013-14 winter.

Figure 13: ET Energy Price Impacts

7.6 THE COMMERCIAL TERMS ON MAINLINE ARE MORE ONEROUS

Customers noted that capacity currently exists on the NBS but some customers have been unable to sign up for this capacity in previously held existing capacity open seasons ("ECOS"). Customers mentioned that the renewal rights of this existing capacity is being held for use on the Energy East project

Customers also noted that replacement capacity in the EMP and future expansions requires a 15 year contract term. Some of these customers stated that they are unable to contract for long term capacity because of the required financial commitment and toll uncertainty. These customers feel that this will negatively affect Ontario markets and economy. They are concerned that this will:

- Create a barrier for new investment and undermine existing investment in Ontario
- Undermine natural gas generation competition and operation
- Increase the lead time to access future capacity requirements

7.7 POTENTIALLY HIGHER OPERATING AND MAINTENANCE COSTS AND REDUCED RELIABILITY FROM THE OLDER GAS LINES

Customers mentioned that the NOL lines have experienced integrity issues in the past. The newest NOL line is being transferred to Energy East. The remaining older lines may be more susceptible to future integrity issues resulting in:

- Risks of higher operating and maintenance costs
- Reliability concerns resulting in security of supply concerns during peak periods

7.8 ADDITIONAL INFORMATION IS REQUIRED TO BETTER UNDERSTAND THE APPLICATION

These gas customers commented that more information is required to assess the long term toll impacts of the Energy East and Eastern Mainline projects. Customers would like additional flow and costing information to better understand the future facility requirements and resulting toll impacts. For example, customers believe a 42 inch line may be more cost efficient per unit of capacity than the proposed 36 inches and will result in a better facilities plan. Customers would therefore like flow and cost information of the EMP comparing the 42 inch option to the 36 inch proposal.

Customers would like more information to better understand the long term tolling impacts of EE's $500 million contribution.

7.9 Some Customers Want New Services

Customers suggested that the proposed system changes may require new service offerings to those parties that are not able to contract for long term FT. For example, gas generators may need new services to reflect the system changes and the changes to the Ontario power market such as the move towards a capacity power market. To help customers adapt to these changes and new risk, the LDCs are looking at developing new distribution services such as:

- Possible IT changes
- Dawn T-Service

Furthermore, these customers felt that without these new services companies that are multi-national and have the capability to move production out of Ontario will do so if they are not able to contract in a commercially reasonable and economic manner.

7.10 FT Contracting

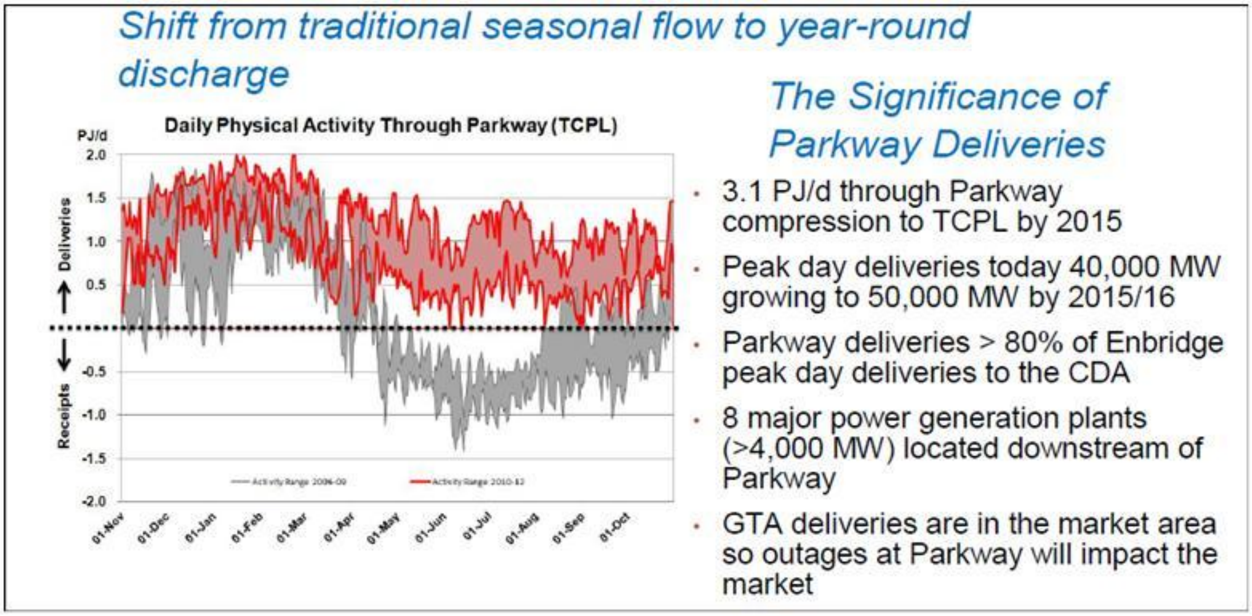
The LDCs would like clarity on the policy implications of contracting for FT contracts in the following situations:

- To meet the needs of direct purchase customers that are unable to contract under the current commercial environment (term and price risk)
- To contract for Advance Capacity to meet the LDCs' growth requirements

8 Other Key Issues in Ontario

8.1 Shift to the Dawn Hub

New infrastructure is being built in Ontario to facilitate the increase in deliveries at Parkway. Union Gas's **Figure 14** shows the dramatic shift in delivery profile at Parkway over time. Deliveries at Parkway are projected to increase and continue to flatten the seasonal profile as shown in **Figure 14**.



Source: Union Gas

Figure 14: Parkway Deliveries

8.2 INCREMENTAL GROWTH FROM LNG

Additional growth is projected by Union based on possible demand increase related to development of Ontario's liquefied natural gas ("LNG") market. Union has projected a potential LNG market of up to 142 PJ/year[14].

8.3 INCREASED MINING LOADS

Further increases in demand could include Ring of Fire energy requirements.

8.4 GROWTH OF SHALE SUPPLIES

Ontario is a key transportation crossroad for adjacent markets. New growth opportunities for Ontario could develop. The conversion to short haul services has been driven by the increase in Shale gas production such as Marcellus and Utica. These shale plays are located close to Ontario. This has resulted in less gas coming from the Western Canadian Sedimentary Basin ("WCSB") due to the transportation differentials, except when capacity is constrained from these local supplies. A significant portion of gas (most commercial, industrial and power contracts including OPA power generation contracts) is now priced and purchased at the Dawn Daily Index.

[14] Union Gas "Cold Weather & Growth"; Calgary Customer Meeting, March 3. 2014, slide 36

Future delivery dynamics continue to change. Union expects over 50% of Long Haul (i.e. capacity from western Canada) transportation capacity contracts will be converted to Short Haul (i.e. sourcing gas in or nearer Ontario) transportation capacity contracts[15]. At the same time there will likely continue to be a reduction in sourcing supply from the WCSB and an increase in Marcellus and Utica supply.

[15] Cold Weather & Growth Calgary Customer Meeting, Union Gas; Slide 27; March 3, 2014

APPENDIX 1

GLOSSARY

1. AMPCO: Association of Major Power Consumers of Ontario
2. APPrO: Association of Power Producers of Ontario
3. BCF/D: Billion Cubic Feet per Day
4. CDA: Central Delivery Area
5. CME: Canadian Manufacturers and Exporters
6. DTE: DTE Energy
7. ECOS: Existing Capacity Open Season
8. EDA: Eastern Delivery Area
9. EE: Energy East
10. EGD: Enbridge Gas Distribution
11. EMP: Eastern Mainline Project
12. ET: Eastern Ontario Triangle
13. EZ: Eastern Zone
14. FT: Firm Transportation
15. GLGT: Great Lakes Gas Transmission
16. GMi: Gaz Metropolitan Inc
17. GTA: Greater Toronto Area
18. IT: Interruptible Transportation
19. IGUA: Industrial Gas Users Association
20. KPUC: Kingston PUC
21. LDC: Local Distribution Company
22. LNG: Liquefied Natural Gas
23. LTAA: Long Term Adjustment Account
24. OEB: Ontario Energy Board
25. NB: North Bay
26. NBV: Net Book Value
27. NBS: North Bay Shortcut
28. NCOS: New Capacity Open Season
29. NEB: National Energy Board
30. NG: Natural Gas
31. NGLs: Natural Gas Liquids
32. NOL Northern Ontario Line
33. NPS: Nominal Pipe Size
34. OPA: Ontario Power Authority
35. STFT: Short Term Firm Transportation
36. TCPL: TransCanada PipeLines Limited
37. TSA: Toll Stabilization Account
38. WCSB: Western Canadian Sedimentary
39. UGL: Union Gas Limited

APPENDIX 2
ELENCHUS PRESENTATION TO ONTARIO CUSTOMERS

elenchus

Consultation on Behalf of the OEB on the Implications of Energy East to Ontario Gas Consumers

by
Fred Hassan
John Wolnik

12/14/2014 elenchus

Purpose

- Minister of Energy requested that the OEB consult with Ontarians on Energy East
- A variety of Energy East consultations underway, this consultation only deals with the commercial, operational and regulatory impacts to Ontario natural gas customers
- To receive feedback from customers on the implications of Energy East which in turn would be summarized and provided to the Minister

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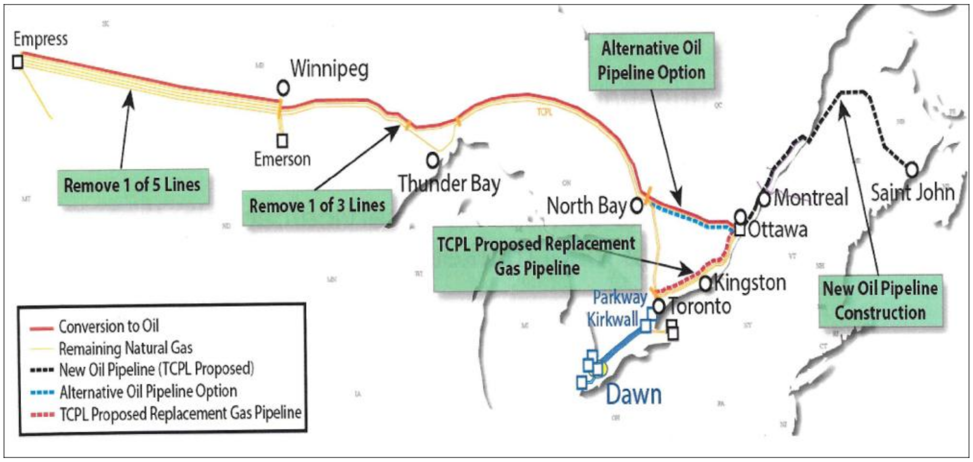
Agenda

- Provide a brief overview of the Energy East and the related Eastern Mainline Expansion Projects
- Identify key natural gas issues that have already been identified, and
- Discuss the large volume users' perspectives on the key Ontario natural gas issues emanating from the Energy East Pipeline.

Energy East & Eastern Mainline Projects



Source: Union Gas

Eastern Mainline Project (EMP) Expansion

Source: TCPL

- 245 km of NPS 36 proposed looping adjacent to the Montreal Line
- 575 TJ/d of capacity
- 5 new compressor stations
- Capex (2014 $)
  - Pipe $1.1 b
  - Compression $0.4 b
  - TOTAL $1.5 b
- In-service date to be concurrent with the NBS transfer (Mar '17)
- TransCanada to provide $0.5 b in contribution to lower revenue requirement to 2030

Energy East Asset Transfer

- Mainline NPS 42 Assets Proposed for Transfer
  - 940 km of Prairies line
  - 1640 km of Northern Ontario Line (NOL)
  - 420 km of North Bay Shortcut (NBS)
- Assets proposed to be transferred at NBV ~$1 billion
- Transfer between March 2016 – March 2017
  - NBS March 2017
- Energy East proposed in-service date Q4 2018

Capacity Implications of Asset Transfer

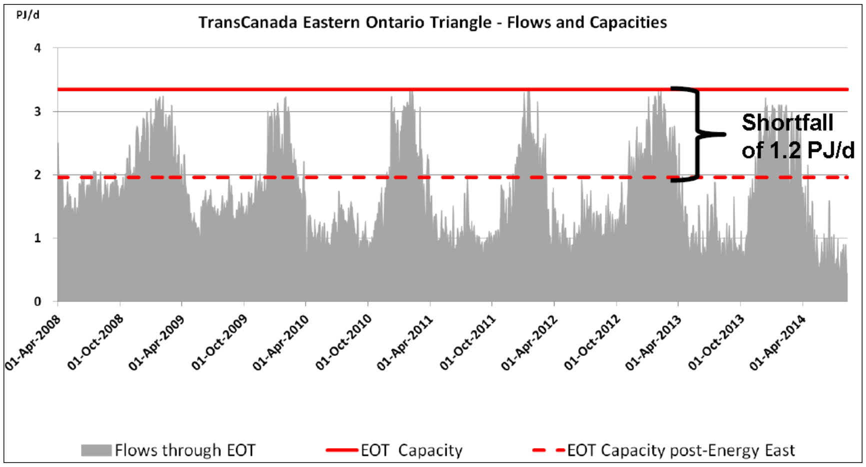
(TJ/d)	Prairies	Northern Ontario	Eastern Triangle (EDA)
Existing Capacity	6,462	3,600[2]	3,180
Capacity Lost Upon Transfer	1,131	1,474	1,210
Capacity Post Transfer	5,331	2,126[2]	1,970[4]
FT Contracts	769[1]	1,109[3]	2,545
Comments	Sufficient	Sufficient s.t. integrity work	Shortfall of 575 TJ/d

Notes
1. As of November 2016.
2. Includes capacity currently idled for integrity reasons. Integrity work underway to restore capacity. Integrity costs on line being transferred is being paid for by Energy East, other integrity work paid for by Mainline and included in rates.
3. Includes GLGT.
4. Based on existing firm contracts plus 2016 new capacity open season (NCOS).

Eastern Triangle (ET) Capacity

- Asset transfer requires large replacement capacity
- What is the right amount of capacity to replace?
  - Capacity being transferred in NBS; 1,210 TJ/d?
  - TransCanada proposes existing FT contracts + 2016 NCOS?
    - Does 2016 NCOS reasonably represent true demand?
    - Should the market have access to some discretionary capacity?
    - Forecasted growth?
  - Some other capacity?
    - Potential Northeast US FT shippers non-renewal risk
    - 2017 NCOS
- Less on-peak discretionary capacity available post transfer

ET Usage & LDC View on Potential Impact



Source: Union Gas & Enbridge

Other Aspects of Transfer

- Asset transfer at net book value
- TransCanada/Energy East to contribute '$500 m' to EMP
  (reduces Mainline revenue requirement by ~$33 m/yr. to 2030)
- TransCanada reports a NPV benefit of $900 m in lower revenue requirement
  - Reduced rate base in Prairies and NOL segments
  - Lower pipeline abandonment costs
  - Lower O&M costs
  - Offset by higher fuel

Benefits of Energy East

- Lower revenue requirement from
  - Reduced rate base for Prairies, NOL ($1.1 b) and ET ($0.4 b)
  - Reduced abandonment costs
  - Lower O&M on assets transferred
- Offset by:
  - Higher fuel costs from greater use of compression
  - Cost of Eastern Mainline Expansion
- TransCanada has calculated NPV benefits to 2030 of Energy East
  - $400 m to Prairies and NOL section
  - $500 m to Eastern Triangle

Gas Shippers Risks

- Capital Cost
  - All increases in capital cost associated with the EMP will be at the gas shippers risk
- Cost for Future Growth
  - Since the full 1,200 TJ/d is not being fully replaced, future growth, up to this amount, is at the risk of gas shippers
- Tolls
  - Compression will be utilized to a greater degree post Energy East, therefore fuel use and costs will increase
  - RH-1-0214 will fix rates through to 2020 and then set rates based on segmentation. Rate base of the Eastern Triangle will increase by $0.5 b as a result of this Energy East, this cost will be reflected in tolls post 2020
  - TransCanada's contribution expires in 2030, so the Eastern Triangle rate base will therefore increase by $0.5 b (less depreciation), this cost will be reflected in tolls post in 2030

NG Issues Already Identified by LDCs

- Agree with repurposing assets in Prairies and NOL
- Appropriateness of NBS transfer vs. a new oil line
- Capacity issues
  - LDCs view that historical usage of NBS is a better indicator of need than 2016 NCOS
  - LDCs do not believe that 2016 NCOS is a fair representation of additional demand due to:
    - Uncertainty of toll at time of open season
    - Commercial terms associated with NCOS
    - Parties interested in capacity may not have known the implications of not entering open season
  - Include current Northeast US contracts in long term Eastern Triangle requirements
  - Having some discretionary capacity is appropriate
  - LDC projection of incremental capacity required post 2016 is 400-700 TJ/d
- Concerns on costs/tolls
  - $0.5 b rate base contribution reduces tolls only to 2030 (~$33 m annually)
  - Construction risk of new pipeline
  - Capital cost for future capacity up to 1,200 TJ/d
  - NPV to 2030 is not an appropriate measure of impact as rate base will be much higher post 2030
- Solution: Cost neutrality or Eastern Triangle preserved through to 2040, all excess costs paid for by oil shippers

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Your Feedback on Energy East

- What are the positive natural gas aspects of the Energy East proposal for Ontario gas users?
- What are the key concerns of large volume customers regarding Energy East? How do you see these being addressed?
- What recommendations do the customers have regarding Energy East and how would these recommendations benefit Ontario?

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