Impact of Energy East on Ontario Natural Gas Prices

Prepared for

Ontario Energy Board

Prepared by

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Disclaimer

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Glossary of Terms

AECO – The AECO gas hub located is Alberta, Canada and is one of the more liquid gas price indices in North America. It is often considered as the reference point for natural gas in Canada.

Basis – For natural gas, basis is the difference between any two market price point locations. Basis values are typically used to assess pipeline congestion between different market regions. Basis is often calculated relative to the Henry Hub price point, which is considered as the North American reference price for natural gas.

Billing determinants – the volumes of gas over which the revenue requirement is spread to yield the toll for a pipeline service. The number representing the billing determinants is the denominator in the calculation of tolls, where the numerator is the revenue requirement for the pipeline service.

Design day – Design day refers to the daily gas demand that results in an area due to extreme cold weather conditions. Design day demand is usually determined from the actual demand on the coldest day over a given time interval, such as 20 or 30 years, and the expected growth in demand over time. Utilities typically plan their gas supply to meet a design day demand in the winter.

Discount rate -- The interest rate used in determining the present value of future cash flows to account for the time value of money.

Discretionary Miscellaneous Revenue – revenues earned by TCPL primarily from short term firm transportation and interruptible transportation services.

Firm Service Customers – A group of gas pipeline shippers who hold firm capacity contracts with the pipeline in order to receive gas on an uninterrupted basis for the term of the contracts.

Interconnects – A segment of the pipeline system where there are one or more connections between pipelines, such that natural gas can be transferred across the different pipeline systems.

Interruptible Service and Secondary Market Customers – A group of gas pipeline shippers who hold interruptible capacity contracts with the pipeline, or who have obtained capacity that has been released by primary contract holders. Such services are available only when there is spare capacity on the pipeline and can be interrupted or recalled when firm service customers require the capacity.

LDC – LDCs, or Local Distribution Companies maintain the portion of the utility supply grid that is closest to the residential, or smaller commercial consumer. LDCs are responsible for delivering natural gas to these consumers.

Market Hub – A given location where there are many buyers and sellers transacting on a daily basis. A market hub has a high level of liquidity. Henry Hub and AECO are examples of a market hub.

MMBtu – Million British thermal units. British thermal units (BTUs) are a set of traditional units of energy, with one BTU being approximately equivalent to 1,055 joules.

Net present value -- is the present value sum of a future stream of revenue minus the costs, where the future values are discounted by a discount rate to reflect the time value of money.

Off-peak – A period of time when the demand for natural gas is lower than average for the rest of the season, or year. Typically, off-peak occurs outside of the winter months when temperatures are warmer.

On-peak (winter) – A period of time when the demand for natural gas is the higher than average for the rest of the season, or year. Typically, on-peak occurs during the winter when temperatures are coldest.

Ontario Consumer – Natural gas end-user located in Ontario. Includes consumers served by the Ontario LDC's (such as Enbridge, Union Gas, and KPUC), as well as industrial and power generation customers located in Ontario that purchase and transport their own natural gas.

Peak-Shaving – Refers to energy infrastructure that comes online during on-peak time periods, in order to meet extreme levels of market demand. Typically, they include small-scale LNG facilities and gas storage facilities that are designed for peak-shaving needs.

Price Elasticity – A measure of the responsiveness of demand or supply of the commodity to changes in price.

Quarterly Base Case – Each financial quarter, ICF releases its Quarterly Base Case derived from its proprietary Gas Market Model (GMM). Each release includes gas supply, demand, and price forecasts for several gas markets within North America, in addition to energy insights from ICF's experts.

Revenue requirement – the total cost associated with providing a pipeline service, i.e., point-to-point transportation, where the total cost is the sum of all fixed costs including return on investment, and variable costs. Revenue requirement is the numerator in the calculation of tolls where the billing determinants are the denominator.

TransCanada Shipper –Large volume customer that purchases gas and contracts for pipeline capacity directly on the TransCanada system, including LDCs (such as Enbridge, Union Gas, KPUC, and Gaz Métro), industrial customers, and power generators. TransCanada shippers serve natural gas load in Ontario as well as outside of Ontario.

Ultimate recoverable resources – An estimate of the total amount of hydrocarbon resource that can ever be recovered and produced.

Acronyms

DMR – Discretionary Miscellaneous Revenue

EDA – Eastern Delivery Area

EOT – Eastern Ontario Triangle

GDP – Gross Domestic Product

GMM – Gas Market Model

HDD – Heating Degree Days

IFFCO – Indian Fertilizer Farmers' Cooperative, Ltd.

IGTS – Iroquois Gas Transmission System

IPM – Integrated Planning Model

LNG – Liquefied Natural Gas

MMCFD – Million cubic feet per day

NEB – National Energy Board (Canada)

NPV – Net Present Value

OEB – Ontario Energy Board

RPS – Renewable Portfolio Standard

TCF – Trillion Cubic Feet (volume)

TCPL – TransCanada PipeLines

Executive Summary

The Energy East project is a proposal by TransCanada PipeLines Limited (TCPL or TransCanada) to convert of a section of its Canadian Mainline (Mainline) from natural gas to crude oil service from Empress (at the Alberta Saskatchewan border) to and across northern Ontario, through North Bay and southeast to Cornwall. The project is expected to remove approximately 1.47 petajoules per day (PJ/d) of natural gas transportation capacity in Northern Ontario and 1.21 (PJ/d) in eastern Ontario. To offset some of the reduced gas transport capacity, TCPL has proposed the Eastern Mainline Expansion Project to add about 0.58 PJ/d of capacity in Eastern Ontario.

The OEB engaged ICF Consulting Canada, a subsidiary of ICF International (ICF), to produce a report on the effects of the combined Energy East and Eastern Mainline Expansion projects (collectively referred to the Energy East projects) on natural gas prices and consequent consumer costs in Ontario. This report will be submitted to the Ontario Ministry of Energy, so that the Ministry can actively participate in the National Energy Board (NEB) hearings on TCPL's Energy East proposal. The report is driven by an *Ontario perspective*, with a focus on impacts on natural gas consumers in Ontario, and does not discuss the broader aspects of the Energy East project.

ICF used its proprietary North American Gas Market Model (GMM®) to evaluate the impacts of the Energy East project. The GMM® is a widely recognized, comprehensive, detailed supply and demand equilibrium model of the North American gas market, and it has been used in ICF's previous OEB studies. For this engagement, ICF used its updated January 2015 quarterly "Base Case" model assumptions, which includes the Energy East project. To evaluate the effects of the Energy East project, ICF developed a status-quo case that removes Energy East but keeps all of the other assumptions intact. The differences between the model runs in terms of gas prices, basis spreads, and pipeline flows, show the effect of Energy East on the Ontario market.

Pipeline capacity expansions over the next 4 to 5 years in ICF's modeling are consistent with announced projects; however, when multiple projects are announced targeting the same markets, ICF limits the total capacity expansions to the level that would be supported by the market. In the long-term, pipeline capacity is expanded in the model when the market forecast indicates the need for additional capacity (i.e., increased basis). Several pipeline expansions to and within Ontario are included such that consumers in Ontario can access new supplies coming out of the Marcellus/Utica production basin. Furthermore, ICF included expansions of pipeline capacity from the Marcellus/Utica producing region into the U.S. northeast and New England.

Price and Flow Impacts due to Energy East

With the expected growth of gas demand in eastern Ontario, and the continued reliance on Canadian supply by U.S. consumers in New England and New York, the reduction in pipeline capacity due to Energy East will affect market prices in eastern Ontario. These effects will be most obvious in winter months, when gas demand is high, than in summer months. The ICF analysis has shown that gas prices at Iroquois/Waddington can be expected to increase by an average of 3.5 percent annually over the 2016-2035 time period. In winter, Iroquois/Waddington gas prices can be expected to average 12 percent higher over the same 2016-2035 period. Summer prices at Iroquois/Waddington would largely be unaffected by the Energy East Project. See Table ES-1 for details.

Table ES-1. Average 2016-35 Gas Price Effects of Energy East (2014 US$/MMBtu)

		Iroquois-Waddington	Dawn
Annual	Without EE	5.82	5.50
	With EE	6.02	5.51
	Difference	*0.20*	*0.01*
	% Diff.	***3.5%***	***0.2%***
Winter* (Dec-Feb)	Without EE	6.57	5.64
	With EE	7.35	5.68
	Difference	*0.78*	*0.04*
	% Diff.	***11.9%***	***0.8%***
Summer (May-Sep)	Without EE	5.38	5.32
	With EE	5.37	5.31
	Difference	*-0.01*	*-0.01*
	% Diff.	***-0.1%***	***-0.2%***
Design Day	Without EE	35.59	35.65
	With EE	39.82	35.93
	Difference	*4.24*	*0.28*
	% Diff.	***11.9%***	***0.8%***

*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 peak day price provides an "indicative value" for a peak day, estimated by assuming the ratio of the observed peak day price to the average winter price from the 2013-14 winter.

Figure ES-1. Seasonal Price Comparisons over Time at Iroquois/Waddington and Dawn

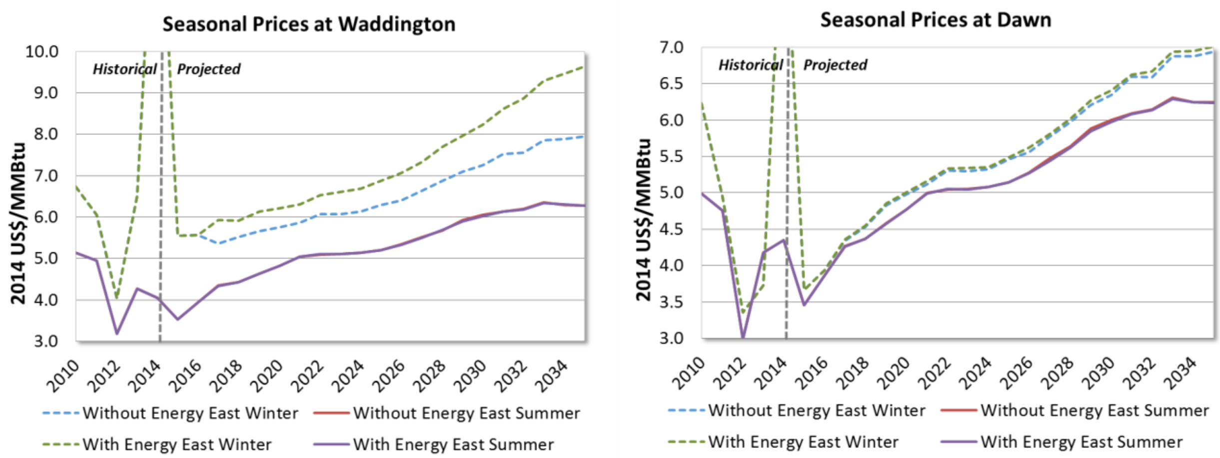


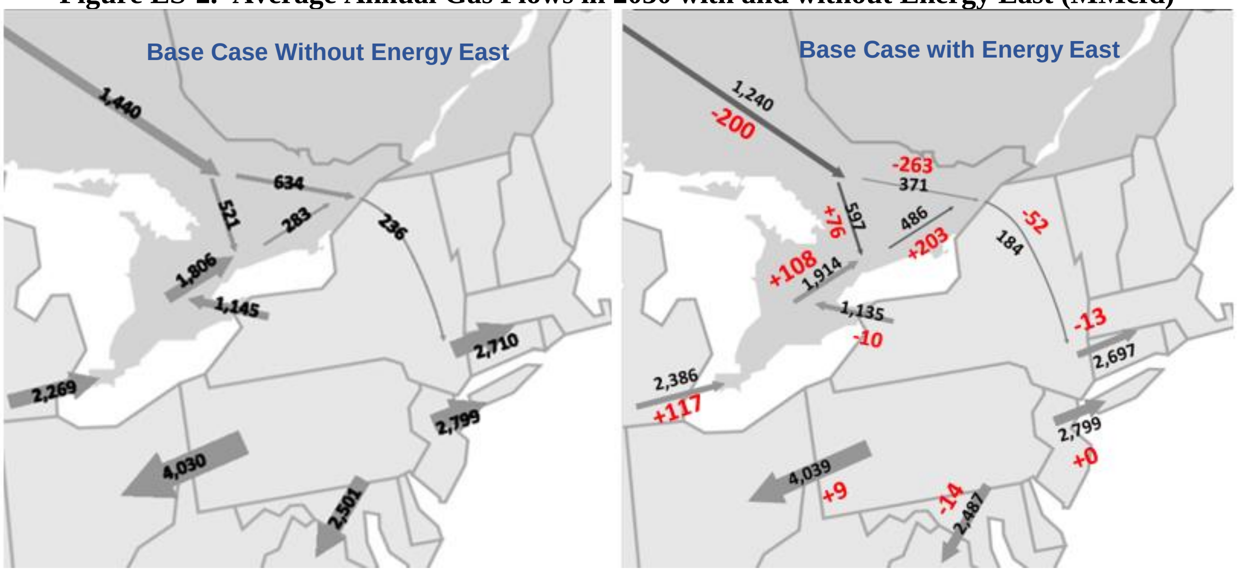
Figure ES-1 shows the seasonal price effects of Energy East over time at Iroquois/Waddington and Dawn. The impact of Energy East on prices at Dawn and at AECO are relatively modest when compared to the price impact at Iroquois/Waddington. Price differences at Dawn would be expected to be small given the large volume of storage in the region and that Dawn is upstream of the Energy East reduction in pipeline capacity in the Eastern Ontario Triangle (EOT).

In terms of basis, Energy East increases the basis spreads between supply points outside the EOT and the Iroquois/Waddington hub. Energy East increases the annual basis from Dawn to Waddington by about 60% and the winter basis by about 80%, on average.

ICF also examined pipeline flows with and without Energy East. Figure ES-2 compares average annual daily gas flows in 2030, where the map on the left represents flows without Energy East, and the map on the right shows flows if Energy East as proposed were implemented. The red boxes on the right map shows the differences in flows between the two cases.

With Energy East, gas flows across the Eastern Mainline would increase to make up for the reduced flows down the eastern leg of the EOT triangle, from North Bay to Iroquois. This pattern holds for both average annual flows and average winter flows; although for the latter, the differences between the with-and-without Energy East cases are larger. Southward flows into the Iroquois pipeline at Waddington remain substantial even in the Energy East case, although they are much reduced from current levels or the case without the Energy East Project. The majority of the decline in flows occurs during off-peak periods. Southward peak winter flows down to Iroquois pipeline remain an important source of gas supply into U.S. demand centers in the Northeast.

Figure ES-2. Average Annual Gas Flows in 2030 with and without Energy East (MMcfd)



Review of Other Studies

ICF reviewed several studies, reports and presentations by other firms, who have assessed the impacts of the Energy East project. ICF reviewed the following studies:

- Wood Mackenzie
  - Presentation to the OEB on behalf of Union Gas (dated January 29, 2015).
  - Report for Société en commandite Gaz Métro and Gazifère Inc. (September 2, 2014).
- Concentric Energy Advisors
  - Testimony by John Reed on behalf of TransCanada in October 2014, submitted to NEB.
  - Report and Presentation submitted to the Régie de L'énergie Du Québec at the request of TransCanada on natural gas market assessment in Québec (September/October 2014).
- KPMG
  - Report to the Régie for Gaz Métro (October 28, 2014).

Only the Wood Mackenzie Presentation to the OEB provided gas price impact information and other studies do not provide specific information on the price impacts of the Energy East project. Wood

Mackenzie's findings on the effects of Energy East on gas prices at Iroquois/Waddington are directionally consistent with ICF's analysis, although there are a few key differences.

Impacts on Ontario Consumers

The impact of Energy East on the tolls paid by shippers in the EDA is less conclusive, given the many uncertainties surrounding the elements that go into the calculation of tolls and the points of comparison for scenarios with and without Energy East. ICF's analysis concludes that the Energy East project may end up either benefiting or costing Ontario gas consumers, depending on how the project is implemented and assessed.

ICF finds that the TransCanada analysis of the effect on tolls is based upon several assumptions that are uncertain: that there will be a relatively low demand for pipeline capacity, as well as optimistic assumptions related to project gas price impacts. Therefore, TransCanada's estimation may be considered as an upper bound on a range of reasonable estimates of the project benefits to Ontario consumers.

Based on ICF's review of the filings made by TransCanada, we have identified several key factors that affect the impact on Ontario consumers, namely:

1) Analysis parameters, including time frame and discount rates. This is important since virtually all of the benefits occur in the near term and the costs accrue in later years.
2) Market outlook impacting future demand for TransCanada pipeline capacity. If there is more need for pipeline capacity than TransCanada has forecast, the benefits would be less than what was identified in TransCanada's filing.
3) Expected impact on TransCanada's Discretionary Miscellaneous Revenues (DMR) (i.e., primarily revenues earned from short term firm transportation and interruptible transportation services). Reduced pipeline capacity in EDA would imply less DMR and hence, less benefits to EDA firm shippers.
4) Expected impact of Energy East on natural gas prices at market centers that are relevant to Ontario consumers. TransCanada assumes that the Energy East would not impact natural gas prices; however, ICF's market analysis concludes otherwise.
5) Expectations on the future use of Western Mainline capacity by Ontario shippers affects how savings in the west would flow through to Ontario shippers.
6) Timing of the Energy East Project affects benefits since they mostly occur in the early years of the project; any delay would reduce these benefits.

Depending on how these factors are used, the impact of Energy East on natural gas costs to Ontario consumers could range from a net reduction in natural gas costs of $421 million (based on the TransCanada market assumptions, analysis time frame, and discount rates) to a net increase in costs to Ontario consumers of about $670 million.

A large portion of the savings estimated by TransCanada is based on avoiding the costs associated with accelerated depreciation of the Northern Ontario Line. A delay in project timeline would significantly reduce the amount of accelerated depreciation costs that could be avoided by the transfer of assets to Energy East. ICF estimates that a one year delay in initiation of the project would reduce the benefits calculated by TransCanada for all shippers by $177 million, and a two year delay would reduce the calculated benefits by $304 million. This would reduce savings (i.e., increase costs) to Ontario consumers by around $59 million for a one year delay and $101 million for a two year delay.

Finally, ICF has conducted an initial assessment of the impact of expanding the Eastern Mainline Expansion project to fully replace the capacity displaced by Energy East in the higher pipeline system demand scenarios. Based on an initial cost estimate for increasing the capacity based on installing larger diameter pipe, ICF believes that the cost of increasing the capacity of the Eastern Mainline Expansion likely would be offset by the increase in long term pipeline revenue and the elimination of the natural gas price impacts of the project.

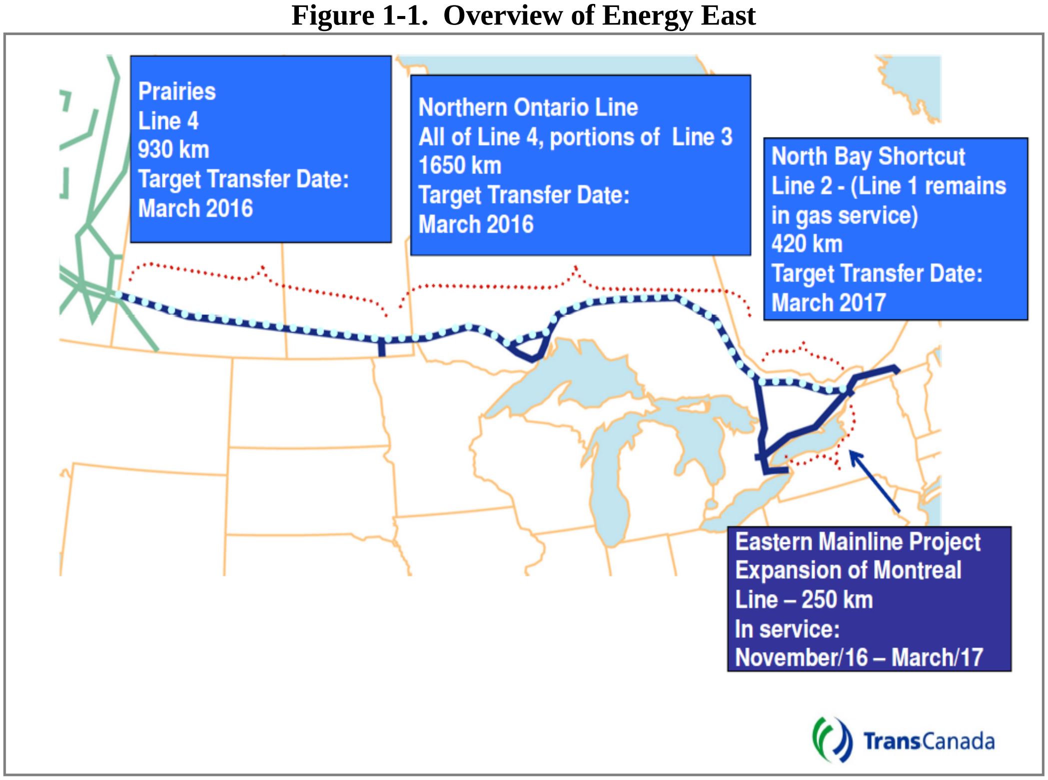
1. Introduction

In November 2013, the Ontario Energy Board (OEB or Board) was directed by the Ontario Minister of Energy to report on certain aspects of TransCanada PipeLines Limited's (TCPL or TransCanada) proposal to develop the Energy East Pipeline project (Energy East). It is in the interest of the provincial government to be fully informed so that it can actively participate in National Energy Board (NEB) hearings on TCPL's Energy East proposal. Accordingly, they asked the Board to examine and report on the Energy East project *from an Ontario perspective* [emphasis added] and submit its findings in the form of a report to the Minister.

The OEB engaged ICF Consulting Canada, a subsidiary of ICF International (ICF), to conduct an independent study of the effects of the Energy East pipeline project on natural gas prices in Ontario, which will be used to help inform the government on the implications of Energy East for Ontario gas markets.

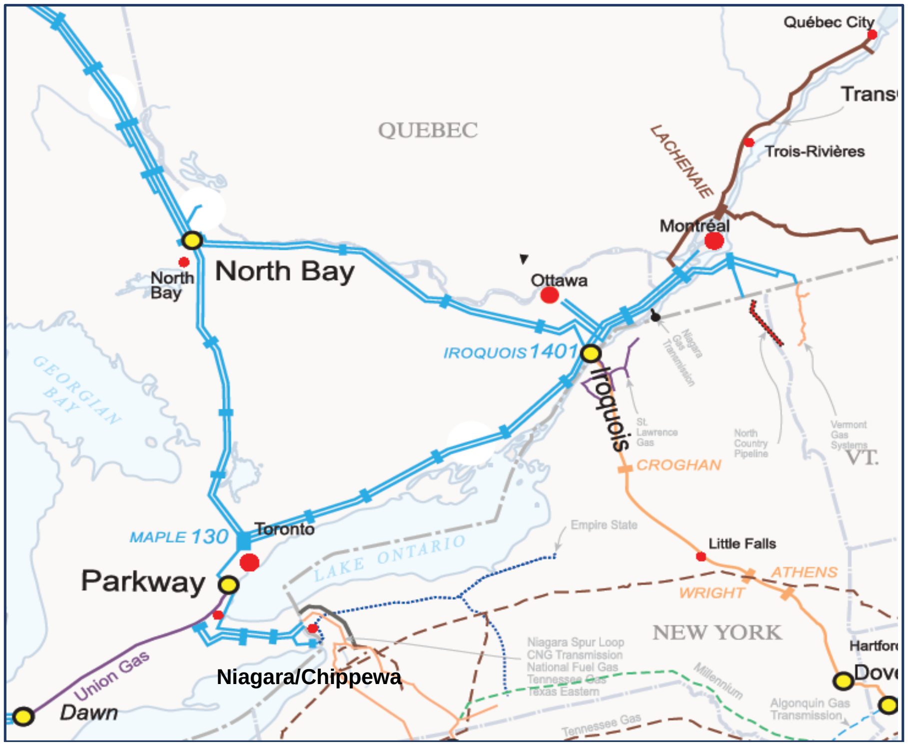
The Energy East Pipeline project involves the conversion of a section of TransCanada's Canadian Mainline (Mainline) from natural gas to crude oil service from Empress (at the Alberta Saskatchewan border) to and across northern Ontario, through North Bay and southeast to Cornwall, where a section of new pipeline running to the Québec border would be constructed. (See Fig. 1-1.) Three crude oil terminals will be built along the pipeline's route in Saskatchewan, in the Québec City area, and in the Saint John, New Brunswick area. The terminals in the Québec City and Saint John areas will include facilities for marine tanker loading. The project also will supply oil to refineries in Montréal, near Québec City, and in Saint John.

Figure 1-1. Overview of Energy East



A key aspect of the project important to Ontario is the removal from service of approximately 1.47 petajoules per day (PJ/d) of natural gas transportation capacity in Northern Ontario and 1.21 (PJ/d) in eastern Ontario[1]. To offset the reduction in gas transport capacity, TCPL also proposes to expand its Eastern Mainline. The Eastern Mainline Project (EMP) would add about 0.58 PJ/d of capacity in Eastern Ontario. [Note: the gas market in Eastern Ontario is referred to as the Eastern Delivery Area (EDA.). The three legs of the TCPL pipeline serving the EDA are referred to as the Eastern Ontario Triangle (EOT).]

Figure 1-2. EOT Pipeline Configuration



Source: TCPL via KPMG

ICF's scope of work involved the analysis of natural gas markets to evaluate the impact of the Energy East Pipeline project, including the Eastern Mainline expansion, on monthly and design day gas prices. The analysis assessed these price effects in the relevant gas markets, in particular in the EDA, under a reference case set of assumptions with and without the Energy East project over the next 20 years. ICF's scope further included a review of several other studies that have examined similar issues, as well as an evaluation of the impact of the Energy East project on Ontario consumers due to changes in transportation tolls and natural gas supply costs.

The remainder of this report is organized as follows. Section 2 describes ICF's general analytical approach, which involved modeling gas market scenarios with and without Energy East. This section also provides the key assumptions used in the model that can affect the results. Section 3 provides the model results with and without the Energy East project and assesses the project's impact on prices, basis spreads and gas flows. Section 4 reviews previous studies currently in the public record. Section 5 presents ICF's analysis of the impacts on Ontario consumers due to the Energy East project. ICF's summary and conclusions are in the final section.

[1] Table 4-1. Vol 2A Sale and Purchase of Mainline Assets - Effects of Transfer on Mainline Shippers - A4D8S4

2. ICF's Technical Approach

This section presents ICF's analytical approach to assessing the impact of Energy East. The North American Gas Market Model (GMM®) used in the analysis is described briefly below. We also list the key assumptions applied in the model. ICF used the GMM previously in an OEB consultation in 2010, where the Board had initiated a stakeholder process to consider changes in natural gas markets brought on by shale gas production.[2] This study uses the same analytical framework with updated assumptions and reflects subsequent developments in the North American gas market.

2.1 North American Gas Market Model

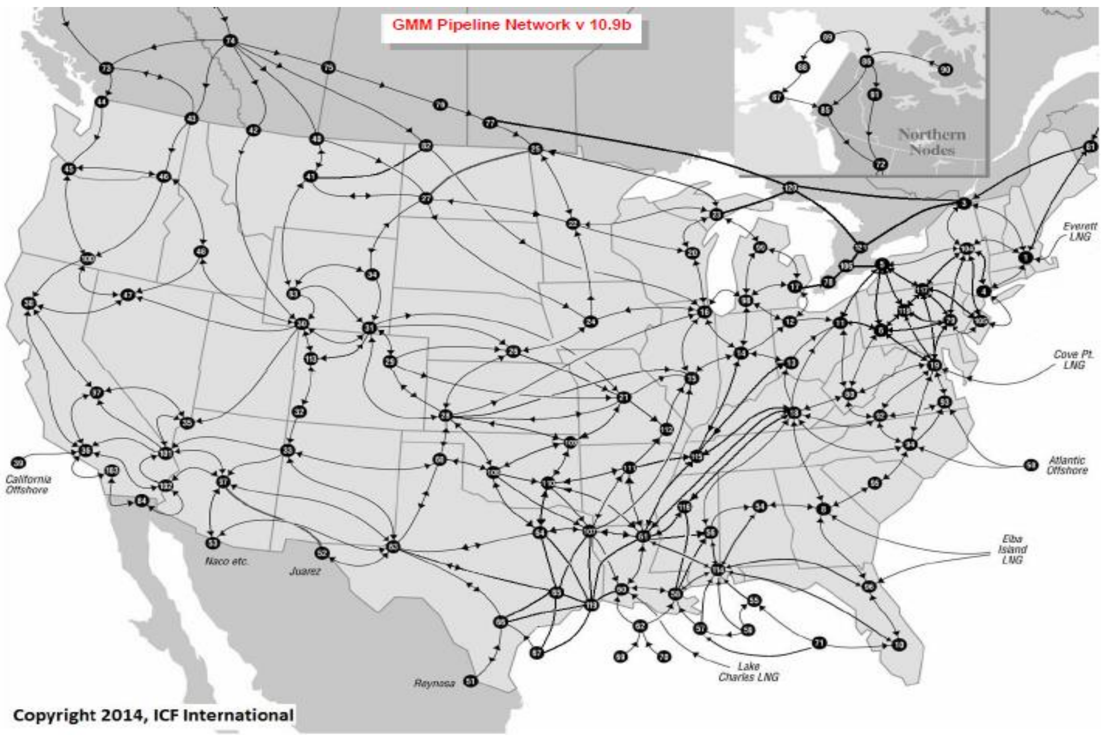
The GMM® is a widely recognized, comprehensive, detailed supply and demand equilibrium model of the North American gas market. The key features of the model are described below (a more detailed description of the GMM is found in Appendix A).

- The model has detailed representations of regional supply with data on production costs, ultimate recoverable reserves, per-well decline rates, and total production capabilities. The supply module also incorporates factor adjustments for technology improvements that tend to reduce the cost of production. Supply is made available to the model network solution at supply nodes that correspond to the geographic locations where supply is produced.
- The demand module represents the gas-consuming sectors (residential, commercial, industrial, and electricity generation). Each sector is characterised by price elasticity, alternative fuel costs, weather sensitivity, and technology trends that contribute to enhanced efficiencies (the power sector is more detailed and incorporates input from ICF's Integrated Planning Model (IPM®) to represent the generation fleet and plant dispatch economics; industrial demand incorporates heat and process uses as well as feedstock uses of gas). Demand is represented at demand nodes corresponding to geographic market centers and that have the full cross-section of demand from the consuming sectors characteristic of those locations. Demand is represented monthly over the course of the year where weather is based on a 20 year "normal" pattern of heating degree days (HDD).
- The model contains a network of gas pipeline links that reflect pipeline capacity and costs of moving gas, including fuel costs. The costs of flow over the links increases with throughput. The links connect supply nodes with demand nodes.
- Storage is represented in the model on a regional basis, where during off-peak periods gas is delivered into storage to be available in the on-peak (winter) periods. Storage use is an economic dispatch decision that depends in part on the price spread between injection volumes in the off-peak period and withdrawal in the on-peak period.
- The model also includes LNG import and export facilities. Export volumes are based on estimates made outside the model of world demand and supply for LNG and the costs of North American LNG relative to other sources. LNG exports are stipulated in the model set-up.

[2] See, OEB, 2010 Natural Gas Market Review (EB-2010-0199). http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/2010+Natural+Gas+Market+Review+(RP-2010-0199)

- The model operates by equilibrating supply and demand across the pipeline network on a monthly basis for a forecast period. The model generates gas production and gas consumption forecasts, shows pipeline utilization and flows, and storage operations. The GMM forecasts gas supply, consumption, and prices at over 120 supply and demand market nodes, including Henry Hub, Louisiana; AECO and Empress; Chicago; Dawn, and the major border hubs (e.g., Niagara, Waddington, Sumas, and Kingsgate). The model reports consumption by sector, by month.
- The model operates through 2035. Beyond 2035, ICF has estimated demand, supply, and prices based on trends of the final years of the forecast and judgement on future potential developments.

Figure 2-1. GMM Pipeline Network and Supply and Demand Nodes



For this engagement, ICF used its January 2015 quarterly Base Case, which includes the Energy East project. To evaluate the effects of the Energy East project, ICF developed a Status Quo Case that removes Energy East but keeps all of the other assumptions intact. The differences between the model runs in terms of gas prices, basis spreads, and pipeline flows, show the effect of Energy East on the Ontario market.

2.2 Assumptions used in the Modeling Framework

Below are listed the key assumptions used in the GMM Base Case for this analysis.

The GDP growth rate drives the demand for energy and natural gas. Our assumptions are:

- For Canada -- 2.5% per year throughout the forecast

- For United States in 2015: 2.9% Wall Street Journal's September 2014 Survey of Economists and for 2016 forward, 2.6% per year

Electricity demand growth also drives demand for natural gas in that higher electricity demand means greater use of existing power plants and the construction of new power plants. Natural gas-fired generation tends to increase with higher levels of electricity demand. Our assumptions are:

- Canada electricity demand growth at 1.2% per year;
- U.S. electricity demand growth is also 1.2% per year.

Projected weather in the model is consistent with a 20-year average pattern. The consumption of natural gas is highly dependent on weather given that gas is a heating fuel. Extreme weather, as has been experienced recently, causes spikes in demand and higher gas prices. ICF has run the analysis for average weather conditions as well as for an extreme weather scenario to assess the project's price impact under a "design day" [3] condition.

Our power sector outlook reflects ICF's expected outcome of environmental regulations that generally favor continued replacement of coal plants with gas plants. ICF also assumes that in the United States each state's Renewable Portfolio Standard ("RPS") goal is met on schedule and a national cap and trade program starting in 2020.

ICF assumes a maximum life span of 60 years for U.S. nuclear plants, which results in nearly 25 GWs of retirements between 2028 and 2035 and an increase in gas demand in the power sector leading to higher gas prices. For Canada, all nuclear units at the Pickering Station are assumed to be offline by 2020. Planned refurbishment of all the units at the Darlington and Bruce stations will remove substantial portions of nuclear capacity from service starting in 2016.

We assume that economically recoverable natural gas resources in the U.S. and Canada total roughly 4,000 trillion cubic feet (Tcf), and further that:

- Shale gas resources account for over 50% of the total recoverable resources.
- Gas supply development is expected to be consistent with recent levels.
- No significant restrictions on permitting or hydraulic fracturing occur beyond restrictions that are currently in place.
- The Alaska and Mackenzie Valley gas pipelines are not included in the forecast.

Pipeline capacity expansions over the next 4 to 5 years are assumed to be consistent with announced projects (see Table 2-1 below). When multiple projects are announced targeting the same markets, ICF limits the total capacity expansions to the level that would be supported by the market. In the long-term, pipeline capacity is expanded in the model when the market forecast indicates the need for additional capacity (i.e., increased basis). When a forecast basis spread between two points is higher

[3] Gas utilities typically define peak demand conditions in terms of "design-day" criteria, design day refers to the coldest weather conditions over a given time interval, such as 20 or 30 years.

than the cost of expansion, ICF will add a pipeline where there are sponsors proposing such expansions, even if the expansions are not fully subscribed. Thus, we include some "generic" expansions, examples of which in the table below are the Access Northeast / Northeast Energy Direct pipeline proposals. In both cases, ICF believes the market will eventually support one of the projects being proposed.

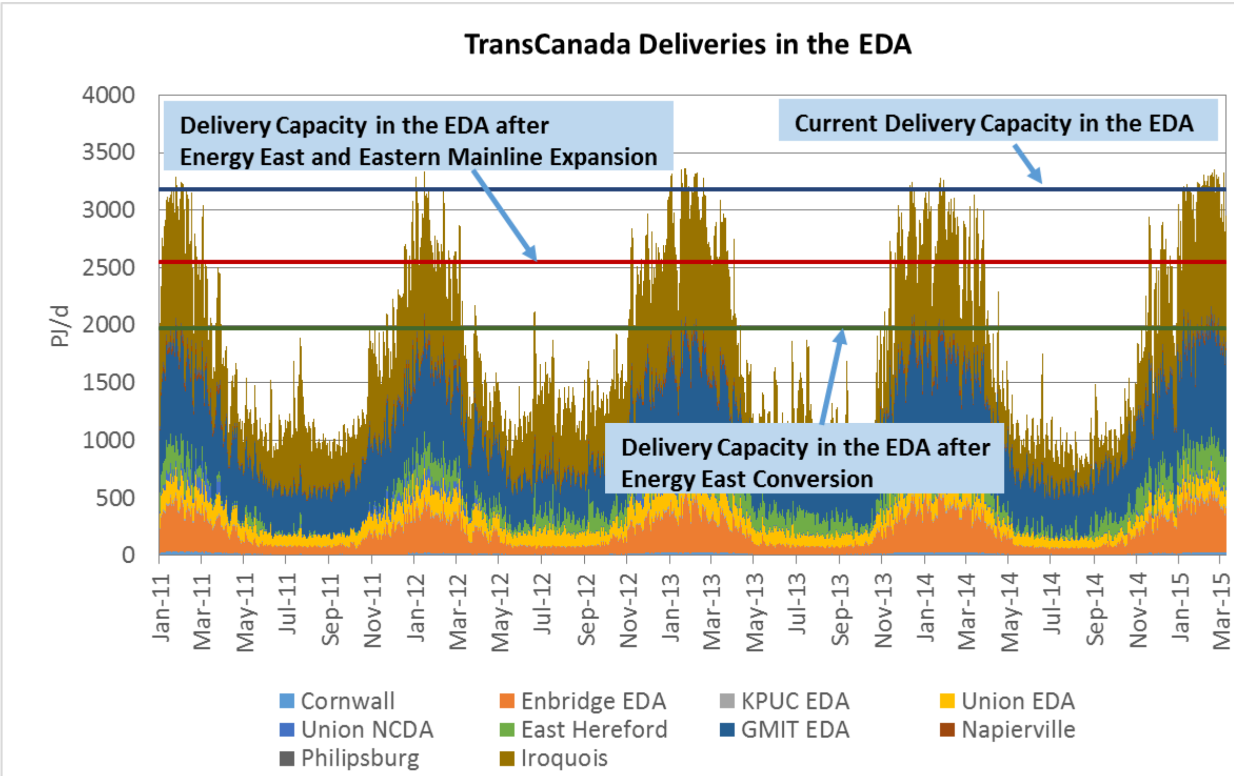
Pipeline expansions in this region can be important for two reasons. First, in this analysis, many of the pipeline expansions to and within Ontario will allow consumers in the province to access new supplies coming out of the Marcellus/Utica production basin by alleviating pipeline constraints that have limited Ontario consumers' ability to take full advantage of the availability of these gas resources.

Second, the expansions of pipeline capacity into the U.S. northeast and New England from the Marcellus/Utica producing region — since these regions historically have accessed western Canadian gas over TCPL — should have an effect on flows over TCPL if U.S. shippers swing from Canadian supply to U.S. supply. Figure 2-2 illustrates this potential: it shows flows over TCPL into the EDA from 2011 through most of 2014 color coded by delivery locations. Deliveries to the Iroquois, Phillipsburg, and East Hereford are export points to the United States, with Iroquois by far the largest since it serves the Iroquois Gas Transmission System (IGTS) for deliveries into New York and New England. The horizontal lines indicate the current capacity on TCPL, capacity with Energy East, and capacity with the Eastern Mainline Expansion. The topmost line shows that the current system is fully utilized on peak days. Were these exports to decline significantly due to pipeline expansions, the reduction in gas pipeline capacity driven by Energy East should have less of an impact than otherwise would be the case.

Table 2-1. Pipeline Expansion Assumptions in GMM

Pipeline	From	To	Capacity (MMcfd)	Year
To Ontario from Outside the Province				
TGP Niagara Expansion	New York	Niagara/Chippewa	158	2015
National Fuel	Leidy	Niagara	140	2015
TCPL Niagara Expansion	Niagara/Chippewa	Niagara Parkway	380	2016
Rover/Nexus	Marcellus/Utica	Vector Pipeline	1,050	2017
Within Ontario				
Enbridge GTA	Parkway	Albion	1,140	2015
TCPL Kings North	Albion	Vaughn	530	2015
TCPL Niagara Expansion 2015	Niagara/Chippewa	Parkway	333	2015
Union 2015	Dawn	Parkway	690	2015
TCPL Niagara Expansion 2016	Niagara/Chippewa	Parkway	380	2016
Union 2016	Dawn	Parkway	460	2016
TCPL Vaughn Loop	Parkway	Maple	380	2016
Eastern Mainline Expansion	Parkway	Iroquois/Waddington	550	2017
TCPL 2017	Parkway	Maple	348	2017
To Northeast/New England				
Constitution	Northeast Pennsylvania	Wright, New York	650	2016
AIM (Algonquin)	New York	New England	342	2016
TGP Connecticut	New York	New England	72	2016
Atlantic Bridge	Marcellus Interconnections	New England & Maritimes	300	2017
Access Northeast /Northeast Energy Direct	Marcellus Interconnections	New England	1,000	2018

Figure 2-2. Flows into the Eastern Delivery Area by Delivery Point and Energy East Capacity



3. Comparison of Model Results

In this section, we present the results of ICF's two comparative model runs to evaluate the impact of Energy East on gas prices:

- Base Case – includes both Energy East and the Eastern Mainline Expansion.
- Status Quo (Without EE) Case – excludes both Energy East and the Eastern Mainline Expansion.

All other model assumptions are the same.

The GMM simulates the operations of the natural gas market for each month over the next 20 years. The model matches gas supply with gas demand over a pipeline network defined by a series of links denoted by capacity and cost. Gas is produced at supply nodes in the model and dispatched over the pipeline network to satisfy the demand at market nodes. The price of supply is determined by cost/supply curves and the value of gas at the demand nodes is determined by price/demand curves for each consuming sector (residential, commercial, industrial, and power generation.) The model finds a solution each month in the forecast that satisfies demand at the lowest delivered cost at each node throughout the network and in the process generates results showing the amount of gas produced by location, flows through the pipeline links, the amount of demand served in each market by sector, and the price of gas at each node. There are about 122 supply and demand nodes. (A more complete description of GMM is provided in Appendix A.) As in the real natural gas market, gas supply, gas demand, pipeline flows, and gas prices are interrelated. In conducting our analysis, ICF changed the factors that can influence the model results centering on the Energy East Project changes in gas pipeline capacity available in the EOT.

The gas prices presented by the GMM are monthly prices, which are best thought of in commercial terms as first-of-the-month prices at the market hubs. These prices reflect the balance of supply and demand for the marginal unit of natural gas purchased at that location. As such, the prices reflect the locational value of gas to those buyers purchasing gas at that location, inclusive of pipeline costs, but do not reflect the gas prices paid by LDC's (such as Union Gas and Enbridge Gas Distribution) or other large-volume customers in these markets who purchase natural gas at upstream markets and hold sufficient firm pipeline capacity to deliver the purchases into their market. The model also does not produce daily prices.

Another output of the model is pipeline "basis." Basis is the difference in prices between two points along a pipeline corridor or between two market hubs. An example would be the difference in price between AECO and Dawn or Dawn and Iroquois/Waddington. The basis spread provides an indication of pipeline congestion. For example, high demand at a market node relative to available pipeline capacity leads to higher prices at that node which will be reflected in an increased basis between that hub and other hubs.

ICF has reported prices in Canada in U.S. dollars per million British thermal units (MMBtu) at three locations: AECO, the pricing point for Alberta-produced gas; Dawn, the pricing point for gas traded at Dawn, Ontario; and at Iroquois/Waddington, where the IGTS interconnects with TCPL. These are the three hubs in Canada at which gas prices are reported in the trade press and they represent liquid trading hubs. Iroquois/Waddington, at the eastern end of the EOT facilities, is a proxy for the EDA even though it reflects demand in the U.S. to a considerable extent. Buyers in the EOT would pay a price similar to the Waddington price, especially those in Québec.

The comparative analysis detailed below looks at gas demand, pipeline flows, gas prices, and gas price basis.

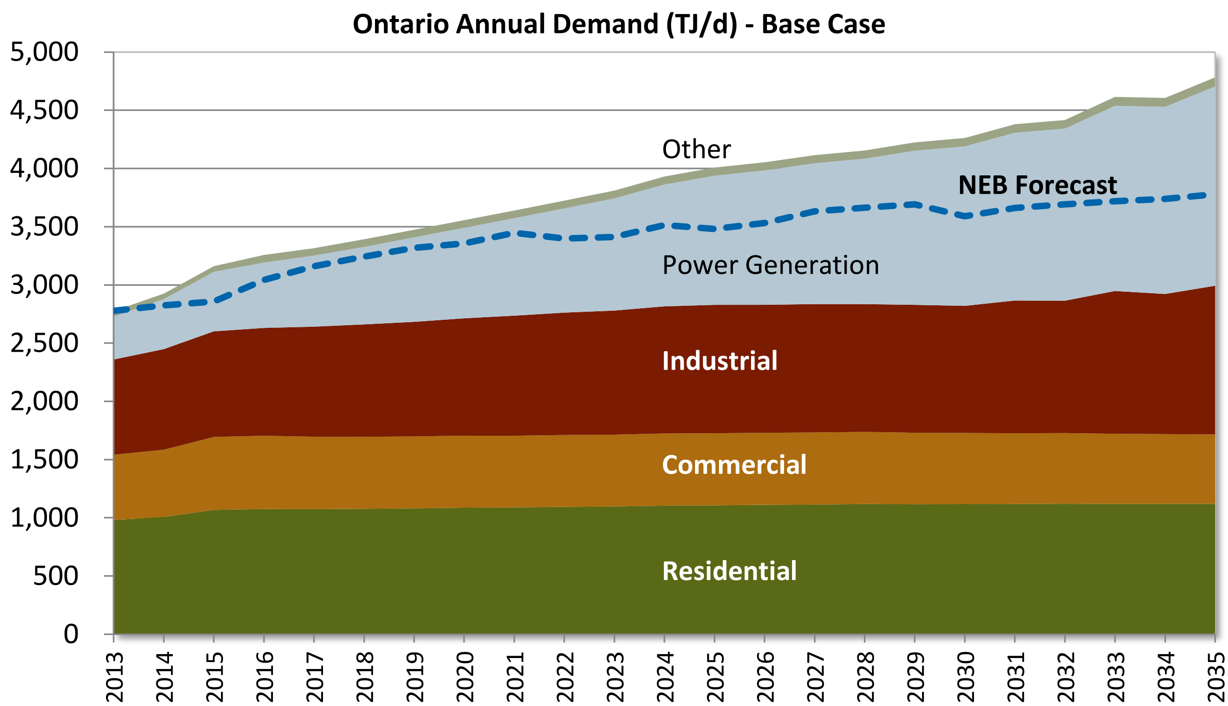
3.1 Ontario Gas Demand Forecast

Figure 3-1 shows ICF's demand forecast under our Base Case. The demand forecast under the "Status Quo" case without Energy East is essentially the same, and so we do not present a comparison. The figure also shows the demand forecast of the NEB for all demand in Ontario as a dotted line.

In ICF's forecast, residential and commercial demand remains relatively flat through the term of the forecast, increasing from around 1,440 TJ/d in 2010 to 1,700 TJ/d by 2035. Industrial consumption increases by about 600 TJ/d over the period. The main driver of demand growth is the power sector, where ICF forecasts that demand will increase by about 1,300 TJ/d over the period. Overall, Ontario gas demand is projected to grow to 3,560 TJ/d by 2020 and 4,780 TJ/d by 2035.

ICF's forecast for the power sector reflects underlying assumptions about how long nuclear plant refurbishment will take, which is more pessimistic than the most recent NEB forecast. By 2020, the NEB expects gas demand to be 3,360 TJ/d in 2020, which is similar to the ICF forecast. But by 2035, demand is forecast to be 3,780 TJ/d, only about three-quarters of the ICF forecast of 4,780 TJ/D. ICF's forecast of gas demand in Ontario reflects an assumption that refurbishing the nuclear power plants in Ontario will take as long as such refurbishments have taken in the past, which is longer than was assumed in the NEB forecast. Therefore, ICF assumes a longer period of nuclear plant outage, and as a result, we forecast more demand for gas in Ontario's power sector.

Figure 3-1. Base Case Gas Demand Forecast



3.2 Pipeline Flows with and without Energy East

The GMM forecast of pipeline flows are shown in the following graphics that focus on gas pipeline links in Ontario and the U.S. Northeast. (The map in Figure 1-2 on page 7 shows the basic pipeline configuration in the EOT and U.S. northeast.) The key pricing points are Dawn and Iroquois, also known as Waddington. Dawn is a major market hub for deliveries into Ontario and eastern Canada. Important pipeline segments are the line between Dawn and Parkway, owned by Union Gas; the Parkway to Maple segment, a TCPL line; and the EOT, where the Eastern Mainline is the link from Maple to Iroquois/Waddington. The Iroquois pipeline receives gas from TCPL at the Iroquois/Waddington interconnect for deliveries into New York and New England. Iroquois/Waddington is a market hub at the eastern end of the EOT that represents about 36 percent of average annual daily flows and about 38 percent of peak day flows in the EOT. TCPL also delivers and receives gas at the Niagara and Chippewa interconnects with U.S. pipelines.

Figure 3-2 compares average annual daily gas flows in 2030, where the map on the left represents flows without Energy East, and the map on the right shows flows if Energy East as proposed were implemented. These flow maps illustrate the major differences between the two cases:

- With Energy East, flows into North Bay would decline by about 200 MMcfd; flows across the Northern leg of the EOT would decline about 263 MMcfd.
- Energy East would increase flows from North Bay to Maple by about 76 MMcfd and across the Eastern Mainline by about 203 MMcfd.
- Flows across Ontario from Dawn to Parkway would increase by about 100 MMcfd; into Ontario at Niagara/Chippewa would be little changed.
- Flows down the Iroquois system into New York and New England would decline from 236 MMcfd to 184 MMcfd.

Figure 3-2. Average Annual Gas Flows in 2030 with and without Energy East (MMcfd)

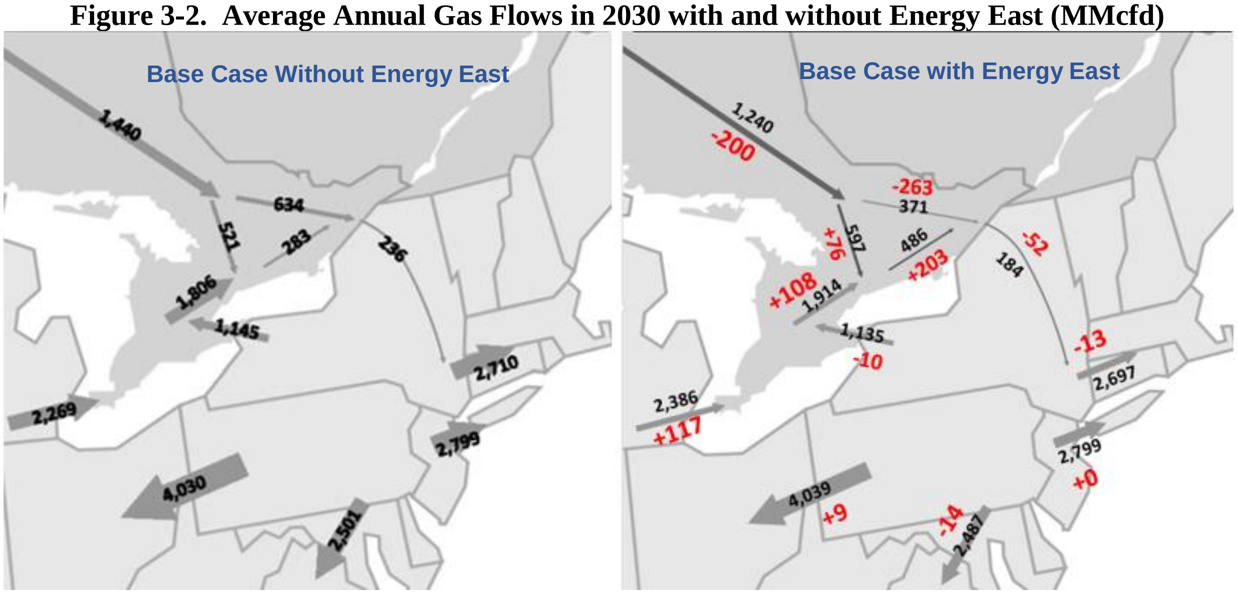
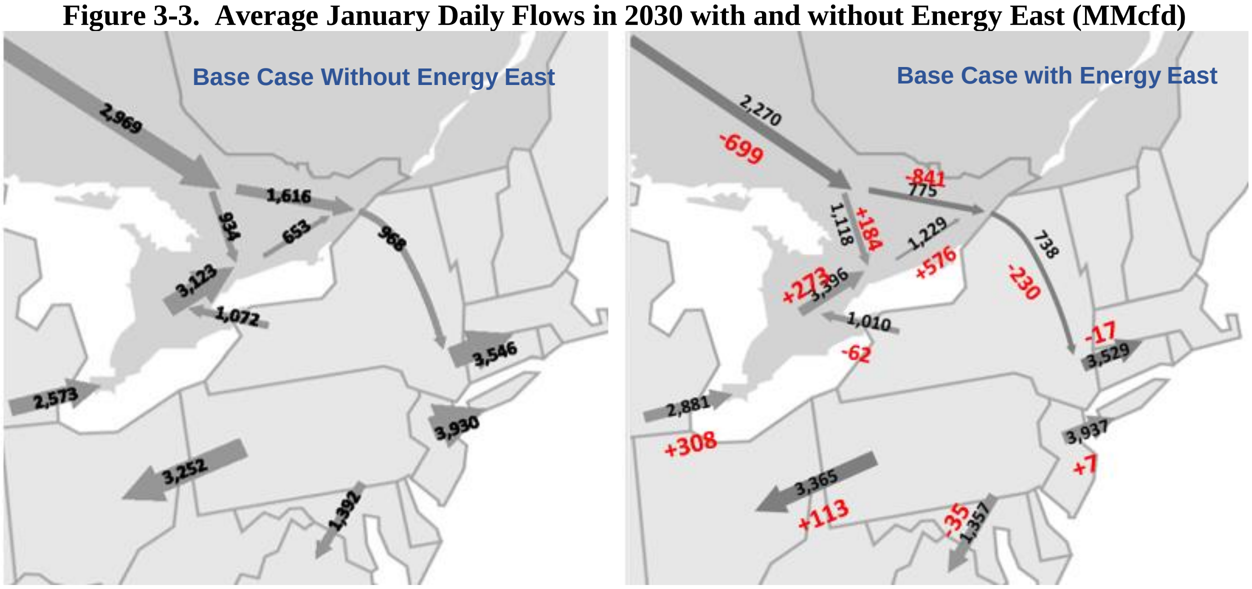


Figure 3-3 below compares the average daily flows in the peak heating season month of January for the model cases:

- With Energy East, flows into North Bay would decline by about 699 MMcfd; flows across the northern leg of the EOT would decline about 841 MMcfd.
- Energy East would increase flows from North Bay to Maple by about 184 MMcfd and across the Eastern Mainline by about 576 MMcfd.
- Flows across Ontario from Dawn to Parkway would increase with Energy East by nearly 275 MMcfd, with over 300 MMcfd of additional imports to Dawn and slightly less imports across Niagara/Chippewa.
- In January, Energy East would reduce flows into the United States at Iroquois/Waddington from 968 MMcfd to 738 MMcfd, which is about 71 percent of the average flow during January over the last five winters. (From 2011 through 2015, January deliveries into Iroquois/Waddington have averaged 1,044 MMcfd with a peak January day flow of 1,320 MMcfd (Jan. 27, 2013). ICF's forecast is based on a 20-year normal winter. The last two winters in the Northeast have been colder than recent winters, but have not exceeded design day. Local distribution companies typically contract for capacity on transmission pipelines to meet their design day send-out requirements (exclusive of their peak-shaving and other peaking services), typically the expected demand on the coldest day in the last 20 years. The pipeline in turn is sized to meet the sum of all customers' coincidental contracted design day requirements, rather than average monthly flows.

Figure 3-3. Average January Daily Flows in 2030 with and without Energy East (MMcfd)



3.3 Gas Prices with and without Energy East

Table 3-1 presents the forecasts of gas prices at the Iroquois/Waddington hub under the Base Case with Energy East and Status Quo Case without Energy East. The Iroquois/Waddington hub was selected because of its proximity to the EOT as a liquid trading hub for which historical prices are reported daily, and because the GMM forecasts that TCPL will continue to be used by New England and New York shippers to transport gas into the northeastern U.S. market over the Iroquois pipeline.

The table below shows the annual average price generated by the GMM, an average winter price (December through February), and an average summer price (May through September). ICF has also estimated a design day winter price to illustrate the impact on a peak winter day. This estimate is based on recent observations of the relationship between peak day prices at the hub and average winter prices. As might be expected, the output shows that Energy East would have an impact on prices in the winter because of the high demand for gas and congestion on the pipeline; and little or no impact in summer when demand is lower and the pipeline is operating well below capacity. Similarly, the estimated peak day price impact is higher, again because of the high demand for gas when the pipeline is operating at or near capacity.

Table 3-1. Gas Price Effects of Energy East Measured 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	4.84	5.05	5.19	5.38	5.64	6.50	6.84	5.82
	With EE	4.49	4.90	4.94	5.17	5.31	5.50	5.80	6.74	7.28	6.02
	Difference	*0.02*	*0.14*	*0.10*	*0.12*	*0.12*	*0.12*	*0.16*	*0.24*	*0.44*	*0.20*
	% Diff.	***0.4%***	***3.0%***	***2.2%***	***2.4%***	***2.3%***	***2.1%***	***2.8%***	***3.7%***	***6.5%***	***3.5%***
Winter* (Dec-Feb)	Without EE	5.56	5.36	5.52	5.65	5.75	5.86	6.29	7.25	7.95	6.57
	With EE	5.56	5.93	5.92	6.13	6.21	6.31	6.88	8.23	9.64	7.35
	Difference	*0.00*	*0.57*	*0.40*	*0.48*	*0.46*	*0.45*	*0.59*	*0.98*	*1.69*	*0.78*
	% Diff.	***0.0%***	***10.6%***	***7.2%***	***8.5%***	***7.9%***	***7.6%***	***9.4%***	***13.5%***	***21.2%***	***11.9%***
Summer (May-Sep)	Without EE	3.94	4.34	4.43	4.64	4.82	5.05	5.20	6.05	6.28	5.38
	With EE	3.94	4.33	4.42	4.63	4.82	5.05	5.21	6.03	6.28	5.37
	Difference	*0.00*	*-0.01*	*-0.01*	*-0.01*	*0.00*	*0.00*	*0.01*	*-0.02*	*0.00*	*-0.01*
	% Diff.	***0.0%***	***-0.3%***	***0.0%***	***-0.2%***	***0.1%***	***0.0%***	***0.1%***	***-0.3%***	***0.0%***	***-0.1%***
Design Day (January)	Without EE	30.13	29.04	29.93	30.64	31.19	31.77	34.08	39.31	43.09	35.59
	With EE	30.13	32.12	32.08	33.24	33.66	34.18	37.28	44.63	52.24	39.82
	Difference	*0.00*	*3.07*	*2.15*	*2.60*	*2.47*	*2.41*	*3.20*	*5.32*	*9.15*	*4.24*
	% Diff.	***0.0%***	***10.6%***	***7.2%***	***8.5%***	***7.9%***	***7.6%***	***9.4%***	***13.5%***	***21.2%***	***11.9%***

*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.

On an annual basis, the reduction in gas pipeline capacity into Ontario in the ICF Base Case relative to the case without Energy East results in higher gas prices at Iroquois/Waddington by about US$0.20 per MMBtu on average over the entire period, with the difference increasing from US$0.02 per MMBtu in 2016 (when the northern line segments are taken out of gas service) to US$0.44 per MMBtu by 2035. Summer prices are forecast to be virtually unchanged by Energy East. In the winter, when demand is strongest, the reduction of pipeline capacity into the EDA results in gas prices being higher by an average of US$0.78 per MMBtu over the entire period. In 2017, the price difference is US$0.57 per MMBtu with Energy East, rising to US$1.69 per MMBtu by 2035. Peak day prices could experience higher swings with Energy East, where by 2035, the price could be 21% higher than a case without Energy East.

Table 3-2 shows the price effects of Energy East as seen at Dawn, Ontario. As the table shows that the price effects are small, US$0.01 per MMBtu on an annual basis over the forecast period, and US$0.04 per MMBtu in winter over the forecast period. Price differences at Dawn would be expected to be small given the large volume of storage in the region and that Dawn is upstream of the Energy East reduction in pipeline capacity in the EOT.

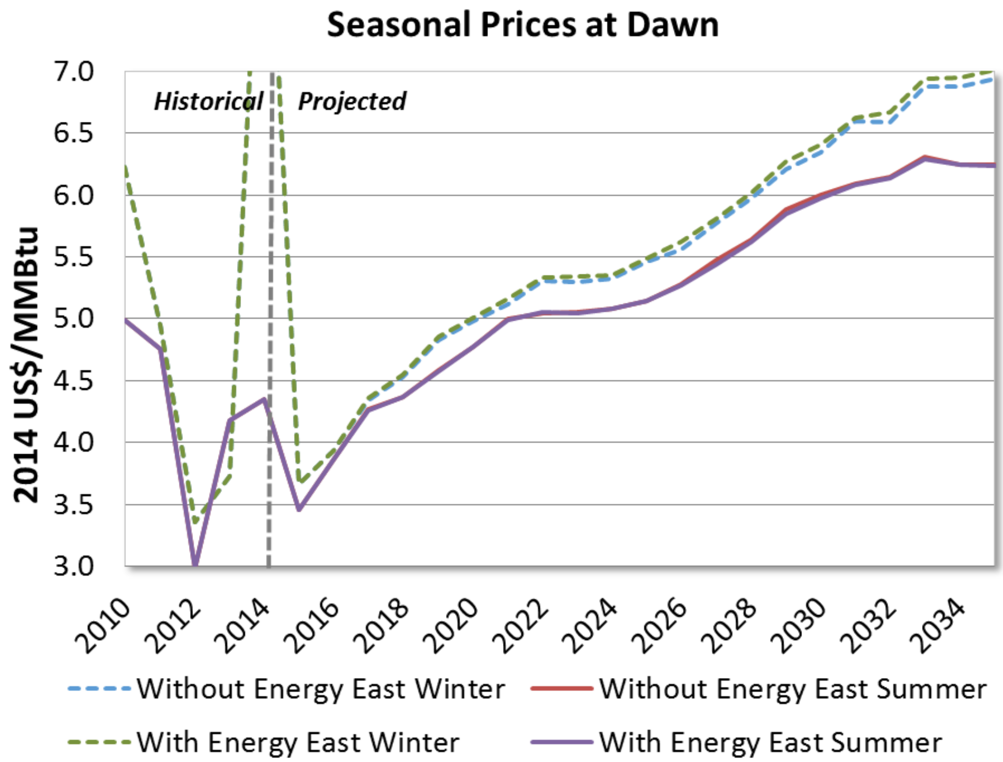
Table 3-2. Gas Price Effects of Energy East Measured at Dawn (2014 US$/MMBtu)

		2016	2017	2018	2019	2020	2021	2025	2030	2035	Avg. 2016-35
Annual	**Without EE**	3.95	4.39	4.50	4.75	4.92	5.12	5.35	6.18	6.50	5.50
	With EE	3.95	4.39	4.51	4.76	4.93	5.13	5.36	6.18	6.52	5.51
	Difference	*0.00*	*0.00*	*0.01*	*0.01*	*0.01*	*0.01*	*0.01*	*0.00*	*0.02*	*0.01*
	% Diff.	***0.1%***	***0.0%***	***0.2%***	***0.1%***	***0.3%***	***0.3%***	***0.2%***	***0.0%***	***0.4%***	***0.2%***
Winter* (Dec-Feb)	**Without EE**	3.94	4.34	4.53	4.83	4.98	5.11	5.45	6.34	6.94	5.64
	With EE	3.94	4.36	4.55	4.86	5.01	5.16	5.48	6.41	7.01	5.68
	Difference	*0.00*	*0.02*	*0.02*	*0.03*	*0.03*	*0.05*	*0.03*	*0.07*	*0.07*	*0.04*
	% Diff.	***0.0%***	***0.3%***	***0.5%***	***0.6%***	***0.6%***	***0.9%***	***0.6%***	***1.1%***	***1.1%***	***0.8%***
Summer (May-Sep)	**without EE**	3.86	4.27	4.37	4.59	4.77	5.00	5.14	6.00	6.24	5.32
	With EE	3.86	4.26	4.37	4.58	4.77	4.99	5.14	5.97	6.23	5.31
	Difference	*0.00*	*-0.01*	*0.00*	*-0.01*	*0.00*	*-0.01*	*0.00*	*-0.03*	*-0.01*	*-0.01*
	% Diff.	***0.1%***	***-0.2%***	***0.0%***	***-0.2%***	***0.0%***	***-0.1%***	***0.0%***	***-0.6%***	***-0.2%***	***-0.2%***
Peak Day (March)	**Without EE**	24.88	27.45	28.62	30.51	31.48	32.31	34.47	40.06	43.86	35.65
	With EE	24.88	27.53	28.75	30.70	31.66	32.61	34.66	40.49	44.32	35.93
	Difference	*0.00*	*0.08*	*0.13*	*0.18*	*0.18*	*0.30*	*0.19*	*0.43*	*0.46*	*0.28*
	% Diff.	***0.0%***	***0.3%***	***0.5%***	***0.6%***	***0.6%***	***0.9%***	***0.6%***	***1.1%***	***1.1%***	***0.8%***

*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 peak day price provides an "indicative value" for a peak day, estimated by assuming the ratio of the observed peak day price to the average winter price from the 2013-14 winter.

Figure 3-5 presents the price effects of Energy East in the GMM in a slightly different way. These graphs show the average winter price track over time and the average summer price track over time. Most of the effects of Energy East are in winter. Summer prices are little affected and the with-and-without Energy East prices appear as a single line. These graphs also show the price effects at Dawn and AECO where Energy East has little effect, winter and summer.

Figure 3-5. Seasonal Price Comparisons



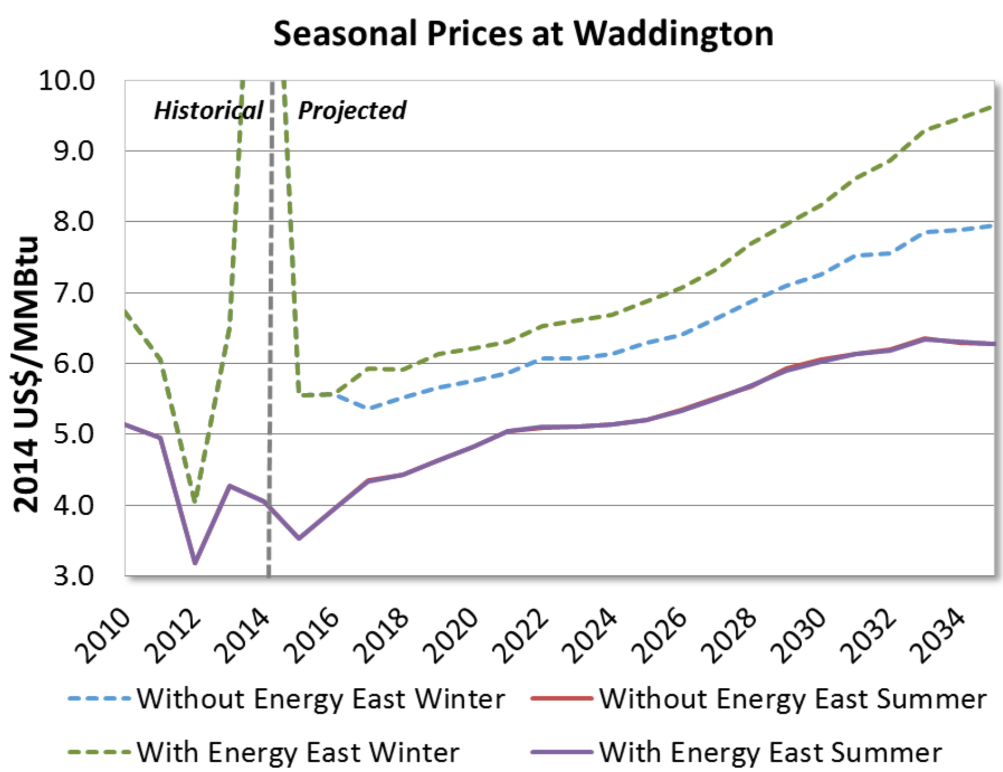
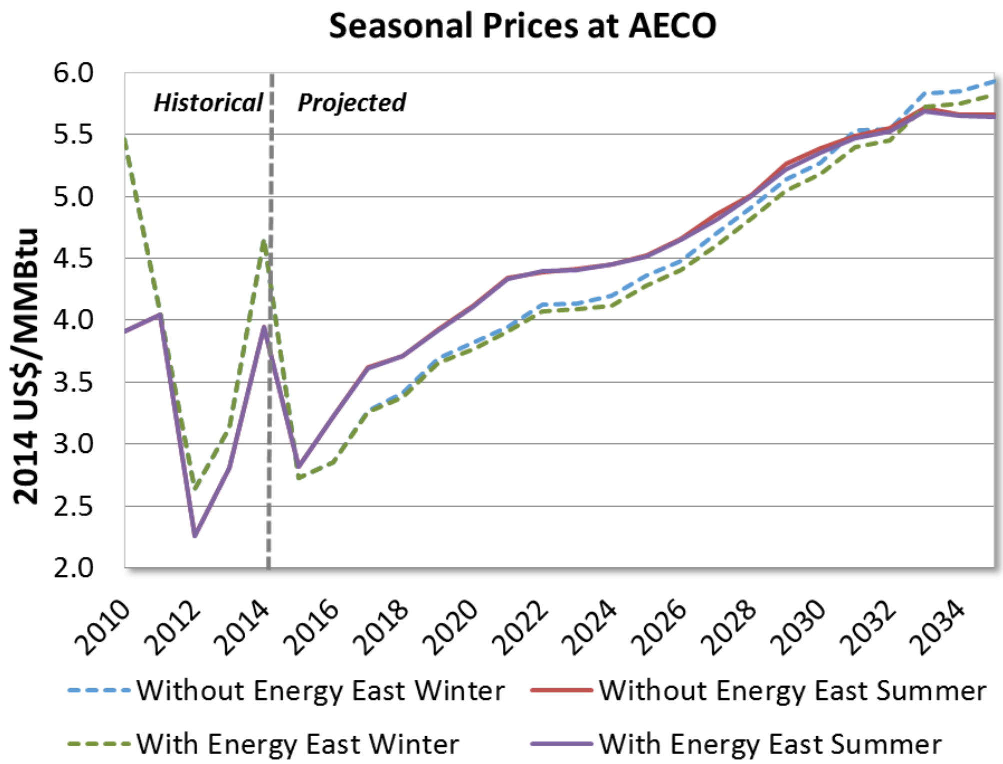


Figure 3-5. Seasonal Price Comparisons (continued)



ICF's analysis of the price impacts of Energy East is based on the ICF Base Case forecast of demand. As noted in the assumptions section above, because we expect the nuclear plants to be off-line longer than the NEB assumes, ICF's forecast has higher demand in the power sector. To determine if this assumption impacted the results of the Energy East price analysis, ICF ran sensitivity cases using the NEB forecast of power generation gas demand to evaluate the effects of lower demand on the results of the Energy East cases. With lower demand, both Dawn and Waddington prices are reduced by about $0.10/MMBtu, on average, from 2016 through 2035. However, the annual, seasonal, and peak day price differences observed with and without Energy East are similar to the differences shown in the tables and charts presented above. So roughly the same price impacts occur even with lower growth in Ontario's gas use.

3.4 Gas Price Basis with and without Energy East

Gas price basis refers to the difference in prices between two points on the pipeline system. The difference in prices between two points can indicate the effects of different market factors driving prices in the two markets. Basis also indicates where pipelines are constrained. A supply market may not have enough pipeline capacity to transport gas out of the region, bottling up supply and driving down prices. Conversely, high demand can be exacerbated by limited pipeline capacity to meet that demand, driving prices up in the consuming market. These effects can be seen in expanding or contracting basis spreads between two markets.

Energy East reduces pipeline capacity on the EOT in the consuming EDA market. Thus, it would be expected that some of the effects of Energy East would be seen in basis spreads between the EDA and other markets. Table 3-3 shows the model results for basis forecasts as annual and winter averages over the entire forecast period. It is not surprising to see that the major expansions in basis with Energy East occur between supply points outside the EOT and the Iroquois/Waddington hub. Energy East increases the annual basis from Dawn to Waddington by about 60% and the winter basis by about 80%, on average.

Table 3-3. 2016-35 Average Basis with and without Energy East (2014US$/MMBtu)

	From	Henry Hub			Marcellus	AECO	Henry Hub	Marcellus	AECO	Dawn
	To	Marcellus	AECO	Dawn			Iroquois/Waddington			
Annual	**Without EE**	-1.04	-0.85	0.00	1.03	0.85	0.32	1.35	1.17	0.32
	With EE	-1.03	-0.87	0.01	1.05	0.88	0.53	1.56	1.40	0.51
	Difference	*0.01*	*-0.02*	*0.01*	*0.02*	*0.03*	*0.21*	*0.21*	*0.23*	*0.19*
	% Diff.	***-0.3%***	***2.8%***	***0.0%***	***1.3%***	***4.7%***	***65.7%***	***15.2%***	***19.9%***	***60.1%***
Winter* (Dec-Feb)	**Without EE**	-0.96	-0.82	0.27	1.24	1.09	1.20	2.16	2.02	0.92
	With EE	-0.96	-0.89	0.32	1.28	1.21	1.98	2.94	2.87	1.66
	Difference	*0.00*	*-0.07*	*0.05*	*0.04*	*0.12*	*0.78*	*0.78*	*0.85*	*0.74*
	% Diff.	***-0.6%***	***8.7%***	***15.8%***	***3.0%***	***10.5%***	***65.1%***	***35.8%***	***42.2%***	***79.8%***

*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.

4. Review of Other Studies

As part of the analysis, ICF reviewed several studies, reports and presentations by other firms, who have assessed the impact of the Energy East project. A list of the studies, as well as the firms who conducted them is provided below:

- **Wood Mackenzie**
  - Presentation to the OEB on behalf of Union Gas (dated January 29, 2015).
  - Report for Société en commandite Gaz Métro and Gazifère Inc. (September 2, 2014).
- **Concentric Energy Advisors**
  - Testimony by John Reed on behalf of TransCanada in October 2014, submitted as Appendix Volume 1-2 of TransCanada's Energy East Project and Asset Transfer Applications to the NEB.
  - Report submitted to the Régie de L'énergie Du Québec at the request of TransCanada on natural gas market assessment in Québec (September 23, 2014).
  - Presentation to the Régie de L'énergie Du Québec at the request of TransCanada on natural gas market assessment in Québec (October 7, 2014).
- **KPMG**
  - Report to the Régie for Gaz Métro (October 28, 2014).

Only the Wood Mackenzie Presentation to the OEB provided gas price impact information and as such we focus on this report primarily in this section. The other studies do not provide specific information on the price impacts of the Energy East project.

4.1 Wood Mackenzie

Wood Mackenzie's presentation and report was conducted on behalf of Union Gas and Gaz Métro and Gazifère, respectively. ICF considered the January 2015 presentation as the primary source of information, as this work appears to be based on Wood Mackenzie's latest modeling. However, the September 2014 report for Gaz Metro is more detailed, and ICF used this report to develop a better understanding of the assumptions used in the Wood Mackenzie modeling.

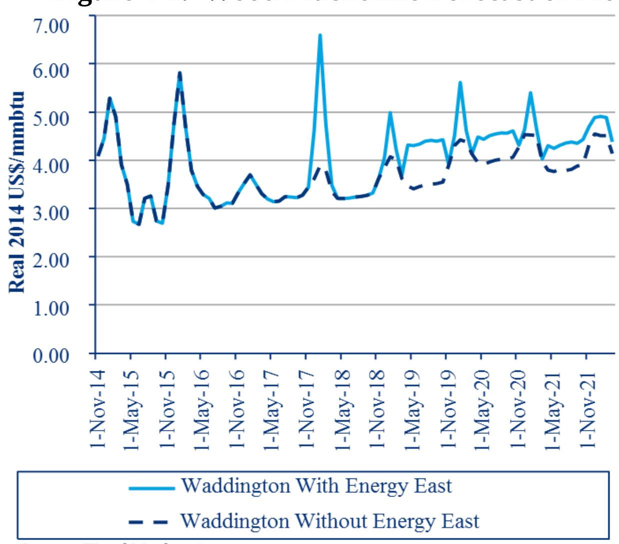
Similar to ICF projections, Wood Mackenzie also projects gas production from the Marcellus/Utica area to more than double by 2025, relative to the current production. This gas is expected to displace gas supply across the region, including Canada. Increasing volumes of the Marcellus/Utica gas is expected to flow into Ontario, such that roughly half of Ontario's gas needs is expected to be met from Marcellus/Utica by 2017. By 2020, the share is projected to increase to about 80%, which then limits the need for WCSB gas, as well as other sources. Québec is expected to source about half of its gas needs from WCSB and the rest from Marcellus by 2020, in contrast to over 90% being sourced from WCSB at present.

Wood Mackenzie's Ontario's gas demand outlook is consistent with NEB estimates, as power generation demand growing steadily until 2021. Nuclear refurbishments in the 2020s reduce gas demand from its peak in 2021 by at least 100 MMcfd by 2030. According to Wood Mackenzie, gas demand in Ontario is expected to increase by 640 MMcfd (675 TJ/d) by 2030 (compared to today's level) by 2030. In contrast, ICF's Base Case assumes an increase of about 1000 MMcfd in Ontario between 2015 and 2030.

Similar to ICF's analysis, Wood Mackenzie concludes that there are no material impacts on the markets served by the Prairies and Northern Ontario Line. However, Wood Mackenzie notes that not all peak day markets using the EOT can be served in a scenario with Energy East. Similar to our discussion around Figure 2.2, Wood Mackenzie also notes that flows in the EOT during the winter of 2013-14 exceeded the proposed capacity that will remain after the Energy East project, which indicates the competitive pressure between Ontario and New England markets.

Wood Mackenzie also assumes that the gas price impact on consumers in Ontario can be represented by gas prices at Waddington/Iroquois. Figure 4-1 shows the gas price impact at Waddington/Iroquois according to Wood Mackenzie. They note that with the Energy East project, the average peak month price in January 2018 will be $2.70/MMBtu greater than a case that excludes Energy East. However, the peak month difference will drop to about $0.40/MMBtu in January 2022. The average winter prices will increase by about $1.00/MMBtu in 2017-18, dropping to roughly $0.30/MMBtu over the next four winters.[4]

Figure 4-1. Wood Mackenzie Forecast of Monthly Average Gas Prices (2014 US$/MMBtu)



Period	Waddington Without EnergyEast	Waddington With Energy East	Difference	Peak Month Difference
Winter 2016–17	$3.48	$3.48	$0.00	$0.00
Winter 2017–18	$3.62	$4.58	$0.96	$2.70
Winter 2018–19	$3.84	$4.11	$0.28	$0.91
Winter 2019–20	$4.23	$4.56	$0.33	$0.91
Winter 2020–21	$4.37	$4.61	$0.24	$0.87
Winter 2021–22	$4.41	$4.75	$0.34	$0.40

Source: Wood Mackenzie

Table 4-2. Comparison of ICF and Wood Mackenzie Price Changes at Iroquois/Waddington (2014US$/MMBtu)

Winter	ICF	Wood Mac	Peak Month	ICF	Wood Mac
Winter 2016-17	$0.57	$0.00	Jan-17	$0.92	$0.00
Winter 2017-18	$0.40	$0.96	Jan-18	$0.66	$2.70
Winter 2018-19	$0.48	$0.28	Jan-19	$0.80	$0.91
Winter 2019-20	$0.46	$0.33	Jan-20	$0.77	$0.91
Winter 2020-21	$0.45	$0.24	Jan-21	$0.74	$0.87

Note: ICF winter is Dec-February; Wood Mackenzie winter is Nov.-March.

[4] Note that Wood Mackenzie uses a November to March winter, whereas ICF uses a December to February winter.

These price impacts are directionally consistent with the impacts in ICF's modeling; although there are some differences. (Table 4-2 compares ICF and Wood Mackenzie price impacts of the Energy East project). First, Wood Mackenzie projects a significant summer price impacts that ICF does not project, and it is not clear what is driving the summer price difference between the two Wood Mackenzie scenarios. Second, although Wood Mackenzie includes five months (November to March) as their "winter", they show a higher price impact of the Energy East in the initial years, compared to ICF, which defines "winter" as December to February.

4.2 Other Reports

As noted above, none of the other reports that ICF reviewed contained information about price impacts of the Energy East project.

Concentric Energy Advisor's (Concentric) September 23, 2014 report and presentation to Régie de L'énergie Du Québec were prepared at the request of TransCanada to assess the effects of Energy East on the natural gas market in Québec. The focus of these reports is the Québec market, rather than Ontario. The Concentric analysis does not provide any natural gas price impact assessments of the Energy East project in Ontario or Québec, but reproduces NEB and Energy Information Administration (EIA) forecasts and the futures market forward prices as a general indication for expected prices.

Concentric estimates incremental pipeline capacity requirements of about 80 MMcfd through 2030 for Québec due to market growth. They note that the demand for the proposed Indian Fertilizer Farmers Cooperative Ltd. (IFFCO) fertilizer plant and TCPL's Bécancour power plant in Québec, which is expected to return on-line in 2018, are included in the Eastern Mainline expansion, as they have firm contracts with TransCanada. Concentric notes that incremental demand growth in Québec can be met by:

a) potential expiration and non-renewal of existing firm capacity contracts on the Eastern Triangle by customers in the northeast U.S.;
b) shale gas production in Québec and from existing and proposed LNG peak-shaving facilities in Québec; and
c) contracting for pipeline capacity on proposed projects to deliver Marcellus/Utica gas into Dawn, Iroquois/Waddington, Niagara, and Chippewa.

John Reed, Chairman and Chief Executive Officer of Concentric, testified at the NEB on behalf of TransCanada in support of the Energy East project. Mr. Reed's testimony presents information about the economic benefits of the Energy East project. In general, he concludes that Energy East would have a limited impact on firm service customers in Ontario. His testimony did not address the potential natural gas price impacts of the Energy East project on Ontario or the impact on interruptible or secondary market customers in Ontario.

KPMG-SECOR developed a report to the Régie in Québec on behalf of Gaz Métro on potential economic losses to Québec from Energy East because of the reduction of EOT pipeline capacity currently available to Québec shippers. The report focuses on the adverse effects on six potential gas-intensive projects in Québec from reduced access to supply. They note that limitations on access would result in higher gas cost and greater project risk, thus reducing project economics for the potential projects. They also describe the economic impact of making these projects less viable for Québec. Nonetheless, KPMG-SECOR does not estimate a specific natural gas price impact from the Energy East in Québec.

5. Consumer Cost Impacts of Energy East

The Ontario Energy Board requested ICF to estimate the impacts of the Energy East project on Ontario consumers. Ontario consumers include all natural gas customers that consume natural gas in Ontario, including customers of the LDCs, as well as the large industrial and power generation companies located in Ontario that purchase and ship their own gas.

Shippers on the TransCanada Mainline include LDCs, such as Enbridge and Union gas, and large volume customers, such as industrial and power generation companies that contract directly with TransCanada for pipeline capacity. These shippers deliver gas to end-users who are located both inside and outside of Ontario. As a result, the estimated project costs and benefits as submitted by TransCanada to the NEB includes costs and benefits to Ontario natural gas consumers, as well as to natural gas consumers located outside of Ontario.

In this section, we provide an overview of our analysis in Section 5.1, followed by a discussion of the two main impacts of the Energy East project on Ontario consumers. In Section 5.3, we present the results of our analysis.

5.1 Overview and Key Conclusions

In its submission to the NEB, TransCanada estimated that, over the 15 year time horizon from 2016 through 2030, Energy East will reduce the costs to TransCanada shippers by a net present value of $946 million, with $503 million in net benefits allocated to the shippers holding capacity on the Eastern Ontario Triangle, and the remaining $443 million allocated to shippers holding capacity on the Prairies and Northern Ontario Line sections of the Mainline.[5] Based on these TransCanada assumptions, ICF estimates that about 45 percent of the system benefits calculated by TransCanada, or about $421 million, would accrue to Ontario consumers, with the remaining $525 million in benefits accruing to natural gas consumers outside of Ontario.

The assessment of project impacts on Ontario consumers is quite sensitive to evaluation time frame and the discount rate used to determine the net present value. TransCanada used a 15-year evaluation period, and a discount rate reflecting TransCanada's cost of capital of 8.55 percent. These evaluation parameters are appropriate when evaluating the impact of the project from the perspective of a pipeline contract, but they do not necessarily capture the impacts of the project on Ontario consumers. Hence, ICF considered various evaluation time frames and discount rates to provide a range of potential project impacts for Ontario consumers.

While the currently available information in TransCanada's NEB submission is insufficient to completely reproduce TransCanada's projections, ICF believes that the TransCanada analysis is based upon a relatively low pipeline capacity demand scenario, as well as optimistic assumptions related to project gas price impacts. Therefore, TransCanada's estimation may be considered as an upper bound on a range of reasonable estimates of the project benefits to Ontario consumers.

For this evaluation, ICF conducted an initial assessment of the impacts of the projects on Ontario consumers, based largely on the TransCanada's NEB submission. We then adjusted several elements to

[5] Tables 4-12 and 4-15 of the TransCanada Energy East Project Application.

reflect reasonable changes in market assumptions and analysis parameters. For this analysis, ICF considered changes in:

1) Analysis parameters, including time frame and discount rates;
2) Market outlook impacting future demand for TransCanada pipeline capacity;
3) Expected impact of Energy East on TransCanada's Discretionary Miscellaneous Revenues (DMR) (i.e., primarily revenues earned from short term firm transportation and interruptible transportation services);
4) Expected impact of Energy East on natural gas prices at market centers that are relevant to Ontario consumers. TransCanada assumes that the Energy East project under their market outlook would not impact natural gas prices. However, ICF's market analysis has more demand for TransCanada services, with a resulting modest impacts on gas prices paid by Ontario consumers.
5) Expectations on the future use of Western Mainline capacity by Ontario shippers.

With the changes in these parameters, we have identified a potential range of about $1.3 billion in cost impacts on Ontario consumers due to the combined Energy East and Eastern Mainline expansion projects. These projects could result in an increase of overall costs to Ontario consumers by as much as $769 million (depending on specific assumptions) or decrease the gas supply costs by about $513 million. The potential for positive and negative cost implications for Ontario consumers highlight the importance, and the sensitivity, of the selection of different assumptions and scenarios used to make the calculations.

Impact of Potential Project Delay

A large portion of the savings estimated by TransCanada is based on avoiding the costs associated with accelerated depreciation of the Northern Ontario Line. A delay in project timeline would significantly reduce the amount of accelerated depreciation costs that could be avoided by the transfer of assets to Energy East. ICF estimates that a one year delay in initiation of the project would reduce the benefits calculated by TransCanada for all shippers by $177 million, and a two year delay would reduce the calculated benefits by $304 million. This would reduce savings (i.e., increase costs) to Ontario consumers by around $59 million for a one year delay and $101 million for a two year delay.[6]

Impact on Ontario Consumer Gas Costs of Expanding the Eastern Mainline Expansion Project to Fully Replace EOT Capacity

The TransCanada impact analysis is based on a market forecast that TransCanada believes would not require additional pipeline capacity on the EOT prior to 2030, while the ICF market forecast suggests that additional capacity on the EOT would be needed earlier. ICF has conducted an initial assessment of the impact of expanding the Eastern Mainline Expansion project to fully replace the capacity displaced by Energy East in the higher pipeline system demand scenarios. Based on an initial cost estimate for increasing the capacity based on installing larger diameter pipe, ICF believes that the cost of increasing

[6] The ICF analysis was completed prior to the announcement by TransCanada that the Energy East project would be delayed by two years on April 2, 2015. TransCanada has not yet filed a revised application providing information on the impact of the delay on project costs.

the capacity of the Eastern Mainline Expansion likely would be more than offset by an increase in long term pipeline revenue and the elimination of the natural gas price impacts of the project.[7]

It is important to recognize that the ICF analysis reflects a variety of simplifying assumptions due to lack of complete information as well as general market uncertainty. Nonetheless, an important conclusion from our analysis is that the Energy East project may end up either benefiting or costing Ontario gas consumers, depending on how the project is implemented and assessed.

5.1.1 Analysis Time Frame and Discount Rate Parameters

In addition to different perspectives on market conditions and impacts of the changes resulting from the reduction in EOT pipeline capacity, the evaluation of the Energy East impact on Ontario consumers is also sensitive to basic assumptions concerning the time frame of the analysis and the discount rate used to calculate the net present value of the project costs and benefits. TransCanada has used an evaluation time period and discount rate that is typical for evaluating projects from a corporate perspective, but are not necessarily appropriate for evaluating the impact of the project on Ontario consumers. As a result, ICF has considered additional time periods and discount rates to assess the impact of the project.

1) Discount Rates. Different discount rates provide a range of different perspectives on the cost of capital and the time value of the costs, and the benefits of the project to Ontario consumers. Higher discount rates tend to reduce the importance of future costs and benefits on total costs and benefits of the project. For this analysis, ICF used three different discount rates to assess the net present value of the impacts on Ontario consumers.
    a. TransCanada Discount Rate: 8.55 percent corporate discount rate.
    b. Ontario LDC Discount Rate: 5.49 percent reflecting the average of the after tax discount rates used by Enbridge and Union Gas.[8]
    c. Ontario Government Discount Rate: 4.9 percent reflecting the rate used by the Ontario Justice Department to evaluate compensatory damages.

2) Analysis Period. The analysis time period is important, particularly when evaluating the impact of Energy East on EOT shippers. The net benefits to EOT shippers occur between 2016 and 2020 and the project starts to increase EDA shippers' revenue requirements starting in 2021. Costs are expected to increase again after 2030, because the $500 million TCPL premium is spread over the 15-year period from 2016 to 2030, reducing the pipeline cost of service for EDA shippers by about $60 million per year over this period. After 2030, once this benefit disappears, revenue requirements and pipeline tolls are expected to increase.

    In order to address this issue, ICF considered two different analysis periods: 15 years and 30 years. The 15-year analysis reflects the time frame for the Eastern Mainline Expansions transportation contracts and the 30-year analysis better represents the life of the asset.

[7] The ICF analysis was completed prior to the announcement by TransCanada that market demand for the Eastern Mainline Expansion project is likely to be sufficient to increase the size of the project above the 575 PJ/day initially proposed.
[8] Discount rate used by utilities for recent projects, as provided to ICF by the OEB.

5.2 Impact of Energy East on Ontario Consumers

The Energy East project could impact Ontario consumers' natural gas costs in two ways.

1) The project will change the firm transportation tolls that shippers pay to transport gas on TCPL, which will be passed along to Ontario consumers. This includes both the change in costs on the Eastern Ontario Triangle capacity used by all TransCanada shippers to serve Ontario consumers, as well as the change in costs on the share of the Prairies and Northern Ontario Lines used by some TransCanada shippers to serve Ontario consumers.
2) The project could change the purchase price for natural gas that Ontario LDCs and end-users (including power generators and industrial consumers) pay to acquire natural gas supplies.

5.2.1 Transportation Cost Impacts

Pipeline tolls are the cost to transport a GJ of natural gas along a pipeline. Conceptually, the calculation of tolls, using a cost-of-service model, is an exercise in calculating the amount of revenue that the pipeline needs to recover from certain services or class of shippers (revenue requirements or cost of service) and dividing those required revenues by the amount of gas over which the costs will be spread (billing determinants). A project could lower the tolls certain shippers pay by either reducing the revenue requirements or increase billing determinants for this class of shippers.

Revenue requirements typically include returns on rate base (the value of the pipelines' assets), operating and maintenance (O&M) costs, depreciation and taxes. In assessing the firm tolls applicable to Ontario, ICF focused on the revenue requirements that need to be recovered from firm shippers, adjustments to the revenue requirements, and the firm contract volumes in billing determinants.

The Energy East project impacts two different components of TransCanada's pipeline tolls and transportation costs:

1) The Eastern Ontario Triangle component accounts for the revenue requirements allocated to Eastern Ontario Triangle shippers. All firm contracts with deliveries in Ontario and other EDA points, regardless of their respective receipt points, contribute to the recovery of this component. The Energy East project removes assets from gas service, reducing the revenue requirement for EOT assets. However, the construction of the Eastern Mainline Expansion project increases the overall size of the rate base, increasing the cost of service. The net change in revenue requirements from these two projects will result in changes in tolls and transportation costs, which will be ultimately borne by all shippers utilizing capacity on the EOT (including shippers serving both Ontario and Non-Ontario consumers).

2) The Western Mainline component, consisting of the Prairies and Northern Ontario segments of the TransCanada system applies to firm contracts with delivery points in Ontario and receipt points in Western Canada, to the extent that they contribute to the recovery of costs associated with the Western Mainline assets. Removal of the Prairie line and the Northern Ontario line from gas service reduces the revenue requirements associated with the Western Mainline assets, which is expected to lead to lower transportation costs to all shippers using these assets.

Since both portions of the TransCanada system are used by shippers serving both Ontario and non-Ontario consumers, the cost assessment conducted by ICF allocates the cost impacts of the project to

Ontario consumers, based on the firm service requirements on each section of the pipeline system that will be used meet the natural gas demand of Ontario consumers.

For transportation tolls assessment, ICF did not create a full-scale cost of service model; instead, ICF made a number of simplifying assumptions based on TCPL's Energy East Project and Asset Transfer Applications (Energy East Application) filed with NEB in October 2014 and the Application for Approval of Mainline 2013-2030 Settlement (Settlement Application) in 2013. In addition, ICF's transportation cost impact analysis excluded pipeline abandonment cost and fuel cost impacts. These assumptions and the results of ICF's analysis are subject to change, once TCPL files detailed rate studies and as other information on the project's impacts becomes publicly available.

Key Drivers of the Project's Transportation Cost Impacts

ICF identified the following key drivers of Ontario shippers' toll and subsequent impacts on consumer transportation costs:

1) Market Outlook. The TransCanada analysis, as submitted to the NEB, is based on the assumption that the reduction in Eastern Triangle pipeline capacity will *not* constrain demand for Eastern Triangle firm capacity. This would only occur if U.S. shippers were to reduce or eliminate gas purchases from Canada and deliveries into Iroquois-Waddington because they would opt to buy gas from the Marcellus/Utica supply region, shipped over new pipelines into the New England and Mid-Atlantic region. As pointed out earlier in Section 3.2, deliveries to Iroquois-Waddington constitute about 36 percent of the total flows through the EOT; therefore, a reduction in demand from U.S. shippers for gas flowing over the EOT would have a major effect on EOT firm capacity requirements. TCPL also forecasts significant growth in natural gas production from Quebec shale resources, which would provide an additional source of supply for Quebec and eastern Canada.

   TransCanada is also projecting significantly more LNG export demand for Alberta natural gas than ICF's projection. As a result, the TransCanada forecast has less WCSB gas supply available to ship to eastern consumers than ICF believes is likely. This further reduces the potential impacts of Energy East on gas markets in the TransCanada market outlook.

   ICF's analysis, as presented in Section 3 of this report, shows that TCPL deliveries to Iroquois are still needed in peak winter months to meet northeastern U.S. demand, albeit at lower levels than historical demand. In its current Base Case, ICF forecasts less pipeline capacity to be built from the Marcellus to New England and more aggressive demand growth in the northeastern United States than TransCanada's outlook. ICF also do not project significant shale gas production from Quebec.

   Besides the continued need for TCPL deliveries into Iroquois-Waddington, ICF forecasts peak deliveries into EOT to continue to increase as market demand in Ontario grows. While TransCanada forecasts a constant level of firm transportation capacity at 2.546 TJ/d, the ICF outlook anticipates the demand for FT capacity to increase, along with market growth after 2020. The increase in firm transportation capacity needs increases the billing determinants and reduces pipeline tolls in ICF's analysis.

2) Discretionary Miscellaneous Revenues (DMR). TransCanada's analysis focuses on the overall pipeline revenue requirement, and does not address the impact of potential changes in the DMR. Implicitly, the TransCanada analysis assumes that DMR will not change when Energy East is built.

   DMR reduces revenue requirements to firm shippers. In the Energy East scenario, it would be expected that reducing available pipeline capacity by 0.58 TJ/d would reduce the pipeline space available to maintain the same level of discretionary services and DMR will be reduced. The decrease in DMR would increase the costs that must be recovered in firm transportation rates, increasing the costs of firm transportation capacity.

3) Allocation of Cost of Service Impacts to Ontario Consumers.
   The TransCanada Pipeline serves a broad market region both inside and outside of Ontario. In order to determine the impact of changes in pipeline costs on Ontario consumer, the total change in pipeline costs to shippers on the TransCanada system must be allocated between the shippers that serve Ontario vs. non-Ontario consumers. ICF has allocated the costs based on an assessment of the percentage of firm pipeline capacity likely to be held by shippers to serve Ontario consumers, relative to the total firm pipeline capacity for all shippers. Where possible, ICF has used TransCanada data from the Energy East Application as the starting point for the allocation. Where data is not available from the Energy East Application, ICF has used the billing determinants from the TransCanada Settlement Agreement as the starting point.

   Over time, the share of Ontario shipper use of the system is expected to shift based on changes in market conditions, and increased use of short-haul transportation paths. ICF has estimated the change in Ontario utilization of the EOT based on changes in peak period pipeline flows over time. For the Prairies and NOL segments, ICF developed two different pipeline utilization scenarios, based on the billing determinants and provisions in the TransCanada Settlement Agreement and our assessment of potential future market changes. The high utilization case reflects a continuation of the status quo, while the low utilization case reduces capacity held by the Ontario LDC's to the minimum levels set in the TransCanada Settlement Agreement through 2020, and declining to minimum operational levels needed to serve Western Ontario demand after 2020.

   The decision to shift the source of supply from long-haul transportation from Alberta to short-haul transportation on the EOT is based on overall gas supply economics and other gas supply planning criteria, including reliability and diversity of supply. Generally, the Energy East project will reduce costs on the Prairies and NOL segments of the pipeline, and increase costs on the EOT. This shift in costs will impact the relative attractiveness of the different gas supply alternatives, and may impact the future supply decisions by shippers serving Ontario consumers. ICF's scenarios related to the level of reliance on long-haul capacity relative to short-haul capacity are intended to reflect reasonable upper and lower estimates. We have not attempted to assess the impact of the relative change in system costs on the allocation of gas supplies.

5.2.2 Natural Gas Purchase Cost Impacts

ICF estimated Energy East's impacts on Ontario consumers' natural gas purchase costs by multiplying Energy East's price effects at key market points where Ontario shippers source their gas supplies (e.g., Empress, Dawn, Niagara and Iroquois) with the projected gas volumes that Ontario shippers are expected to purchase from these market points.

The price impacts and volume estimates are based on ICF's market analysis of price impacts and projected peak pipeline flows into Ontario that are described in the previous sections.

As discussed in Section 3.3, ICF forecasts that the Energy East and the Eastern Mainline Expansion will change natural gas prices along the TCPL system. Specifically, for the period between 2016 and 2035, ICF forecasts a moderate increase in average nominal gas prices of US$0.01 per MMBtu at Dawn, US$0.02 per MMBtu at Niagara, a significant increase of US$0.27 per MMBtu at Iroquois-Waddington and a decline of US$0.04 per MMBtu at Empress. Between 2035 and 2045, we have held gas prices constant in real terms at the prices projected for 2035.

For Ontario firm shippers who purchase gas at these market centers, the price effects will impact their gas purchasing costs accordingly. ICF utilized the projected pipeline flows with Energy East scenario to estimate the percentage of firm gas supply sourced through the different market centers. On average, EDA and Ontario firm shippers sourced 46% of their volume through Dawn, 22% through Niagara, and 25% through Empress. No firm shippers were projected to source gas at the Iroquois-Waddington market center. The purchase cost increase for firm gas sourced through Dawn and Niagara is partially offset by the decline in purchase gas costs for natural gas sourced at Empress.

ICF assumed that 100% of gas consumption from the LDCs (such as Enbridge and Union Gas), and power generation sector would be firm purchases, whereas 25% of industrial gas use would be purchased at local market prices without firm transport capacity from one of the market centers. The purchases at local market prices were assumed to be equally distributed between Dawn and Iroquois-Waddington, resulting in an average purchase cost impact for these shippers at halfway between the Dawn price and the Iroquois-Waddington price.

Table 5-1 presents the change in NPV of shipper gas purchase costs (in nominal Canadian dollars) with and without Energy East project. Under a scenario where there is continued baseline reliance on Western Mainline, the Energy East project increases Ontario consumer gas supply costs by between $62 million and $268 million depending on the time frame and discount rate used in the evaluation (as discussed above). The cost of gas purchased by shippers using firm transportation capacity to serve Ontario consumers increased by between $9 and $67 million while non-firm shippers' gas purchase costs increased by between $71 million and $307 million.

The total impact on gas purchase costs is less than the sum of the direct impact on firm and non-firm shippers. Since non-firm transportation costs are linked to the market price, a portion of the increased non-firm gas purchase costs will be reflected as higher DMR to TransCanada, or in payments to shippers holding capacity on TransCanada. We have credited Ontario firm shippers with a share of this revenue, based on the Ontario share of FT capacity on the EOT. Hence, the total impact is lower than the sum of the firm and non-firm direct impacts.

If the Ontario shippers rely less on the Western Mainline, then the impact of the changes in natural gas prices are higher. In this scenario, the Energy East project increases Ontario consumer gas costs by between $113 and $494 million. Direct gas purchase costs for consumers served by shippers with firm transportation capacity increase by between $66 million and $293 million when evaluated under different parameters, and non-firm shippers' gas purchase costs increased by between $71 million and $307 million.

Table 5-1. Impact of Changes in Gas Prices on Ontario Shippers (Million Nominal Can$)

Impact of Energy East and the Eastern Mainline Expansion Projects								
High Pipeline Capacity Demand Scenario		TransCanada Discount Rate		Ontario Utility Discount Rate		Ontario Government Discount Rate	
		15-Year NPV	30-Year NPV	15-Year NPV	30-Year NPV	15-Year NPV	30-Year NPV
Baseline Reliance on Western Mainline Shippers Serving Ontario Consumers	Direct Impact of Gas Price Changes on Firm Ontario Consumer Gas Costs	14	36	10	60	9	67
	Direct Impact of Gas Price Changes on Non-Firm Ontario Consumer Gas Costs	71	168	91	277	96	307
	Total Impact of Gas Price Changes on Ontario Consumer Gas Costs	**62**	**147**	**72**	**242**	**74**	**268**
Lower Reliance on Western Mainline Shippers Serving Ontario Consumers	Direct Impact of Gas Price Changes on Firm Ontario Consumer Gas Costs	66	158	81	263	84	293
	Direct Impact of Gas Price Changes on Non-Firm Ontario Consumer Gas Costs	71	168	91	277	96	307
	Total Impact of Gas Price Changes on Ontario Consumer Gas Costs	**113**	**269**	**142**	**445**	**149**	**494**

5.3 Energy East Project's Net Costs and Benefits

ICF estimated the toll and transportation impacts on three alternative pipeline capacity scenarios using two different market outlooks. The alternative market outlooks are:

- **Low Pipeline Capacity Demand Outlook**, based on the market outlook presented in the TransCanada Energy East Application.
- **High Pipeline Capacity Demand Outlook**, based on ICF's March 2015 Base Case.

The pipeline scenarios are:

- **Pipeline Status Quo,** where TCPL continues to operate under the current capacity without the Energy East project.
- **With Energy East Project,** where the Energy East project is implemented as proposed by TransCanada.
- **With Energy East Project, and Full Replacement of Capacity Reduction in EOT,** where ICF assume that the capacity added by the Eastern Mainline project was increased to meet market demand in the High Pipeline Capacity Demand Outlook.

In this section, the *net* costs/benefits are defined as the cost differences between the **With Energy East Project** scenario and the **Pipeline Status Quo** scenario. The net cost/benefits are presented for the two different market outlooks. The results from the scenario **With Energy East Project, and Full Replacement of Capacity Reduction in EOT** is presented in a separate subsection. The tables below show the results of the impact assessment for two different time periods and three different interest rates, as noted in Section 5.1.1.

The specific steps in ICF's analysis are:

- Use the TCPL economic impact analysis in the Energy East application, revenue requirements and other tolling assumptions in the Settlement Application as the starting point;

- Extend the analysis time frame from 15 years to 30 years to shift from a corporate perspective to a consumer perspective.
- Adjust TCPL's analysis to incorporate the impact on revenue requirements from potential changes in Discretionary Miscellaneous Revenues (DMR) caused by the decrease in available pipeline capacity.
- Estimate revenue requirements impacts for the Eastern Triangle component and the Western Mainline component under each scenario.
- Estimate the tolls and transportation cost impacts for shippers serving Ontario consumers under two alternative market outlook and billing determinants assumptions described above.

ICF considered potential range of DMR due to the decrease in EOT pipeline capacity, and range of capacity on the Prairies and NOL sections of the TransCanada mainline that shippers are likely to hold in the future to serve Ontario consumers. For the DMR calculations under the Low Pipeline Capacity Demand Outlook, ICF relied on TCPL's forecast of DMR through 2020, as reflected in the Settlement Application, as the baseline for discretionary revenues in the absence of Energy East. Under the High Pipeline Capacity Demand Outlook, ICF assumed that DMR will remain at the average levels projected by TransCanada for 2015 and 2016 in the absence of Energy East. To evaluate the importance of DMR on the overall project impacts, ICF assumed that the Energy East project will reduce DMR by 50 percent relative to the levels that would be achieved in the absence of Energy East.

A range of impacts presented in the tables below show how different assumptions on analysis timeframe, discount rate, market outlook, discretionary revenue and reliance on Western Mainline capacity to serve Ontario consumers affect the costs for Ontario consumers. The ultimate impact of Energy East on Ontario consumer costs varies from a reduction of $513 million in natural gas costs to an increase in natural gas costs to Ontario consumers of $769 million. These impacts represent a relatively modest percentage of total natural gas costs for Ontario Consumers. In the highest benefit and cost scenarios, the total impact of the project is a change of roughly +/- one percent of the total cost of natural gas to Ontario consumers.

The results of ICF's assessment of the Energy East project impacts on TransCanada shippers and on Ontario consumers are shown in Table 5-2 and Table 5-3. Table 5-2 presents a summary of Energy East's net impacts on TransCanada shippers and on Ontario consumers under the Low Pipeline Capacity Demand scenario, which is consistent with the market outlook presented in the TransCanada application. Table 5-3 presents a summary of Energy East's net impacts on TransCanada shippers and on Ontario consumers under the High Pipeline Capacity Demand scenario, which is based on the ICF Base Case market outlook. The Table 5-3 results include both the reduction in DMR, and the lower utilization of the Western Mainline by shippers serving Ontario consumers (as shown earlier in Table 5-1).

Table 5-2. Impact of Energy East and the Eastern Mainline Expansion on Shippers and Ontario Consumers (Low Pipeline System Demand Market Scenarios)

Impact of Energy East and the Eastern Mainline Expansion Projects (Changes in Natural Gas Costs - Million $)							
Low Pipeline Capacity Demand Scenario		TransCanada Discount Rate		Ontario Utility Discount Rate		Ontario Consumer Discount Rate	
Impact on TransCanada Shippers		15-Year NPV	30-Year NPV	15-Year NPV	30-Year NPV	15-Year NPV	30-Year NPV
No Impact on Discretionary Misc. Revenue	Increase in Costs on the Eastern Ontario Triangle	-503	-292	-520	-126	-523	-77
	Increase in Costs on the Western Mainline	-443	-595	-545	-829	-568	-890
	Total Increase In Costs	**-946**	**-887**	**-1065**	**-955**	**-1091**	**-967**
Low Discretionary Misc. Revenue	Increase in Costs on the Eastern Ontario Triangle	-368	-113	-353	122	-348	189
	Increase in Costs on the Western Mainline	-281	-380	-345	-530	-360	-569
	Total Increase In Costs	**-649**	**-493**	**-698**	**-408**	**-708**	**-380**
Impact on Ontario Consumers							
No Impact on Discretionary Misc. Revenue or Western Mainline Allocation	Increase in Costs on the Eastern Ontario Triangle	-153	-68	-156	2	-157	23
	Increase in Costs on the Western Mainline	-268	-359	-329	-499	-343	-536
	Increase in Natural Gas Purchase Costs	0	0	0	0	0	0
	Total Increase In Costs	**-421**	**-427**	**-486**	**-497**	**-500**	**-513**
Low Discretionary Misc. Revenue	Increase in Costs on the Eastern Ontario Triangle	-107	-4	-99	92	-96	120
	Increase in Costs on the Western Mainline	-171	-230	-209	-320	-218	-343
	Increase in Natural Gas Purchase Costs	0	0	0	0	0	0
	Total Increase In Costs	**-277**	**-234**	**-308**	**-227**	**-314**	**-223**
Low Discretionary Revenue and Low Reliance on Western Mainline by Ontario Shippers	Increase in Costs on the Eastern Ontario Triangle	-107	-4	-99	92	-96	120
	Increase in Costs on the Western Mainline	-130	-168	-156	-227	-162	-242
	Increase in Natural Gas Purchase Costs	0	0	0	0	0	0
	Total Increase In Costs	**-236**	**-172**	**-254**	**-134**	**-258**	**-122**

Table 5-3. Impact of Energy East and the Eastern Mainline Expansion on Ontario Consumers (High Pipeline System Demand Market Scenarios)

Impact of Energy East and the Eastern Mainline Expansion Projects (Changes in Natural Gas Costs - Million $)							
High Pipeline Capacity Demand Scenario		TransCanada Discount Rate		Ontario Utility Discount Rate		Ontario Government Discount Rate	
Impact on TransCanada Shippers		15-Year NPV	30-Year NPV	15-Year NPV	30-Year NPV	15-Year NPV	30-Year NPV
No Impact on Discretionary Misc. Revenue	Increase in Costs on the Eastern Ontario Triangle	-503	-292	-520	-126	-523	-77
	Increase in Costs on the Western Mainline	-443	-595	-545	-829	-568	-890
	Total Increase In Costs	**-946**	**-887**	**-1065**	**-955**	**-1091**	**-967**
Low Discretionary Misc. Revenue	Increase in Costs on the Eastern Ontario Triangle	-143	181	-77	525	-61	621
	Increase in Costs on the Western Mainline	-228	-322	-282	-457	-294	-492
	Total Increase In Costs	**-371**	**-142**	**-359**	**68**	**-355**	**128**
Impact on Ontario Consumers							
No Impact on Discretionary Misc. Revenue or Western Mainline Allocation	Increase in Costs on the Eastern Ontario Triangle	-153	-68	-156	2	-157	23
	Increase in Costs on the Western Mainline	-268	-359	-329	-499	-343	-536
	Increase in Natural Gas Purchase Costs	62	147	72	242	74	268
	Total Increase In Costs	**-359**	**-280**	**-414**	**-256**	**-426**	**-245**
Low Discretionary Misc. Revenue	Increase in Costs on the Eastern Ontario Triangle	44	221	99	426	112	482
	Increase in Costs on the Western Mainline	-139	-196	-171	-276	-179	-298
	Increase in Natural Gas Purchase Costs	62	147	72	242	74	268
	Total Increase In Costs	**-34**	**172**	**-1**	**391**	**7**	**453**
Low Discretionary Revenue and Lower Reliance on Western Mainline by Ontario Shippers	Increase in Costs on the Eastern Ontario Triangle	44	221	99	426	112	482
	Increase in Costs on the Western Mainline	-105	-141	-126	-193	-131	-207
	Increase in Natural Gas Purchase Costs	113	269	142	445	149	494
	Total Increase In Costs	**53**	**349**	**114**	**677**	**129**	**769**

In our analysis, the NPV of project benefits to Ontario consumers generally decline and the NPV of project costs generally increase, when a longer time period or lower discount rates are used to assess the project impacts. This is the result of the timing of the costs and benefits associated with the EOT, where the project benefits are expected to occur prior to 2021. The Energy East project will lead to higher costs to Ontario consumers starting in 2021 when the project is no longer benefiting from the displacement of the accelerated depreciation of the NOL. After 2030, costs again increase significantly once the 15 year amortization period for TransCanada's $500 million contribution to the project has been completed.

The project impact due to changes in natural gas prices also increases over time as market growth runs up against a smaller available pipeline capacity, leading to an increase in Ontario consumer gas supply prices, particularly as the analysis time frame is increased and the discount rate is lowered.

In the Low Pipeline Capacity Demand scenario (reflecting TransCanada market outlook), the net impacts on Ontario consumers ranges from a net reduction of $421 million based on the TransCanada assumptions to a net reduction in natural gas costs of $122 million dollars if the analysis time frame is extended to 30 years, a lower discount rate is used, and if DMR is assumed to decline with the decrease in pipeline capacity.

In the High Pipeline Capacity Demand scenario (reflecting ICF Base Case scenario), the net impacts on Ontario consumers ranges from a net reduction in natural gas costs of $359 million using TransCanada assumptions to a net increase in natural gas costs of $769 million based on the ICF market assumptions, 30-year analysis time frame, lower discount rates, and if DMR is assumed to decline with the decrease in pipeline capacity.

5.3.1 Impact of Expanding the Eastern Mainline Expansion Project to Fully Replace EOT Capacity

ICF conducted an initial assessment of the impact of expanding the Eastern Mainline Expansion project to fully replace the capacity displaced by Energy East. The assessment was based on an estimate of the cost of increasing the capacity by installing a larger diameter pipe. According to our preliminary assessment, using a larger diameter pipe would result in a cost increase of about 33 percent.

ICF estimates that the cost of increasing the capacity of the Eastern Mainline Expansion would be offset by the increase in pipeline revenue and the elimination of the natural gas supply price impacts. As a result, a full replacement of the capacity that is being removed from service for the Energy East project likely could reduce the total cost of gas supply to Ontario shippers relative to the project as currently specified. Given that this conclusion is based on a preliminary estimate of the cost of increasing pipeline capacity, it might change based on a more detailed assessment of the costs of increasing the size of the expansion project. Increasing the size of the Eastern Mainline Expansion project is likely to be less expensive than building new capacity at a later date to meet demand.

Table 5-4 shows the potential impact of an increase in the capacity of the Eastern Mainline Expansion on shippers and Ontario consumers, based on ICF's preliminary assessment of the increase in project costs and capacity. In this scenario, the impact of the Energy East project on TransCanada shippers ranges from -$384 million to +$107 million depending on time frame and discount rate. For Ontario consumers, the capacity increase in the Eastern Mainline Expansion project would result in a range of -$146 million to +$33 million depending on time frame and discount rate. The relative impact of the increase in the Eastern Mainline Expansion would be a net benefit to Ontario consumers due to the reduction in natural gas supply cost changes. The shippers would also benefit due to the increase in potential DMR. Overall, the increase in the size of the Eastern Mainline Extension would reduce costs to TransCanada shippers by between $13 million and $22 million relative to the Eastern Mainline Extension as proposed. The benefits to Ontario consumers would be significantly larger, ranging from $198 million to $736 million.

Table 5-4. Impact of Increased Eastern Mainline Expansion Capacity

Impact of Expanded Eastern Mainline Expansion Project (Changes in Natural Gas Costs - Million $)							
High Pipeline Capacity Demand Scenario		TransCanada Discount Rate		Ontario Utility Discount Rate		Ontario Government Discount Rate	
Impacts on TransCanada Shippers		15-Year NPV	30-Year NPV	15-Year NPV	30-Year NPV	15-Year NPV	30-Year NPV
Eastern Mainline Extension As Proposed by TransCanada	Increase in Costs on the Eastern Ontario Triangle	-143	181	-77	525	-61	621
	Increase in Costs on the Western Mainline	-228	-322	-282	-457	-294	-492
	Total Increase In Costs	**-371**	**-142**	**-359**	**68**	**-355**	**128**
Eastern Mainline Extension Expanded for Full Replacement	Increase in Costs on the Eastern Ontario Triangle	-156	164	-92	504	-76	599
	Increase in Costs on the Western Mainline	-228	-322	-282	-457	-294	-492
	Total Increase In Costs	**-384**	**-158**	**-374**	**47**	**-370**	**107**
Impacts on Ontario Consumers							
Eastern Mainline Extension As Proposed by TransCanada	Increase in Costs on the Eastern Ontario Triangle	44	221	99	426	112	482
	Increase in Costs on the Western Mainline	-105	-141	-126	-193	-131	-207
	Increase in Natural Gas Purchase Costs	113	269	142	445	149	494
	Total Increase In Costs	**53**	**349**	**114**	**677**	**129**	**769**
Eastern Mainline Extension Expanded for Full Replacement	Increase in Costs on the Eastern Ontario Triangle	-41	78	-18	205	-12	240
	Increase in Costs on the Western Mainline	-105	-141	-126	-193	-131	-207
	Increase in Natural Gas Purchase Costs	0	0	0	0	0	0
	Total Increase In Costs	**-146**	**-62**	**-144**	**11**	**-143**	**33**
Relative Impacts of Expanding the Eastern Mainline Extension							
Relative Increase in Costs to TransCanada Shippers		**-13**	**-17**	**-15**	**-21**	**-15**	**-22**
Relative Increase in Costs to Ontario Consumers		**-198**	**-411**	**-259**	**-666**	**-273**	**-736**

6. Conclusions

The Energy East Project with the inclusion of the expansion of the Eastern Mainline within the EOT will reduce pipeline capacity in the EDA by approximately 0.63 PJ/d. With the expected growth of gas demand in eastern Ontario, and the continued reliance on Canadian supply by U.S. consumers in New England and New York, the reduction in pipeline capacity will affect market prices in eastern Ontario. These effects will be most obvious in winter months, when gas demand is high, than in summer months.

The ICF analysis examined the impacts on the EDA with and without the Energy East Project and corresponding expansion of the Eastern Mainline. The analysis has shown that gas prices at Iroquois/Waddington can be expected to increase by an average of 3.5 percent annually over the 2016-2035 time period. In winter, gas prices can be expected to average 12 percent higher over the same 2016-2035 period. Summer prices at Iroquois/Waddington would largely be unaffected by the Energy East Project. The impact of Energy East on prices at Dawn and at AECO are relatively modest when compared to the price impact at Iroquois/Waddington.

ICF's analysis also examined pipeline flows with and without Energy East. As would be expected, with Energy East, gas flows across the Eastern Mainline would increase to make up for the lower flows down the eastern leg of the EOT triangle, from North Bay to Iroquois. This pattern holds for both average annual basis flows and average winter flows; although for the latter, the differences between the with-and-without Energy East cases are larger. Southward flows into Iroquois pipeline remain substantial even in the Energy East case, although they are much reduced from current levels or the case without the Energy East Project. The majority of the decline in flows occurs during off-peak periods. Peak winter flows down Iroquois remain an important source of gas supply into U.S. demand centers in the Northeast.

ICF's findings on the effects of Energy East on gas prices at Iroquois/Waddington are directionally consistent with those of the Wood Mackenzie report.

The impact of Energy East on tolls paid by shippers in the EDA is less conclusive given the many uncertainties surrounding the elements that go into the calculation of tolls and the points of comparison with and without Energy East. ICF's analysis concludes that the Energy East project may end up either benefiting or costing Ontario gas consumers, depending on how the project is implemented and assessed.

ICF finds that the TransCanada analysis of the effect on tolls is based upon several assumptions that are uncertain: that there will be a relatively low demand for pipeline capacity, as well as optimistic assumptions related to project gas price impacts. Therefore, TransCanada's estimation may be considered as an upper bound on a range of reasonable estimates of the project benefits to Ontario consumers.

Based on ICF's review of the filings made by TransCanada to demonstrate the benefits of the Energy East project on shippers, we identified several key factors that affect the impact on Ontario consumers.

Depending on how these factors are used, the impact of Energy East on natural gas costs to Ontario consumers could range from a net reduction in natural gas costs of $421 million (based on the TransCanada market assumptions, analysis time frame, and discount rates) to a net increase in costs to Ontario consumers of about $670 million.

A large portion of the savings estimated by TransCanada is based on avoiding the costs associated with accelerated depreciation of the Northern Ontario Line. A delay in project timeline would significantly reduce the amount of accelerated depreciation costs that could be avoided by the transfer of assets to Energy East. ICF estimates that a one year delay in initiation of the project would reduce the benefits calculated by TransCanada for all shippers by $177 million, and a two year delay would reduce the calculated benefits by $304 million. This would reduce savings (i.e., increase costs) to Ontario consumers by around $59 million for a one year delay and $101 million for a two year delay.

Finally, ICF has conducted an initial assessment of the impact of expanding the Eastern Mainline Expansion project to fully replace the capacity displaced by Energy East in the higher pipeline system demand scenarios. Based on an initial cost estimate for increasing the capacity based on installing larger diameter pipe, ICF believes that the cost of increasing the capacity of the Eastern Mainline Expansion likely would be more than offset by an increase in long term pipeline revenue and the elimination of the natural gas price impacts of the project.

Appendix A – ICF Gas Market Model

ICF's Gas Market Model (GMM®) is a nationally-recognized modeling and market analysis system for the North American gas market that will be used to forecast gas prices and avoided costs for this project. GMM was developed in the mid-1990s to provide forecasts of the North American natural gas market under different assumptions. Subsequently, the GMM has been used to complete strategic planning studies including:

- Analyses of different pipeline expansions
- Measuring the impact of gas-fired power generation growth
- Assessing the impact of low and high gas supply
- Assessing the impact of different regulatory environments

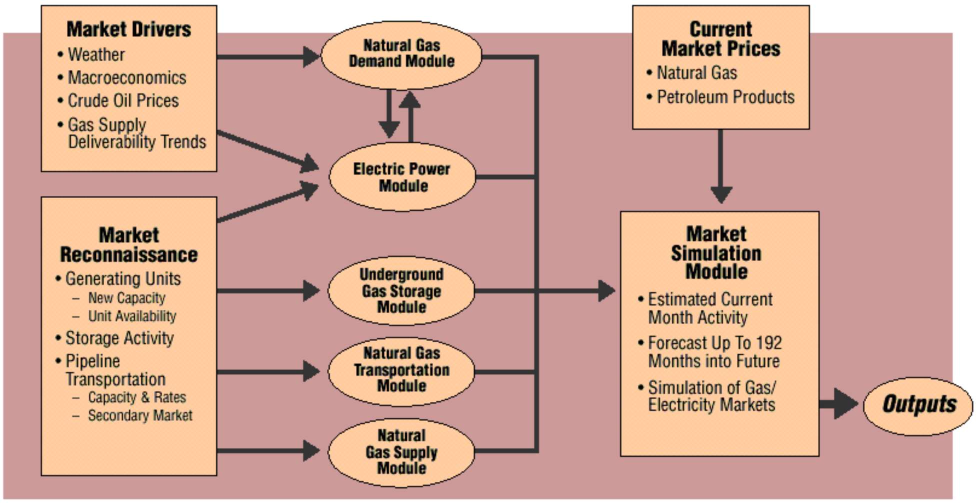
In addition to its use for strategic planning studies, the GMM has been widely used by a number of institutional clients and advisory councils, including INGAA, which relied on the model for the 30 Tcf market analysis completed in 1998 and again in 2004. The model was also the primary tool used to complete the widely referenced study on the North American gas market for the National Petroleum Council in 2003.

GMM is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America given different supply/demand conditions, the assumptions for which are specified by the user.

Overall, the model solves for monthly market clearing prices by considering the interaction between supply and demand curves at each of the model's nodes. On the supply-side of the equation, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization. Prices are also influenced by "pipeline discount" curves, which reflect the change in basis or the marginal value of gas transmission as a function of load factor. On the demand-side of the equation, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes in the model at the market clearing prices determined by the shape of the supply and demand curves. ICF does significant back-casting (calibration) of the model's curves and relationships on a monthly basis to make sure that the model reliably reflects historical gas market behavior, adding confidence to projected results.

There are nine different components of the GMM, as shown in Exhibit A-1. The user specifies input for the model in the "drivers" spreadsheet. The user provides assumptions for weather, economic growth, oil prices, and gas supply deliverability, among other variables. ICF's market reconnaissance keeps the model up to date with generating capacity, storage and pipeline expansions, and the impact of regulatory changes on gas transmission. This is important to maintaining model credibility and confidence of results.

Exhibit A-1: GMM© Structure



The first model routine solves for gas demand across different sectors given economic growth, weather, and the level of price competition between gas and oil. The second model routine solves the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. The model nodes are tied together by a series of network links in the gas transportation module. The structure of the transmission network is shown in Exhibit A-2 and the nodes are identified by name in Exhibit A-7. The gas supply component of the model solves for node-level natural gas deliverability or supply capability. The Hydrocarbon Supply Model (HSM) may be integrated with the GMM to solve for deliverability. The supply module also creates LNG supply curves that are used by the model to solve for LNG imports. The last routine in the model solves for gas storage injections and withdrawals at different gas prices. The components of supply (i.e., gas deliverability, storage withdrawals, supplemental gas, LNG imports, and Mexican imports) are balanced against demand (i.e., end-use demand, power generation gas demand, Markets, and Mexican exports) at each of the nodes and gas prices are solved for in the market simulation module. Other charts that summarize input/output and regional breakout for the GMM are shown as Exhibits A-3 through A-6.

Exhibit A-2: GMM® Transmission Network

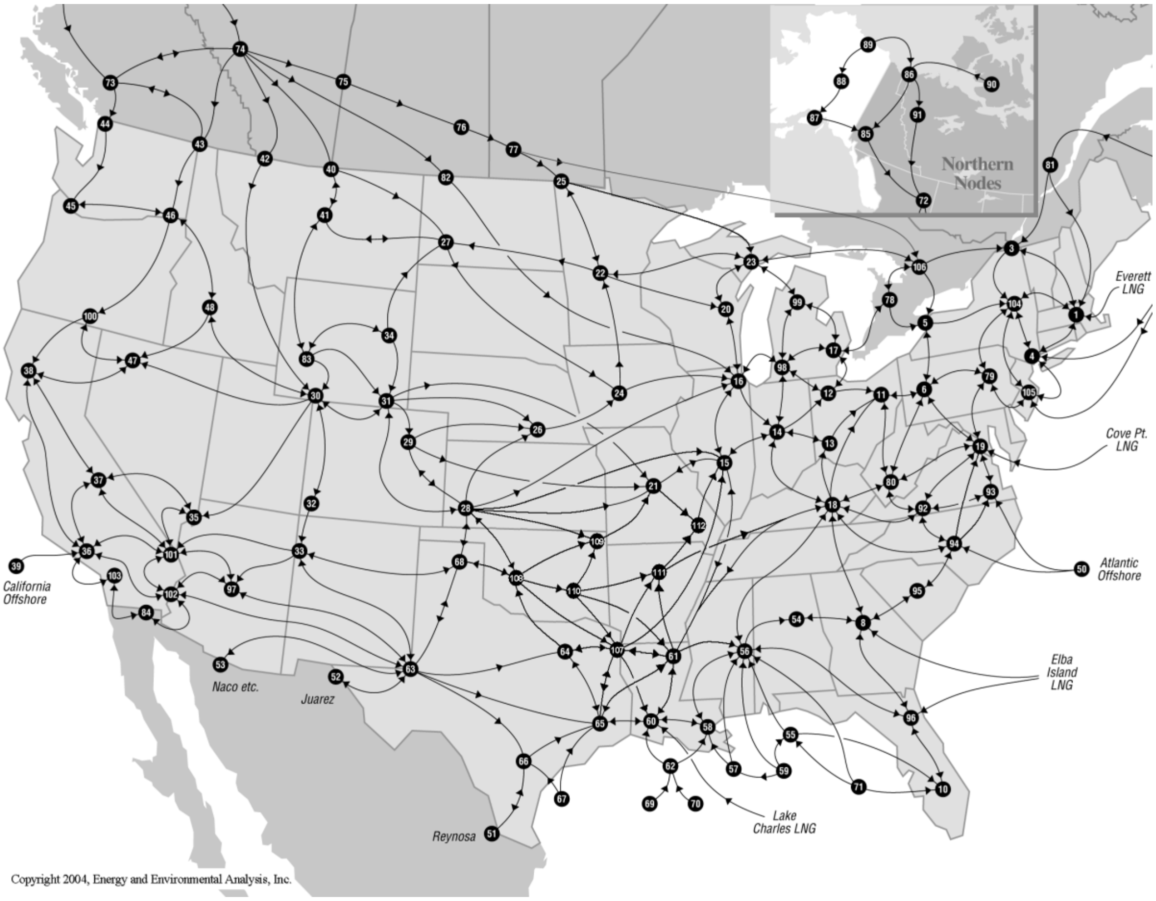


Exhibit A-3: Model Input and Output

Model Drivers And Output

R/C/I Natural Gas Demand

DRIVERS
- Heating Degree Days
- Economic Activity
- Gas & Petroleum Prices

OUTPUT
- ► *Residential, Commercial, & Industrial Gas Demand*

Gas Supply

DRIVERS
- Base Deliverability Trends
- Gas Prices
- LNG Supply

OUTPUT
- ► *Natural Gas Production*
- ► *Wellhead and Gathering System Deliverability*

Gas Transportation

DRIVERS
- Pipeline Capacity
  - *Existing Capacity*
  - *Capacity Expansions*
  - *Operating Conditions*
- Transportation Rates
  - *FERC Tariffs*
  - *Discounted Rates*
  - *Brokered Capacity Prices*

OUTPUT
- ► *Flow on pipeline corridors*
- ► *Value of gas transmission, i.e. forecast rates based on corridor load factors.*

Electric Utility Gas Demand

DRIVERS
- Total Electricity Generation
- Non-fossil Generation
- Unit Availability
  - *New Capacity On-Line*
  - *Scheduled Downtime*
  - *Maintenance & Availability Conditions*
- Fuel Prices
- Heating & Cooling Degree Days
- Economic Activity

OUTPUT
- ► *Gas Consumed by Power Generators*

Gas Storage

DRIVERS
- Storage Capacity
- Deliverability
- Withdrawal Season:
  - *Market Demand*
  - *Usage Patterns*
  - *Cycling Requirements*
- Injection Season:
  - *Inventory Targets*
  - *Refill Patterns*
  - *Spot/Futures Price Spread*

OUTPUT
- ► *Storage Inventory*
- ► *Net Storage Injections/Withdrawals*
- ► *Net Storage Injections/Withdrawals*

Exhibit A-4: Model Input and Output

Outputs of the Forecasting System

MONTHLY DATA	DATA CONTENT	GEOGRAPHIC DETAIL OF DATA
Gas Pricing	Delivered to Pipeline and Citygate Prices	112 Points
Pipeline Transportation	Inter-Regional Capacity Tariffs Caps Market Value of Capacity	327 Network Corridors
Gas Storage	Working Gas Capacity Inventories Injection/Withdrawal Activity	26 Storage Regions
Natural Gas Demand	By Sector (R/C/I)	34 U.S. and 7 Canada/Alaska Regions
Natural Gas Supply	Deliverability Dry Production Gas Imports/Exports Supplemental Fuels	62 U.S. and 13 Canada/Alaska Regions
Electricity Markets (U.S. Only With Explicity Imports)	Natural Gas Demand Electricity Demand Power Generation Balance Gas-fired Generation	13 "NERC" Regions

Exhibit A-5: Demand Regions

Exhibit A-6: Production Regions

Exhibit A-7: GMM® Network Node List

Node	Name
1	New England
2	Everett LNG
3	Quebec
4	New York City
5	Niagara
6	Leidy
7	Cove Point LNG
8	Georgia
9	Elba Island LNG
10	South Florida
11	East Ohio
12	Maumee/Defiance
13	Lebanon
14	Indiana
15	South Illinois
16	North Illinois
17	Southeast Michigan
18	Tennessee/Kentucky
19	MD/DC/Northern VA
20	Wisconsin
21	Northern Missouri
22	Minnesota
23	Crystal Falls
24	Ventura
25	Emerson Imports
26	Nebraska
27	Great Plains
28	Kansas
29	East Colorado
30	Opal
31	Cheyenne
32	San Juan Basin
33	EPNG/TW
34	North Wyoming
35	South Nevada
36	SOCAL Area
37	Enhanced Oil Recovery Region
38	PGE Area
39	Pacific Offshore
40	Monchy Imports
41	Montana/North Dakota
42	Wild Horse Imports
43	Kingsgate Imports
44	Huntingdon Imports
45	Pacific Northwest
46	NPC/PGT Hub
47	North Nevada
48	Idaho
49	Eastern Canada Offshore
50	Atlantic Offshore
51	Reynosa Imp/Exp
52	Juarez Imp/Exp
53	Naco Imp/Exp
54	North Alabama
55	Alabama Offshore
56	Mississippi/South Alabama
57	East Louisiana Shelf
58	Eastern Louisiana Hub
59	Viosca Knoll/Desoto/Miss Canyon
60	Henry Hub
61	North Louisiana Hub
62	Central and West Louisiana Shelf
63	Southwest Texas
64	Dallas/Ft Worth
65	East Texas (Katy)
66	South Texas
67	Offshore Texas
68	Northwest Texas
69	Garden Banks
70	Green Canyon
71	Eastern Gulf
72	North British Columbia
73	South British Columbia
74	Caroline
75	Empress
76	Saskatchewan
77	Manitoba
78	Dawn
79	Philadelphia
80	West Virginia
81	Eastern Canada Demand
82	Alliance Border Crossing
83	Wind River Basin
84	California Mexican Exports
85	Whitehorse
86	MacKenzie Delta
87	South Alaska
88	Central Alaska
89	North Alaska
90	Arctic
91	Norman Wells
92	Southwest Virginia
93	Southeast Virginia
94	North Carolina
95	South Carolina
96	North Florida
97	Arizona
98	Southwest Michigan
99	Northern Michigan
100	Malin Interchange
101	Topock Interchange
102	Ehrenberg Interchange
103	SDG&E Demand
104	Eastern New York
105	New Jersey
106	Toronto
107	Carthage
108	Southwest Oklahoma
109	Northeast Oklahoma
110	Southeastern Oklahoma
111	Northern Arkansas
112	Southeast Missouri