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VIA RESS, EMAIL and COURIER

March 31, 2017

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

Re: Enbridge Gas Distribution Inc. ("Enbridge")
EB-2016-0215 – 2017 Rate Application
ICF International Study on Enbridge Storage Requirements

In its oral decision for the Enbridge Gas Distribution Inc. ("Enbridge" or the "Company") 2017 rates application the Ontario Energy Board (the "Board") directed the Company to comply with certain commitments contained in the Settlement Proposal for that proceeding. One of the commitments made by Enbridge was that the Company would file, upon completion, the final version of the study concerning storage requirements which at the time was being prepared by ICF International. Please find attached the final version of the ICF International storage study. Enbridge reserves its right to file evidence in relation to its future storage requirements in a proceeding relevant to its gas supply plan.

Please contact the undersigned should you have any questions.

Yours truly,

(Original Signed)

Joel Denomy
Technical Advisor

Enbridge Gas Storage Assessment

Potential Value of Incremental Storage Capacity for Enbridge Gas

January 26th, 2017

Submitted to:
Enbridge Gas Distribution

Submitted by:
ICF Resources, L.L.C.

9300 Lee Highway

Fairfax, VA 22031

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1. Summary

1.1 Purpose

In 2015, the Ontario Energy Board approved changes to Enbridge Gas Distribution Inc. (Enbridge or the Company)'s storage deliverability targets, extending the January maximum deliverability maintained by the Company to the end of February, and extending the maximum March deliverability to the end of March.

These changes in storage deliverability targets were made to reduce the possibility of situations similar to the winter of 2013/14, when low storage inventories at the end of the winter necessitated the purchase of additional gas supplies from Dawn during high price periods. The change in deliverability targets results in a shift in gas supply purchases to earlier in the winter season, providing additional flexibility later in the year, and allowing Enbridge to minimize future rate impacts on Enbridge customers due to late season price spikes.

In order to meet the new deliverability targets, the Company's gas supply plan has been altered to shift the timing of gas supply purchases. To meet these new targets, Enbridge has increased its early winter season supply purchases to offset storage withdrawals and maintain a higher storage balance later into the winter, which will reduce late winter season purchases. Enbridge also began to consider the acquisition of incremental storage capacity to allow shifting of incremental natural gas purchases to lower priced periods, and to further reduce the volatility in delivered natural gas prices to its customers.

Prior to acquiring incremental storage, Enbridge agreed to perform a detailed review of the need for incremental storage with the support of an external consultant.[1] As a result of this agreement and the changes in storage deliverability targets, Enbridge requested the assistance of ICF to determine whether a reduction in overall Enbridge natural gas supply costs could be achieved by acquiring incremental storage space within the Company's gas supply plan.

1.2 Structure of Report

This report documents the results of ICF's market analysis and storage value analysis, and provides an assessment of the reduction in expected natural gas supply portfolio costs that Enbridge should expect to see should additional storage capacity be added to the Company's gas supply portfolio. The remainder of **Section 1** provides an overview of the analysis and a summary of results. **Section 2** of this report provides a broad overview of the current Enbridge storage portfolio and approach to evaluating storage requirements. **Section 3** of this report reviews the results of the ICF review of storage practices by other similarly situated natural gas distribution companies. **Section 4** of this report provides an overview of the key market trends expected to determine storage value and utilization in the future. **Section 5** documents the

[1] Enbridge Gas Distribution Ontario Energy Board Case EB-2015-0122

approach used in the storage analysis, and provides the results of ICF's analysis and recommendations for Enbridge future storage capacity.

1.3 Overview of Approach

ICF used its April 2016 Gas Market Model (GMM) as the starting basis for its evaluation of the North American natural gas markets and Enbridge's gas storage operations. The GMM is an internationally recognized model of the North American gas market that includes projections for natural gas demand by sector, conventional and unconventional natural gas resources, production costs, and other major gas market developments, such as potential Liquefied Natural Gas (LNG) exports. The GMM projects monthly natural gas demand, supply, and prices for more than 120 regions and is a general equilibrium market model. The model is described in more detail in Appendix D. ICF used the GMM to conduct sophisticated analysis of the potential impacts and risks associated with alternative weather scenarios on natural gas demand and prices.

Development of Weather Scenarios

In order to assess the value of natural gas storage for Enbridge under different weather scenarios, ICF used the GMM to develop three alternative price scenarios reflecting Enbridge's planning scenarios for Budgeted Weather, Colder than Budgeted Weather, and Warmer than Budgeted Weather. The alternative weather scenarios were developed for the 3-year period from April 2017 through March 2020. For each weather scenario, Enbridge's daily load profile includes the company's peak day design criteria, which includes 18 separate peak days that are designed to mimic the coldest temperatures expected over the winter season.[2] Enbridge's Peak Design Day is based on a 1 in 5 recurrence interval derived from a lognormal distribution of Heating Degree Days (HDDs).

In order to develop the three different weather scenarios, ICF ran the GMM iteratively using 85 sets of actual 3-year weather patterns to assess the potential impact of weather on demand and prices in order to project demand and gas prices. The use of actual weather scenarios is an important consideration to allow for a more complete assessment of the actual range of impacts due to the range of positive and negative correlations between the weather patterns of different regions across North America.

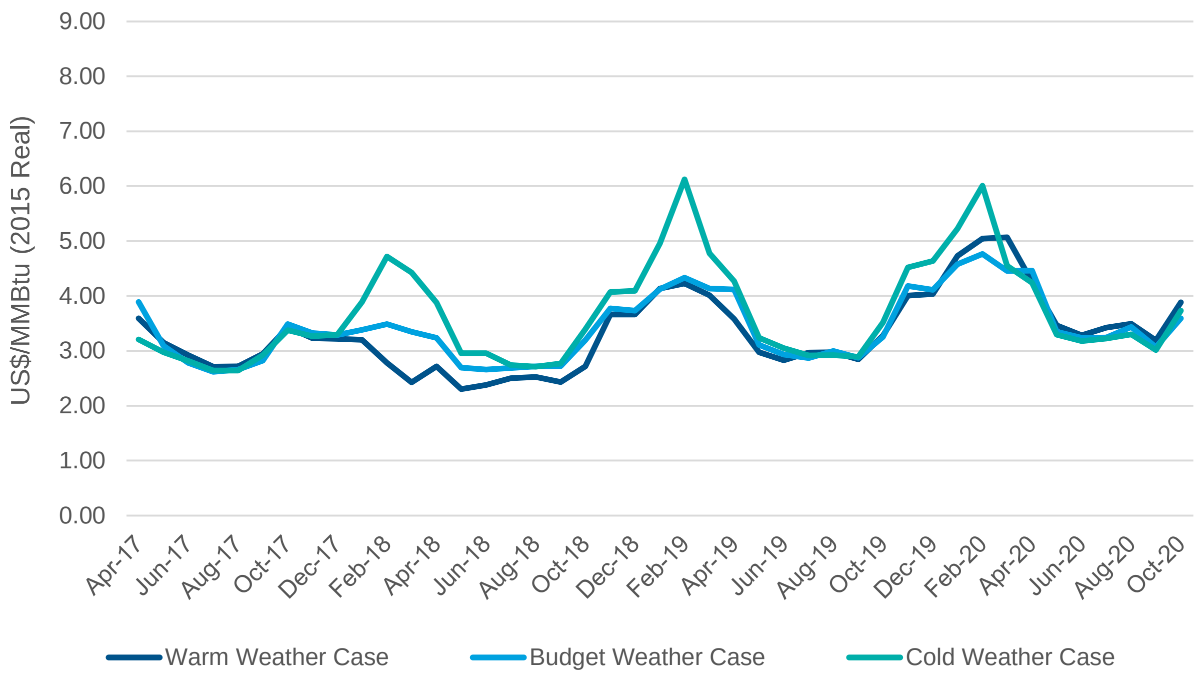
Using the 85 unique three year weather scenarios, ICF developed three separate scenarios; a Warmer than Budgeted case, a Budgeted Weather case, and a Colder than Budgeted case. The three Enbridge weather scenarios (Colder, Budgeted, and Warmer) were constructed to best approximate Enbridge's HDD forecast for each of its weather planning scenarios. Each of these three weather scenarios were crafted from an average of four unique weather cases selected from the larger set of 85 weather cases. These four weather cases for each scenario were selected to develop a composite scenario that most closely aligned with Enbridge's three planning scenarios.

[2] Enbridge Gas Distribution 2017 Rate Case Application EB-2016-0215, Exhibit D1

Enbridge's Budgeted Weather scenario assumptions are determined by the company's Economics and Business performance department, which utilizes an OEB approved methodology to determine the level of HDDs to be used in gas supply planning. For the purpose of this analysis, the Colder than Budgeted weather scenario reflects a winter with daily average weather 10 HDDs colder than the Budgeted weather scenario. The Warmer than Budgeted scenario reflects a winter with daily average weather 10 HDDs warmer than the budgeted weather conditions.

The resulting commodity price and demand outlooks across the Colder than Budgeted, Budgeted, and Warmer than Budgeted weather cases were used by Enbridge to assess the impact of alternative storage scenarios on Enbridge's natural gas supply portfolio costs using the Enbridge SENDOUT© model. The storage scenarios include five different levels of storage capacity, and two different storage cost scenarios.

Exhibit 1-1: Dawn Prices (US$) Under the Three Enbridge Weather Scenarios



Source: ICF Gas Market Model

ICF used the results of the Enbridge SENDOUT© analysis to assess the impact on Enbridge supply portfolio costs of the alternative storage scenarios and weather scenarios to determine the potential costs and benefits of increasing the amount of storage capacity used by Enbridge Gas.

1.4 Summary of Conclusions

ICF analyzed the SENDOUT© optimization results prepared by Enbridge in order to evaluate the impact of the alternative price scenarios on Enbridge supply purchases under five different storage capacity cases, ranging from the current level of storage capacity up to an additional 20

Bcf of incremental storage capacity,[3] and for two different storage cost scenarios in order to assess the potential reduction in gas portfolio costs resulting from the addition of incremental storage capacity to Enbridge's gas supply portfolio.

Considering the current cost of storage capacity available from third parties, supply portfolio costs are minimized by adding at least 20 Bcf of incremental storage capacity to the Enbridge supply portfolio in the Colder than Budgeted and Budgeted Weather scenarios, and up to 20 Bcf of storage capacity in the Warmer than Budgeted Weather scenario.

Raising the incremental cost of storage capacity by 50 percent relative to existing levels has minimal impact on the amount of additional storage capacity that would be economic in the Budgeted and Colder than Budgeted weather scenarios. At the higher storage cost the Enbridge supply portfolio cost would be minimized by adding at least 20 Bcf of storage capacity in the Colder than Budgeted scenario, and the Budgeted Weather scenario. Under the higher storage cost assumptions the Enbridge supply portfolio cost would be minimized by adding up to 15 Bcf of storage capacity.

The overall results of the three year period from April 2017 through March 2020 of all weather, demand, and storage cost scenarios are shown in Exhibit 1-2.

Exhibit 1-2: Average Annual Change in Total Gas Costs from Incremental Storage Capacity From Enbridge SENDOUT© Results

Average Annual Impact of Incremental Storage Capacity on Enbridge Supply Portfolio Costs for the Three Year Period from April 2017 to March 2020		
(CAD$Millions)	Reference Storage Costs	50 Percent Increase in Storage Costs
Colder than Budgeted Weather Scenario		
5 Bcf	-12.3	-9.7
10 Bcf	-24.4	-19.3
15 Bcf	-36.7	-29.0
20 Bcf	-47.6	-37.3
Budgeted Weather Scenario		
5 Bcf	-3.2	-0.6
10 Bcf	-6.1	-1.0
15 Bcf	-9.0	-1.3
20 Bcf	-11.7	-1.4
Warmer than Budgeted Weather Scenario		
5 Bcf	-2.9	-0.3
10 Bcf	-5.5	-0.4
15 Bcf	-8.0	-0.4
20 Bcf	-8.0	2.3

Recommendations of Future Additions to Storage Capacity

[3] The storage capacity scenarios were capped at 20 Bcf due to uncertainty of incremental storage availability at levels higher than 20 Bcf

Based on the assessment of natural gas market trends, expected natural gas prices at Dawn, and the value of natural gas storage as part of the Enbridge overall supply portfolio, ICF's analysis of Enbridge's SENDOUT© results indicates that additional storage capacity across the three weather scenarios and both cost scenarios would reduce the expected overall cost of the Enbridge gas supply portfolio.

The overall amount of incremental capacity that should be considered by Enbridge will depend on the cost of the incremental storage, and the level of importance Enbridge places on minimizing the cost impacts of a colder than normal winter for its customers, relative to minimizing the long-term average cost.

A strategy designed to minimize the total long-term cost of the Enbridge supply portfolio to consumers would be heavily weighted toward the Budgeted Weather scenario based on the expected distribution of the weather scenarios given the likelihood of either the Warmer or Colder than budgeted scenarios. Based on a weighting of 60 percent for the Budgeted Weather scenario, and 20 percent (one year in five) for both the Colder than Budgeted and Warmer than Budgeted weather scenarios. (Exhibit 1-3) Under this set of priorities:

- If the cost of additional storage capacity from third parties remains at or near current storage costs, ICF would recommend consideration of to 20 Bcf of incremental storage capacity.
- If incremental storage costs increase by 50 percent relative to existing contracted storage costs, ICF would recommend consideration of 20 Bcf of incremental storage capacity.

A strategy designed to minimize the potential impact of a colder than normal winter on costs to Enbridge consumers would still weigh the Budgeted scenario most heavily, but would discount the Warmer than Budgeted scenario and over-weight the Colder than Budgeted scenario. The weighting of the different scenarios used to accomplish this objective is a policy judgement that will need to be made by Enbridge. For the purposes of this analysis, ICF has weighted the Colder than Budgeted Weather Scenario at 40 percent, the Budgeted Weather Scenario at 60 percent, and the Warmer than Budgeted Weather Scenario at 0 percent. (Exhibit 1-3) Under this set of priorities:

- If the cost of additional storage capacity from third parties remains at or near current storage costs, ICF would recommend consideration of at least 20 Bcf of incremental storage capacity.
- An increase in incremental storage costs of 50 percent relative to existing contracted storage costs would not change the recommendation. ICF would recommend consideration of at least 20 Bcf of incremental storage capacity.

If incremental storage costs increase by more than the 50 percent increase relative to existing levels assessed in this analysis, ICF would recommend additional analysis be undertaken to ensure that the benefits of increasing storage capacity will exceed the incremental costs of the storage capacity.

Exhibit 1-3: Average Annual Change in Total Gas Costs from Incremental Storage Capacity, Weighted by Weather Probability

Average Annual Weighted Average Impact of Incremental Storage Capacity on Enbridge Supply Portfolio Costs for the Three Year Period from April 2017 to March 2020					
(CAD$Millions)	Reference Storage Costs			50 Percent Increase in Storage Costs	
Scenario	Balanced Weighting	Cold Weather Weighting		Balanced Weighting	Cold Weather Weighting
Colder than Budgeted Weather Scenario	20%	40%		20%	40%
Budgeted Weather Scenario	60%	60%		60%	60%
Warmer than Budgeted Weather Scenario	20%	0%		20%	0%
Incremental Storage Capacity					
5 Bcf	-4.9	-6.8		-2.4	-4.3
10 Bcf	-9.7	-13.4		-4.6	-8.3
15 Bcf	-14.3	-20.0		-6.6	-12.4
20 Bcf	-18.2	-26.1		-7.8	-15.8

2. Enbridge Storage Operation Review

Enbridge Gas Distribution serves over 2.1 million customers, with its customer base divided into a Central weather zone, an Eastern weather zone and a Niagara weather zone. Enbridge currently owns and leases 114 Bcf of underground storage in southwestern Ontario and southeastern Michigan to serve Enbridge in-franchise customer gas supply requirements. This capacity includes 92 Bcf of utility-owned storage near the Dawn Hub, operated by Enbridge Gas Storage, along with contracts for an additional 22 Bcf of physical and “synthetic” storage capacity with other storage providers near the Dawn Hub.

Following the winter of 2013/14, which resulted in gas storage inventories being largely depleted toward the end of the heating season, Enbridge recommended changes in storage utilization to the Ontario Energy Board (OEB) as part of Enbridge’s 2015 Rate Case Application (EB-2014-0276). The Based on this recommendation, the OEB approved changes to Enbridge’s gas storage deliverability targets to be used in future gas supply plans and rate case applications. Modifications to the company’s gas storage operations included adjustments to the gas storage deliverability targets to increase the levels of storage inventory maintained until the end of February and the end of March. The change in deliverability targets results in a shift in gas supply purchases to earlier in the winter season, providing additional flexibility later in the year.

The purpose of the changes in storage deliverability targets was to reduce the possibility of situations similar to the winter of 2013/14, when low storage inventories at the end of the winter necessitated the purchase of additional gas supplies from Dawn during high price periods, resulting in a significant and unexpected increase in delivered natural gas prices to Enbridge consumers.

ICF projects that over the next several years gas storage will become more important in balancing peak winter demand requirements as well as ensuring against a repeat of the winter of 2013/14. As the importance of gas storage operations increase, a review of the optimal level of gas storage and operating practices becomes a prudent step in Enbridge’s gas supply planning process.

2.1 Summary of Enbridge’s Gas Storage Operations

Prior to developing a gas supply plan, Enbridge conducts an annual design day and baseload day demand analysis over a five year planning horizon, with the primary focus being the first two years. A core purpose of these analyses is to determine the expected demand in future years, in order to evaluate the renewal, addition and shedding of transportation and/or other market-based solutions to meet that demand. Enbridge develops the gas supply plan over a two year planning horizon with the primary focus being on the first year. The two year planning horizon ensures that a complete storage management cycle is taken into account as the gas supply plan is developed.

In addition to establishing a cost-effective gas supply plan, Enbridge’s gas supply planning process also considers diversity in gas supply sourcing, diversity in the type of gas storage utilized, system reliability, and system flexibility. Each of these factors are also influenced by the level of available gas storage and operating parameters.

2.1.1 Storage usage criteria

Enbridge's gas supply plan identifies planned injection and withdrawal volumes, storage balances, as well as a review of the costs for its storage facilities. The company manages its gas storage inventories to meet the following storage inventory guidelines:

- Required storage space is full by October 31.
- Sufficient inventory on February 28 to meet winter peak day storage withdrawal requirements.
- Sufficient inventory on March 31 to meet the March peak day storage withdrawal requirements.

3. Review of Storage Operations in Other Jurisdictions

As part of the review of Enbridge's gas storage operations, ICF was asked by Enbridge to review nearby regulated local gas distribution companies (LDCs) profiles, customer bases, gas storage assets, and how those companies manage their gas storage profiles in support of their gas supply strategies. This review was to serve as a benchmark for other storage practices and an understanding of how other LDCs manage their gas storage assets as part of their gas supply plans.

ICF reviewed public regulatory filings for LDCs in Ontario, Manitoba, Quebec, Michigan, Illinois, and Pennsylvania to complete this third party review. The regulated gas utilities reviewed are listed in Exhibit 3-1, and a summary of the storage practices for each utility is provided in the following sections. A more detailed review of each LDC's gas storage operations is included in Appendix A.

Exhibit 3-1: Summary Information on the Ten LDCs Reviewed

Utility	Number of Customers	2015 Gas Sales (Bcf)	Total Gas Storage Capacity (Bcf)
Enbridge	2,129,000	437	114[4]
Union Gas	1,437,000	490	163
Gaz Métro	195,000	202	19
Centra Gas Manitoba	270,000	74	15
Consumers Energy	1,700,000	350	150
DTE Gas	1,200,000	287	135
National Fuel Gas Distribution (NY & PA)	740,000	141	78
Peoples Gas	828,000	340	37
Ameren Illinois	816,000	160	~50
Nicor Illinois	2,000,000	>500	150
MidAmerican Energy	733,000	154	Not Reported

Source: Company Filings

3.1 Summary

Each LDC reviewed by ICF operates its gas planning process subject to the judgements of the regulating entity, the constraints and limitations of its access to natural gas pipelines, gas storage facilities, and the nature of its customer base. Despite differences across each LDC, each company utilizes a mix of gas storage and pipeline capacity agreements to balance the seasonal nature of their gas demand. The level of pipeline contracting, owned or contracted storage, and utilization of spot gas purchases vary significantly across each company and can have a large impact on the role that gas storage plays in meeting peak winter demand.

[4] Enbridge holds 22 Bcf of 'physical and synthetic' contracted storage and 92 Bcf of gas storage at the Enbridge Gas Storage Facility to serve Enbridge Gas distribution customer requirements. The Enbridge Gas Storage Facility also includes 14 Bcf of gas storage capacity available to third parties.

Storage capacity is generally utilized to allow LDCs to balance their daily gas demands over the winter periods and meet withdrawal requirements on peak design days. Gas storage operations are also used by some of the LDCs to minimize gas supply costs via increased levels of purchases in typically less expensive summer months, as well as to minimize the need for firm pipeline capacity agreements upstream of the storage capacity by having more uniform gas purchases. Gas storage is also used by some LDCs as part of price risk mitigation strategies, weighting increased levels of supply purchases toward less volatile summer periods.

Each company has an established target fill level and target storage fill date that corresponds to the beginning of that company's winter heating season. Six of the ten LDCs have a target for gas storage levels to be at 100 percent of capacity at the End of October. Two LDCs have a target for gas storage levels to be at 95 percent of capacity at the End of October and two LDCs have a target for storage levels to be 100 percent of capacity by November 15th.

Not all of the companies release publicly available information on storage utilization targets and target criteria. Where this information is available, it indicates LDCs will target an incremental drawdown in storage balances throughout the winter season. It is typical that LDCs make allowances throughout the heating season to make spot gas purchases as needed to maintain storage levels that will allow a company to meet storage withdrawal requirements of the company's Peak Design Day Demand throughout the winter period.

3.2 State Differences in Regulatory Approaches for Public Utility Commissions

The review of storage operations for other LDCs performed by ICF highlighted the large differences in the public reporting of storage operations, which are largely a function of the levels of details required by each utility's regulator. ICF reviewed storage operations for LDCs across three Canadian provinces and four states in the U.S., which were located in seven different jurisdictions of PUCs. There exist significant differences across these seven PUCs, which has a significant influence on the level of detail for each LDC's gas storage operations as well as a company's gas supply plan for manages its gas supplies to meet peak winter demands.

Most of the PUCs require regular filings and status updates on the LDC's gas supply plans and rate adjustments. Within these rate and gas plan regulatory filings there are varying levels of detail related to gas storage operations and the criteria governing the company's usage of gas storage assets. The Michigan Public Utility Commission (PUC) for instance, requires annual gas supply plans, which provide a high level of detail regarding monthly gas storage targets and inventory levels, while Illinois does not provide annual gas supply plans with the same level of detailed gas storage information.

Exhibit 3-2: Public Utility Commission Summary

Utility Commission	Gas Utility	Summary
Régie de l'énergie (Quebec, Canada)	Gaz Métro	Limited ability to review public documents due to French Language reporting and a limited number of translated filings.
Ontario Energy Board	Union Gas, Enbridge Gas Distribution	Detailed review process with annual Gas Supply plans and quarterly rate adjustments. High level of detail included in regulatory documents for assessing gas storage operations.
Manitoba Public Utilities Board	Centra Gas Manitoba	Detailed review process with annual Gas Supply plans and quarterly rate adjustments.
Illinois Commerce Commission	Peoples Gas, Ameren Illinois, Nicor Illinois, MidAmerican Energy	The PUC uses an after the fact prudence review of LDCs gas supply plans. This provides significant flexibility for how companies manage storage inventory levels and pipeline contracts.
Michigan Public Service Commission	Consumers Energy, DTE Gas	LDCs must file gas supply purchase plans that dictate operational guidelines. Annual reconciliation reviews take place after the year.
New York Public Service Commission	National Fuel Gas Distribution	Provides for semi-automatic adjustment clauses in its rate filing process. The NY PUC will also allow for multi-year rate cases, limiting the quarterly and annual filing requirements.
Pennsylvania Public Utility Commission	National Fuel Gas Distribution	In addition to natural gas tariff filings, the PA PUC requires Winter Readiness plans that include information on gas supply planning.

Source: ICF, Public Utility Commission reports

3.3 Comparison of regulated Local Gas Distribution Utilities Gas Storage Operating Criteria

The following section includes several summary tables that compare different aspects of each LDC's gas storage operations in order to provide a benchmarking of Enbridge's gas storage operations. The information for these tables were developed through a review of publicly available information from regulatory proceeding filed with each state PUC. There are varying levels of information for each LDC making a full comparison difficult.

Of the ten LDCs reviewed, seven own their own storage capacity, with three companies (Gaz Metro, Centra Gas Manitoba, and MidAmerican Energy) relying solely on contracted storage capacity. LDCs that have their own gas storage assets will often contract for additional storage capacity, which can provide added flexibility to the company based on the type and availability of contracted storage near their service area.

Of the ten LDCs reviewed, seven have provided details on the storage deliverability and role of storage in meeting the company's Peak Design Day Demand. The absolute levels of storage deliverability varies widely, from 0.3 Bcfd to 2.5 Bcfd, and is largely dependent on the size of the LDC and the structure of demand in the company's service territory.

Storage deliverability typically plays a much larger role in meeting peak day demand, averaging 53 percent of peak demand, than in meeting average winter demand.

Exhibit 3-3: Gas Utility Storage Operating Profile Comparison

Gas Utility	Gas Storage Ownership	Annual Storage Capacity (Bcf)	Max Deliverability from Storage (Dth/d)	Peak Design Day Demand (Dth/d)	Storage % of Peak Design Day Demand
Enbridge	Yes	92 Bcf owned (with 14 Bcf available to third parties) & 22 Bcf contracted storage	2,180,000	3,811,000	57%
Union Gas	Yes	152 (95 in-franchise)	1,718,000	3,276,000	52%
Gaz Métro	No	19.8 contracted	306,000	510,000	60%
Centra Gas Manitoba	No	14.7 contracted			
Consumers Energy	Yes	150	363,746	454,683	80%
DTE Gas	Yes	135.1	1,578,193	2,391,202	66%
National Fuel Gas Distribution (NY & PA)	Yes	78	810,347	1,724,143	47%
Peoples Gas	Yes	36.5 (owned) & contracted storage			36%
Ameren Illinois	Yes	24.6 (owned) & contracted storage	570,000	1,140,000	50%
Nicor Illinois	Yes	150 (owned) & contracted storage	2,550,000	5,100,000	50%
MidAmerican Energy	No				30-35%

Sources: ICF, LDC Regulatory Proceeding and Company Sources

Gas storage operations across the LDCs follow similar trends, with injections over the summer months sufficient to reach full inventories at the start of winter withdrawal seasons and inventory withdrawals over the course of the winter heating season. However, within these seasonal trends, there are some variations in how gas storage inventories are managed and the type of storage guidelines used. ICF has summarized these differences to highlight how Enbridge's guidelines compare to other LDCs practices.

Each LDC's gas storage guidelines plan to have storage inventory levels full at either the end of October or by November 15th. Three LDCs[5] published monthly storage inventory targets as part of the regulatory filing process. Additional LDCs may also use monthly storage inventory targets but are not required to disclose this in regulatory filings. Enbridge's storage guidelines are to maintain sufficient inventory levels to maintain minimum deliverability targets at the end of February and end of March. Compared to monthly storage targets, this allows for more flexibility throughout the season than monthly inventory levels.

[5] The Michigan LDCs include their monthly storage inventory and gas storage sendout volumes as part of the regulatory filings. This level of detail was not included in other PUC jurisdictions.

Exhibit 3-4: LDCs Storage Capacity Targets

Gas Utility	Reported Storage Capacity (Bcf)	Date Storage Capacity to be Full	Type of Storage Guidelines
Enbridge	92 Bcf owned (with 14 Bcf available to third parties) & 22 Bcf contracted storage	End of October	Sufficient inventory at End of February to meet maximum withdrawal requirements
Union Gas	152 (95 in-franchise)	End of October	Sufficient inventory at End of February to meet maximum withdrawal requirements
Gaz Métro	19.8 contracted	End of October	Unknown
Centra Gas Manitoba	14.7 contracted on ANR	End of October	Unknown
Consumers Energy	175.6 (150 owned)	End of October	Monthly Storage Inventory Levels
DTE Gas	135	End of October	Monthly Storage Inventory Levels
National Fuel Gas Distribution (NY & PA)	78	96% Full at the End of October	Monthly Storage Inventory Levels
Peoples Gas		End of October	Unknown
Ameren Illinois	36.5 (owned) & contracted storage	Full Nov. 15th	Unknown
Nicor Illinois	26 (owned) / total of 36.5	Full Nov. 10th	Unknown
MidAmerican Energy	150 (owned) & contracted storage	End of October	Unknown

Sources: ICF, LDC Regulatory Proceeding and Company Sources

Five of the ten LDCs reviewed had publicly available details on how each company's gas storage is used and what factors are considered in daily and seasonal withdrawals. Several LDCs gas storage operations and withdrawals levels are designed to meet end of month target inventory levels and will have withdrawal volumes vary according to changes in weather and demand patterns, similar to Enbridge. Some LDCs manage their storage operations in less regulated manner, with only a beginning and ending target levels. While this may appear to have more flexibility, despite not having monthly targets throughout the winter, these LDCs typically have their own internal guidelines and storage operation criteria that can include factors like the level of contracted storage, nature of gas storage fields in use, minimizing costs of firm transport in winter months.

Exhibit 3-5: Gas Utility Storage Usage and System Balancing

Gas Utility	Storage Operations Criteria	Key Factor for System Balancing
Enbridge	Targeted control points for storage levels; November 1st is full; February 28th has capacity to meet Design Day needs; March 31st has capacity to meet March peak day.	Uses SENDOUT© model to optimize for the lowest-cost gas supply over the full year.
Union Gas	Targeted control points for storage levels, with allowances for integrity volumes; November 1st is full; February 28th has capacity to meet Design Day needs; Minimum levels of storage at end of March	Optimize for contracted upstream capacity to be utilized at 100% load factor.
Gaz Métro		
Centra Gas Manitoba		Gas storage to diversify supply sources
Consumers Energy	Beginning and end of season gas storage targets of 175.6 Bcf at end of October & 70.1 Bcf at end of March	Majority of gas purchases (75%) occur in the summer months
DTE Gas	Minimum levels of gas remaining in storage at the end of winter months	
National Fuel Gas Distribution (NY & PA)	Minimum levels of gas remaining in storage at the end of the month	Balance seasonal pipeline utilization and hedge against winter prices
Peoples Gas		Uses computer models to optimize for the lowest-cost gas supply over the full season.
Ameren Illinois	Target full storage at November 15th. Injection and withdrawal schedules are developed to operate storage facilities for reliability to protect the storage reservoir integrity at the lowest cost.	Winter usage favors pipeline capacity, then no-notice storage withdrawals from contracted storage, then balance remaining demand from on-system storage.
Nicor Illinois	Uses historical aquifer performance and operational experience for target inventory levels and aquifer pressures necessary to meet peak, seasonal, and daily needs. Injections as required.	Maximize access to available pipeline deliveries
MidAmerican Energy		

Sources: ICF, LDC Regulatory Proceeding and Company Sources

4. Implications of Changes in Natural Gas Markets on Storage Value

ICF is forecasting significant changes in the value of natural gas storage over the next five years. The rapid expansion of natural gas production, particularly from the Marcellus and Utica shales, has helped suppress natural gas prices over the past five years. This has led to generally declining natural gas prices, lower seasonal value of natural gas, lower natural gas price volatility, which has generally held down the value of natural gas storage during this period.

However, gas markets are in a period of transition away from the over-supplied gas market of the past several years. Supply growth is expected to lag demand and natural gas prices are expected to begin to increase. The shift in the natural gas markets is expected to lead to a higher seasonal value of natural gas, and higher gas price volatility, leading to an increase in the value of natural gas storage.

This section of the report reviews the changes in natural gas market conditions that ICF expects to impact the natural gas markets and the value of gas storage for Enbridge. The first section presents an overview of ICF's North American natural gas market outlook. The second section is focused on the Canadian gas market, examining the potential shifts in inter-regional pipeline flows and natural gas prices. The third section looks at the impact of weather on natural gas storage scenarios and how ICF constructed its weather cases that Enbridge used to evaluate various gas storage options.[6]

4.1 North America Gas Market Outlook

4.1.1 North American Demand Outlook

The rapid growth of Marcellus/Utica production encourages continued growth in gas consumption and exports from North America. Through 2020, growth in North America demand is primarily export driven, and the majority of the expected exports are via LNG terminals and piped gas to Mexico. Natural Gas demand trends in Canada are expected to closely follow the rest of North America.

The power generation sector has been the major driver of incremental gas consumption within North America. The growth in power sector gas consumption is driven by multiple factors, including the favorable economics of gas-fired generation, pre-existing environmental regulation (such as Mercury and Air Toxic Standards), and – for now – the Clean Power Plan (CPP) which encourage the retirement of coal plants.

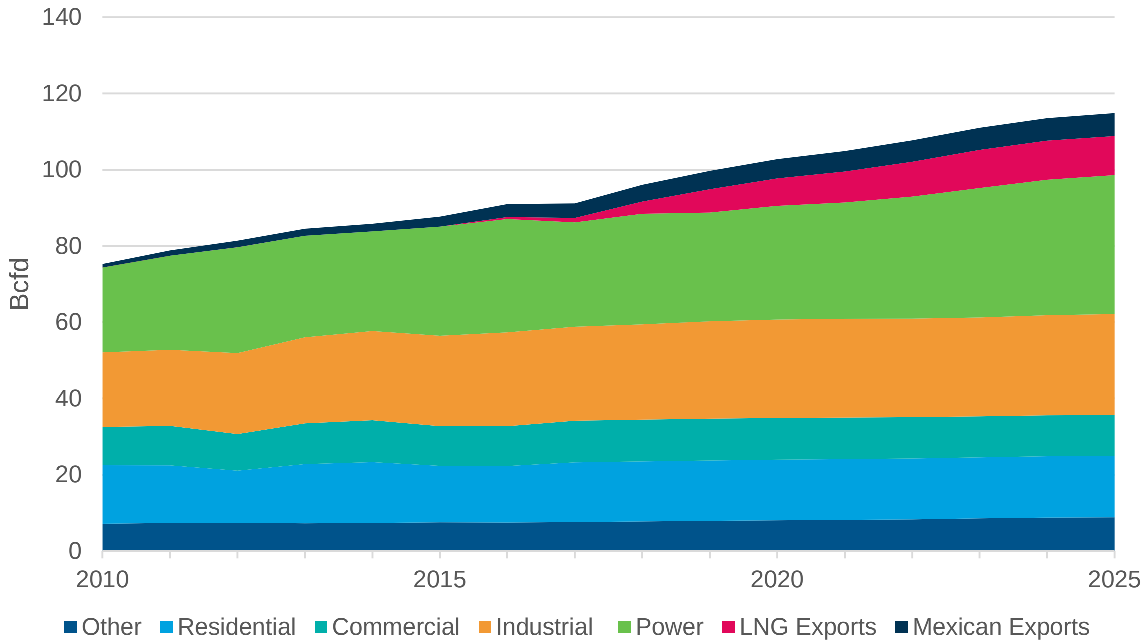
[6] The outlook and forecasts discussed in this section are those of ICF and may differ from views of Enbridge in some respects.

Gas demand is also expected to grow in other sectors, but at a more modest pace. Industrial demand is projected to increase by about 10 percent through 2025, primarily due to increases in petrochemicals industries which are concentrated on the U.S. Gulf Coast. Residential and commercial gas demands are expected to rise only slightly, as increased demand due to the addition of new gas customers is partially offset by reductions in per-customer consumption due to energy efficiency improvements.

ICF's base case model includes carbon price assumptions reflecting known and anticipated North American carbon policy. Most of the impact from carbon policies on natural gas demand will occur post-2025.

Gas demand in Mexico is expected to increase sharply in order to meet growing power generation gas demand in Mexico. By 2025, ICF projects that pipeline export to Mexico will reach 6 Bcfd, more than double the 2014 export volumes.

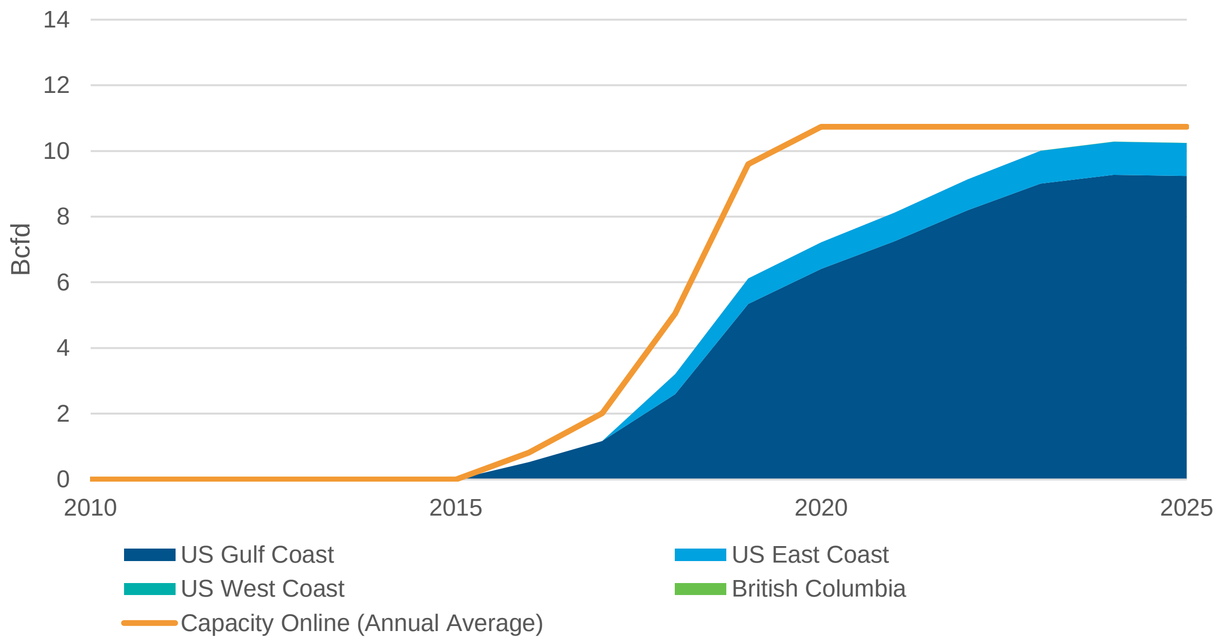
Exhibit 4-1: U.S. and Canada Natural Gas Demand by Sector



Source: ICF GMM®

Since 2012, the U.S. Department of Energy (DOE) has approved applications for LNG exports from nine U.S. LNG terminals; the majority of these facilities are planned for the Gulf Coast, and one terminal (Cheniere's Sabine Pass) has already started exporting volumes. In Canada, the National Energy Board (NEB) has approved ten proposals for export terminals located on the British Columbia coast. ICF's current projection assumes total North American LNG exports reach 10.2 Bcfd by 2025, with the majority (9.2 Bcfd) coming from the U.S. Gulf Coast.

Exhibit 4-2: LNG Export Volume versus Capacity



Source: ICF GMM®

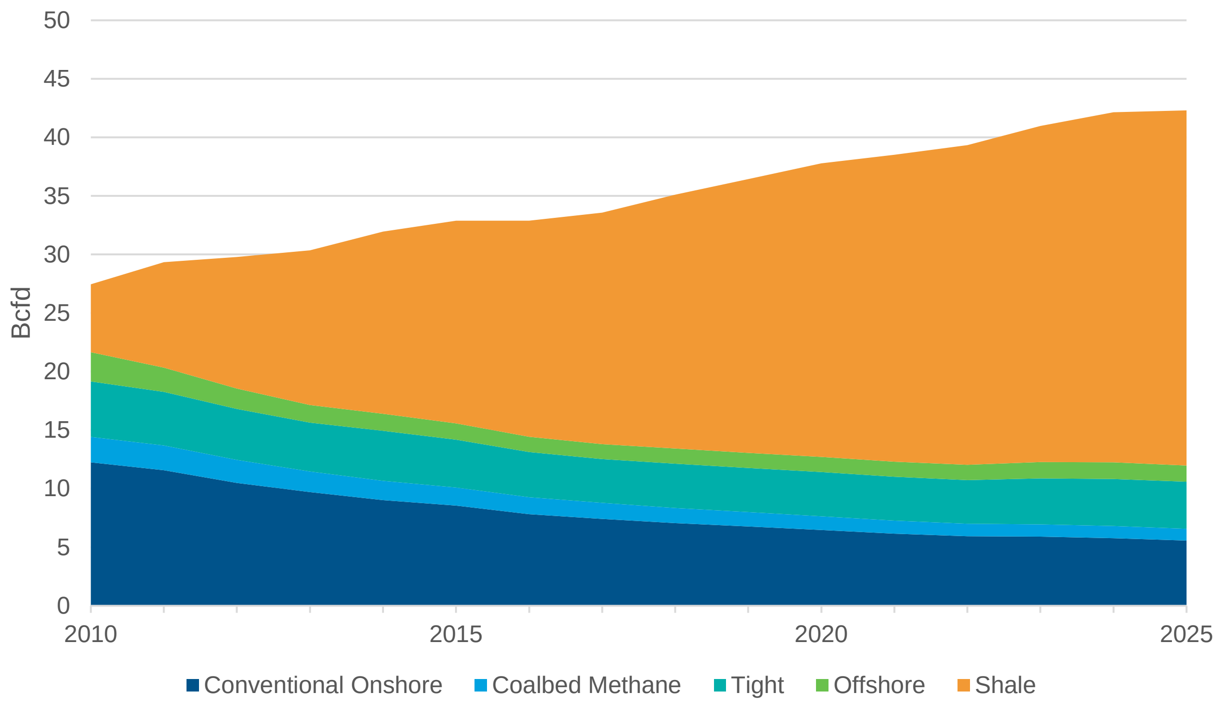
4.1.2 North American Supply Outlook

With the advent of new shale gas supplies, the North American natural gas market has changed dramatically in the past ten years. Prior to the rise of shale gas, U.S. consumption was increasing more quickly than production, and as a result gas prices were relatively high and volatile. As gas prices increased, investments were made in new technologies to develop the vast natural gas reserves found in shale formations.

While it had been long known that there were large deposits of gas and oil in shale formations, it was not until the early 2000s that techniques were developed to economically tap these reserves. The new combination of directional drilling and hydraulic fracturing techniques were first applied in the Barnett Shale in north Texas, but quickly spread to other regions. The first successful shale well in the Marcellus Shale (which stretches from West Virginia through Northeastern Pennsylvania) was drilled in 2004, but Marcellus production did not reach significant levels until 2010. Shale gas development has also spread to the Utica Shale, an over-lapping play that extends into eastern Ohio. Since 2004, over 13,000 wells have been drilled in the Marcellus and Utica shale.

Total U.S. and Canadian gas production is currently about 92 Bcfd, with the Marcellus/Utica accounting for over 20 percent of total North American production. Production growth has been centered in the Marcellus/Utica due to the size of the resource (estimated to be well over 1,000 trillion cubic feet) and low per-unit production costs. Recent declines in oil and gas prices have resulted in a slow-down in drilling rig activity across North America, including in the Marcellus/Utica area. Between November of 2015 and November of 2016, the number of active drilling rigs in the Marcellus and Utica plays declined by 22 percent.[7] Despite the decline in rig activity, Marcellus/Utica production has continued to increase due to improvements in well productivity (i.e. more gas produced per well drilled). ICF projects Marcellus/Utica production will reach about 31 percent of total North American production by 2025. While other shale plays are also increasing, Marcellus/Utica accounts for a large majority of the projected production growth from 2015 through 2025.

Exhibit 4-3: U.S. and Canada Natural Gas Production



Source: ICF GMM®

The shifts in regional gas supply and demand have changed interregional pipeline flow patterns, and the changes are likely to continue in the future. Marcellus/Utica production growth has already resulted in dramatic changes to pipeline flow patterns, with the Northeast becoming a net exporting region. Prior to the development of Marcellus and Utica, the Mid-Atlantic and Northeast U.S. relied on gas supplies from the Gulf Coast and Western Canada.

As Marcellus/Utica production continues to grow and becomes an even larger source of gas supplies to other areas, flows along the traditional in-bound paths are increasingly reversed as gas flows out of the region to the South, to the Midwest, and to Eastern Canada.

Flows from Western Canada to the east remain low, as consumers in Eastern Canada increasingly rely on Marcellus/Utica supplies. Flows out of Western Canada are also limited by

[7] "Rig Count Overview & Summary Count". Baker Hughes. November 18, 2016.

increased gas demand within the region to support LNG exports from British Columbia and oil sands development in Alberta.

Impact of Flow Changes to Enbridge

In recent years Enbridge has undertaken a review of the gas supply sources used as part of the company's gas supply planning, letting select pipeline contracts expire and taking out new pipeline contracts to access low-cost gas sources.[8] The changes taking place across North America in natural gas supply and demand will have fundamental impact on the price relationships between the available sources of natural gas for Enbridge. For instance;

- The rapid growth in Marcellus/Utica supply is turning the Northeastern U.S. into a major supply center, pushing down prices at major Northeast hubs, including Dominion South Point. Dominion South Point is the most liquid hub in the Marcellus/Utica area, and is used as a proxy for Marcellus/Utica prices.
- The concentration of demand growth along the Gulf Coast (from LNG exports, Mexican exports, and industrial demand) is changing the Gulf Coast into a net demand region. Prices at Henry Hub are expected to increase relative to Dominion South Point, which attracts gas from Marcellus/Utica to flow southward.
- In Western Canada, the decline in conventional natural gas production, combined with growth in natural gas demand for oil sands production and LNG exports is expected to lead to higher prices at AECO relative to Marcellus/Utica.

These changes in price relationships increase the attractiveness of natural gas supply purchased from the Marcellus/Utica area for consumers throughout the Northeastern U.S, the Midwest and Central Canada, relative to the supply basins that these regions have historically relied upon.

A major determinant of the production outlook for the Marcellus and Utica is the availability of gas pipeline infrastructure to export gas out of the region. In the last three years over 40 distinct projects have been proposed to expand capacity out of the Marcellus/Utica. Appendix C includes ICF's assumptions of the planned pipeline capacity additions near Ontario by their primary destination markets.

As these facilities are constructed and Marcellus and Utica production gains better access to the broader gas market, gas prices in the Marcellus/Utica area would be expected to increase, relative to Henry Hub. Basis spreads between Marcellus/Utica and other markets will better reflect the cost of pipeline transportation than the effects of constraints in takeaway capacity as is now the case.

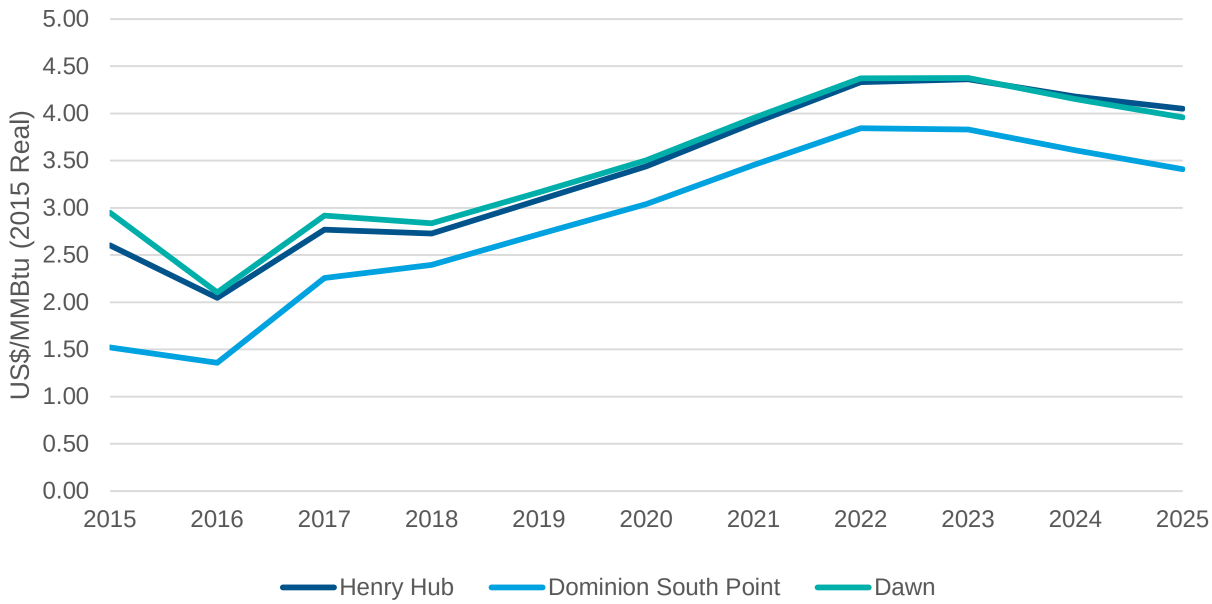
[8] Enbridge's 2017 Rate Application (EB-2016-0215) states, "changes to the TransCanada Pipelines Limited ("TCPL") Mainline toll structure and increasing supply opportunities in the United States northeast have influenced a shift from Alberta purchases (paired with long haul transportation) to Ontario purchases at the Dawn and Niagara receipt points (paired with short haul transportation)."

4.1.3 North American Price Outlook

ICF expects natural gas prices across North America to increase in the coming years as producers continue to reduce capex and gas demand increases. Low gas production costs will prevent large price increases from occurring, as a supply response is expected due to increasing gas prices that make it economic to grow gas production in areas outside of the Marcellus and Utica shale. For instance, gas prices ranging from US$4.00 to US$5.00 per MMBtu are sufficient to foster strong supply development in areas outside of the Marcellus and Utica shales.

ICF's forecast is for Henry Hub natural gas prices to stay below US$4.00 per MMBtu through 2020 and longer-term prices are expected to range between US$4.00 and US$5.00 per MMBtu. ICF projects that prices at Dawn will rise above US$4.00/MMBtu (in 2015 US$) by 2022 and range between US$4.00 and US$4.50/MMBtu (in 2015$) through 2025.

Exhibit 4-4: Natural Gas Prices (US$) at Henry Hub, Dominion South Point, and Dawn



Source: ICF GMM®

As new natural gas pipeline capacity from Marcellus/Utica is added, basis between Dawn and Dominion South Point will decline to US$0.50-US$0.60/MMBtu (in 2015 US$). Furthermore, as Dawn receives a greater portion of its gas supplies from the Marcellus/Utica, Dawn's basis to Henry Hub will continue to narrow and by 2025 prices at Dawn are projected to trade at a slight discount to Henry Hub.

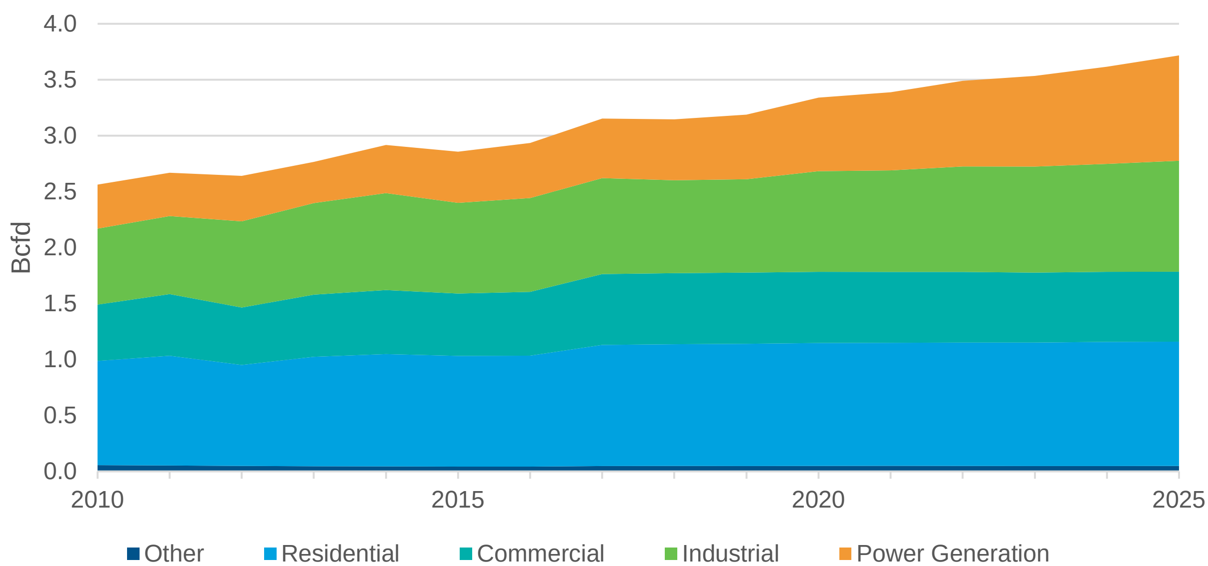
4.2 Ontario Natural Gas Market Outlook

4.2.1 Supply and Demand Trends

Ontario's natural gas demand in 2015 was about 2.6 Bcfd and accounted for approximately 26 percent of Canada's total natural gas demand. The demand in Ontario is expected to increase slightly to 2.7 Bcfd in 2016. ICF projects Ontario's natural gas demand to increase to 3.6 Bcfd by 2025.

Currently, the residential sector, which mainly relies on natural gas for space and water heating, has the largest demand for natural gas in Ontario and averages about 0.9 Bcfd annually. The residential and power generation sectors together comprise over half of Ontario's natural gas demand. ICF expects power generation gas demand to experience the most growth during the next decade, increasing from 0.5 Bcfd in 2016 to 0.9 Bcfd in 2025. As nuclear power plants retire and access to gas from the Marcellus/Utica supply region of the U.S. improves, natural gas-fired power generation is projected to increase significantly.

Exhibit 4-5: Ontario Natural Gas Demand



Source: ICF GMM® Case

ICF's base case model includes a carbon price assumptions reflecting Ontario's Cap & Trade program.[9] The expected impacts of this program and related initiatives to reduce Green House Gas (GHG) emissions on future natural gas demand in Ontario are evolving as Ontario policy

[9] The Government of Ontario passed legislation establishing a Cap and Trade Program in an effort to reduce Greenhouse Gas ("GHG") emissions. This program is set to commence in January 2017.

continues to be developed and implemented. Much of the impact will effect natural gas demand levels post-2025.[10]

4.2.2 Regional Supply Trends

Ontario has little natural gas production of its own, and thus imports practically all of its supply from other regions in Canada and the United States. Ontario receives its natural gas from three main flow pathways, from Michigan, Western Canada and Niagara, with minimal volumes from Iroquois. In 2015, the largest regional supplier of natural gas to Ontario was Western Canada, which supplied 2.0 Bcfd on an average annual basis.

ICF projects that flows from Western Canada into Ontario will decline in the medium-term and begin to grow slowly starting in 2020, reaching 1.4 Bcfd by 2025. There will be another noteworthy increase in flows from Western Canada after 2031 as power sector gas demand increases mainly due to nuclear retirements.

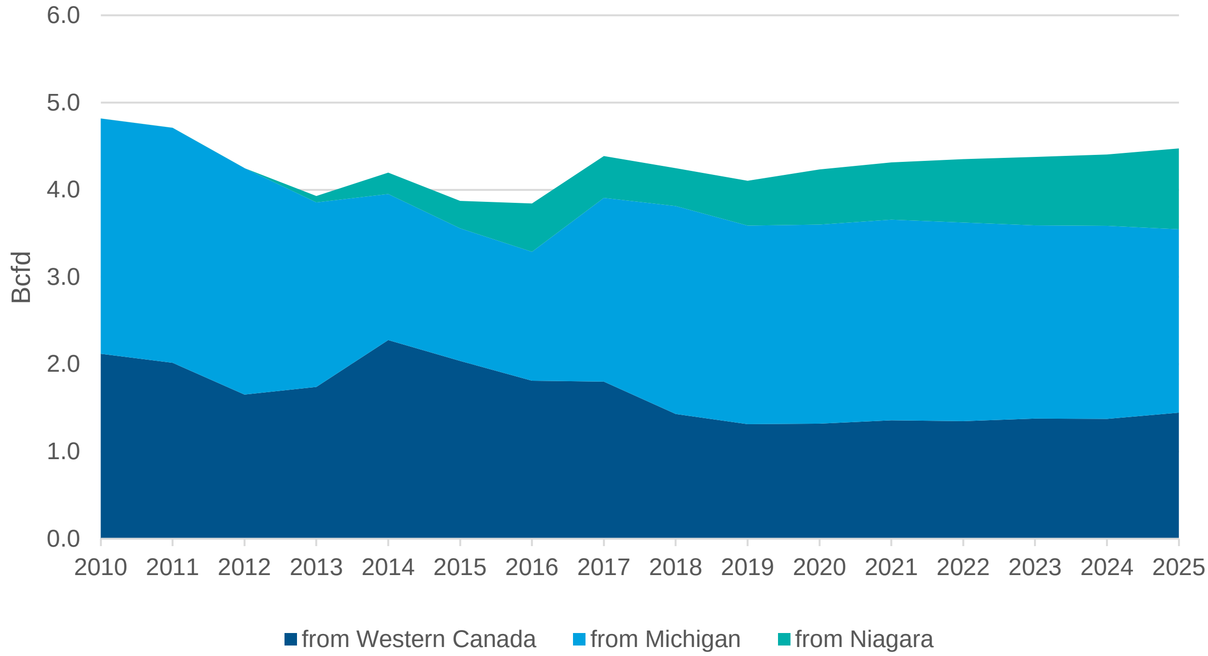
The second biggest source of natural gas for Ontario is Michigan, which in turn sources its gas from the Midcontinent, Rockies, and increasingly the Marcellus/Utica supply region. In 2015, 1.5 Bcfd flowed from Michigan into Ontario. The supply from Michigan is projected to reach 2.4 Bcfd in 2018 and will remain relatively stable near 2.2 Bcfd until 2025.

In recent years Marcellus/Utica gas has also been flowing northbound on the Tennessee and National Fuel pipeline systems to supply Ontario via the border crossing at Niagara, New York. By 2025 Ontario will receive 33 percent of its supplies from Western Canada, 47 percent via Michigan, and 20 percent via Niagara. ICF does not anticipate development of the TransCanada South-to-North (SONO) Pipeline due to concerns about the economic viability of the project as well as concerns about ongoing environmental opposition to pipeline development in New York, including completion of the Constitution Pipeline. As a result, ICF's forecast does not include physical pipeline flows from New York into Ontario via the Iroquois Pipeline.[11]

[10] ICF's forecast includes several related carbon reduction initiatives (Renewable Natural Gas, Energy Efficiency, Liquid Natural Gas/Compressed Natural Gas, Combined Heat and Power) that are expected to reduce emissions by 10-12 Mt CO2e, refined fuel initiatives reduce emissions by 5-8 Mt CO2e, and a reduction of 3-5 Mt CO2e due to increasing fuel prices.

[11] See Appendix C for pipeline build assumptions included in ICF Base Case.

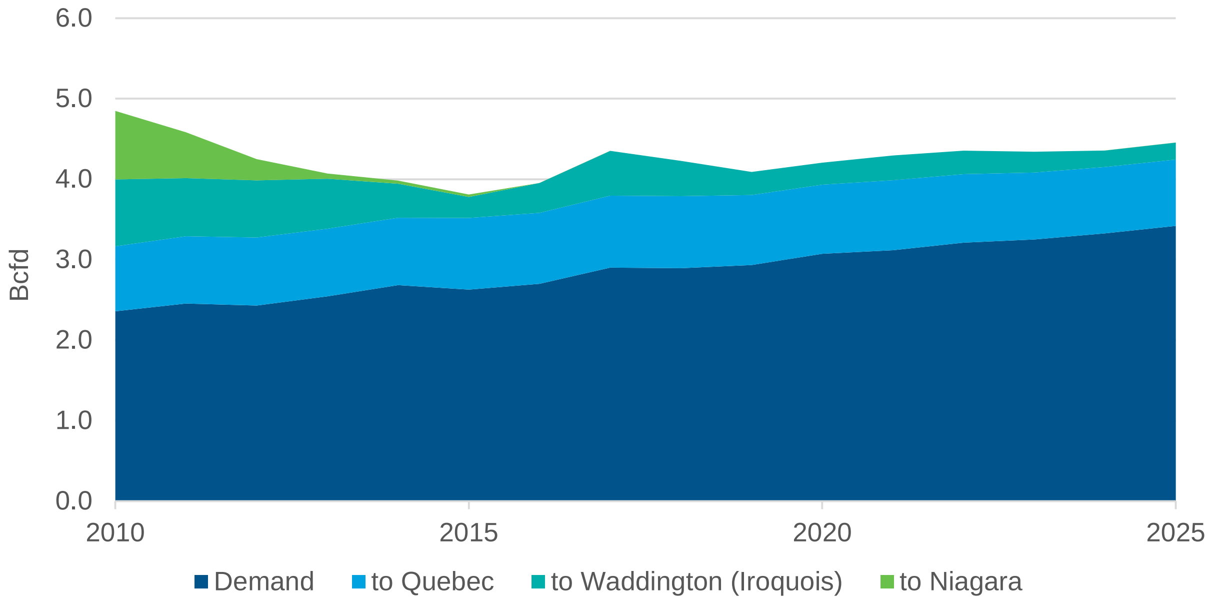
Exhibit 4-6: Ontario Natural Gas Supply, Annual In-bound Flows



Source: ICF GMM® Case

Another important factor that will influence pipeline flows in Ontario will be the growth in New York and New England peak winter demand. That demand growth is expected to be greater than the planned pipeline capacity additions from the Appalachian Basin directed toward that region. Flows from Ontario and Québec into the Northeastern U.S. will remain a critical component of peak period supply in the U.S. Northeast. Flows into Québec/Waddington are expected to peak in 2017 at 1.45 Bcfd, and decline through 2025.

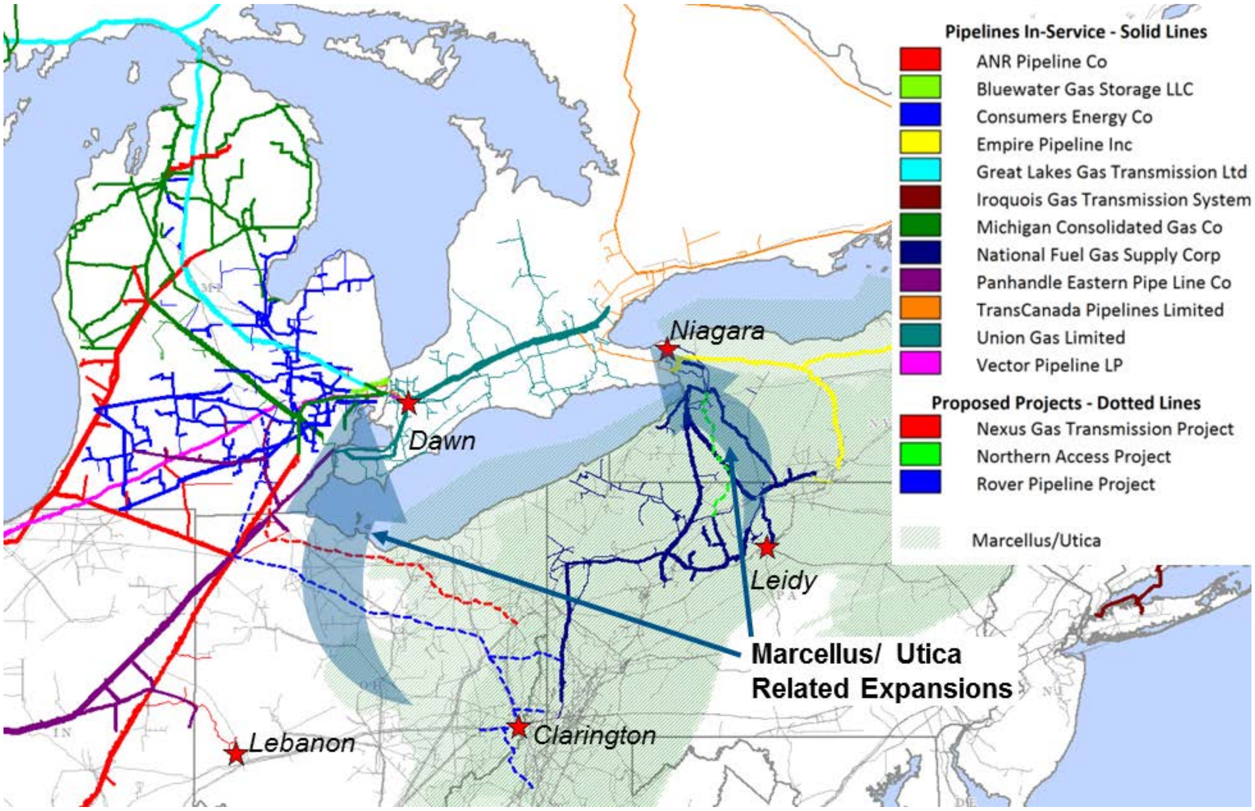
Exhibit 4-7: Annual Ontario Demand and Out-bound Flows



Source: ICF GMM®

Over the past 3 years, capacity expansions by Tennessee, Dominion, National Fuel, and Empire have made it easier to move Marcellus gas to Niagara and Parkway. Out of Michigan, there is approximately 789 MMcfd of contracted capacity in Ontario on the Great Lakes pipeline, 167 MMcfd of capacity on Panhandle Eastern, and 1,081 MMcfd on the Vector pipeline. If completed, new pipelines proposed by Spectra Energy and DTE Energy (NEXUS) and Energy Transfer Partners (Rover) would allow additional Marcellus and Utica production to move to Dawn. Capacity expansions within Ontario will also allow greater access to Marcellus/Utica supplies.

Exhibit 4-8: Marcellus/Utica Flows into Ontario



Sources: ICF, ABB Velocity Suite

Countering increased flows from the Marcellus/Utica region, ICF anticipates decreased flows from Western Canada due to TransCanada's Energy East pipeline project, which is included in ICF's base case pipeline assumptions. If approved, TCPL's Energy East project would remove about 1.2 Bcfd of capacity from service on the Mainline from Alberta to eastern Ontario. In conjunction with the Energy East project, TCPL also proposes to add some new capacity in eastern Ontario (Eastern Mainline Expansion), though net capacity into Ontario would be below what is currently available. This could put a strain on the supply infrastructure in Ontario since during two of the last three winters, all of the current capacity was used on peak winter days.

ICF's Pipeline Buildout Assumptions are included in Appendix C.

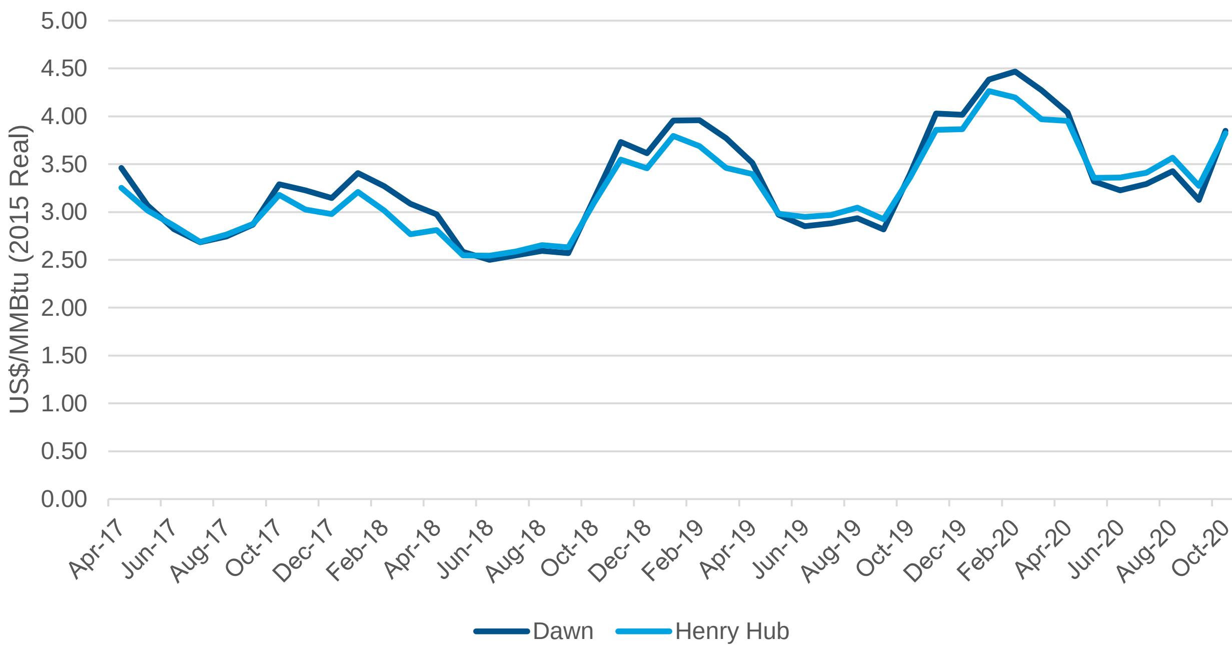
4.3 Implications to Ontario Storage Values

The North American gas markets are in a period of transition, going from being over-supplied and possessing low seasonal gas spreads to a market that is expected to be driven by rapidly growing gas demand and more volatility. As the market shifts, the seasonal value of natural gas, which is highly related to natural gas price trends, is expected to recover sharply over prior year levels.

In a declining price environment the difference between summer and winter prices is narrower than what it would be in flat or rising price scenario. Indeed, the declining price trends of the past several years has resulted in low values of seasonal natural gas in storage as the annual Henry Hub price declined by an average of $0.40 per MMBtu per year since 2010.

ICF's July 2016 Base Case natural gas price forecasts for Henry Hub and Dawn used in this analysis are shown in Exhibit 4-9 below.

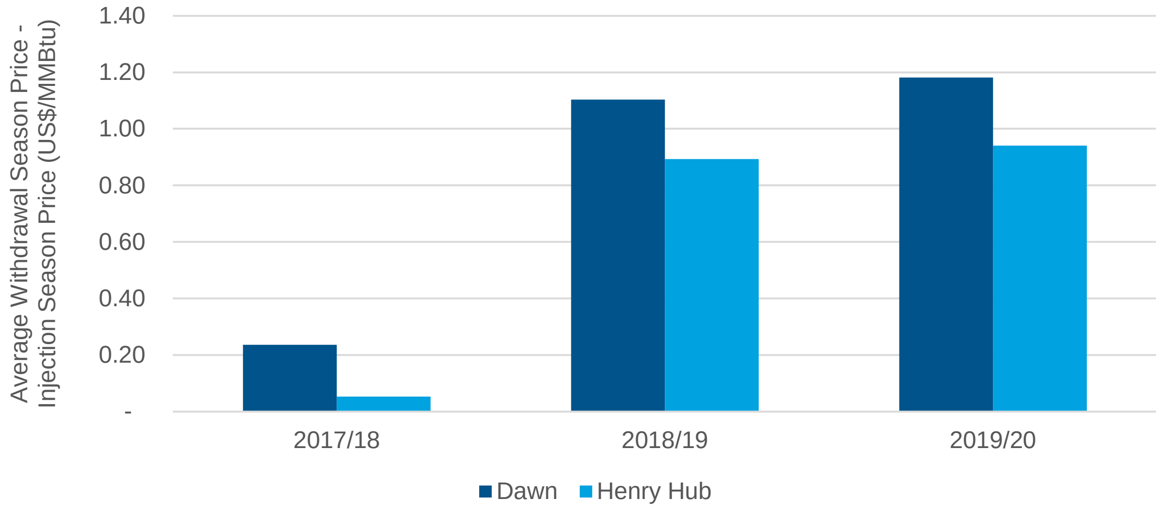
Exhibit 4-9: ICF's April 2016 Base Case Monthly Gas Price (US$) Forecast for Henry Hub and Dawn



Source: ICF Gas Market Model

ICF expects that rising natural gas prices will be supportive of seasonal price differentials over the next few years. In 2018/19, the seasonal value of gas at Dawn is expected to be $1.10 per MMBtu, rising to $1.18 per MMBtu in 2019/20. Due to higher seasonality in prices, the seasonal value of gas at Dawn is also expected to average $0.21 per MMBtu higher than the seasonal value of gas at Henry Hub.

Exhibit 4-10: Seasonal Gas Price (US$) Spread for Dawn and Henry Hub



Sources: ICF GMM® Case

In addition to an increase in seasonal values of natural gas, ICF also expects that the tighter gas market will exhibit increased gas price volatility, which can further increases the value of holding natural gas storage.

5. Value of Incremental Storage to Enbridge Gas

5.1 Approach

ICF has used the analysis of North American and Ontario natural gas markets, combined with the assessment conducted by Enbridge on the company's gas supply portfolio costs, to assess the impact of changes in natural gas storage capacity held by the company on the utility's overall gas supply portfolio cost.

The analysis was conducted in three steps:

1) ICF developed a series of alternative natural gas market scenarios reflecting differences in weather corresponding to Enbridge planning scenarios for Budgeted Weather, Colder than Budgeted Weather, and Warmer than Normal Weather.
2) ICF specified a series of alternative storage capacity and cost scenarios, and Enbridge used the Enbridge SENDOUT© model to evaluate total supply portfolio costs for each weather scenario, storage capacity scenario, and storage cost scenario.
3) ICF used the results of the Enbridge SENDOUT© analysis of supply portfolio costs to evaluate the impact of changes in natural gas storage capacity on Enbridge supply portfolio costs.

Each of these steps is described in more detail below.

5.1.1 Alternative Weather Scenarios

ICF used its April 2016 Gas Market Model (GMM) Base Case as the starting basis for its evaluation of the North American natural gas markets and Enbridge's gas storage operations. The GMM is an internationally recognized model of the North American gas market that includes projections for natural gas demand by sector, conventional and unconventional natural gas resources, production costs, and other major gas market developments, such as potential Liquefied Natural Gas (LNG) exports. The GMM projects monthly natural gas demand, supply, and prices for more than 120 regions and is a general equilibrium market model. The model is described in more detail in Appendix D. ICF used the GMM to conduct sophisticated analysis of the potential impacts and risks associated with alternative weather scenarios on natural gas demand and prices.

ICF used the GMM to develop three alternative price scenarios reflecting Enbridge's planning scenarios for Budgeted Weather, Colder than Budgeted Weather, and Warmer than Budgeted Weather.

This analysis is used to determine the value of storage capacity during a variety of weather conditions, such as the weather observed during the winter of 2013/14, which drove citygate prices outside of the producing regions to extremely high levels. Each weather scenario is based on the 3-year time period from April 2017 through March 2020.

For each weather scenario, Enbridge's daily load profile includes the company's peak day design criteria, which includes 18 separate peak days that are designed to mimic the coldest temperatures expected over the winter season.[12] Enbridge's Peak Design Day is based on a 1 in 5 recurrence interval derived from a lognormal distribution of Heating Degree Days (HDDs).

In order to evaluate the impact of colder than normal and warmer than normal weather on market demand and prices, ICF ran 85 cases of actual 3-year weather patterns in the GMM to assess the potential impact of weather on demand and prices in order to project demand and gas prices.

The use of actual weather scenarios is important for assessing the actual range of impacts due to the range of positive and negative correlations between weather patterns in different regions of North America. This weather sensitivity analysis forms the basis needed to evaluate the company's gas storage operations and the impact of weather volatility on natural gas prices and basis at the natural gas market centers considered important by Enbridge.

The three Enbridge weather scenarios (Colder, Budgeted, and Warmer) were constructed to best approximate Enbridge's HDD forecast for each of its weather planning scenarios. Each of these three weather scenarios were crafted from an average of four unique weather cases selected from the larger set of 85 weather cases. These four weather cases for each scenario were selected to develop a composite scenario that most closely aligned with Enbridge's three planning scenarios.

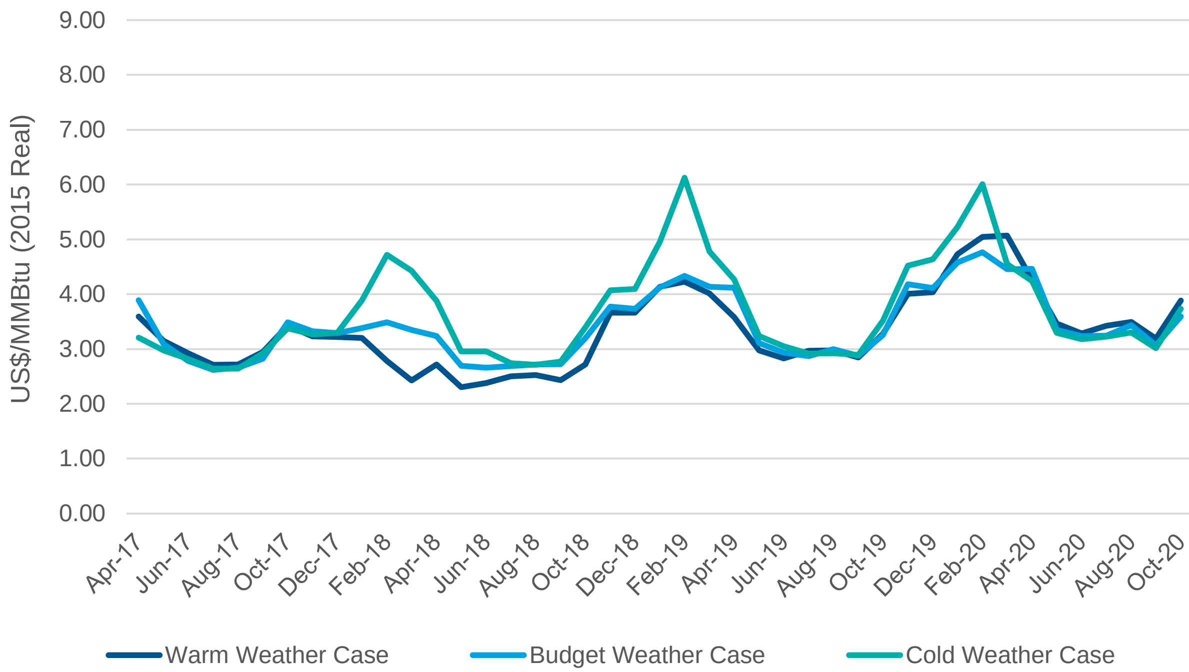
Enbridge's Budgeted Weather scenario assumptions are determined by the company's Economics and Business performance department, which utilizes an OEB approved methodology to determine the level of HDDs to be used in gas supply planning. For the purpose of this analysis, Enbridge then developed a Colder than Budgeted and Warmer than Budgeted weather scenario. The Colder than Budgeted weather scenario reflects a winter with daily average weather 10 HDDs colder than the Budgeted weather scenario. The Warmer than Budgeted scenario reflects a winter with daily average weather 10 HDDs warmer than the budgeted weather conditions. The three weather scenarios are summarized below:

- The **Colder than Budgeted Weather Scenario** had a target of 3,373 HDDs at Toronto. ICF selected the three year weather period starting in 1933 (3,368 HDDs), 1942 (3,335 HDDs), 1969 (3,403 HDDs), and 1977 (3,403 HDDs) to construct the aggregated Cold Weather Case. These four ICF weather cases had an average of 3,377 HDDs.
- The **Budgeted Weather Scenario** had a target of 2,835 HDDs at Toronto. ICF selected the three year weather period starting in 1936 (2,822 HDDs), 1948 (2,824 HDDs), 1953 (2,911 HDDs), and 1992 (2,825 HDDs) to construct the aggregated Budget Weather Case. These four ICF weather cases had an average of 2,846 HDDs.
- The **Warmer than Budgeted Weather Scenario** had a target of 2,665 HDDs at Toronto. ICF selected the three year weather period starting in 1952 (2,706 HDDs), 1997 (2,682

[12] Enbridge Gas Distribution 2017 Rate Case Application EB-2016-0215, Exhibit D1

HDDs), 1999 (2,717 HDDs), and 2015[13] (2,510 HDDs) to construct the aggregated Warm Weather Case. These four ICF weather cases had an average of 2,654 HDDs.

Exhibit 5-1: Dawn Prices (US$) Under the Three Enbridge Weather Scenarios



Source: ICF Gas Market Model

5.1.2 Alternative Storage Scenarios

The resulting commodity price and demand outlooks across the Colder than Budgeted, Budgeted, and Warmer than Budgeted weather cases were provided to Enbridge by ICF and then used by Enbridge to assess the impact of alternative storage scenarios on Enbridge natural gas supply portfolio costs using the Enbridge SENDOUT© model.

The SENDOUT© analysis was conducted for five different levels of storage capacity specified by ICF:

1) Base Case storage capacity: 114 Bcf
2) Base Case Storage Capacity plus 5 Bcf
3) Base Case Storage Capacity plus 10 Bcf
4) Base Case Storage Capacity plus 15 Bcf
5) Base Case Storage Capacity plus 20 Bcf

The Base Case capacity includes Enbridge gas storage capacity, plus capacity currently contracted from third party storage providers. For each alternative storage scenario ran in

[13] The 2015 weather case uses a 20 year weather average (1991-2010) for the second and third year of weather data.

SENDOUT©, Enbridge added five Bcf of incremental storage capacity. For the purposes of this analysis, Enbridge assumed that the gas storage would be available at or near Dawn.[14]

5.1.3 Incremental Storage Costs

The cost of the incremental storage capacity added to the Base Case storage levels were based on currently estimated costs of contracting gas storage capacity from nearby storage providers. Given the potential volume of incremental storage capacity, these costs were considered to represent a floor, or minimum cost, on prices for incremental storage capacity.

In order to evaluate the impact of a significant increase in storage costs, Enbridge also replicated the analysis with storage costs 50 percent above the Base Case storage costs. The storage cost estimate of 50 percent above the Base Case costs was chosen as a reasonable High Storage Cost scenario based on an assessment of the potential impact of changes in natural gas markets on the seasonal value of natural gas held in storage.

For each additional five Bcf of storage capacity, Enbridge included a one percent increase in the capacity costs from the Base and High Storage Cost capacity estimates in the SENDOUT© Model scenario, reflecting a modest impact of the increase in demand for storage capacity on storage costs.

The costs of incremental storage for the Base Case and High Storage Cost Case are shown in Exhibit 5-2.

Exhibit 5-2: Incremental Storage Costs Used in Enbridge SENDOUT© Modeling

	Base Case	High Storage Cost Case
Capacity Cost ($/10^3 M3/Month)	CAD$2.99[15]	CAD$4.48
Rate - Injection ($/10^3 M3)	CAD$0.23	CAD$0.23
Rate - Withdrawal ($/10^3 M3)	CAD$0.23	CAD$0.23
Fuel - Injection (%)	0.60%	0.60%
Fuel - Withdrawal (%)	0.60%	0.60%
Carrying Cost (% per Year)	7.81%	7.81%

5.1.4 Pipeline Capacity and Capacity Costs

The Enbridge SENDOUT© Model results and corresponding analysis were based on the Company's currently projected natural gas pipeline portfolio.[16] No adjustments were made to Enbridge's pipeline contract portfolio, gas storage targets, or spot gas purchasing guidelines to

[14] For the SENDOUT© analysis, Enbridge has assumed that new storage is available at or near Dawn and does not require incremental pipeline capacity. Hence, the Enbridge SENDOUT© Model analysis does not include any changes to the upstream transportation portfolio, resulting in fixed transportation costs across all scenarios.

[15] A 1 percent increase in storage capacity costs was added for each additional 5 Bcf tranche of storage capacity.

[16] Portfolio assumptions correspond to Enbridge's contracts in place as of the time of analysis for the forecast period of April 2017 to October 2020, which align with the portfolio assumptions underpinning the 2017 Rate Application (EB-2016-0215).

reflect the change in gas storage capacity and peak period storage deliverability. Gas supply purchases reflect the lowest cost source of natural gas supply consistent with the availability of contracted pipeline capacity and gas storage operational targets. Generally, the changes in gas supply purchases due to the changes in storage capacity and deliverability are reflected in changes in natural gas purchases at Dawn, rather than changes in pipeline deliveries.

5.2 Projected Impact of Incremental Storage Capacity on Enbridge Gas Supply Portfolio Costs

ICF evaluated the results of Enbridge's SENDOUT© Model runs to determine the value of incremental natural gas storage capacity for each of the five levels of contracted storage capacity for each of the three weather scenarios, using two different storage cost scenarios.

5.2.1 Reference Storage Costs

The results of the SENDOUT© analysis for each Weather scenario that are based on the assumption that storage costs would remain consistent with costs currently available in the market are shown in Exhibit 5-3[17]. Exhibit 5-4 illustrates the impact of the increase in storage capacity on Enbridge supply portfolio costs for these scenarios.

5.2.2 50 Percent Higher Storage Costs

The results of the SENDOUT© analysis for each Weather scenario that are based on the assumption that storage capacity costs will increase by 50 percent from current costs are shown in Exhibit 5-5, with an additional 1 percent increase in storage capacity costs for each storage increment of 5 Bcf. The storage cost estimate of 50 percent above the Base Case costs was chosen as a reasonable High Storage Cost scenario based on an assessment of the potential impact of changes in natural gas markets on the seasonal value of natural gas held in storage.

Exhibit 5-6 illustrates the impact of the increase in storage capacity on Enbridge supply portfolio costs for these scenarios.

5.2.3 Summary

In all of the scenarios, the increase in storage capacity allows Enbridge to purchase additional lower cost natural gas supply during off-peak periods for use during the winter when prices typically are higher.

[17] Storage costs include an additional 1 percent increase in storage capacity costs for each additional storage increment of 5 Bcf.

Exhibit 5-3: Average Annual Impact of Incremental Storage Capacity on Enbridge Supply Portfolio Costs: Current Storage Capacity Costs (Million CAD$)

Average Annual Supply Portfolio Costs by Case for the Three Year Period from April 2017 to March 2020 Reference Storage Costs					
(CAD$Millions)	Colder than Budgeted Weather Scenario	Budgeted Weather Scenario	Warmer than Budgeted Weather Scenario	Change from Budgeted (Colder)	Change from Budgeted (Warmer)
Total Supply Portfolio Costs					
Existing Storage Capacity	2,152.0	1,800.5	1,686.6	351.5	-113.9
Plus 5 Bcf	2,139.8	1,797.3	1,683.7	342.4	-113.6
Plus 10 Bcf	2,127.6	1,794.4	1,681.0	333.2	-113.3
Plus 15 Bcf	2,115.4	1,791.5	1,678.5	323.9	-113.0
Plus 20 Bcf	2,104.4	1,788.8	1,678.6	315.6	-110.2
Gas Supply Costs					
Existing Storage Capacity	1,610.6	1,258.9	1,144.8	351.7	-114.1
Plus 5 Bcf	1,592.6	1,250.0	1,136.1	342.6	-113.9
Plus 10 Bcf	1,574.5	1,241.3	1,127.6	333.2	-113.7
Plus 15 Bcf	1,556.3	1,232.6	1,119.2	323.7	-113.4
Plus 20 Bcf	1,539.4	1,223.9	1,113.3	315.4	-110.7
Storage Costs					
Existing Storage Capacity	27.9	28.1	28.3	-0.2	0.2
Plus 5 Bcf	33.7	33.8	34.1	-0.1	0.3
Plus 10 Bcf	39.6	39.6	40.0	0.0	0.3
Plus 15 Bcf	45.5	45.4	45.9	0.1	0.5
Plus 20 Bcf	51.5	51.4	51.8	0.2	0.4
Transport Costs					
Existing Storage Capacity	513.5	513.5	513.5	0.0	0.0
Plus 5 Bcf	513.5	513.5	513.5	0.0	0.0
Plus 10 Bcf	513.5	513.5	513.5	0.0	0.0
Plus 15 Bcf	513.5	513.5	513.5	0.0	0.0
Plus 20 Bcf	513.5	513.5	513.5	0.0	0.0

Exhibit 5-4: Average Annual Change in Enbridge Supply Portfolio Costs From Incremental Storage Capacity: Current Storage Capacity Costs (Million CAD$)

Average Annual Impact of Incremental Supply Portfolio Costs by Case for the Three Year Period from April 2017 to March 2020 Reference Storage Costs			
(CAD$Millions)	Colder than Budgeted Weather Scenario	Budgeted Weather Scenario	Warmer than Budgeted Weather Scenario
Total Supply Portfolio Costs			
Existing Storage Capacity	2,152.0	1,800.5	1,686.6
Plus 5 Bcf	-12.3	-3.2	-2.9
Plus 10 Bcf	-24.4	-6.1	-5.5
Plus 15 Bcf	-36.7	-9.0	-8.0
Plus 20 Bcf	-47.6	-11.7	-8.0
Gas Supply Costs			
Existing Storage Capacity	1,610.6	1,258.9	1,144.8
Plus 5 Bcf	-18.1	-8.9	-8.7
Plus 10 Bcf	-36.1	-17.6	-17.2
Plus 15 Bcf	-54.3	-26.3	-25.6
Plus 20 Bcf	-71.3	-35.0	-31.5
Storage Costs			
Existing Storage Capacity	27.9	28.1	28.3
Plus 5 Bcf	5.8	5.7	5.8
Plus 10 Bcf	11.7	11.5	11.6
Plus 15 Bcf	17.6	17.3	17.6
Plus 20 Bcf	23.6	23.3	23.5
Transport Costs			
Existing Storage Capacity	513.5	513.5	513.5
Plus 5 Bcf	0.0	0.0	0.0
Plus 10 Bcf	0.0	0.0	0.0
Plus 15 Bcf	0.0	0.0	0.0
Plus 20 Bcf	0.0	0.0	0.0

Exhibit 5-5: Average Annual Impact of Incremental Storage Capacity on Enbridge Supply Portfolio Costs: 50 Percent Higher Storage Capacity Costs (Million CAD$)

Average Annual Supply Portfolio Costs by Case for the Three Year Period from April 2017 to March 2020 50 Percent Higher Storage Costs					
(CAD$Millions)	Colder than Budgeted Weather Scenario	Budgeted Weather Scenario	Warmer than Budgeted Weather Scenario	Change from Budgeted (Colder)	Change from Budgeted (Warmer)
Total Supply Portfolio Costs					
Existing Storage Capacity	2,152.0	1,800.5	1,686.6	351.5	-113.9
Plus 5 Bcf	2,142.3	1,799.9	1,686.3	342.4	-113.6
Plus 10 Bcf	2,132.7	1,799.5	1,686.1	333.2	-113.3
Plus 15 Bcf	2,123.1	1,799.2	1,686.2	323.9	-113.0
Plus 20 Bcf	2,114.7	1,799.1	1,688.9	315.6	-110.2
Gas Supply Costs					
Existing Storage Capacity	1,610.6	1,258.9	1,144.8	351.7	-114.1
Plus 5 Bcf	1,592.6	1,250.0	1,136.1	342.6	-113.9
Plus 10 Bcf	1,574.5	1,241.3	1,127.6	333.2	-113.7
Plus 15 Bcf	1,556.3	1,232.6	1,119.2	323.7	-113.4
Plus 20 Bcf	1,539.4	1,223.9	1,113.3	315.4	-110.7
Storage Costs					
Existing Storage Capacity	27.7	28.1	28.3	-0.4	0.2
Plus 5 Bcf	36.2	36.4	36.6	-0.1	0.3
Plus 10 Bcf	44.7	44.7	45.1	0.0	0.3
Plus 15 Bcf	53.2	53.1	53.6	0.1	0.5
Plus 20 Bcf	61.8	61.7	62.1	0.2	0.4
Transport Costs					
Existing Storage Capacity	513.5	513.5	513.5	0.0	0.0
Plus 5 Bcf	513.5	513.5	513.5	0.0	0.0
Plus 10 Bcf	513.5	513.5	513.5	0.0	0.0
Plus 15 Bcf	513.5	513.5	513.5	0.0	0.0
Plus 20 Bcf	513.5	513.5	513.5	0.0	0.0

Exhibit 5-6: Average Annual Change in Enbridge Supply Portfolio Costs Due To Incremental Storage Capacity: 50 Percent Higher Storage Capacity Costs (Million CAD$)

Average Annual Impact of Incremental Supply Portfolio Costs by Case for the Three Year Period from April 2017 to March 2020 50 Percent Higher Storage Costs			
(CAD$Millions)	Colder than Budgeted Weather Scenario	Budgeted Weather Scenario	Warmer than Budgeted Weather Scenario
Total Supply Portfolio Costs			
Existing Storage Capacity	2,152.0	1,800.5	1,686.6
Plus 5 Bcf	-9.7	-0.6	-0.3
Plus 10 Bcf	-19.3	-1.0	-0.4
Plus 15 Bcf	-29.0	-1.3	-0.4
Plus 20 Bcf	-37.3	-1.4	2.3
Gas Supply Costs			
Existing Storage Capacity	1,610.6	1,258.9	1,144.8
Plus 5 Bcf	-18.1	-8.9	-8.7
Plus 10 Bcf	-36.1	-17.6	-17.2
Plus 15 Bcf	-54.3	-26.3	-25.6
Plus 20 Bcf	-71.3	-35.0	-31.5
Storage Costs			
Existing Storage Capacity	27.7	28.1	28.3
Plus 5 Bcf	8.5	8.3	8.3
Plus 10 Bcf	16.9	16.6	16.8
Plus 15 Bcf	25.5	25.0	25.2
Plus 20 Bcf	34.1	33.6	33.8
Transport Costs			
Existing Storage Capacity	513.5	513.5	513.5
Plus 5 Bcf	0.0	0.0	0.0
Plus 10 Bcf	0.0	0.0	0.0
Plus 15 Bcf	0.0	0.0	0.0
Plus 20 Bcf	0.0	0.0	0.0

5.3 Impact of Incremental Storage Capacity on Enbridge Gas Supply Portfolio Costs

Under all of the weather, demand, and the reference storage cost scenarios that ICF evaluated, Enbridge is able to reduce total natural gas portfolio costs by increasing storage capacity under contract during the three year period from April 2017 through March 2020, except for the addition of 20 Bcf of storage capacity in the Warmer that Budgeted scenario with a 50 percent increase in storage costs.

Under the reference costs total supply portfolio costs are minimized by adding at least 20 Bcf of incremental storage capacity to the Enbridge supply portfolio in both the Colder than Budgeted and Budgeted Weather scenarios, while gas portfolio costs are minimized by adding 15 Bcf of storage capacity in the Warmer than Budgeted Weather scenario.

Under the scenario where storage capacity costs increase by 50 percent relative to existing levels, the Enbridge supply portfolio cost would still be minimized by adding at least 20 Bcf of storage capacity in the Colder than Budgeted scenario and Budgeted Weather scenario. Under the higher storage cost assumptions the Enbridge supply portfolio cost would be minimized by adding up to 15 Bcf of storage capacity.

The overall results of the three year period from April 2017 through March 2020 of all weather, demand, and storage cost scenarios are shown in Exhibit 5-7.

Exhibit 5-7: Average Annual Change in Total Gas Costs from Incremental Storage Capacity From Enbridge SENDOUT© Results (Million CAD$)

Average Annual Impact of Incremental Storage Capacity on Enbridge Supply Portfolio Costs for the Three Year Period from April 2017 to March 2020		
(CAD$Millions)	Reference Storage Costs	50 Percent Increase in Storage Costs
Colder than Budgeted Weather Scenario		
5 Bcf	-12.3	-9.7
10 Bcf	-24.4	-19.3
15 Bcf	-36.7	-29.0
20 Bcf	-47.6	-37.3
Budgeted Weather Scenario		
5 Bcf	-3.2	-0.6
10 Bcf	-6.1	-1.0
15 Bcf	-9.0	-1.3
20 Bcf	-11.7	-1.4
Warmer than Budgeted Weather Scenario		
5 Bcf	-2.9	-0.3
10 Bcf	-5.5	-0.4
15 Bcf	-8.0	-0.4
20 Bcf	-8.0	2.3

5.4 Conclusions and Recommendations

Based on the assessment of natural gas market trends, expected natural gas prices at Dawn, and the value of natural gas storage as part of the Enbridge overall supply portfolio, ICF's analysis of Enbridge's SENDOUT© results indicates that additional storage capacity across all scenarios but one would reduce the expected overall cost of the Enbridge gas supply portfolio.

The overall amount of incremental capacity that should be considered by Enbridge will depend on the cost of the incremental storage, and the level of importance Enbridge and its regulator place on minimizing the cost impacts of a colder than normal winter for its customers, relative to minimizing the long-term average cost.

The ICF recommendations are dependent on the cost of incremental storage capacity. If incremental storage costs increase by more than the 50 percent increase relative to existing levels assessed in this analysis, ICF would recommend additional analysis be undertaken to ensure that the benefits of increasing storage capacity will exceed the incremental costs of the storage capacity.

5.4.1 Value of Incremental Storage to Minimize Long-Term Average Costs

A strategy designed to minimize the total long-term cost of the Enbridge supply portfolio to consumers would be heavily weighted toward the Budgeted Weather scenario based on the expected distribution of the weather scenarios given the likelihood of either the Warmer or Colder than budgeted scenarios. Based on a weighting of 60 percent for the Budgeted Weather scenario, and 20 percent for both the Colder than Budgeted and Warmer than Budgeted weather scenarios:

- If the cost of additional storage capacity from third parties remains at or near current storage costs, ICF would recommend consideration of between and 20 Bcf of incremental storage capacity.
- If incremental storage costs increase by 50 percent relative to existing contracted storage costs, ICF would recommend consideration of about 20 Bcf of incremental storage capacity.

5.4.2 Value of Incremental Storage to Minimize Impacts of Colder than Budgeted Weather

A strategy designed to minimize the potential impact of a colder than normal winter on costs to Enbridge consumers would still weigh the Budgeted scenario most heavily, but would discount the Warmer than Budgeted scenario and over-weight the Colder than Budgeted scenario. The weighting of the different scenarios used to accomplish this objective is a policy judgement that will need to be made by Enbridge. For the purposes of this analysis, ICF has weighted the Colder than Budgeted Weather Scenario at 40 percent, the Budgeted Weather Scenario at 60 percent, and the Warmer than Budgeted Weather Scenario at 0 percent. Under this set of priorities:

- If the cost of additional storage capacity from third parties remains at or near current storage costs, ICF would recommend consideration of at least 20 Bcf of incremental storage capacity.
- An increase in incremental storage costs of 50 percent relative to existing contracted storage costs would not change the recommendation. ICF would recommend consideration of at least 20 Bcf of incremental storage capacity.

Exhibit 5-8: Average Annual Change in Total Gas Costs from Incremental Storage Capacity, Weighted by Weather Probability (Million CAD$)

Average Annual Weighted Average Impact of Incremental Storage Capacity on Enbridge Supply Portfolio Costs for the Three Year Period from April 2017 to March 2020					
(CAD$Millions)	Reference Storage Costs			50 Percent Increase in Storage Costs	
Scenario	Balanced Weighting	Cold Weather Weighting		Balanced Weighting	Cold Weather Weighting
Colder than Budgeted Weather Scenario	20%	40%		20%	40%
Budgeted Weather Scenario	60%	60%		60%	60%
Warmer than Budgeted Weather Scenario	20%	0%		20%	0%
Incremental Storage Capacity					
5 Bcf	-4.9	-6.8		-2.4	-4.3
10 Bcf	-9.7	-13.4		-4.6	-8.3
15 Bcf	-14.3	-20.0		-6.6	-12.4
20 Bcf	-18.2	-26.1		-7.8	-15.8

Appendix A: Summary Other LDC's Storage Operating Profile

A.1.1 Union Gas

Union Gas serves 1.4 million customers across Ontario and operates over 42,250 miles of natural gas transmission and distribution pipelines. The company's customer base is divided into a Northern and Southern region, each of which has different gas supply availability and utilization of the company's gas storage assets.

Union Gas owns and operates the Dawn Storage hub, one of the most liquid natural gas trading hubs in North America. Union Gas' storage operations include 20 gas fields with a working capacity of 152 Bcf and peak deliverability of 2.3 Bcfd. The Dawn Hub has pipeline interconnections with the Vector, Great Lakes, Panhandle, Michcon, and Bluewater transmission pipelines from Michigan in the west, and TransCanada's pipeline and Enbridge's gas distribution system in the east.

Union Gas' Gas Supply plan sets out to optimize the use of the company's contracted upstream pipeline capacity. To achieve this, the company uses a combination of pipeline agreements, gas supplies sourced from the Dawn hub, and storage capacity to fully meet forecasted annual demand. In order to develop its Gas Supply Plan, Union models all upstream transportation capacity and storage assets for integrated service across all areas as part of its 5 year supply plan.

Over the past several years, Union Gas has been de-contracting its most expensive gas supply sources in response to changing gas market conditions. During 2015/16, Union Gas let long-haul capacity contracts with Alliance Vector and TransCanada Pipelines expire. Reductions in pipeline capacity serving Union Gas' Northern areas would be replaced by the expanded backhaul capacity from Dawn to Empress.

To support increased flexibility and use of natural gas sourced from Dawn, Union Gas is undertaking several projects to expand deliverability within its pipeline distribution network. Included in these efforts are two projects, the Dawn to Parkway Expansion, and the contracting of new pipeline capacity with NEXUS pipeline for 149,755 Dth/d, effective November 1, 2017.

Storage usage criteria

Union Gas targets 95 Bcf of gas storage capacity to be used for in-Franchise customers, with 5 Bcf of that capacity available for short-term sales. Union Gas' Dawn gas storage operating criteria to support its winter demand needs includes the following:

- Required storage space is filled on October 31.
- Sufficient inventory at February 28 to meet the design day needs of sales service and bundled DP customers.
- Storage is empty on March 31 (except for 6 Bcf for integrity).

In addition, Union Gas includes the following gas storage capacity agreements:

- 14.5 Bcf of TCPL Storage Transportation Service and TCPL Dawn Diversions.
- 14.2 Bcf of TCPL STS Withdrawals in Winter Months to meet winter demand.
- 14.5 Bcf of Dawn delivered services as part of Union South Supply portfolio, which is 15 percent of the area total.

A.1.2 Gaz Métro

Gaz Métro serves over 195,000 residential customers across Quebec, while also providing natural gas to commercial and industrial users across the province. The company's customer base is heavily weighted toward large industrial and commercial customers.

Gaz Métro owns and operates a LNG Facility, the LSR facility in eastern Montreal. This facility is primarily used to serve customers not hooked up to the pipeline grid and supply LNG for transportation options. This facility has a capacity of 3 Bcf per year with a storage capacity of 25.2 million gallons.

The company does not own or operate its own gas storage facilities, rather it contracts storage capacity on nearby storage fields and contracts for storage capacity with Union Gas. Gaz Métro's contracted gas storage capacity and peak gas deliverability is show in Exhibit A-1 below.

Exhibit A-1: Gaz Métro storage capacity and deliverability

Gas Storage Source	Storage Capacity (Bcf)	Withdrawal Capacity (Dth/d)
LSR (daQ)	2.0	207,000
Pointe-du-Lac	0.9	44,000
Saint-Flavien	4.4	55,000
Union Gas	12.5	205,000
Total	19.8	511,000

Source: Gaz Metro Regulatory Filing - R-3879-2014 D-2015-177

A.1.3 Centra Gas Manitoba:

Centra Gas serves over 270,000 customers in Winnipeg and southern Manitoba[18]. Centra Gas customers use approximately 74 Bcf of natural gas during a year, of which nearly 100 percent are delivered from Alberta by a mainline transmission pipeline owned by TransCanada (TCPL).[19]

Centra Gas does not own or operate its own gas storage facilities. The company's current 7 year transportation & storage plan outlines a strategy to reduce the amount of Firm Transport Centra Gas holds on the TCPL system and to diversify its gas supply by utilizing gas storage options in the US Midwest via the ANR Pipeline system.

[18] http://www.pub.gov.mb.ca/pdf/reports/14-15.pdf
[19] https://www.hydro.mb.ca/corporate/facilities/manitoba_hydro_naturalgas.shtml

Storage usage criteria

Centra Gas holds contracts for 14.7 Bcf of storage capacity on the ANR pipeline system in Michigan. Storage gas is delivered from Michigan to the Centra Gas service territory in Manitoba via backhaul capacity on ANR Pipeline, Great Lakes Pipeline, and TransCanada Pipeline. The company's contracted storage facilities include:

- 7.7 Bcf of seasonal storage capacity that can be cycled once per year.
- 7.0 Bcf of annual storage with injects/withdrawals that can be cycled 1.4 times annually.
- Delivery capacity of 206,400 Dth/d in the winter season and an injection capacity of 84,000 Dth/d in the summer season.

To support its gas supply needs, Centra Gas holds seasonal pipeline capacity on ANR Pipeline, Great Lakes Pipeline, and TransCanada Pipeline. Pipeline capacity during the summer months includes:

- 50,500 Dth/day on Great Lakes from Emerson, Manitoba to Crystal Falls, MI.
- A firm transport (FT) agreement of 50,200 Dth/d from Crystal Falls to ANR Storage.
- An FT agreement of 7,000 Dth/d on ANR Pipeline from the ANR Joliet Hub, Illinois to ANR Storage in Michigan.

Pipeline capacity during the winter months includes:

- 224,363 Dth/d of FT capacity on Great Lakes from Crystal Falls, MI to Emerson, Manitoba.
- 204,363 Dth/d of FT capacity on ANR Pipeline from ANR Storage to Crystal Falls, MI.
- 40,000 Dth/d of FT capacity on ANR Pipeline from ANR Storage in Michigan to the ANR Joliet Hub, Illinois.

A.1.4 Consumers Energy:

Consumer Energy serves 1.7 million customers across Michigan's Lower Peninsula. Approximately 50 percent of the company's customers are in Detroit, with other major operating areas including Bay City, Flint, Jackson, Kalamazoo, Lansing, Macomb, Midland, Royal Oak, Saginaw and Warren. The company owns and operates over 29,000 miles of distribution and transmission pipelines as well as a network of gas storage facilities. Consumers Energy owns and operates 16 gas storage facilities with a working capacity of 150 Bcf.[20]

Consumers Energy has access to multiple supply areas. To take advantage of the changing cost and availability of gas supplies, the company has increased purchases of gas from the Midwest and has decreased its reliance on Gulf Coast area gas supplies.

Consumer Energy's gas supply plan is to purchase 75 percent of its annual gas needs during the summer months, injecting the balance into its gas storage fields to meet peak winter needs. The company will meet 50 percent of winter demand utilizing its gas storage fields, with the remainder using its Firm Transportation agreements and citygate purchases.

[20] http://www.dleg.state.mi.us/mpsc/gas/storage.htm

Storage usage criteria
Consumer Energy plans to meet its gas supply needs by reaching a gas storage targets of 175.6 Bcf by end of October and having a remaining balance of 70.1 Bcf by March. Throughout the year the company may make gas purchase adjustments in order to meet its targeted storage levels.

A.1.5 DTE Gas

DTE Gas serves 1.2 million customers across the Upper and Lower Peninsula of Michigan. DTE Gas owns four gas storage fields in Michigan, with total working capacity of 135.1 Bcf. These fields are a mix of base-load and peaking facilities.

To meets its customers gas demand needs, DTE Gas holds 400,000 Dth/d of FT pipeline contracts during the winter and 330,000 Dth/d during the summer injection season. These gas supply purchases are supported by pipeline commitments on ANR, Great Lakes, and Panhandle Eastern. The company has also entered into an agreement to purchase additional gas supplies on Nexus, as well as utilizing local gas purchases.

Storage usage criteria
DTE Gas has a total gas storage field capacity of 135.1 Bcf, with 71.9 Bcf allocated to GCR & GCC customers, and 5 Bcf used for contingency space.[21] The company operates its gas storage facilities based on the following operating criteria:

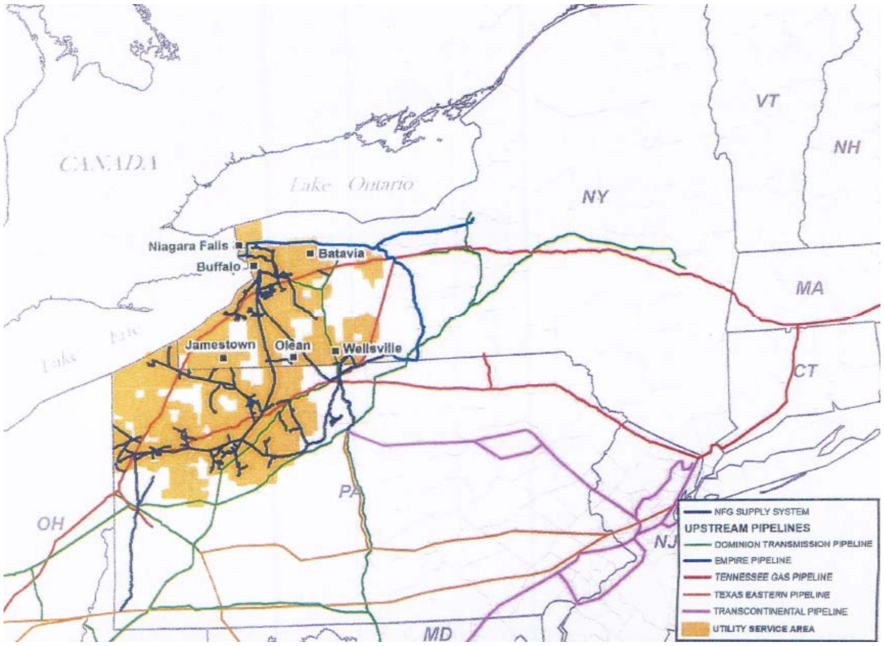
- End of injection season target of 135.1 Bcf, 71.9 Bcf for its GCR & GCC customers.
- Minimum Storage Balances of at the end of the month:
  - January: 48.9 Bcf (25.3 Bcf for GCR/GCC).
  - February: 24.1 Bcf (10.7 Bcf for GCR/GCC).
  - March: 5 Bcf (3.2 Bcf for GCR/GCC).

A.1.6 National Fuel Gas Distribution

National Fuel Gas Distribution Corporation sells natural gas to more than 740,000 customers, with 540,000 customers in New York and 200,000 customers in Pennsylvania. National Fuel Gas owns and operates 2,877 miles of gas transmission and distribution pipelines. The company also owns and operates 28 natural gas storage facilities with a capacity of 78 Bcf. Exhibit A-2 below shows the company's service area and interstate pipelines serving the area.

[21] National Fuel Gas Distribution's New York regulatory filing U-16999

Exhibit A-2: National Fuel Gas Distribution Service areas and pipeline interconnects



Source: National Fuels Gas Distribution Regulatory Filings - 16-G-0257, exhibit GSA

New York

National Fuel Gas (NY) sourcing strategy is based on a five year planning horizon to assess supply sources and needed capacity. Currently, the company secures its gas supply via upstream capacity on Dominion, Empire, Honeoye Storage Corporation, Tennessee, and Transco, as well as purchasing roughly 5 percent of its supply needs from local production. Over the past several years, gas supply purchases have shifted from sourcing gas supplies at Dawn via TCPL capacity to source gas from the Marcellus/Utica. National Fuel Gas (NY) has two remaining FT agreements with TransCanada.[22]

Storage usage criteria

The Company's gas storage portfolio includes storage capacity near its customers on National Fuel Gas and Dominion pipeline systems. These storage assets are used to meet peak winter demand, improve pipeline utilization levels over the summer, and act as a hedge against winter price volatility.[23] The company plans to meet 39 percent of its winter season demand from gas storage deliveries and 61 percent via pipeline deliveries.

[22] Two TransCanada FT agreements are for 10,141 Dth/d and 14,970 Dth/d of capacity and will terminate on October 31, 2017 and on October 31, 2020.
[23] Ventyx SENDOUT II is used to evaluate the economic impact of monthly supply options

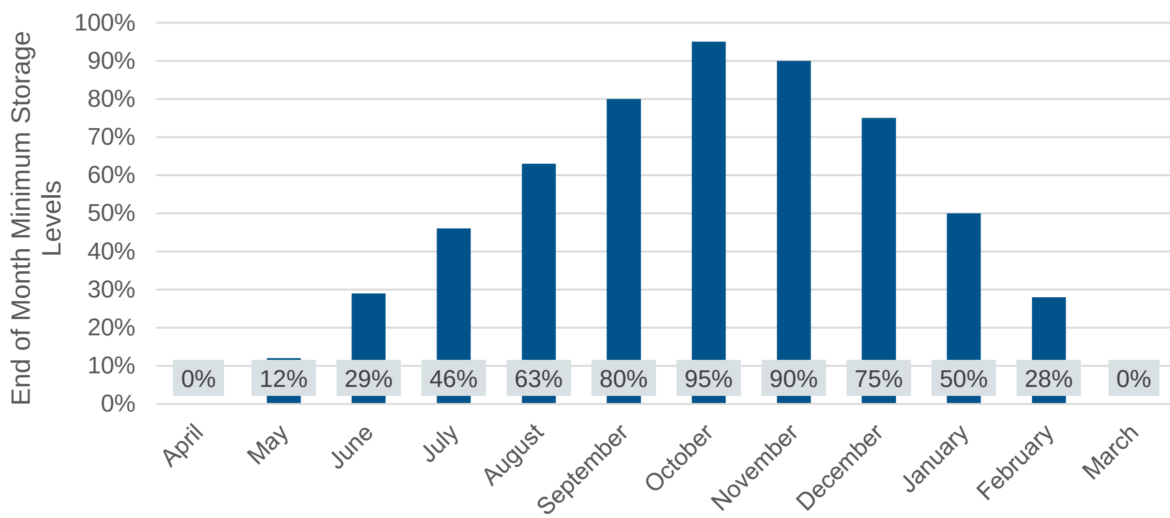
Pennsylvania

Within its Pennsylvania service area, National Fuel Gas (PA) secures its gas supply via upstream capacity on Columbia, Texas Eastern (TETCO[24]), and Tennessee as well as direct purchases from National Fuel Gas SC. Due to the increase in Marcellus shale gas supplies, the company has increased its local sourcing from 12 percent in 2009 to 24 percent in 2016.

Storage usage criteria

To ensure its ability to meet peak day demand, National Fuels (PA) maintains the minimum storage levels detailed in Exhibit A-3 below.

Exhibit A-3: National Fuel Gas (PA) Gas Storage Level Requirements



Source: National Fuel Gas Distribution's Regulatory Filings - PA PUC R-2016-2521819

A.1.7 Peoples Gas

Peoples Gas serves 828,000 customers in an around the City of Chicago. The company owns and operates the Manlove Field with a capacity of 36.5 Bcf. This field accounts for 52 percent of the capacity of Peoples Gas' gas storage portfolio, with the remainder of capacity contracted with third parties ANR and Washington 10. The company also owns and operates an LNG facility as part of its Manlove Field complex. The company stores LNG in two tanks, which have a capacity of 12 million gallons, equivalent of 1 Bcf. Vaporized LNG is used to support peak day needs.

The company has firm transportation contracts on a variety of pipelines, including ANR Pipeline Company, Gulfstream Natural Gas System, Kinder Morgan Illinois Pipeline, and Vector Pipeline. In recent years Peoples Gas has been reducing the levels of contracted pipeline capacity and increasing its purchases of local gas supplies in the Chicago area.

[24] National Fuel (PA) recently added additional Firm Transport capacity on TETCO, increasing capacity from 10,000 Dth/d to 20,000 Dth/d to support peak demand

Peoples Gas uses several modelling forecasts as part of its gas supply planning process, including; a peak day forecast, a long-term gas requirements, and a gas sendout forecast as part of a Gas Dispatch Model that calculates a daily withdrawal requirements. These modelling efforts are designed to support the lowest cost of gas over an annual period.[25]

Storage usage criteria
Peoples Gas begins each season with established storage targets based on normal weather. These storage targets are flexible and are revisited throughout the season to account for weather, estimated customer-owned gas deliveries, and assumptions for other factors not precisely known when the storage plan was initially set.

Due to the characteristics of the Manlove field, which is an aquifer storage, the company does follow strict seasonal patterns of withdrawal and injections. Despite seasonal guidelines, there is significant flexibility in the daily sendout volumes.

A.1.8 Ameren (IL)

Ameren (IL) serves 816,000 natural-gas customers across central and southern Illinois. The company owns 18,200 miles of natural gas transmission and distribution, as well as 12 underground natural gas storage fields (5 aquifer reservoirs and 7 depleted gas reservoirs). These gas storage facilities support peak deliverability of 570,000 Dth/d from 24.2 Bcf of working storage capacity. In addition to on-system storage, the company also contracts for gas storage services with interstate pipelines.

The company's distribution systems is connected to 10 different interstate pipeline systems – Panhandle Eastern Pipe Line, Texas Eastern, Trunkline, Natural Gas Pipeline Company of America, Northern Border Pipeline, American Natural Resources Pipeline, Texas Gas Transmission, Mississippi River Transmission Company, Rockies Express Pipeline and Midwestern Gas Transmission Company – which allow for supply diversity gas purchases and the ability to meet demand on peak days.

Ameren Illinois uses a six-year planning horizon for its gas supply purchases and hedging practices. The primary goal of the company's planning process is to minimize price disruptions, using a layering approach for its gas purchases, which both reduces volatility and allows for the flexibility to respond to changes in the market place.

Storage usage criteria
Ameren's gas storage plan targets for its owned and contracted storage to be 100 percent full on November 15th. During the 2014-15 winter season, Ameren targeted a storage level of 36.5 Bcf in November, with 23.5 Bcf on company owned Storage assets. This level of storage capacity allows Ameren to meet approximately 50 percent of its normal winter requirements via gas storage withdrawals, providing a balance between storage withdrawals and purchased gas supply during the winter season.

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[25] People Gas' Regulatory Filings - Docket No. 14-0736, PGL Ex. 1.0

A core part of the company's gas storage plan is the use of leased storage. Ameren will vary leased storage activity in order to minimizing pipeline balancing penalties in response to changes in firm sales customer requirements.

Ameren's seasonal gas storage injection and withdrawal schedules are developed to ensure the storage facilities are able to provide adequate reliability, protect the integrity of the reservoir, and minimize the overall supply costs. The Company relies on operational experience, historical performance data, and models to ensure that maximum productivity is achieved from its storage fields.

A.1.9 Nicor Gas

Nicor Gas transports and stores natural gas for 129,000 commercial and industrial customers across northern Illinois. The company controls over 34,037 miles of natural gas transmission and distribution pipelines, and owns eight gas storage fields with a total storage capacity of 150 Bcf. The company also purchases contracted storage services from interstate pipelines. Nicor's on-system storage provides critical peak day, peak hour and durational supply.

Nicor's gas system is operated in a manner to maximize access to available pipeline deliveries and features high levels of firm contracting for gas supply purchases. The company possesses interconnects with 8 interstate pipeline systems – Natural Gas Pipeline Company of America, Midwestern Gas Transmission, Northern Natural, Panhandle Eastern, ANR, Northern Border, Alliance, and Horizon Pipeline – which provide significant flexibility in securing a variety of gas supplies.

Nicor uses a gas purchasing strategy that is based on the following four factors:

- Peak Design Day and monthly sendout requirements.
- The timing of monthly gas purchases (injection/withdrawals) to support an appropriate gas storage inventory and sufficient deliverability to meet a significant portion of daily and seasonal winter peak loads.
- Estimates for third party volume and system requirements to Nicor's gas storage assets.
- The mix of supply contracts in its portfolio based on the available price information and the need for system flexibility to adjust to changing conditions on a seasonal, monthly, and daily basis.

Nicor uses a variety of computer models and other analytical methods common to the industry to model seasonal and Peak Design Day Requirements for gas demand for its customers and third-party requirements on its natural gas systems.

Storage usage criteria

The company's storage usage plan is developed following the completion of Nicor's seasonal supply requirements. The level of baseload and daily purchases are established to address supply security concerns and mitigate price volatility, while affording flexibility to accommodate changes due to weather and third party activity.

Part of Nicor's gas storage plan is to ensure that aquifer performance is maintained and related aquifer pressures are able to meet peak, seasonal, and daily needs, via appropriate storage injection/withdrawal schedules. These schedules are established based on operational experience and historical aquifer performance data.

The company's gas storage usage plan is to have the on-system storage filled by November the 10th. The company's storage assets will be managed to ensure the assets are able to meet Peak Design Day withdrawal requirements through January 20th, and are still able to meet post-design day peak requirements through March 15th, while still meeting the seasonal withdrawal targets.

A.1.10 MidAmerican Energy

MidAmerican Energy is a large gas distributor, serving 733,000 customers across Iowa, Illinois, South Dakota and Nebraska. MidAmerican Energy's regulated Illinois Gas Distribution Company does not own or operate its own gas storage facilities. The company has access to multiple supply sources via the Northern Natural, NGPL, Northern Border, ANR, and Alliance pipeline systems.

The company's Peak Design Day gas supply includes the following breakout;

- 50 to 55 percent from FT gas supply purchases.
- 30 to 35 percent from withdrawals on leased storage facilities.
- 10 to 15 percent from peaking facilities (LNG).
- 0 to 10 percent from Citygate purchase.

Appendix B: Natural Gas Prices at Dawn for the Three Alternative Weather Scenarios

Exhibit B-0-1: Natural Gas Prices at Dawn for the Three Enbridge Weather Scenarios

US$/MMBtu	Warm Weather Case	Budget Weather Case	Cold Weather Case
April-17	3.60	3.89	3.21
May-17	3.15	3.09	2.97
June-17	2.92	2.78	2.82
July-17	2.71	2.62	2.64
August-17	2.72	2.66	2.64
September-17	2.94	2.82	2.92
October-17	3.43	3.49	3.37
November-17	3.23	3.32	3.26
December-17	3.22	3.29	3.29
January-18	3.20	3.38	3.89
February-18	2.78	3.49	4.72
March-18	2.43	3.35	4.43
April-18	2.72	3.24	3.88
May-18	2.30	2.70	2.95
June-18	2.38	2.66	2.96
July-18	2.50	2.69	2.74
August-18	2.52	2.72	2.71
September-18	2.43	2.73	2.77
October-18	2.71	3.20	3.39
November-18	3.66	3.77	4.07
December-18	3.66	3.73	4.09
January-19	4.14	4.12	4.96
February-19	4.23	4.33	6.13
March-19	4.02	4.14	4.78
April-19	3.58	4.12	4.27
May-19	2.97	3.11	3.24
June-19	2.83	2.93	3.05
July-19	2.97	2.87	2.92
August-19	2.97	3.00	2.92
September-19	2.85	2.88	2.89
October-19	3.28	3.26	3.52
November-19	4.01	4.18	4.52
December-19	4.04	4.11	4.63
January-20	4.73	4.58	5.23
February-20	5.04	4.77	6.01
March-20	5.07	4.45	4.55
April-20	4.26	4.46	4.24
May-20	3.47	3.34	3.30
June-20	3.28	3.24	3.18
July-20	3.42	3.24	3.22
August-20	3.49	3.44	3.30
September-20	3.19	3.06	3.02
October-20	3.88	3.59	3.73

Source: ICF GMM®

Appendix C: Assumptions behind ICF's Natural Gas Market Outlook – April 2016

Exhibit C-1: Pipelines in the Planning Stages near Ontario

Project(s)	From	To	Capacity (MMcfd)	Year
Capacity to Ontario from Outside the Province				
Rover/Nexus *	Marcellus/Utica	Vector Pipeline	1050	2017
Within Ontario				
TCPL Niagara Expansion 2016	Niagara/Chippawa	Parkway	380	2017
TCPL Vaughan Loop	Parkway	Maple	445	2017
Maple Compression	Parkway	Maple	438	2017
Energy East Conversion	Western Ontario	Quebec	-1140	2019
TCPL Eastern Mainline Expansion	Parkway	Iroquois/Waddington	672	2019
To Northeast/New England				
Dominion New Market Expansion	Marcellus Interconnects	Upstate New York	112	2016
National Fuel Northern Access	Pennsylvania	Western New York	497	2017
Atlantic Bridge	Marcellus	New England & Maritimes	300	2017
Constitution	Northeast Pennsylvania	Wright, New York	650	2018 (inactive)
Wright Interconnect	Schoharie County, NY	Into Iroquois and TGP	650	2018 (inactive)
South to North	Wright, New York	Waddington, New York	650	2018 (inactive)
Access Northeast	Marcellus	New England	500 (+400 Peak shaving capacity)	2018
Diamond East	Marcellus	New Jersey	1,000	2018
Penneast Pipeline	Marcellus Interconnects	New Jersey	1,000	2018
Millennium Upgrade	Marcellus Interconnects	New York	200	2018
PNGTS C2C Expansion	Quebec	New England	130	2017

* Where there are multiple projects competing to add capacity on the same path, the capacity shown is the total amount expected by 2018.

Source: ICF, compiled from various public announcements.

Appendix D: ICF's Gas Market Model (GMM)

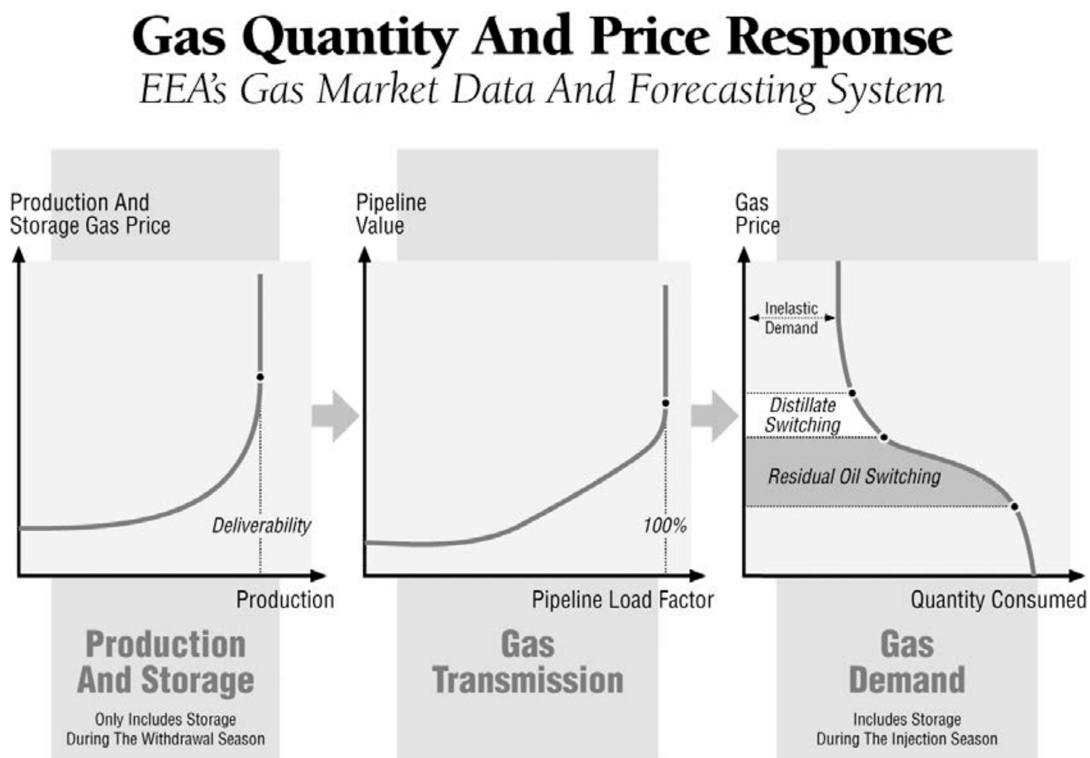
ICF's Gas Market Model (GMM) is an internationally recognized modeling and market analysis system for the North American gas market. The GMM was developed in the mid- 1990s to provide forecasts of the U.S. and Canada natural gas market under different assumptions. In its infancy, the model was used to simulate changes in the gas market that occur when major new sources of gas supply are delivered into the marketplace. Subsequently, GMM has been used to complete strategic planning studies for many private sector companies. The different studies include:

- 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 model has been widely used by a number of institutional clients and advisory councils, including Interstate Natural Gas Association of America (INGAA), which has relied on the GMM for multiple studies over the past ten years. 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, and the 2010 Natural Gas Market Review for the Ontario Energy Board.

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 scenario. 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 (Figure D-1) 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 curves. Unlike other commercially available models for the gas industry, ICF does significant backcasting (calibration) of the model's curves and relationships on a monthly basis to make sure that the model reliably reflects historical gas market behavior, instilling confidence in the projected results.

Figure D-1: ICF's Gas Market Data and Forecasting System



There are nine different components of GMM, as shown in Figure D-2. 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 in gas transmission. This is important to maintaining model credibility and confidence of results.

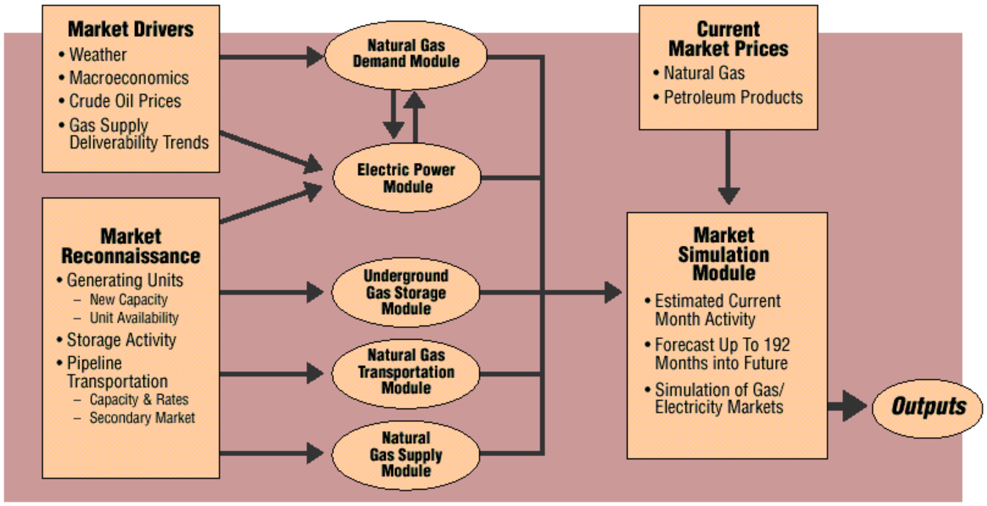
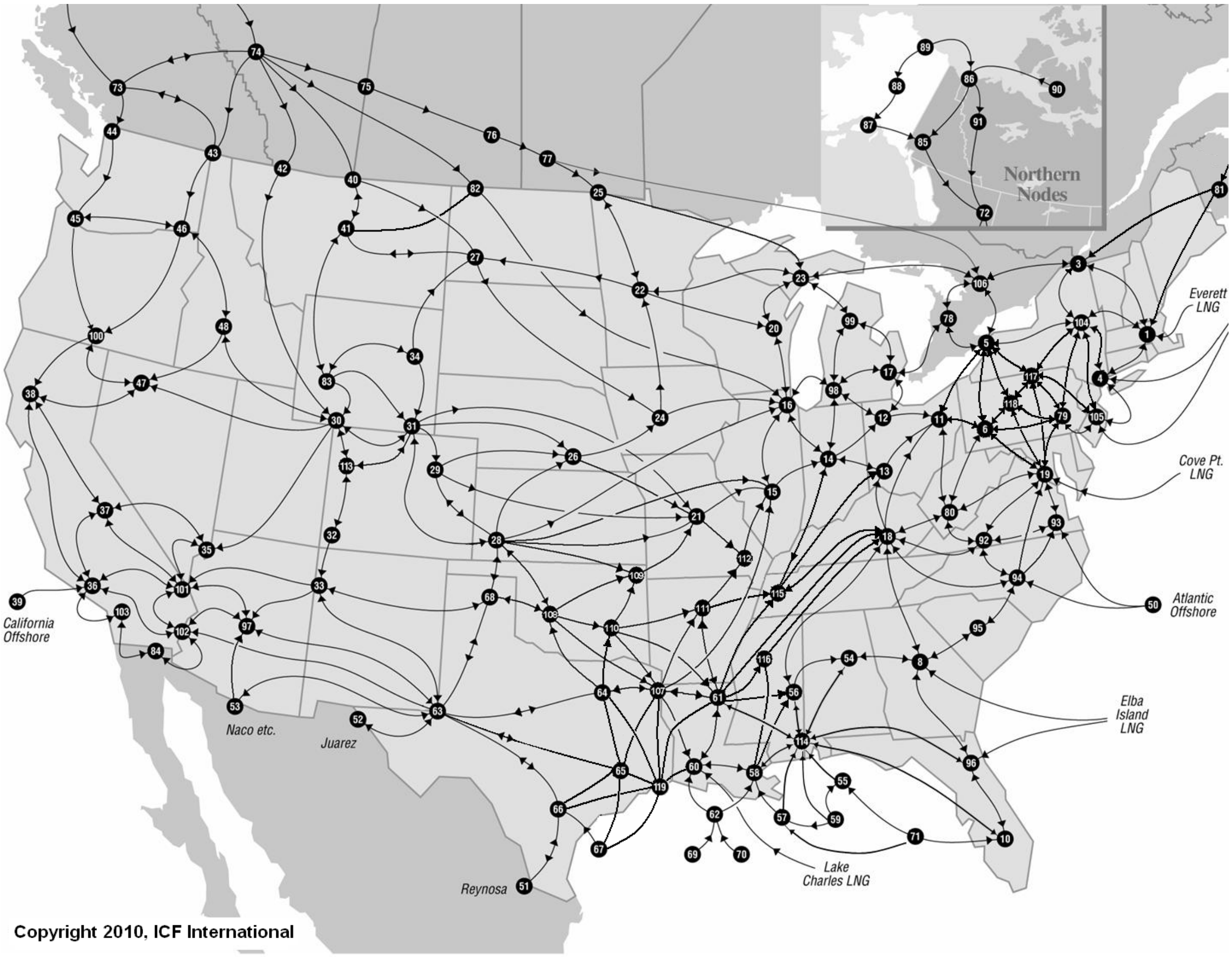


Figure D-2: GMM Components

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 Figure D-3, and the detailed structure in the Marcellus/Utica area is show in Figure D-4. The gas supply component of the model solves for node-level natural gas deliverability or supply capability, including LNG import and export levels. 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, LNG exports, and Mexican exports) at each of the nodes and gas prices are solved for in the market simulation module.

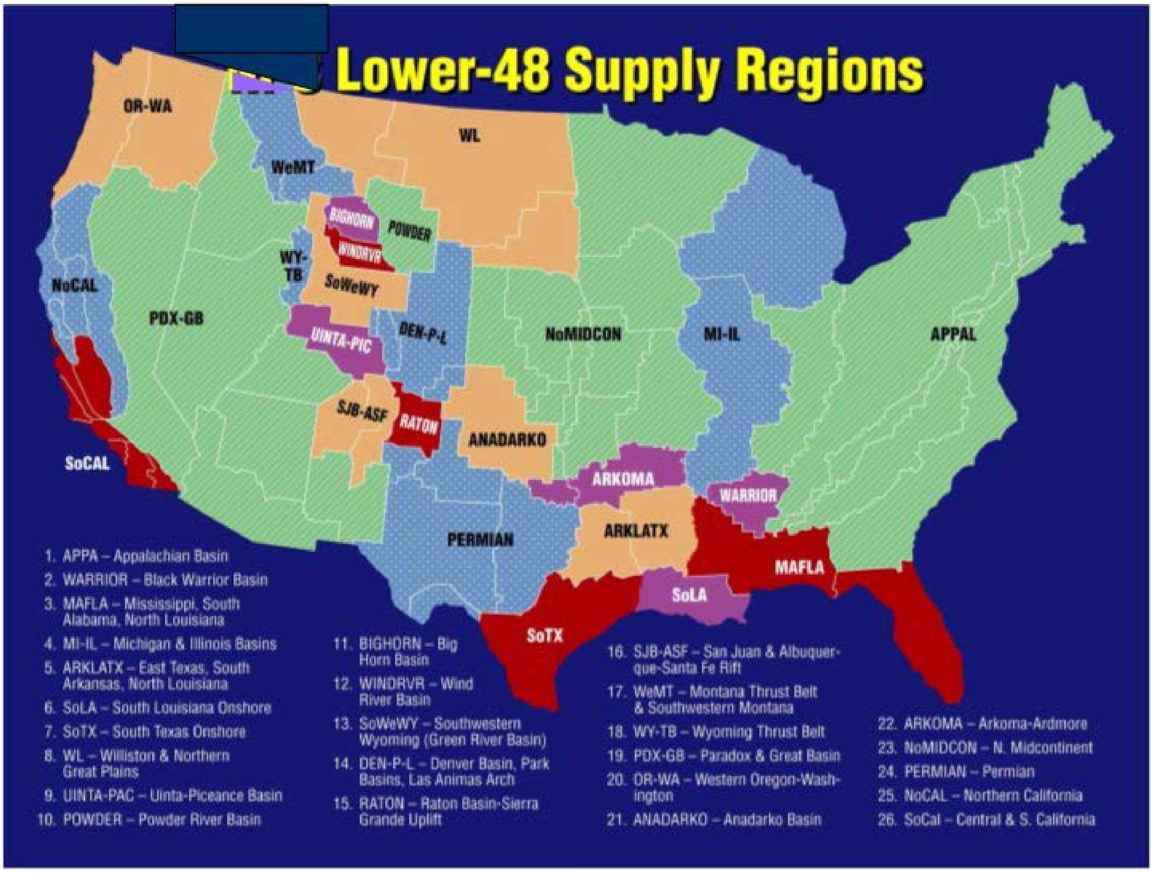
Figure D-3: GMM Transmission Network



ICF Natural Gas Supply Assessment Methodology

ICF's Natural Gas Supply Assessment Methodology (ISAM) covers the Continental United States, Alaska and Canada. The Continental United States is represented in 28 onshore regions (see Figure D-5) and 11 offshore regions.

Figure D-4: NPC Continental US Supply Regions



Alaska is divided into seven regions and Canada is divided into ten regions. All regions are further broken out into subregions or “intervals.” They represent some combination of drilling depths, water depth, or geographic areas.

Resources are divided into three general categories: new fields/new pools, field appreciation, and unconventional gas. The methodology for resource characterization and economic evaluation differs for each.

New Fields

New discoveries are characterized by size class. For the United States, the number of fields within a size class is broken down into oil fields, high permeability gas fields, and low permeability gas fields based on the expected occurrence of each type of field within the region and interval being modeled. The fields are characterized further as having a hydrocarbon make-up containing a certain percent each of crude oil, dry natural gas, and natural gas liquids. In Canada, fields are oil, sweet nonassociated gas, or sour nonassociated gas.

The methodology uses a modified “Arps-Roberts” equation to estimate the rate at which new fields are discovered. The fundamental theory behind the find-rate methodology is that the probability of finding a field is proportional to the field's size as measured by its areal extent, which is highly correlated to the field's level of reserves. For this reason, larger fields tend to be found earlier in the discovery process than smaller fields. The new equation developed by ICF accurately tracks discovery rates for mid- to small-size fields. Since these are the only fields left to be discovered in many mature areas, the more accurate find-rate representation is an important component in analyzing the economics of exploration activity in these areas.

The find-rate equations are used in the model to predict the number of fields of a certain size that will be discovered after a given number of exploratory wells have been drilled. There are separate equations for each field-size class (e.g., size class 6 is between one and two million barrels of oil equivalent) within each depth interval, within each region. The Continental US portion of the model alone has over 3,000 separate find-rate equations. This is a very fine level of detail given that actual annual new field discoveries have been below 600 fields in recent years.

An economic evaluation is made in the model each year for potential new field exploration programs using a standard discounted after-tax discounted cash flow (DCF) analysis. This DCF analysis takes into account how many fields of each type are expected to be found and economics of developing each. There are about 7,000 prototype field development plans in the model for the Continental US that include all capital and operating costs and production timing specifications built up from historical data. The economic decision to develop a field is made using “sunk cost” economics where the discovery cost are ignored and only time- forward development costs and production revenues are considered. However, the model’s decision to begin an exploration program includes all exploration and development costs.

The results for new field exploration are reported in standard output tables that show the marginal economics (internal rate of return and resource cost) of exploration in each region and interval throughout the forecast. There are also outputs in Excel and Access format showing the number of fields being found, recoverable hydrocarbons discovered and recoverable hydrocarbons developed.

Unconventional Gas

The ICF assessment method for shale gas is a “bottom-up” approach that first generates estimates of unrisked and risked gas-in-place (GIP) from maps of depth, thickness, organic content, and thermal maturity. Then, ICF uses a different model to estimate well recoveries and production profiles. Unrisked GIP is the amount of original gas-in-place determined to be present based upon geological factors— without risk reductions. “Risked GIP” includes a factor to reduce the total gas volume on the basis of proximity to existing production and geologic factors such as net thickness (e.g., remote areas, thinner areas, and areas of high thermal maturity have higher risk). ICF calibrates expected well recoveries with specific geological settings to actual well recoveries by using a rigorous method of analysis of historical well data. In late 2011, ICF undertook an extensive analysis of Marcellus well recoveries and compared them with model results with good correlation. ICF confirmed that the model well recoveries are conservative. Additional analysis in 2012 also confirmed these results.

Major Unconventional Natural Gas Categories

Definition of Unconventional Gas: *Quantities of natural gas that occur in continuous, widespread accumulations in low quality reservoir rocks (including low permeability or tight gas, coalbed methane, and shale gas), that are produced through wellbores but require advanced technologies or procedures for economic production.*

Tight Gas is defined as natural gas from gas-bearing sandstones or carbonates with an *in situ* permeability (flow rate capability) to gas of less than 0.1 millidarcy. Many tight gas sands have *in situ* permeability as low as 0.001 millidarcy. Wells are typically vertical or directional and require artificial stimulation.

Coalbed Methane is defined as natural gas produced from coal seams. The coal acts as both the source and reservoir for the methane. Wells are typically vertical but can be horizontal. Some coals are wet and require water removal to produce the gas, while others are dry.

Shale Gas is defined as natural gas from shale formations. The shale acts as both the source and reservoir for the methane. Older shale gas wells were vertical while more recent wells are primarily horizontal with artificial stimulation. Only shale

Upstream Cost and Technology Factors

In ICF's methodology, supply technology advancements effects are represented in three categories:

- Improved exploratory success rates
- Cost reductions of platform, drilling, and other components
- Improved recovery per well

These factors are included in the model by region and type of gas and represent several dozen actual model parameters. ICF's database contains base year cost for wells, platforms, operations and maintenance, and other relevant cost items.

Enbridge Gas Storage Assessment

Potential Value of Incremental Storage Capacity for Enbridge Gas