NYCA Pipeline Congestion and Infrastructure Adequacy Assessment

New York Independent System Operator

September, 2013

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LIMITATION ON LIABILITY

This report has been prepared for NYISO for the sole purpose of assessing the adequacy of the natural gas infrastructure in regard to meeting the fuel delivery needs of gas-fired generation in NYISO. Input parameters to various models are based largely on actual public data from the pipelines and local distribution companies operating in New York State. Findings contained herein depend on the assumptions identified in our report, including the mathematical models used to determine historic congestion levels and flow balances over the study period. Levitan & Associates, Inc. believes these assumptions to be reasonable. However, there is no assurance that any specific set of assumptions associated with new pipeline and storage projects will be encountered.

DISCLAIMER

This report was prepared by Levitan & Associates, Inc. (LAI) for the New York Independent System Operator, Inc. (NYISO). The views and conclusions expressed in this study represent those of LAI and do not necessarily represent those of the NYISO. No official endorsement by the NYISO is intended or should be inferred.

TABLE OF CONTENTS

TABLE OF FIGURES

TABLE OF TABLES

GLOSSARY

Algonquin	Algonquin Gas Transmission, LLC
Bcf	Billion Cubic Feet, approximately equivalent to 1,000 MDth
Btu	British Thermal Unit
CDD	Cooling Degree Day
CHG&E	Central Hudson Gas & Electric Corporation
CME	Chicago Mercantile Exchange
Columbia	Columbia Gas Transmission
Con Edison	Consolidated Edison Company of New York
Corning	Corning Natural Gas Corporation
DHS	Department of Homeland Security
DOE	Department of Energy
Dominion	Dominion Transmission, Inc.
Dominion SP	Dominion South Point
Dth	Dekatherm, equivalent to 1 MMBtu
E&P	Exploration and Production
EBB	Electronic Bulletin Board
EMAAC	Eastern Mid-Atlantic Area Council
Empire	Empire Pipeline Inc.
FERC	Federal Energy Regulatory Commission
HDD	Heating Degree Day
Iroquois	Iroquois Gas Transmission System, LP
Iroquois Z2	Iroquois Zone 2
kWh	Kilowatt Hour
LAI	Levitan & Associates, Inc.
LDC	Local Distribution Company
LHV	Lower Hudson Valley
M&N	Maritimes & Northeast Pipeline
MAAC	Mid-Atlantic Area Council
MDth	Thousand Dekatherms
Millennium	Millennium Pipeline Company, LLC
MMBtu	Million British Thermal Units, equivalent to 1 Dth
MW	Megawatt
MWh	Megawatt Hour

NFG	National Fuel Gas
NFGDC	National Fuel Gas Distribution Corporation
NGrid	National Grid
NYC	New York City
NYCA	New York Control Area
NYFS	New York Facilities System
NYISO	New York Independent System Operator
NYPSC	New York Public Service Commission
NYSE&G	New York State Electric & Gas
O&R	Orange & Rockland Utilities
OFO	Operational Flow Order
PHMSA	Pipeline and Hazardous Materials Safety Administration
PJM	PJM Interconnection
PSD	Pipeline Security Division
PSE&G	Public Service Electric & Gas
RFO	Residual Fuel Oil
RG&E	Rochester Gas & Electric
ROW	Right-of-Way
SCADA	Supervisory Control and Data Acquisition
Spectra	Spectra Energy Corporation
Tennessee	Tennessee Gas Pipeline Company
Tetco M3	Texas Eastern Zone M3
Texas Eastern	Texas Eastern Transmission, LP
TransCanada	TransCanada PipeLines Limited
Transco	Transcontinental Gas Pipe Line
Transco Z6 NY	Transco Zone 6 New York
TSA	Transportation Security Administration
ULSD	Ultra Low Sulfur Diesel

INTRODUCTION

Levitan & Associates, Inc. (LAI) has previously performed several gas studies for the New York Independent System Operator (NYISO), including the 2002-03 *Multi-Region Gas Study*,[1] a 2009 *Gas Infrastructure Study*,[2] and the 2010 *NYCA Pipeline Infrastructure Assessment*.[3] Since these studies were completed, the natural gas infrastructure in and around the New York Control Area (NYCA) has been further expanded to facilitate the deliverability of shale gas from Marcellus to core (gas utility) and non-core (generation) loads throughout New York State.

In this study, LAI expands on prior research conducted for NYISO to update the assessment of the pipeline and storage infrastructure to serve gas-fired generation across NYCA. The primary objectives of Task 2 of the NYISO Fuel Assurance Study are threefold: first, to analyze historical pipeline congestion patterns across NYCA; second, to assess the impact of new pipeline additions over a five-year study horizon into and across New York State in regard to transport deliverability conditions in each of the aforementioned zones; and, third, to identify potentially disruptive gas-side contingencies across the supply chain from the producing area to the market center, including qualitative assessment of the amount of gas-fired generation at-risk. NYISO's increased reliance on natural gas as the primary generation fuel coupled with potential unit retirements in NYCA have raised reliability issues regarding the delivery of natural gas to generators throughout the region, in particular, downstate New York. Although NYCA has experienced increasing congestion levels on key transport paths in recent years, upcoming infrastructure expansions bringing Marcellus gas to market will materially increase infrastructure capability in the heart of the market, thereby lessening concerns over grid security related to fuel assurance.

The Task 2 report includes three general sections, as follows:

- First, we provide an overview of the NYCA gas market and infrastructure;
- Second, we assess historical congestion levels; and,
- Third, we present the results of the infrastructure adequacy forecast, including an analysis of postulated contingency events.

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[1] The *Multi-Region Gas Study* also included PJM, ISO-New England, the ISO of Ontario, and NERC. Hydraulic analysis was performed to assess the ability of the consolidated network of interstate pipelines and storage facilities to sustain natural gas service to power generators under a number of postulated gas-side and electric-side contingencies.

[2] In the *2009 Gas Infrastructure Study* LAI reviewed infrastructure changes and developed postulated contingency events affecting bulk power security across NYCA.

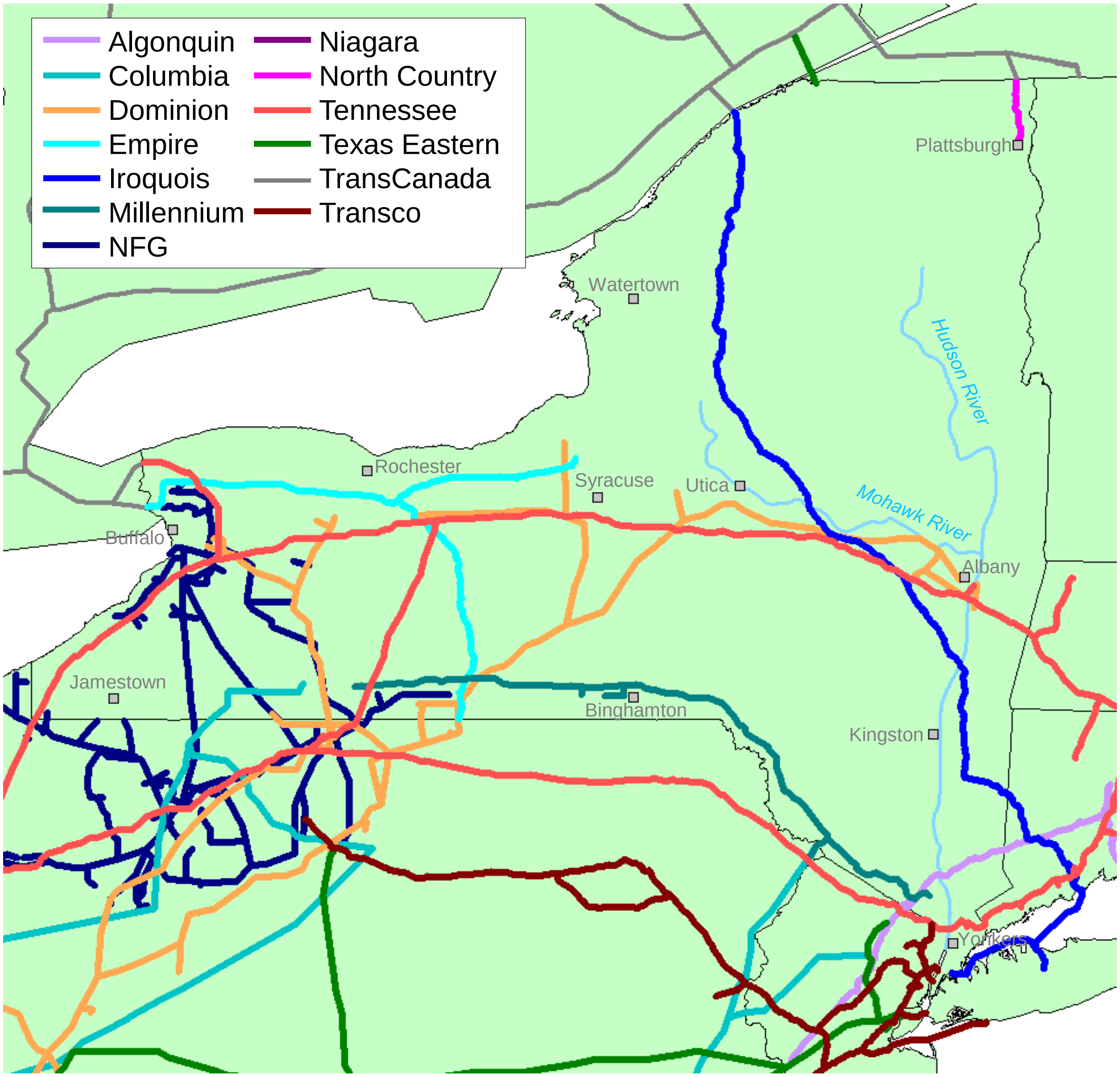
[3] In the *2010 NYCA Pipeline Infrastructure Assessment*, LAI forecasted electric peak day gas demands based on historical data and evaluated postulated cooling season contingency events.

EXECUTIVE SUMMARY

The Northeast has experienced major supply and infrastructure changes over the last three years. Increased production from the Marcellus shale and the development and commercialization of infrastructure projects to bring the new supplies to the downstate market center have impacted flow dynamics and prices across the supply chain of pipeline and storage facilities serving New York. These positive trends in regard to electric system reliability are expected to continue as additional pipeline infrastructure projects are commercialized over the next five years, with no unserved electric generation gas demand seen in either of the forecast cases over the study horizon. This determination is based on the state-wide flow balance construct and is therefore not based on any hydraulic modeling of infrastructure adequacy. We note that this study was not designed to evaluate intra-state deliverability constraints. Therefore plants that are located downstream of constrained segments may still experience gas supply curtailments or interruptions over the study horizon.

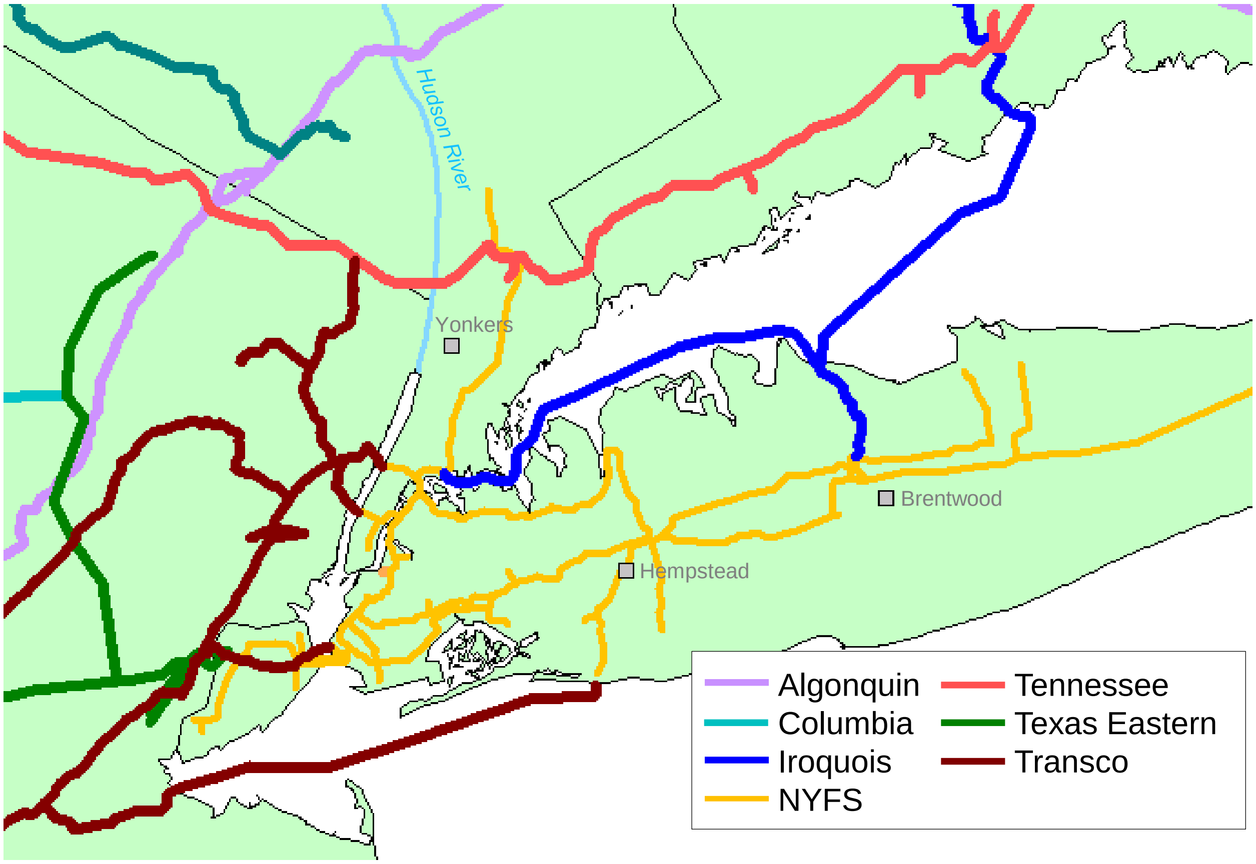
LAI has assessed natural gas deliverability conditions into and within New York State based on an analysis of recent flow patterns and congestion events on the pipelines serving NYCA. Such congestion events bear upon the availability of secondary firm and interruptible transportation arrangements to serve power plants across NYCA. Expansions of transportation pathways into NYCA will begin to reduce or eliminate the occurrence of these contingency events as early as November 2013, particularly in the downstate market. The consolidated network of interstate pipelines serving New York is shown in Figure 1.

Figure 1. Natural Gas Pipeline Network in NYCA



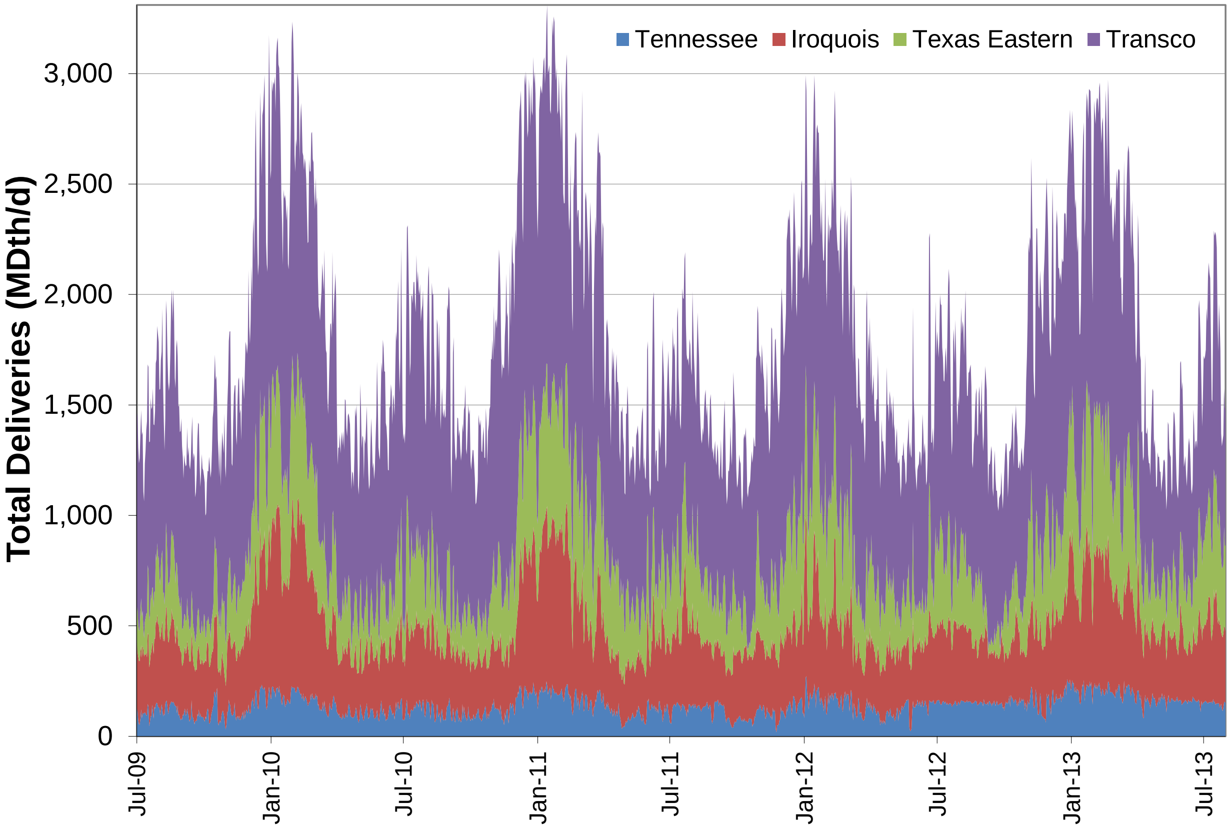
High oil-to-gas price ratios and environmental restrictions have increased NYC's reliance on natural gas for electric generation during the summer. Transco, Texas Eastern, Iroquois and, to a lesser extent, Tennessee serve core (gas utility) and non-core (generation) demand across the New York Facilities System (Figure 2).

Figure 2. Pipelines Serving the New York Facilities System



As shown in Figure 3, these pipelines show high utilization levels during the peak heating season, December through February, but significant slack deliverability, indicated by the "air" above the dataset, during the peak cooling season, June through August, as well as the shoulder months. Utilization levels on Empire, Algonquin and Tennessee are increasingly high, reflecting the downstream demand for shale gas for both core and non-core demand in Ontario and New England.

Figure 3. New York Facilities System Deliveries



A review of the daily operational capacity and critical notice / Operational Flow Order (OFO) postings for each pipeline indicates that forced outages were rare and, when they occurred, were usually of short duration. Reductions in capacity due to scheduled maintenance were more common and, in some cases, longer lasting. Consistent with the pipelines' enviable record of performance across NYCA, these outages were scheduled during the shoulder months, both spring and fall, in order to avoid disruptions to firm entitlement holders, and to minimize disruptions during the peak cooling season. In reviewing the results of this analysis, readers are reminded that congestion events are sometimes paradoxical as they reflect the material de-rate of the pipeline segment at the time when natural gas is either less likely to be needed for grid security requirements or pipeline "workarounds" can be coordinated with interconnected pipelines and gas utilities during outage contingencies.

A summary of our observations regarding pipeline congestion over the last three years and the potential availability of unused pipeline capacity for non-core customers in the winter versus summer under current conditions is presented in Table 1.

Table 1. Potential Slack Pipeline Deliverability (Current Infrastructure)[4]

Pipeline	Location	NYCA Zones Served	Other Markets Served	Slack Deliverability	
				Winter	Summer
Algonquin	Hanover	G-H-I	NE	Moderate	High
	Stony Point	G-H-I	NE	Low	Moderate
	Southeast	G-H-I	NE	Low	Moderate
Empire	Empire Connector	B, C	Ontario	Moderate	Low
Iroquois	Brookfield	J, K	NE	Moderate	High
	Waddington	G-H-I, J, K	NE	Low	Moderate
Millennium	Ramapo	G-H-I	Ontario, NE	Low	Low
Tennessee	Station 224	A, B, C, E, F	Ontario, NE	Low	Low
	Station 245	F	NE	Low	Low
	Station 325	G-H-I, J	NE	Low	High
Texas Eastern	Lambertville	J	NE	Low	High
	Linden	J	N/A	Moderate	High
Transco	Linden	J, K	N/A	Moderate	Moderate

Figure 4 and Figure 5 illustrate pipeline congestion summarized in Table 1 for the peak days during the heating and cooling seasons, respectively, based on the existing infrastructure configuration. The existing infrastructure does not reflect the addition of new facilities in November 2013. Expansion projects that will relieve current deliverability limitations are addressed in Section 1.1 of this report.

[4] The classification of slack seasonal peak day deliverability is based on the peak utilization for each segment during winter 2012-13 (November through March) or summer 2013 (May through July). Segments with peak seasonal utilization less than or equal to 80% are categorized as having high slack deliverability, segments with peak seasonal utilization between 81% and 94% (inclusive) are categorized as having moderate slack deliverability, and segments with peak seasonal utilization greater than or equal to 95% are categorized as having low slack deliverability.

Figure 4. Heating Season Peak Day Pipeline Congestion (Current Infrastructure)

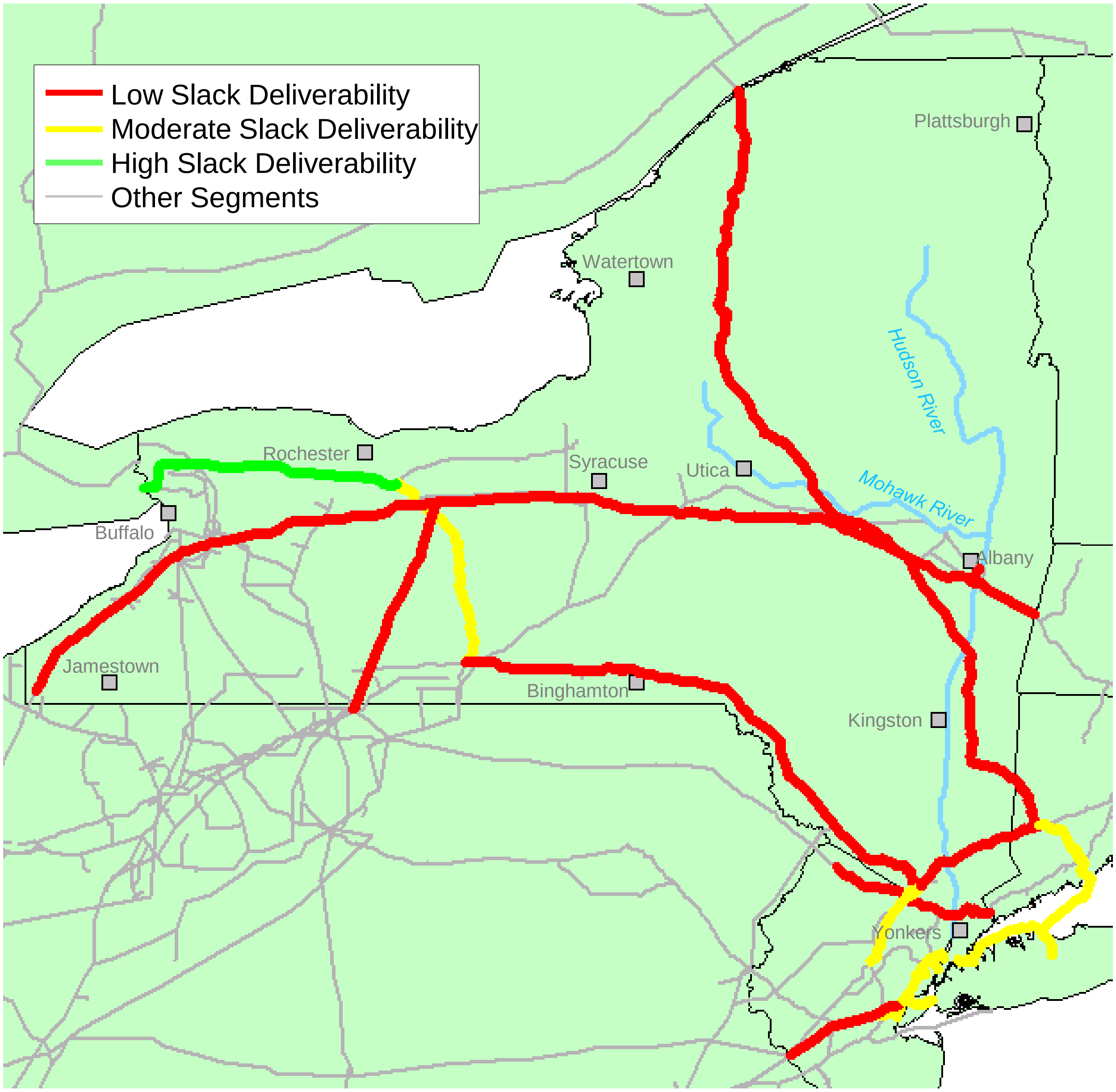
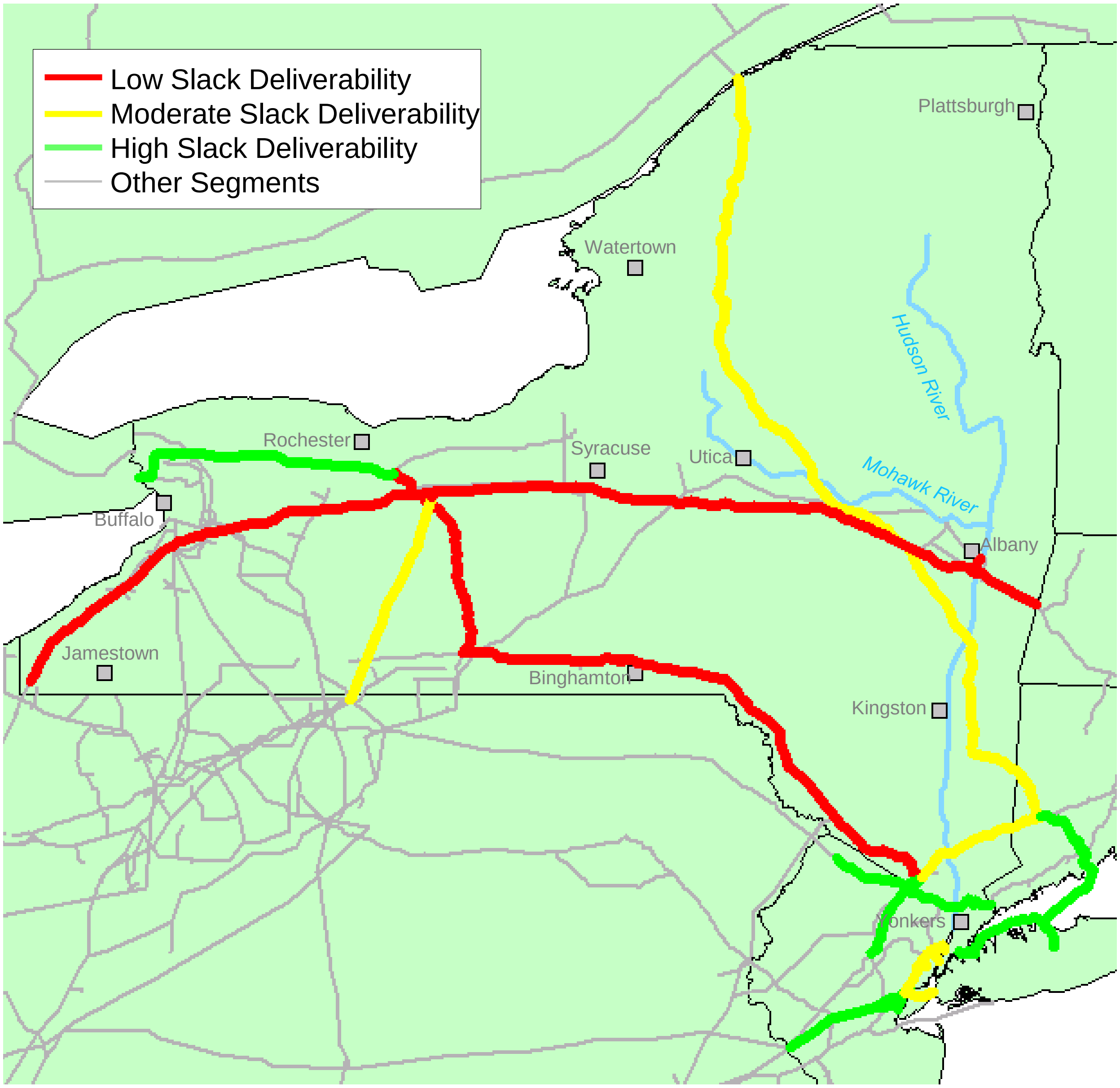


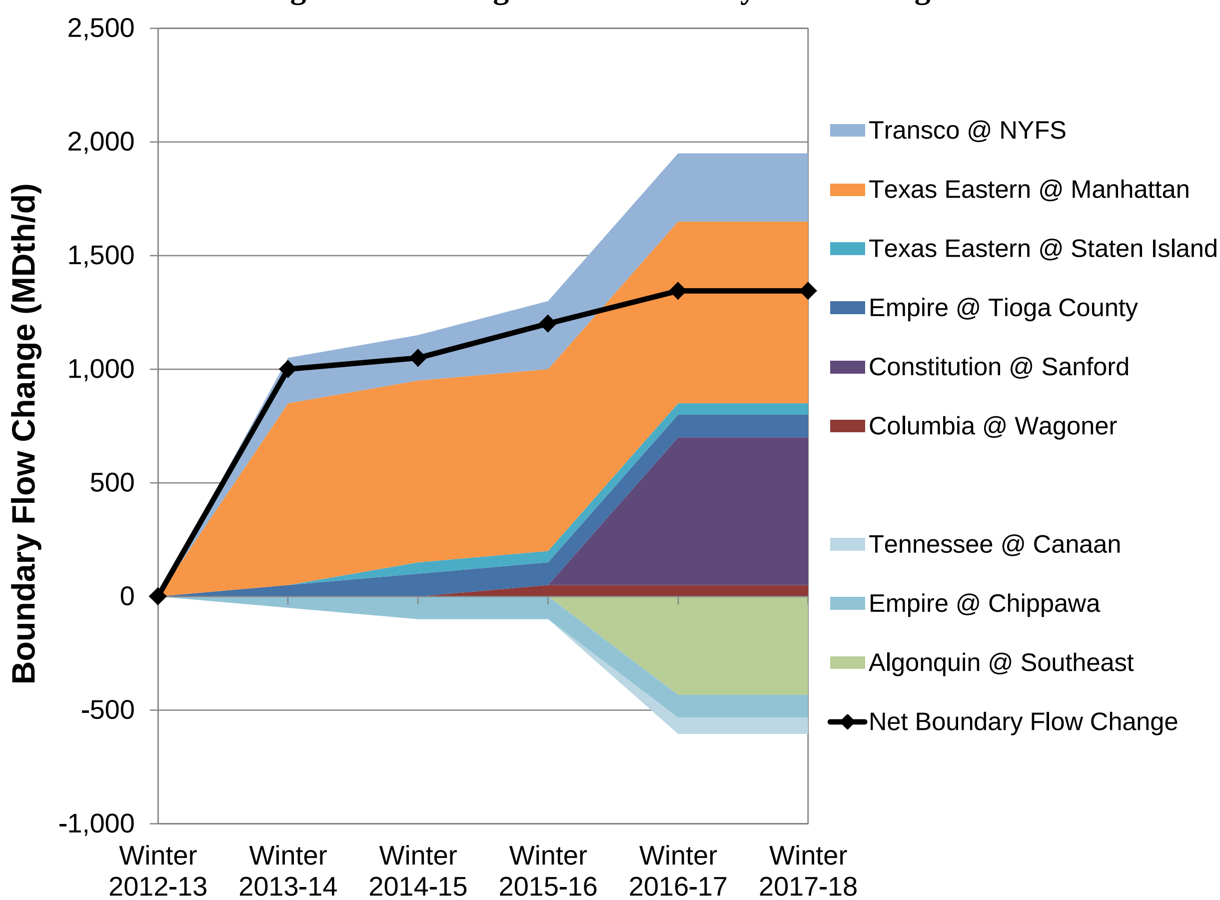
Figure 5. Cooling Season Peak Day Pipeline Congestion (Current Infrastructure)



The congestion analysis results show that capacity serving the New York Facilities System and, to a lesser extent, NYCA-at-large has been frequently constrained during the heating season, November through March. However, major new pipeline expansions are scheduled to be commercialized in Q4-2013 and in the years ahead, thereby reducing congestion effects across NYCA. Spectra's 800-MDth/d New Jersey – New York Expansion Project and Transco's 250-MDth/d Northeast Supply Link Project, of which 200 MDth/d will flow to NYC, will increase deliverability into the New York Facilities System by approximately 30%. Both the New Jersey – New York Expansion Project and the Northeast Supply Link Project are designed to accommodate soaring gas production from Marcellus. These two projects represent 1,000 MDth/d, approximately 1 Bcf/d, of incremental deliverability into NYC. Assuming a conversion efficiency characteristic of new combined-cycle plants, this increased deliverability equates to about 143,000 MWh/d or 6,000 MW of generation for 24 hours at full load.[5] As additional projects come online over the next five years, downstate deliverability will continue to increase. Insofar as prominent producers with substantial positions in Marcellus hold firm transportation entitlements on both Spectra's project into Manhattan and Transco's expansion, incumbent generators across the New York Facilities System will likely be well-positioned to realize the transportation benefits attributable to this new capacity, even if such transportation entitlements are not subscribed to in their own names.[6] In NYC and Long Island, the extent to which facility improvements are needed at the local level to accommodate increased flow from Marcellus is beyond the scope of this analysis.

Figure 6 and Figure 7 shows the net increases in upstream and downstream boundary flows over the study period for the heating and cooling seasons, respectively, relative to existing capacity. To put these boundary flow changes in the context of electric generation, the net boundary flow change of 1,345 MDth/d over the study period represents supply to serve 192,000 MWh/d of gas-fired generation, or 8,000 MW for 24 hours of full load operation.5

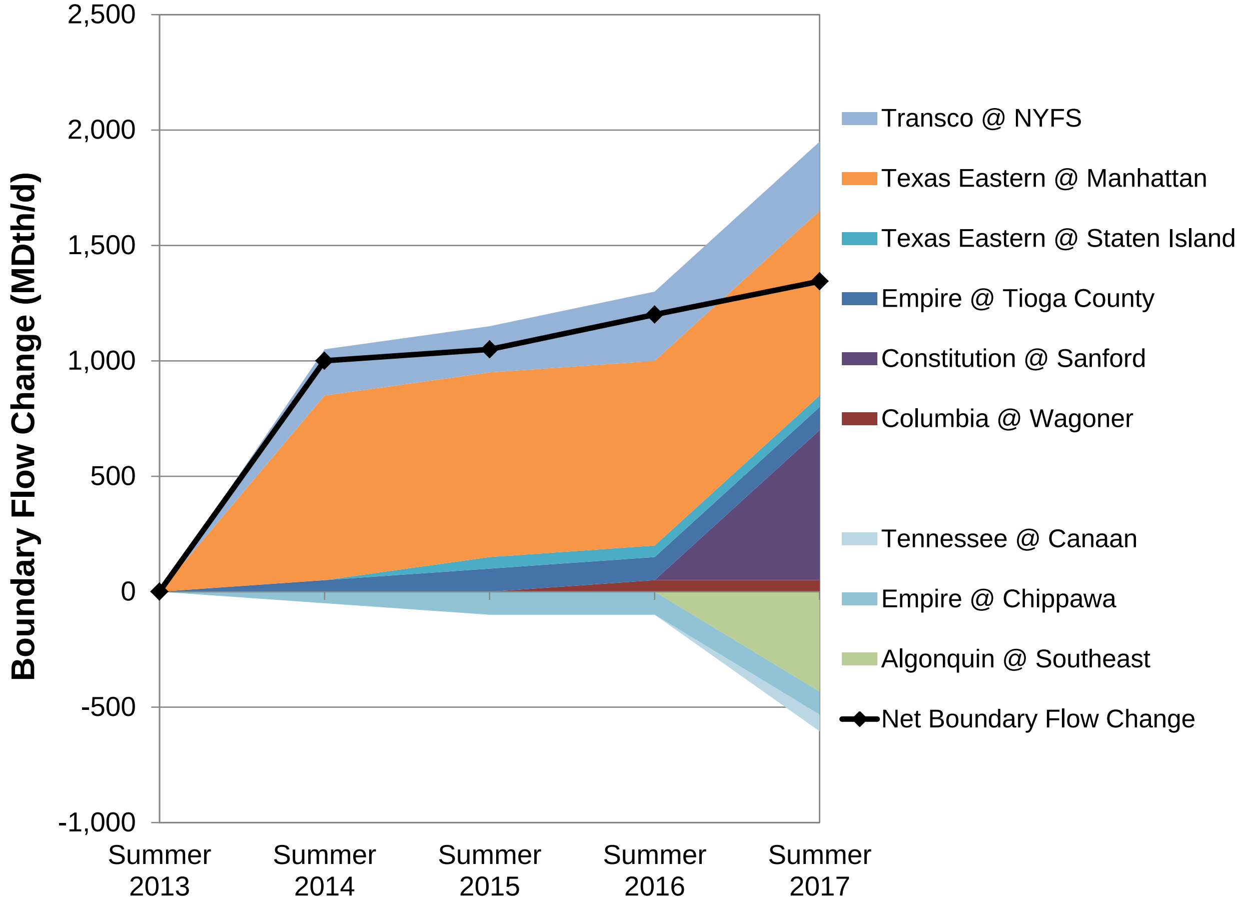
Figure 6. Heating Season Boundary Flow Changes



[5] This conversion assumes a heat rate of 7,000 Btu/kWh, or 7 Dth/MWh.

[6] Growth in core and non-core loads in New Jersey will provide marketers and third-party suppliers with valuable options for new supplies from Marcellus.

Figure 7. Cooling Season Boundary Flow Changes



Three generation (non-core) demand cases were evaluated, as modeled by NYISO. The Base Case represents a *status quo* future, while the +1,000-MW Case represents a future with 1,000 MW of new gas-fired generation added to the supply mix in the Lower Hudson Valley (LHV). The relative total seasonal demands for the two cases are shown in Figure 8. A third case, with a total of 2,000 MW added in the LHV, is discussed in Section 3.7 of this report.

Figure 8. Base v. +1,000-MW Case Non-Core Demand[7]

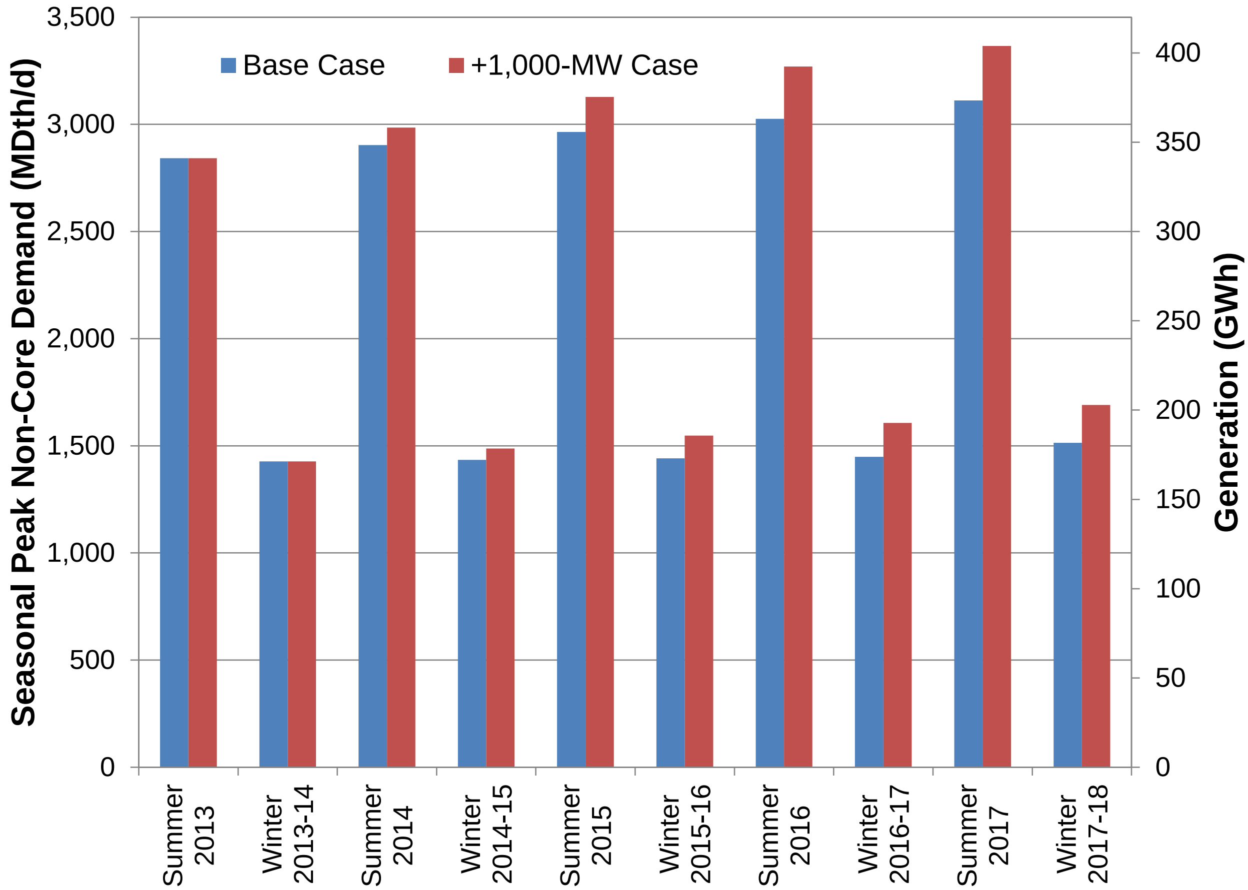


Figure 9 and Figure 10 illustrate the Base Case NYCA supply balance for the heating and cooling seasons, respectively, comparing upstream boundary flows and in-state receipts against downstream boundary flows, core demand, and non-core demand. As shown in Figure 8 above, the non-core demand differential between the Base and +1,000-MW Cases is relatively small. As a result, it does not significantly change the flow balance results. In light of the pipeline facility additions across NYCA over the study period, state-wide supplies are adequate to meet state-wide demand in all cases. We note, however, that these favorable results are predicated on simplifying assumptions about boundary flows at New York's border fully utilizing expansion capacity to serve core and non-core loads alike, and do not consider intra-state locational constraints. Moreover, the favorable results gloss over pipeline scheduling restrictions within the gas day that often limit non-core shippers' ability to schedule gas in conformance with NYISO's dispatch regime.

[7] The generation on the secondary axis is based on a heat rate of 8,334 Btu/kWh, *i.e.*, the average system heat rate for gas-fired units across the seasonal peak days in the years modeled by NYISO for the Base and +1,000-MW Cases.

Figure 9. Heating Season NYCA Flow Balance (Base Case)

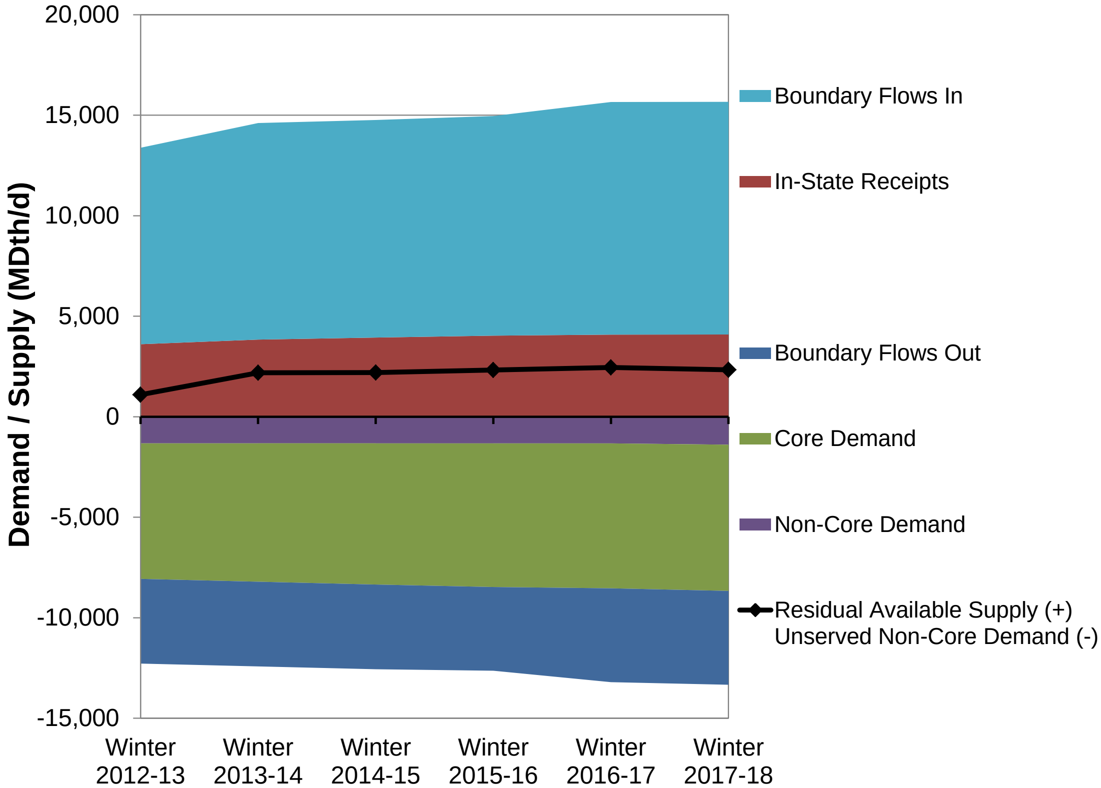
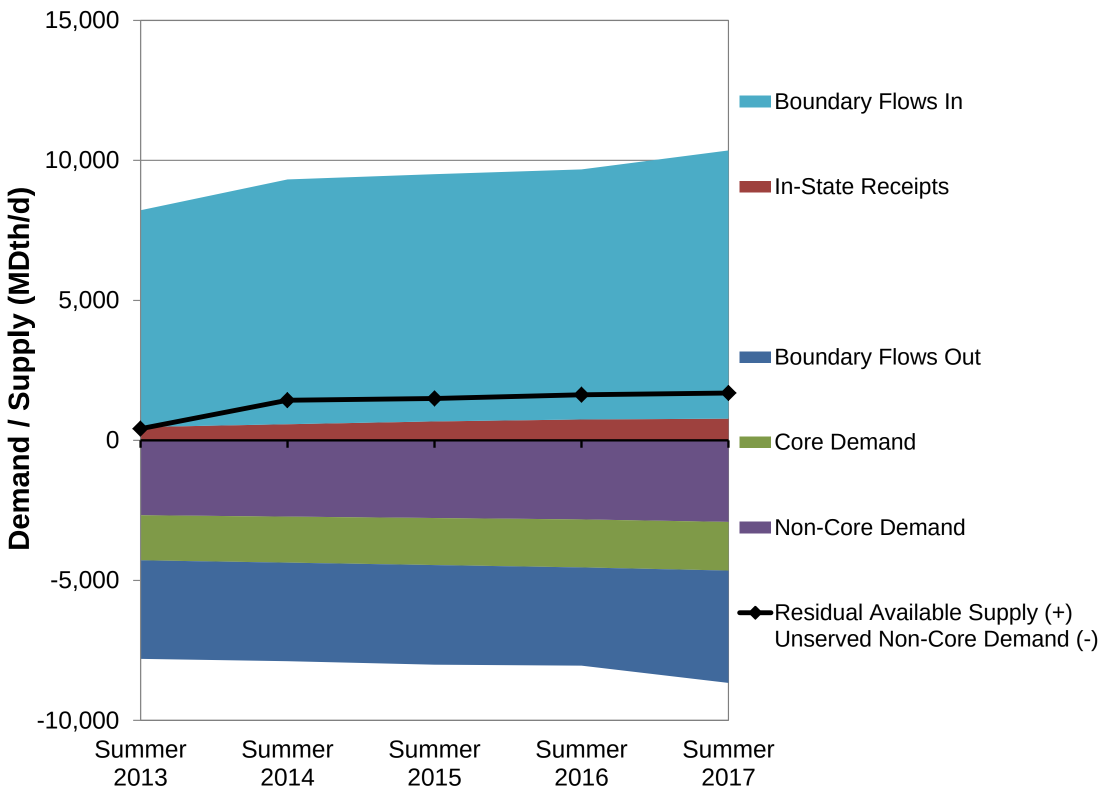
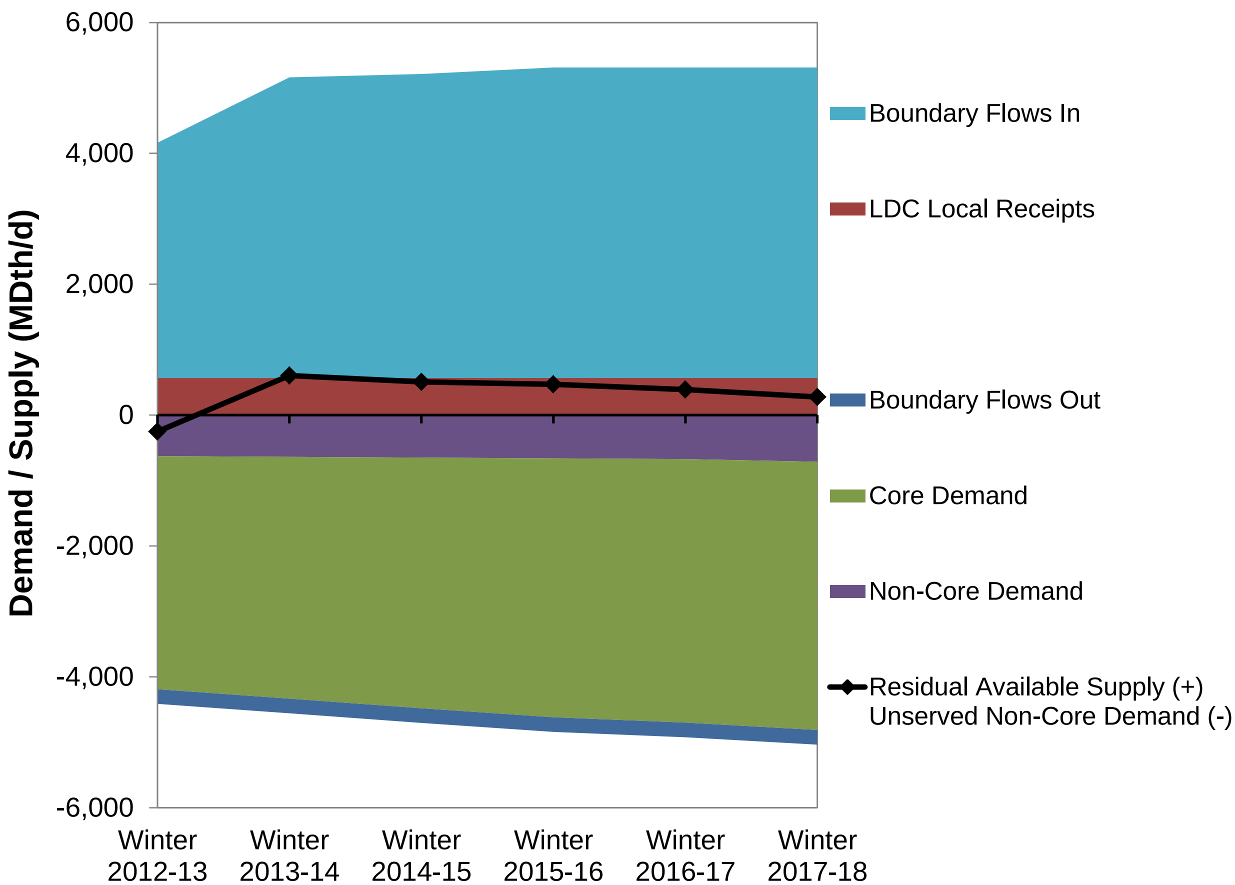


Figure 10. Cooling Season NYCA Flow Balance (Base Case)



Due to the high concentration of core (gas utility) and non-core (electric) demand in NYC and on Long Island, we have also evaluated the flow balance around the New York Facilities System. The results are shown in Figure 11 and Figure 12 for the heating and cooling seasons in the Base Case. As in the NYCA flow balances, the non-core demand between the Base and +1,000-MW Cases is not large enough to notably change the flow balance results. Although the model shows unserved generation during the 2012-13 heating season, in light of the major facility additions into Manhattan this year and next, no unserved downstate generation is reported over the study horizon.[8] This study was not designed to consider flow conditions on the New York Facilities System; hence downstate generators may still experience curtailments or interruptions if gas cannot be transported from the new and/or expanded pipeline delivery points to the plant gate station due to local deliverability constraints.[9]

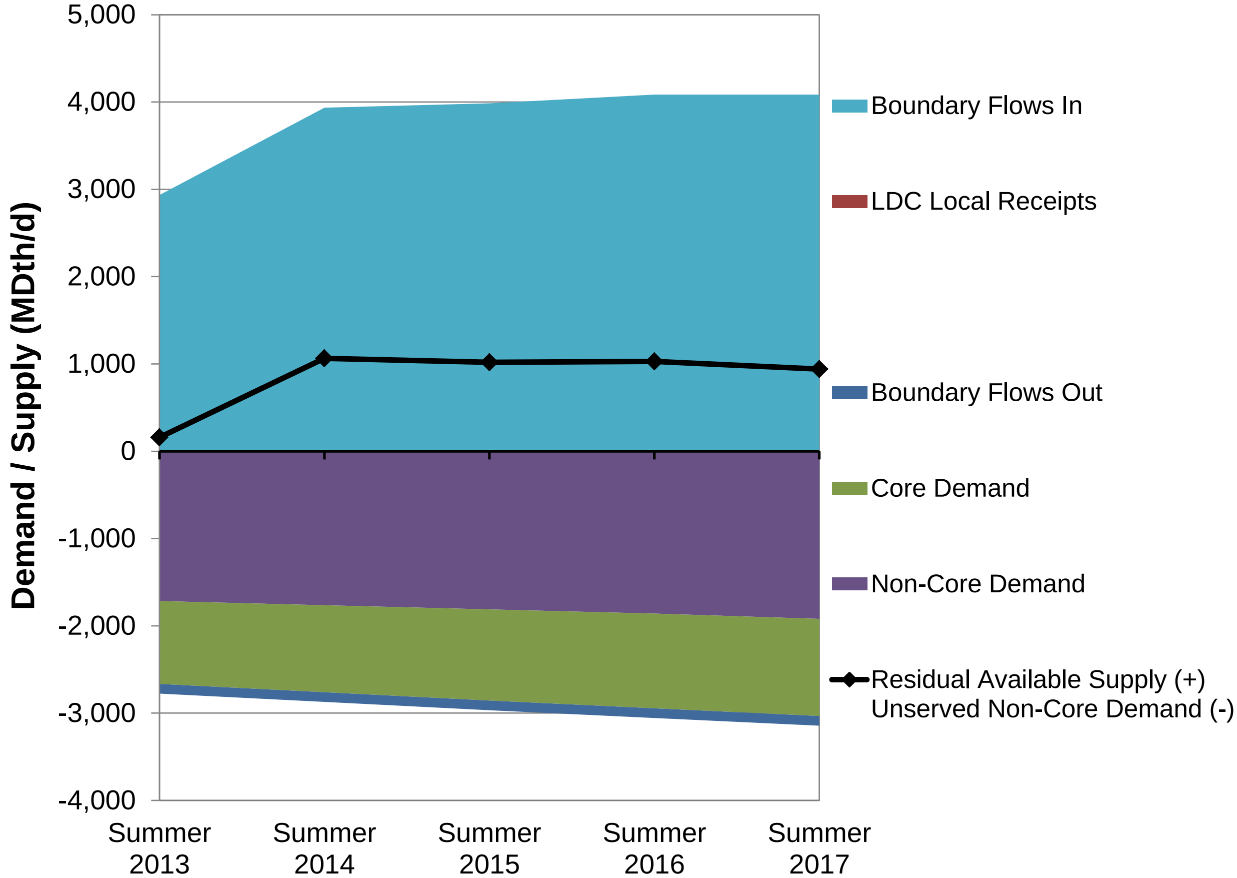
Figure 11. Heating Season NYFS Flow Balance (Base Case)



[8] The shortage during the 2012-13 heating season is consistent with NYISO's experience during the January 2013 cold snap; on January 22nd, over 500 MW experienced fuel-related de-rates.

[9] The extent to which Con Edison or NGrid has undertaken local expansions to meet oil-to-gas conversion program objectives has not been evaluated in this study. While pipeline deliverability into the New York Facilities System is deemed adequate over the study horizon, pressures on each gas utility, in particular, Con Edison, to accelerate core customer conversions has the potential to offset the benefits of new supply through Texas Eastern and Transco, potentially resulting in curtailments or interruptions to existing gas-fired generators.

Figure 12. Cooling Season NYFS Flow Balance (Base Case)



Eight postulated gas-side contingencies were evaluated based on the NYISO's 2016 electric simulation model results to identify the impacts on gas flows to power plants in NYCA.

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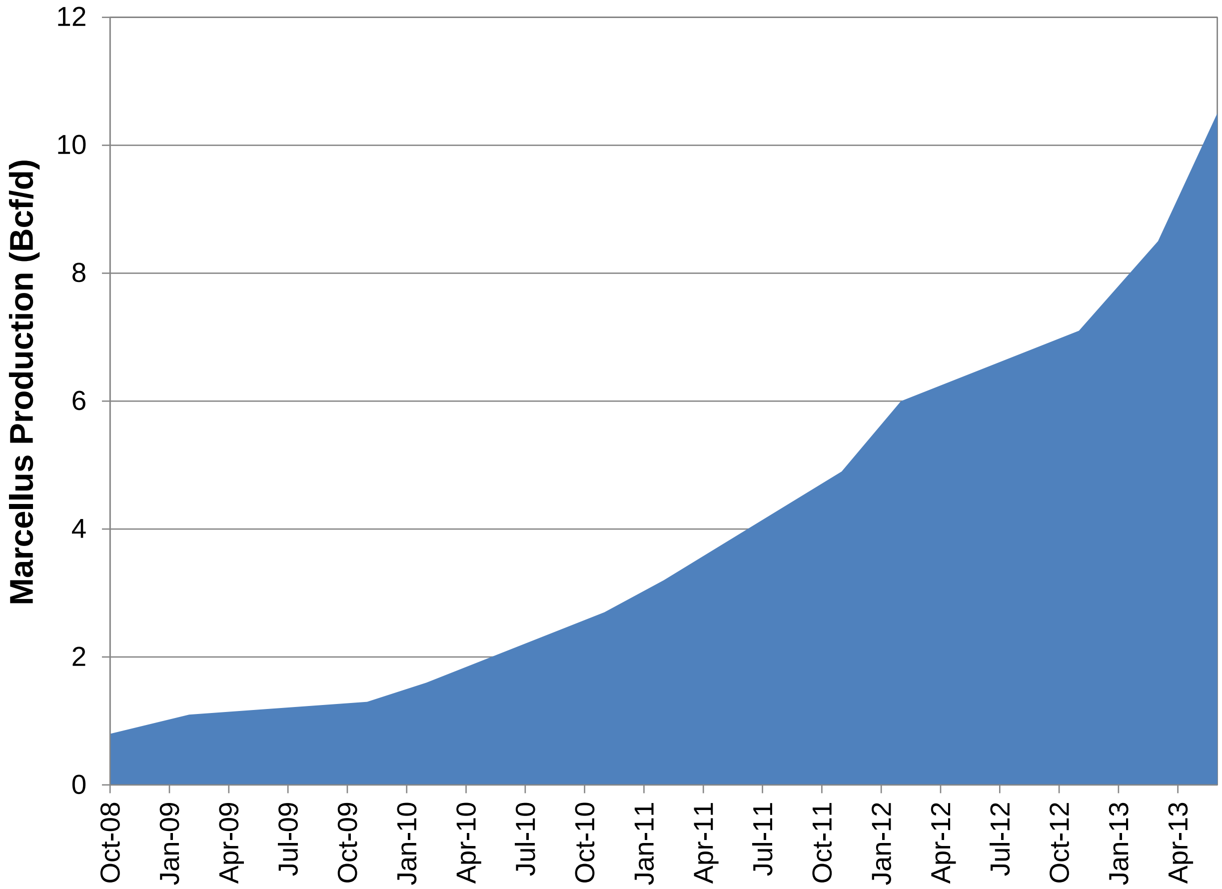
1 MARKET & INFRASTRUCTURE OVERVIEW

The Northeast has experienced major supply and infrastructure developments over the last three years. These developments impacted flow dynamics and prices across the supply chain of pipeline and storage facilities serving New York. Market dynamics during this period were near completely driven by Marcellus shale, one of the most prolific production basins in North America.[10] As shown in Figure 13, in November 2008 production from the Marcellus formation amounted to approximately 800 MMcf/d. By mid-2013 production exceeded 10 Bcf/d.[11]

Figure 13. Marcellus Production[12]



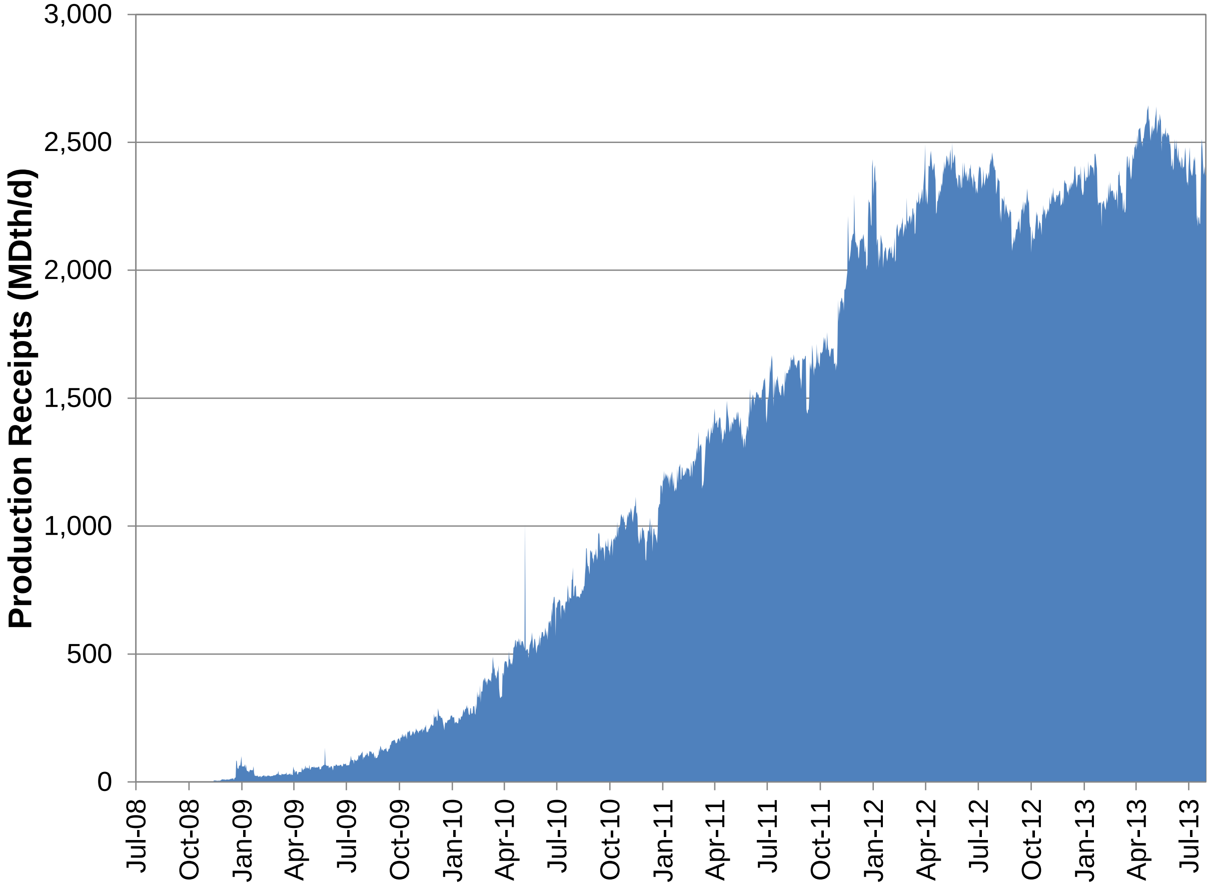
The exploration and production (E&P) outlook from Marcellus has provided the impetus for major pipeline and storage expansions from Ohio and western Pennsylvania across PJM into New York. Producers with large portfolios in Marcellus have been primarily responsible for the

[10] The Marcellus shale formation is found beneath large areas of Pennsylvania, New York, West Virginia and parts of Ohio. To date most of the production has come from Pennsylvania.
[11] According to the U.S. EIA in January 2013 as complied by the Northeast Gas Association, total gas demand in the Northeast in 2011 amounted to 7.6 Bcf/d. Gas used for electricity production accounted for 2.9 Bcf/d, about 39%. In New York, total gas demand amounted to 3.3 Bcf/d, about 1.2 Bcf/d for generation.
[12] Source: Bentek Energy

financial commitments on the new pipeline and storage facilities to accommodate soaring production from Marcellus, including new pipeline projects into the LHV and NYC.

Figure 14 shows the growth in gas receipts on Tennessee's Line 300 from Marcellus for delivery to various shippers and pipelines that interconnect with Tennessee:

Figure 14. Marcellus Production on Tennessee



While the growth in Marcellus production is expected to decelerate, production will likely remain above 10 Bcf/d throughout the remainder of this decade. The U.S. Department of Energy (DOE) estimates that there are 141 Tcf of technically recoverable resources within the formation. Despite controversy over hydraulic fracturing of shale reserves, the E&P outlook remains favorable in light of the comparatively low cost of producing shale gas, particularly in western Pennsylvania and Ohio where wet gas formations include valuable liquids.[13] Continued development of the Marcellus reserves therefore supports the development of new pipeline pathways and storage infrastructure into premium markets in PJM's Eastern Mid-Atlantic Area Council (EMAAC), NYISO, New England, the Midwest ISO, and Ontario.

[13] http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2012).pdf

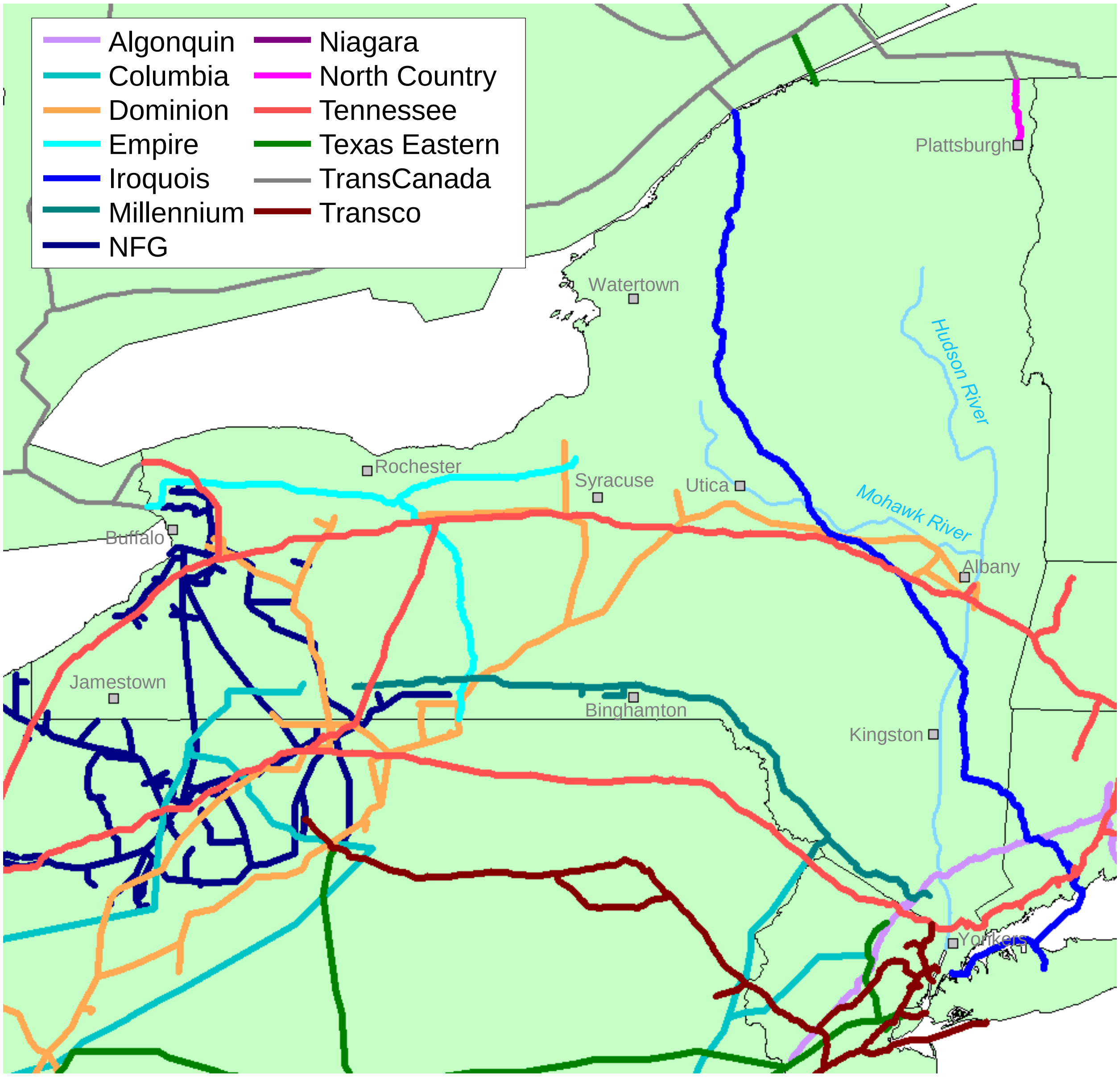
In order to address the nexus between the E&P outlook from Marcellus and pipeline congestion events, a brief review of market highlights is useful. Prior to significant production from Marcellus, nearly all natural gas consumed in New York was sourced from the Gulf of Mexico or Western Canada. Roughly 60% of gas used in New York State emanated from the Gulf Coast via major trunk pipelines from eastern Texas and Louisiana to New York, and 40% from western Canada via the TransCanada mainline from Alberta to import points at Niagara, Chippawa, and Waddington, New York.

1.1 Pipeline Infrastructure

New York State's natural gas infrastructure is large, dynamic and more than adequate to serve the requirements of entitlement holders. Ten pipelines serve New York State, predominantly interstate pipelines that are subject to regulatory jurisdiction by the Federal Energy Regulatory Commission (FERC). The pipelines serving New York include Algonquin, Columbia Gas, Dominion, Empire, Iroquois, Millennium, National Fuel Gas (NFG), Tennessee, Texas Eastern and Transco. With the exception of Empire, an intrastate pipeline serving upstate New York, all of the interstate pipelines serve upstream and/or downstream market areas in PJM and/or New England. NYCA also receives gas from Canada via smaller northern systems which will be addressed in more detail later in this report.

The consolidated network of interstate pipelines is shown in Figure 15.

Figure 15. Natural Gas Pipeline Network in NYCA

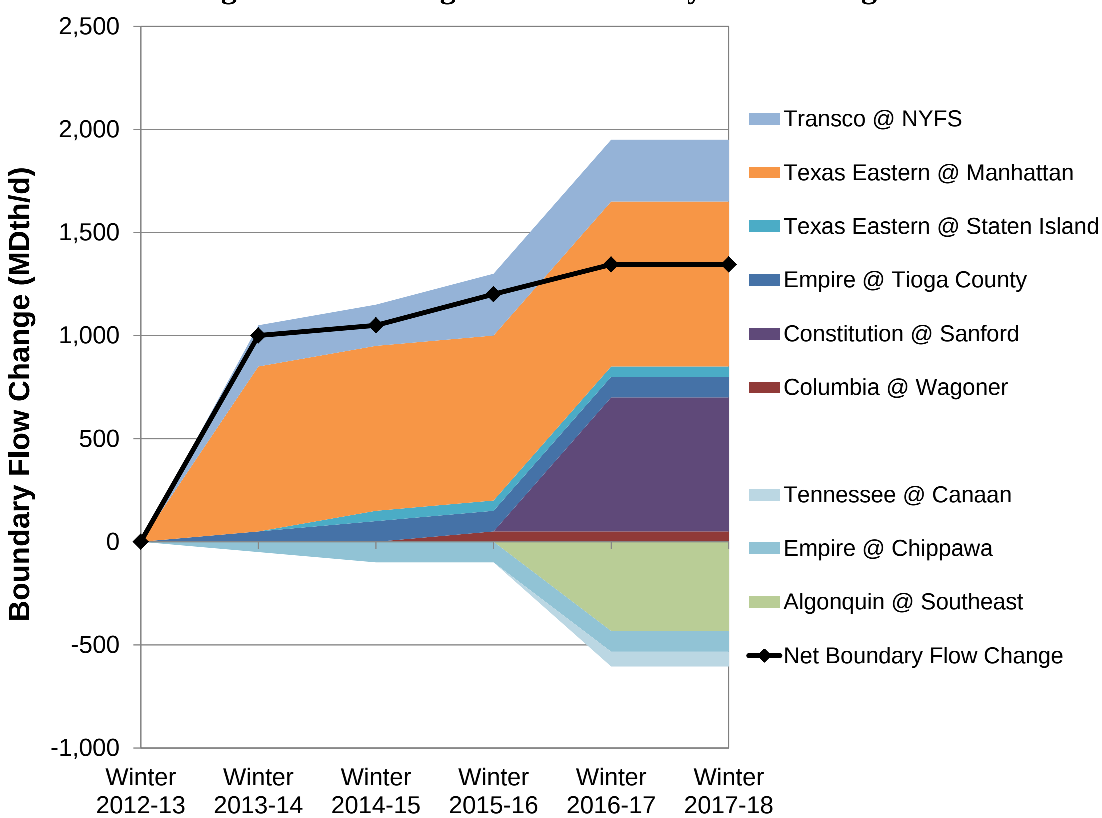


NYCA is located at the center of the Northeast market area. Traditionally, gas has flowed into the state from north to south, from south to north, and from west to east. With the expansion of production from the Marcellus shale, gas from the Rocky Mountains and Gulf of Mexico has been displaced by regional supplies. While New York has benefited from regular exports from western Canada into New York at the Niagara, Chippawa, and Waddington receipt points into Tennessee, Empire and Iroquois, respectively, volumes from western Canada have declined due to economic obsolescence on TransCanada, that is, the comparatively high cost of producing and transporting natural gas from the Western Canadian Sedimentary Basin. Moreover, Tennessee's interconnection with TransCanada at Niagara is presently a delivery point *into* Ontario to accommodate the demand for shale gas from Marcellus. These changes have resulted in gas utilities and power generators in New York State depending on a less geographically diverse portfolio than has previously characterized the state's commodity supply sources.

Notwithstanding the contraction in NYCA's geographic portfolio in favor of low cost gas from Marcellus, there has been a building boom of pipeline and storage infrastructure into and across New York. New pipeline construction has resulted in material improvements across the array of reliable pipeline pathways serving the LHV and NYC, in particular. In LAI's view, the decline in supply diversity is therefore more than compensated for by the improvement in pipeline deliverability to serve power loads in the LHV and NYC.[14] Transco is currently undergoing the FERC certification process for a project that is designed to boost deliverability at Far Rockaway, Queens, which will support National Grid's (NGrid's) reinforcement efforts on the New York Facilities System. Iroquois, too, has a project in development that will strengthen its ability to transport Marcellus gas to Long Island, but the timing of the requisite upstream facility additions on the proposed Constitution Pipeline is uncertain.

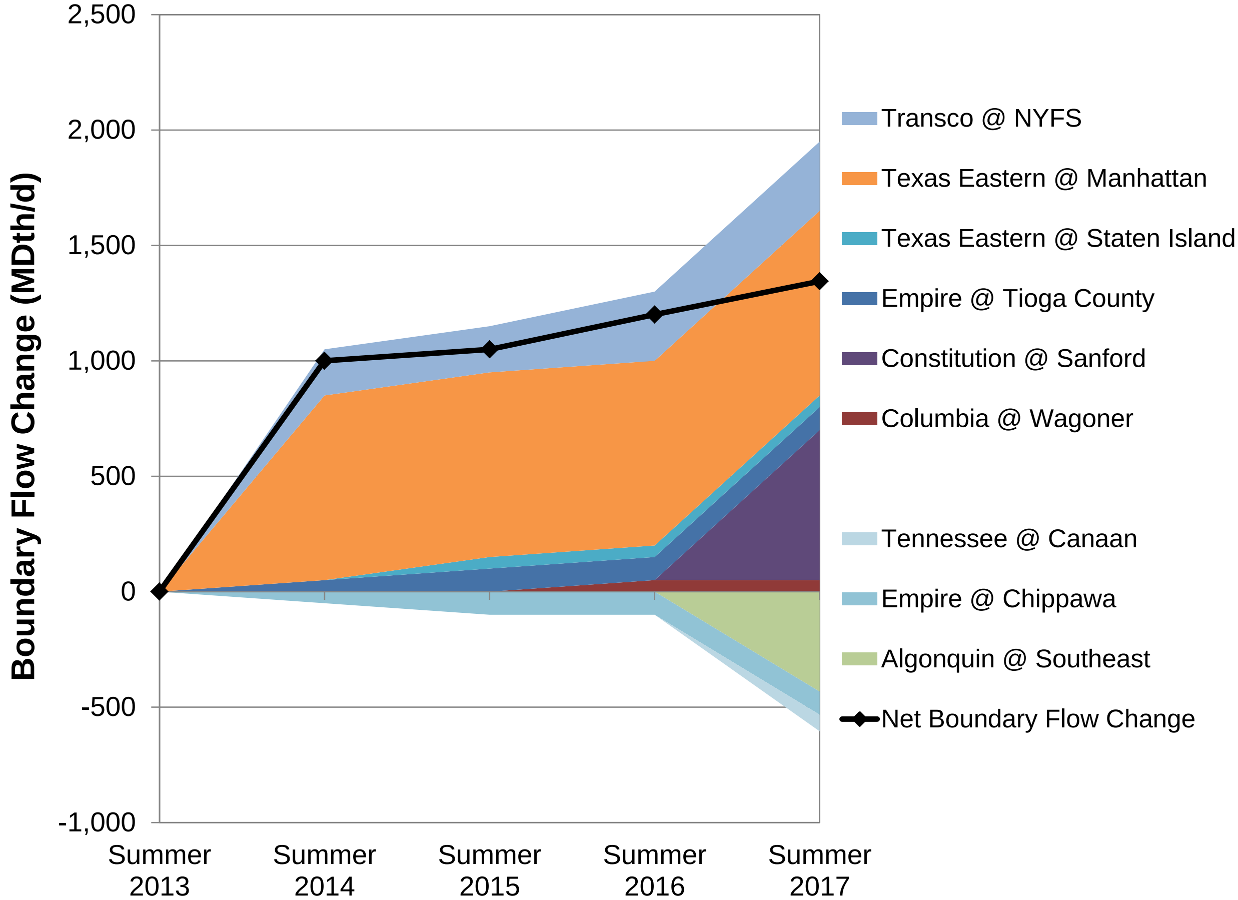
Several noteworthy pipeline expansions have occurred in and around New York since November 2009, many of which are contracted by producers to transport Marcellus gas to the market center in New Jersey and NYC. This growth is expected to continue as additional projects are developed, constructed and commercialized. Figure 16 and Figure 17 illustrate the changes in upstream and downstream boundary flows relative to current transportation capacity. Brief descriptions of these recent and upcoming projects are provided below.

Figure 16. Heating Season Boundary Flow Changes



[14] Gas utilities in New York State, in particular, Con Edison and NGrid, retain sourcing options to the Gulf Coast and Canada through retention of long term transportation contracts on Texas Eastern, Transco and Tennessee that specify primary receipt points in such production areas.

Figure 17. Cooling Season Boundary Flow Changes



1.1.1 Infrastructure Expansion Planning Cycle

There are two main regulatory processes that new pipeline projects must undergo in the State of New York: the FERC 7(c) process and the New York Public Service Commission (NYPSC) Article VII process. Each process is required for both the building of new pipelines as well as the expansion of existing pipelines in order to ensure public safety, general public interest, and environmental protection throughout the execution of the project.

1.1.1.1 FERC Section 7(c) Process

The FERC Section 7(c) process under the Natural Gas Act is broken down into three main sections: the planning process, the application process, and the construction process. The planning process begins when a pipeline company identifies a market need for a new pipeline, or for an extension of an existing pipeline. Support for market need is typically presented to FERC in the form of executed precedent agreements between a pipeline company and those shippers who sign up for firm transportation service. The pipeline company next proposes a specific pipeline route, alerts the relevant landowners, and begins easement negotiations. Public meetings are held to create a forum for landowners, stakeholders, or any member of the public to raise concerns and ask questions about the proposed pipeline. Necessary surveys and reports are also conducted during this time. The planning process ends when the pipeline company files the application with FERC, pursuant to Section 7(c) of the Natural Gas Act, requesting a certificate authorizing the construction and operation of the new natural gas pipeline. The planning process can take as long as two to three years to complete, but varies according to the size of the project and other engineering and environmental challenges. Occurring simultaneously with the pipeline company's planning process is a pre-filing process conducted by FERC, wherein relevant data and stakeholder input are collected for consideration in the environmental review of the project. FERC participates in the public meetings held by the pipeline company and conducts its own meetings and site visits with relevant and interested parties during this time period.

The application process begins when FERC receives the formal application from the pipeline company. The application is reviewed, and requests for additional information are made to the applicant if necessary. At this point, FERC may make a public statement regarding the need for the pipeline project based on non-environmental factors. FERC then conducts an environmental review of the project, resulting in either an Environmental Assessment or Environmental Impact Statement, before ruling on the merits of the certificate application. If the project is denied, the applicant may ask FERC to rehear the case or take FERC to court. If the project is approved, pipeline construction may begin as soon as all certificate conditions are met, including the acquisition of the necessary permits. The duration of the application process is typically about one year, but can last two years, or, in some instances, longer, for complex or controversial projects.

The construction process begins with a finalization of the project design. Plans, surveys, and other necessary information must be filed with FERC before construction may begin. Once the necessary filings have been made and right-of-way (ROW) has been acquired, the pipeline company may construct the new facilities and begin commercial operation. The timelines for select FERC-jurisdictional projects that have been recently completed or are expected to be completed soon are summarized in Table 2.

Table 2. Time from FERC Application to Completion

Project	Application Date	In-Service Date	Elapsed Days	New ROW?
300 Line Project	7/17/2009	11/1/2011	837	No
Tioga County Extension Project	8/26/2010	11/22/2011	453	Yes
Bayonne Delivery Lateral Project	5/21/2009	4/5/2012	1,050	Yes
Northeast Supply Diversification Project	11/12/2010	11/1/2012	720	No
Ellisburg to Craigs Project	11/19/2010	11/1/2012	713	No
TEAM 2012 Project	1/25/2011	11/1/2012	646	No
MARC I Project	8/9/2010	12/1/2012	845	Yes
Northern Access Project	3/7/2011	1/16/2013	681	No
Minisink Compressor Station Project	7/14/2011	6/1/2013	688	No
New Jersey – New York Expansion Project	12/20/2010	11/1/2013 (expected)	1,057	Yes
Northeast Upgrade Project	3/31/2011	11/1/2013 (expected)	946	No
Northeast Supply Link Project	12/14/2011	11/1/2013 (expected)	688	No

1.1.1.2 NYPSC Article VII Process

Once a market need for a new pipeline in New York is established, an application for a Certificate of Environmental Compatibility and Public Need must be filed with the NYPSC. Similar to the FERC 7(c) process, the NYPSC Article VII process is broken down into phases: the pre-application phase, the application phase, the hearing and decision phase, and the post-certification phase.

The pre-application phase is technically optional, but is highly recommended by the NYPSC. The pre-application phase consists of the applicant meeting with various state agencies to informally introduce the proposed project, making a public announcement regarding the planned pipeline project, and launching a public involvement program. The NYPSC stresses the importance of having all interested individuals and groups informed of the project application and invited to participate in whatever way they choose.

The application phase begins with a mandated newspaper notice of the applicant's intent to file an Article VII application with the NYPSC. The application is then filed with the NYPSC, and copies of the application are distributed to all stakeholders and parties involved in the proceedings, including state and local officials, relevant municipalities, special interest groups, and others. Before the hearing begins, the NYPSC may hold a public meeting explaining how the Article VII process works and to further encourage public involvement.

The hearing and decision phase begins once the application is complete, and no requests for additional information by the NYPSC are unfulfilled. An independent Administrative Law Judge is appointed to conduct the public statement and evidentiary hearings. The evidentiary hearings are separated into the applicant's direct case, all other parties' direct cases, and all rebuttal cases, with several weeks separating each hearing. The evidentiary hearings are the official forum for the applicant to present evidence in favor of certification, for the applicant's witnesses to be cross-examined, for all other involved parties to present testimony, and for the NYPSC to (optionally) make a presentation. Following the final evidentiary hearing, briefs are submitted, and then the Administrative Law Judge recommends a decision to the NYPSC.

If the Commission determines that there is a need for the facility in question and that all environmental concerns are addressed, a certificate may be issued. The receipt of the certificate marks the beginning of the post-certification phase for the applicant. Various other documents and filings must be made before construction can begin, the most important of which is the Environmental Management and Construction Plan, which gives detailed information about the location of facilities and all special precautions that will be taken during construction. At this point, any remaining ROW acquisitions are completed, and the pipeline construction may begin. The time frame for completing the NYPSC Article VII process is normally shorter than that of the FERC 7(c) Process. The timelines for select NYPSC-jurisdictional projects that have been recently completed are summarized in Table 3.

Table 3. Time from NYPSC Application to Completion

Project	Application Date	In-Service Date	Elapsed Days	New ROW?
Laser Northeast Gathering	7/20/2010	10/26/2011	463	Yes
Bluestone Gathering	7/27/2011	5/13/2013	656	Yes

1.1.1.3 Additional Permits

In addition to FERC / NYPSC review and certification, expansion projects may be subject to other state permitting requirements, such as the Department of Energy and Environmental Protection 401 Water Quality Certification in Connecticut for projects in Long Island Sound. Other permits that may be necessary include air emission and coastal land use permits. The application process for these permits is straightforward, and the time frame for acquiring these permits is typically short, though significant delays can occur if the regulating agency takes issue with the request.

1.1.2 Recently Completed Infrastructure Expansions

Projects that have been placed into service since November 2009 include the following:

Laser Northeast (NY PSC Case No. 10-T-0350): Laser is a gathering system that consists of 30 miles of pipe and 10,000 HP of compression, designed to deliver up to 400 MDth/d into Millennium. The new facilities entered service in October 2011.

300 Line Project (Tennessee, FERC Docket No.CP09-444): This project added 128 miles of loop line and 55,000 HP of incremental compression to create 350 MDth/d of firm transportation, including 50 MDth/d deliverable into the New York Facilities System at White Plains. These facilities were placed in service in November 2011.

Tioga County Extension Project (Empire, FERC Docket No.CP10-493): This project added a 15-mile extension from Corning to connect to two new producer receipt points in Tioga County, Pennsylvania, along with various other system modifications, to permit Empire to receive up to 350 MDth/d at the southern end of its system for redelivery across its system to Chippawa and secondary points. The new facilities came online in November 2011.

Bayonne Delivery Lateral Project (Transco, FERC Docket No.CP09-417): This lateral to provide 250 MDth/d of transportation capacity to the new Bayonne Energy Center consists of five miles of converted oil pipeline and one mile of new pipe. The lateral was placed in service in April 2012.

Northeast Supply Diversification Project (Tennessee, FERC Docket No. CP11-30) / Ellisburg to Craigs Project (Dominion, FERC Docket No.CP11-41): These projects involve various system upgrades, along with 7 miles of loop line and a new 10,800 HP compressor station, to allow Tennessee to deliver 250 MDth/d of gas from Marcellus receipt points to the Niagara interconnection with TransCanada. These facilities, which resulted in a reversal of flow on the Niagara Spur Line and the conversion of Niagara from an import point to an export point, entered service in November 2012.

TEAM 2012 Expansion Project (Texas Eastern, FERC Docket No. CP11-67): This project created 200 MDth/d of incremental transportation capacity from the Marcellus shale to interconnections with Transco and the Eastern Shore Pipeline in Pennsylvania by adding 5 miles of loop line, replacing 11 miles of pipe with a higher diameter, and adding 21,720 HP of compression. The facilities came online in November 2012.

MARC I Project (Inergy / Central New York Oil & Gas, FERC Docket No. CP10-480): This project connected Stagecoach's South Lateral to Transco through the addition of 39 miles of pipe and 31,660 HP of compression, with 550 MDth/d of deliverability into Transco. The new interconnection was placed into service in December 2012.

Northern Access Project (NFG, FERC Docket No.CP11-128): This project includes system modifications and approximately 14,000 HP of incremental compression to allow NFG to deliver up to 320 MDth/d to Niagara via shared Tennessee facilities. The final components of the project were placed into service in January 2013.

Bluestone Gathering (NY PSC Case No. 11-T-0401): This 44.5-mile gathering system is capable of transporting up to 600 MDth/d combined to both Millennium (in Broome County, NY) and Tennessee (in Susquehanna, PA). Deliveries into Millennium began in May 2013.

Minisink Compressor Project (Millennium, FERC Docket No. CP11-515): This new 12,000 HP compressor station in Minisink, New York (Orange County) was placed into service in June 2013, enabling Millennium to increase its delivery capacity into the Ramapo interconnection with Algonquin by approximately 150 MDth/d. [15]

1.1.3 Pending Infrastructure Expansions

There are several large projects which have not yet been commercialized, but may be commercialized over the next five years. Of particular note among these projects are those that will expand deliverability into the downstate region. Together, Texas Eastern's New Jersey – New York Expansion Project and Transco's Northeast Supply Link Project represent 1,000 MDth/d (or approximately 1 Bcf/d) of incremental deliverability into NYC. To put these infrastructure projects in perspective, it has taken about 65 years to build pipelines into the New York Facilities System with a certificated capability about 3.2 Bcf/d: the new projects will increase total deliverability by approximately one-third.. This additional capacity has the *potential* to serve approximately 143,000 MWh/d or 6,000 MW of generation for 24 hours at full load, assuming the heat rate characteristic of a new combined-cycle plant.[16]

New Jersey-New York Expansion Project (Spectra, FERC Docket No.CP11-56): This 800 MDth/d project involves constructing 15.5 miles of new 30" pipe through Staten Island and Bayonne, Jersey City and Hoboken, New Jersey into Manhattan, along with other system

[15] Although the project is now in service, a community opposition group's challenge is currently pending before the DC Circuit Court of Appeals; briefs were filed in July 2013. Oral arguments have not yet been scheduled.
[16] This conversion assumes a heat rate of 7,000 Btu/kWh, or 7 Dth/MWh, and does not account for Con Edison's firm transportation entitlement of 170 MDth/d for core sendout.

modifications, in order to provide transportation service to new delivery points in EMAAC and Manhattan.[17] Construction is currently underway, for a November 2013 in service date.[18]

Northeast Upgrade Project (Tennessee, FERC Docket No.CP11-161): This project will add approximately 40 miles of loop line and 22,000 HP of compression to Tennessee's system in order to increase deliverability into an interconnection with Algonquin in Mahwah, NJ by 636 MDth/d, in support of Spectra's New Jersey-New York Expansion Project. Construction is currently underway for a November 2013 in service date.[19]

Northeast Supply Link Project (Transco, FERC Docket No. CP12-30): The system upgrades involved in this project include 12 miles of loopline, 27 miles of uprates, and 40,000 HP of compression to create 250 MDth/d of incremental firm transportation service to delivery points in New Jersey and NYC. Construction is currently underway for a November 2013 in service date.

Hancock Compressor Project (Millennium, FERC Docket No.CP13-14): This project involves the construction of a new 15,000-HP compressor station in Hancock, New York (Delaware County) that will enable Millennium to deliver an additional 107.5 MDth/d to Algonquin at Ramapo. The FERC certification process is currently underway.[20] Because the path of the incremental transportation capacity is contained within NYCA, this project does not affect boundary flows, therefore it has not been modeled as coming online at a specific time. It is possible the new station will be online for the 2013-14 heating season, but LAI believes a summer 2014 in-service date is more likely given the delay in receiving FERC authorization.

Rockaway Delivery Lateral Project (Transco, FERC Docket No.CP13-36): This project will construct a new 3-mile lateral, with a capacity of 647 MDth/d, from the existing Lower New York Bay Lateral to an interconnection with NGrid and a new delivery meter station on the Rockaway Peninsula in Queens County. The FERC certification process is currently underway. Because the lateral does not involve new upstream capacity on the Lower New York Bay Lateral, this project does not affect boundary flows. Therefore it has not been modeled as coming online at a specific time. In its certificate application, Transco requested FERC authorization by October 2013 in order to meet a planned November 2014 in-service date. The Environmental Impact Statement is expected to be completed in February 2014, leading to a late-

[17] In addition to the new Manhattan delivery point, Texas Eastern is also constructing new meter stations in Bayonne, NJ and Jersey City, NJ, which will also be served by the 800 MDth/d of incremental transportation capacity.

[18] On October 18, 2012 FERC issued an order denying all requests for rehearing, reconsideration, and stays on construction. Spectra has successfully redressed challenges from Jersey City, Conrail, Sane Energy, and various environmental groups. Jersey City and an environmental group have each filed petitions with the DC Court of Appeals to review FERC's certification order, but this effort is unlikely to delay commercialization at this point.

[19] The project's certification was delayed due to the need to re-route the path of one of the pipeline loops to avoid National Park Service land after permission to parallel an existing Tennessee line was denied. Additional environmental issues concerning local Native American tribes also slowed the project.

[20] FERC issued the Environmental Assessment for this project in February 2013, and state permits were issued in March 2013.

May 2014 FERC-authorization deadline. Hence, we believe a commercial operation date prior to the 2015-16 heating season is more likely.[21]

TEAM 2014 (Texas Eastern, FERC Docket No. CP13-84): This project involves 33 miles of pipe replacement and 77,100 HP of incremental compression to create 600 MDth/d of incremental firm transportation along Texas Eastern's mainline, 300 MDth/d of which will be deliverable to the eastern end of the system – 250 MDth/d to Lambertville and 50 MDth/d to Staten Island. The FERC certification process is currently underway, with facilities projected to be in service for the 2014-15 heating season. The Environmental Assessment schedule is such that the FERC authorization deadline is expected to be only five days later than Texas Eastern's requested November 2013 date, therefore we expect this project to proceed on schedule.[22]

Northeast Connector (Transco, FERC Docket No. CP13-132): This project is designed to bring 100 MDth/d of incremental supplies to the Rockaway Lateral from Station 195 near the Maryland-Pennsylvania border. Transco has submitted a target in-service date in November 2014, but the project is being jointly evaluated with the Rockaway Delivery Lateral. LAI believes it is therefore more likely to be commercialized in time for the 2015-16 heating season.

Constitution Pipeline (FERC Docket No. CP13-499): This new pipeline will consist of 121 miles of 30-inch pipe to transport 650 MDth/d from gathering facilities in Susquehanna County, PA, to an interconnection with Iroquois at the existing Wright Compressor Station in Schoharie County (NY). Constitution will also lease capacity on Iroquois in order to access delivery points on the existing Iroquois and Tennessee systems. Constitution has announced a planned in-service date of March 2015, but due to the complexity of the permitting process for 120 miles of new pipeline and landowner resistance, we have made the conservative assumption that the project will be delayed to the 2016-17 heating season.[23]

Wright Interconnect Project (Iroquois, FERC Docket No. CP13-502): This project will create a new physical receipt point for 650 MDth/d from the Constitution Pipeline into Iroquois at the existing Wright Compressor Station. Iroquois plans to add 22,000 HP of new compression, thereby revitalizing Iroquois's ability to tap into a lower cost gas supply for redelivery across Zone 2 into the LHV, Hunts Point gate station in Queens, and, most important, the South Commack terminus on Long Island. Like the Constitution Pipeline, the currently announced in-service date is March 2015. However,, to the extent that the new pipeline is delayed, the compressor station upgrade may also be delayed. This project will not affect NYCA boundary flows.

[21] While there are no private landowners affected by the new lateral, public opposition has formed against constructing the project through the National Park Service's Gateway Recreation Area.

[22] Conoco Phillips has made a series of filings concerning the selected path of the TEAM 2014 improvements and Texas Eastern's decision not to accept an offer of turnback capacity. The impact of this dispute on the timing and scope of the project is uncertain at this time.

[23] As of May 30th, Constitution reported to FERC that survey permission had been granted for 68.3% of the affected parcels. Owners of 25.9% of the parcels had denied or rescinded permission. Additionally, Constitution may experience protracted delays or regulatory setbacks as a result of public opposition to fracking.

East Side Expansion Project (Columbia, FERC Docket No. PF13-7): This project will expand and upgrade existing facilities in order to enhance interconnects with Millennium at Wagoner and with Tennessee at Milford by up to 310 MDth/d of additional capacity. The FERC pre-filing process is currently underway; Columbia expects to file the certificate application in November 2013 to meet a September 2015 in-service date.

Tuscarora Lateral Project (Empire / NFG, FERC Docket No. PF13-12): This project includes new vertical wells and incremental compression at NFG's Tuscarora Storage Field and a new 18-mile lateral connecting the Tuscarora facilities with Empire. The pre-filed schedule is based on a November 2015 in-service date. Because the new facilities will be located with New York, boundary flows will not be affected.

Algonquin Incremental Market Project (Algonquin, FERC Docket No. PF13-16): This project, as pre-filed, will add 433 MDth/d of transportation capacity from the interconnection with Millennium at Ramapo into New England by constructing 26 miles of mainline replacement and looping, including a new Hudson River crossing, 18 miles of lateral replacement, looping and extension, and 80,000 HP of incremental compression.[24] Algonquin's schedule calls for the new facilities to be in service for the 2016-17 heating season.

Connecticut Expansion Project (Tennessee): For this project, Tennessee will install 13 miles of loopline on Line 200 to provide 72 MDth/d of incremental transportation from Wright, NY to customers in Connecticut. Precedent agreements have been signed and Tennessee expects to file a certificate application with FERC in Q1 2014 for a November 2016 in-service date.

TransCanada Marcellus Project (TransCanada): This project, for which an open season was held in July 2013, involves incremental transportation capacity from receipt points including Niagara and Chippawa to eastern import points including Waddington, Cornwall and Napierville, among other receipt and delivery locations. This would allow access to an alternate path to move Marcellus gas to eastern New York. TransCanada has announced that the new capacity could be available as early as November 2015, with additional volumes available for the 2016-17 heating season. Because the volumes associated with this project are not known at this time, and flows into and out of New York are likely to at least partially offset, we have not included this project in the boundary flow adjustments over the study horizon.

Upstate Pipeline Project (Millennium): This project, as described in the open season materials, would involve the construction of at least one compressor station and approximately 60 miles of new 24-inch (or larger) pipeline that would connect the existing Millennium system to Dominion near Cortland, NY and to Tennessee near Syracuse, NY. Millennium's preliminary in-service date for the new facilities is early 2016. Because the new capacity would be located entirely within New York, boundary flows would not be affected.

Northeast Expansion Project (Tennessee): The project design is still under development. At present, it involves 171 miles of loopline and new build between Wright, NY and Dracut, MA.

[24] Not all of the capacity was subscribed prior to Spectra's pre-filing submission to FERC. According to Spectra management, if Algonquin does not identify additional market support for the uncontracted volumes, the size of the project and scope of the facilities will be reduced.

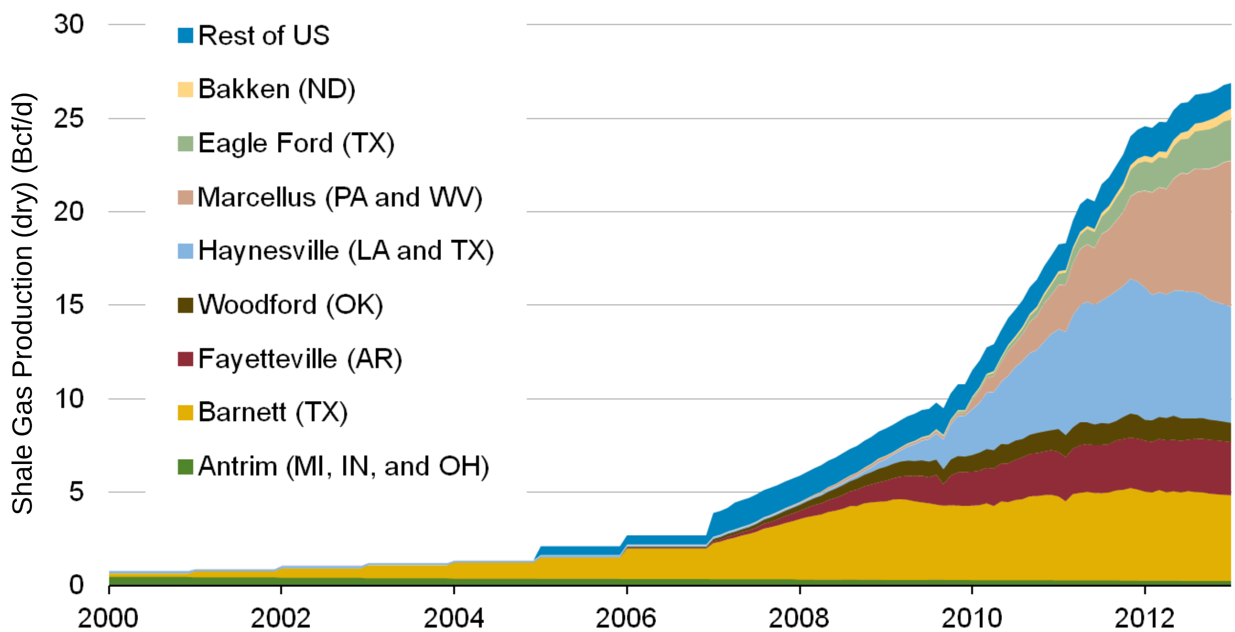
About 60% is along existing rights-of-way, rendering 0.5 to 1.2 Bcf/d into the Boston area. Tennessee has projected an in-service date no earlier than Q4-2017. Given the scale of this project, length of new ROW, and early stage of development, we have assumed that this project will not be commercialized during the study period. Therefore it has not been included in this analysis.

<u>Central Tioga County Extension (Empire)</u>: This project, which appears to be on hold, would boost producer receipts by 365 MDth/d for delivery within New York and export to Canada.[25] Based on the absence of current information, we have assumed that if this project is commercialized, it will after the study period, therefore it has not been included in this analysis..

1.2 Supply Developments and Gas Prices

Shale gas developments in North America have not been confined to Marcellus. As Marcellus production expanded so did shale gas production from other plays including the Eagle Ford in Texas, the Haynesville in Louisiana and Texas, the Fayetteville in Arkansas, and the grandfather of all shale plays, the Barnett formation in Texas. Figure 18 shows the latest EIA data regarding the development of domestic shale gas production.

Figure 18. Domestic Shale Gas Production[26]



Shale gas production in 2008 represented about 13% of total U.S. gas production, primarily production from the Barnett shale in Texas. From 2009 to 2012, domestic shale gas production

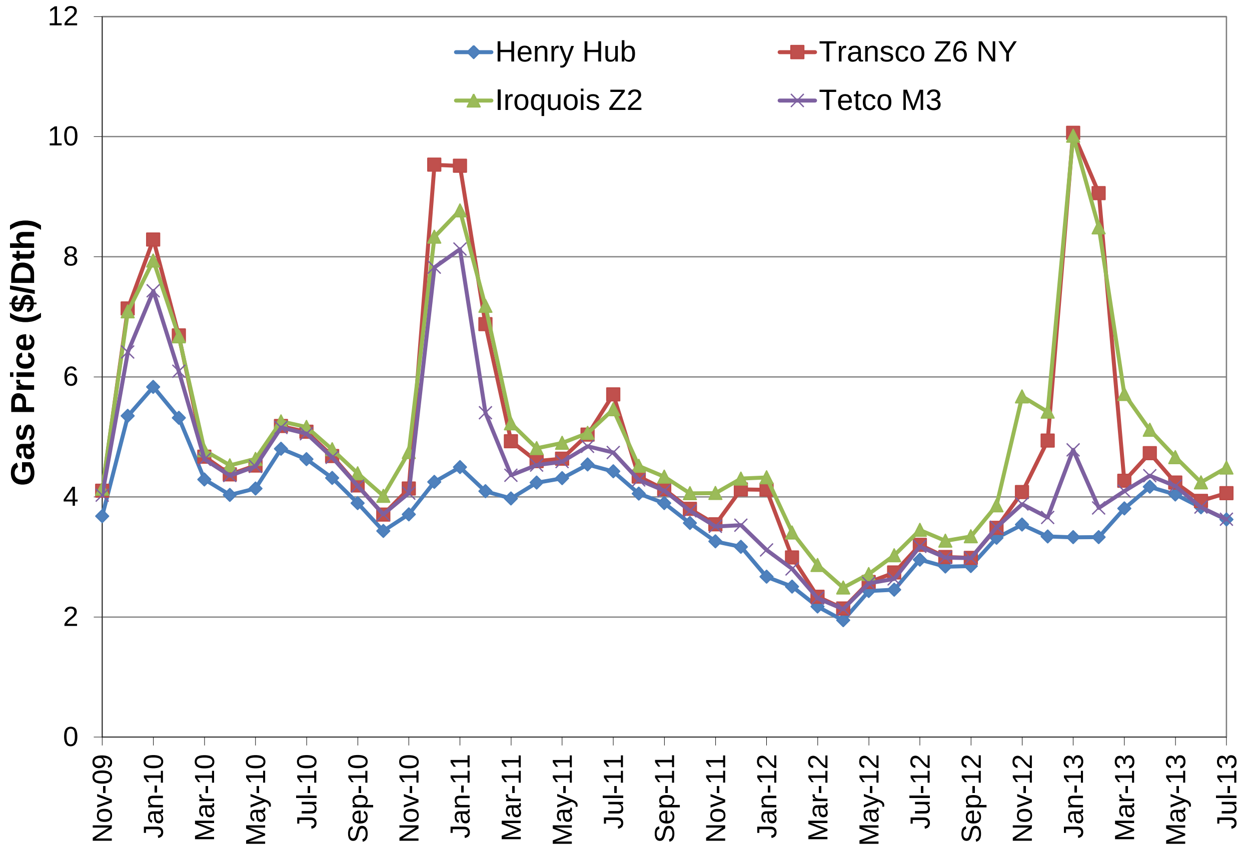
[25] Upon close of its open season, Empire reported that the bid responses met expectations, but the information on Empire's website is outdated, showing a proposed in-service date in September 2013.

[26] Source: A. Sieminski, "Outlook for shale gas and tight oil development in the U.S." presentation to IFRI; Paris, France; March 14, 2013.

more than tripled, reaching 27 Bcf/d, or about 39% of total U.S. production. This market trend is expected to continue over the remainder of this decade, albeit at a slower rate.

Shale gas production has depressed commodity prices across North America. Monthly average spot prices at the Henry Hub, the benchmark North American gas price index, peaked at \$12.69/Dth in June 2008, subsequently falling to about \$2.00/Dth in May 2012 before recovering to about \$4.17/Dth in April 2013. The decline in Henry Hub prices is shown in Figure 19, along with monthly average delivered gas prices at the key pricing points for the downstate New York markets, *i.e.*, Transco Zone 6 New York (Transco Z6 NY), the primary NYC pricing point; Texas Eastern M-3 (Tetco M3), which covers delivery points in Pennsylvania as well as the Hanover and Linden stations in New Jersey; and Iroquois Zone 2 (Iroquois Z2) which covers deliveries to the LHV, Long Island and NYC. The long-term historic correlation between price indices in New York and New England is highly likely to break down in Q4-2013 in response to the new transportation pathways into NYC are expanded.

Figure 19. Average Monthly Spot Prices[27]



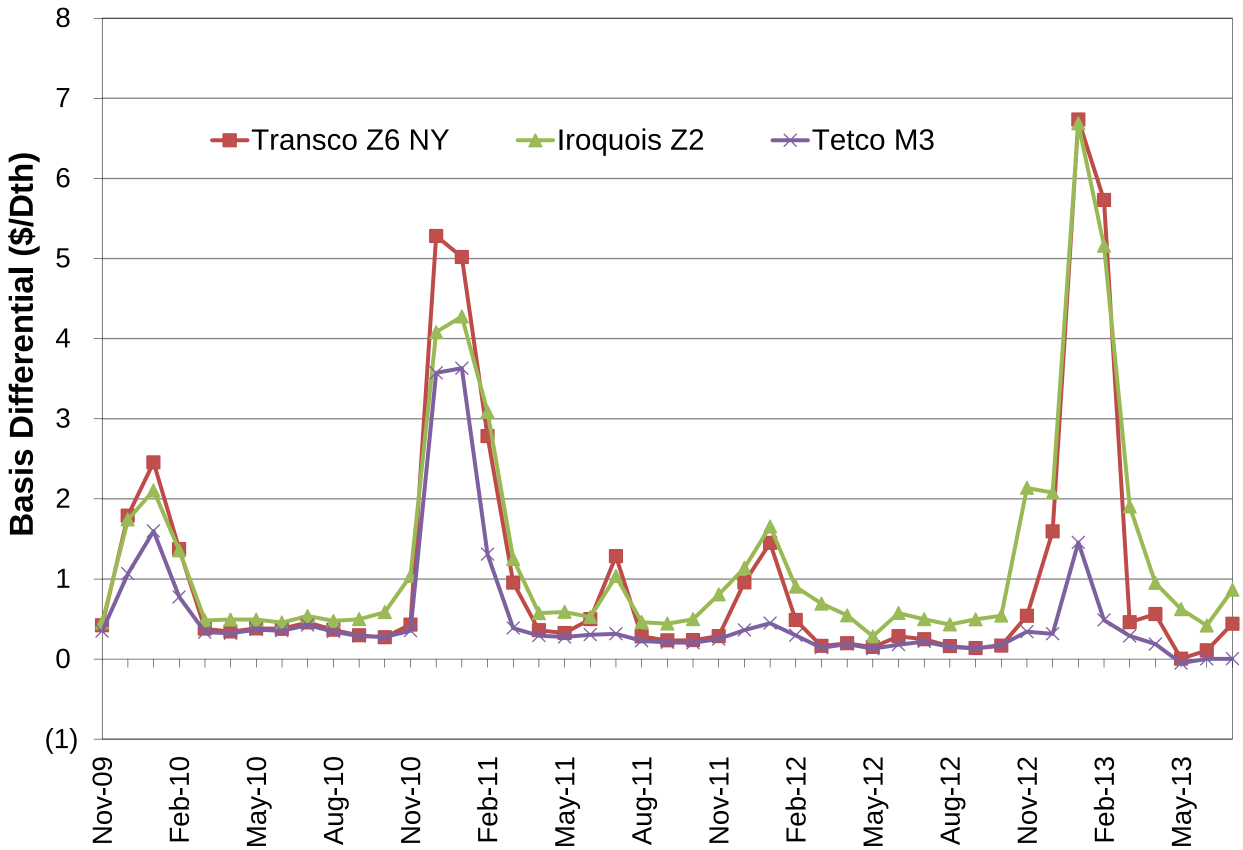
The weak economy coupled with comparatively mild temperature conditions and prolific shale gas production sustained downward pressure on gas prices both at the Henry Hub and at many key pricing points in the market area. Skyrocketing basis during the January 2013 cold snap and winter storm Nemo reflected pipeline congestion on Transco, Tennessee, Texas Eastern and

[27] Source: Bloomberg LP

Algonquin, in part, a reflection of the deterioration in New England's pipeline portfolio diversity due to production problems in Atlantic Canada and the decline in LNG imports.[28]

As shown in Figure 20, for most of the study period, average monthly basis to New York was less than $1.00/Dth, with the most significant exceptions occurring during the 2010-11 and 2012-13 heating seasons.[29] The pronounced basis run-up during the 2012-13 heating season reflects cold weather in the market center and pipeline congestion along supply paths from Marcellus into the Capital District, LHV, and New York Facilities System. The upward pressure on basis also reflects sympathy with New England pricing points, that is, the moderate correlation between New York indices and those of relevance in New England, *i.e.*, Algonquin Citygates and Tennessee Zone 6.

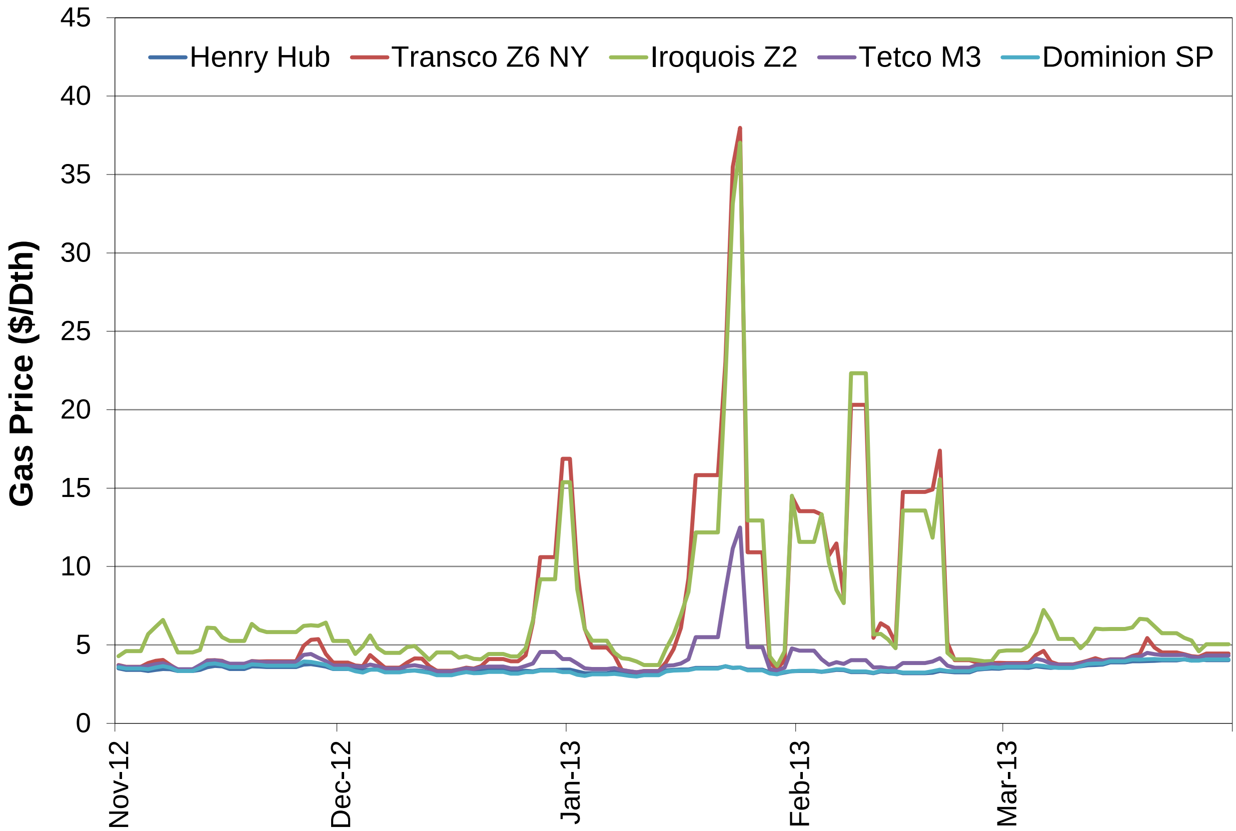
Figure 20. Average Monthly Basis for New York Gas Indices[30]



Soaring basis during the cold snap in January 2013 is more pronounced when expressed on a daily basis. Figure 21 shows daily spot prices for the 2012-13 heating season.

[28] During the cold snap in January 2013, Repsol's Canaport LNG import terminal was used to restore north-to-south flows into New England.
[29] In this study, basis refers to the differential between regional gas prices and prices at the Henry Hub.
[30] *Ibid*

Figure 21. Daily Spot Prices, November 2012-January 2013[31]

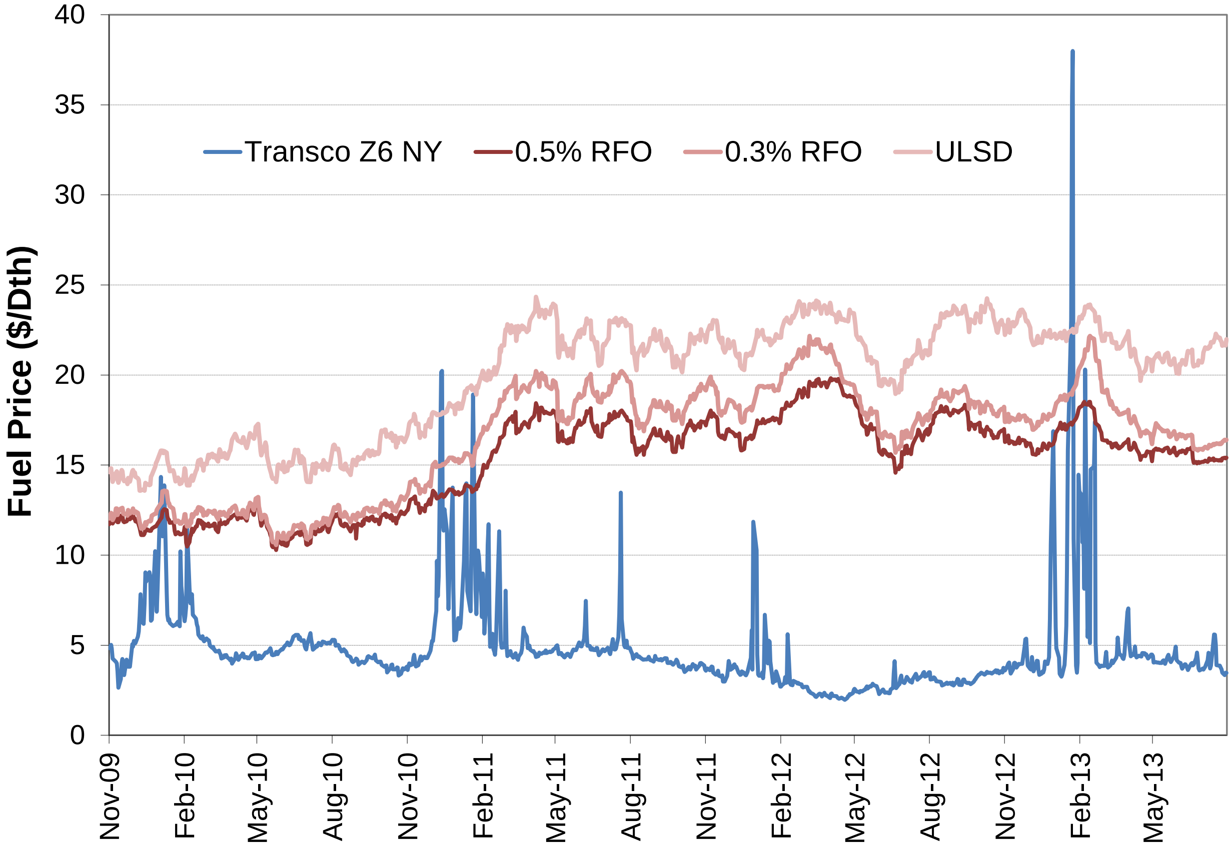


When temperatures fell in late December, Transco Z6 NY and Iroquois Z2 delivered prices rose to a peak above $15.00/Dth. During the January 2013 cold snap, prices more than doubled the December spike, with both Transco Z6 NY and Iroquois Z2 exceeding $35.00/Dth. In contrast, prices at the Henry Hub remained flat. Basis at key pricing points in PJM diverged from leading indices in New York and New England. Like the Henry Hub, Dominion South Point (Dominion SP) remained flat, while Tetco M3 peaked at a much lower level than the Transco and Iroquois pricing points.

According to Bloomberg LP, there were 15 trading days from November 2009 through July 2013 when Transco Z6 NY gas was more expensive than the delivered price of 0.5% residual fuel oil (RFO) and 5 days when Transco Z6 NY gas was more than expensive than ULSD, including three days during the January 2013 cold snap.

[31] Source: Bloomberg LP

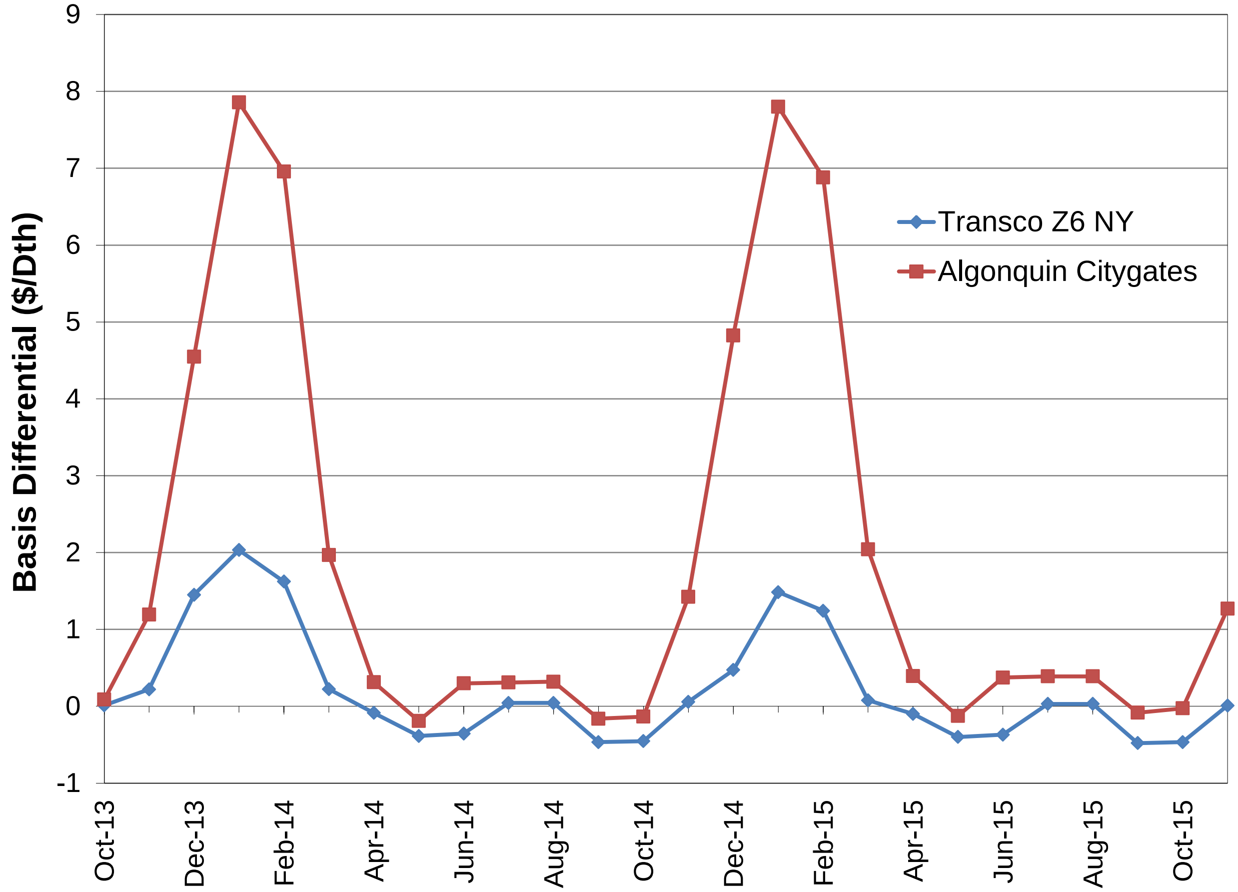
Figure 22. Comparison of Spot Prices for Gas and Oil



Over the historical study period, dual fuel generators across NYCA predominately used natural gas. As we understand it, oil use by steam turbine generators on the New York Facilities System occurred largely in response to local reliability rules IR-3 and IR-5 and from time to time when gas deliverability constraints arose during cold snaps or pipeline outages rendering oil-fired generation in-merit. On a Dth-equivalent basis, the price differential between natural gas delivered to the relevant zones and fuel oil – both RFO and ultra-low sulfur diesel (ULSD) – has caused oil-fired generation to be almost always out-of merit. The exceptions have occurred during brief intervals when skyrocketing basis at key pricing points in the market area reflected pipeline constraints, thus exposing generators to costly penalties for unauthorized gas use.

Favorable production and delivery developments from the Marcellus shale to New York are reflected in the financial market. Market participants routinely hedge gas price risk from the production area to the market area through basis swaps, financial products that capture the anticipated future value differential between the Henry Hub and where gas is consumed. Spectra's New Jersey – New York Expansion Project and Transco's Northeast Supply Link Project will substantially increase in-City deliverability. Over the historical study period, the maximum average monthly basis for Transco Z6 NY was about $7.00/Dth, and it was greater than $2.00/Dth for six heating season months, as shown in Figure 20. Prior to the 2009-10 heating season, basis had been even higher. The favorable deliverability impacts ascribable to the new Spectra pipeline into Manhattan are revealed in the forward curve for swaps for Transco Z6 NY basis traded on the Chicago Mercantile Exchange (CME). As shown in Figure 23, the market expects Transco Z6 NY basis to remain below $0.50/Dth most months for the next several years, rarely exceeding $1.00/Dth and negative during the cooling season months.[32] The materially reduced basis differential evidenced through the basis swap forward curve stands in contrast to the basis swaps of relevance in New England, where pipeline delivery conditions are expected to remain constrained, as illustrated by the Algonquin Citygates forward curve in Figure 23, which shows spikes to nearly $8.00 over the next two heating seasons.

Figure 23. Basis Swap Forward Curves



[32] Source: CME Group. Closing prices from September 10, 2013.

2 HISTORICAL CONGESTION REVIEW

LAI's assessment of natural gas deliverability conditions into and within New York State is based on an analysis of recent flow patterns and congestion events on the pipelines serving NYCA. Relying on pipeline throughput data posted on each pipeline's electronic bulletin board (EBB), LAI has evaluated actual pipeline flows and identified conditions that determine the frequency, duration, and location of congestion events. Such congestion events bear upon the availability of secondary firm and interruptible transportation arrangements to serve power plants across NYCA. In conducting this evaluation, LAI reviewed the issuance of critical notices, flow day alerts and OFOs. We report how pipeline throughput and capacity utilization levels have changed over the period from November 1, 2009 through July 31, 2013. In some instances, we have truncated the time series in order to more accurately capture relevant market dynamics from Marcellus.

Flow patterns were analyzed across critical segments for the Capital District, LHV and into the New York Facilities System operated by Con Edison and NGrid. These pipelines include Algonquin, Empire, Iroquois, Millennium, Tennessee, Texas Eastern, and Transco. Flow patterns across the reticulated pipelines serving upstate New York – NFG, Columbia, and Dominion – have not been included in the congestion review due to the comparatively insignificant non-core gas-fired generation served by these pipelines.

2.1 Approach and Data Sources

To quantify pipeline utilization and congestion levels, LAI relied on daily throughput data posted on EBBs.[33] LAI has found that these daily postings constitute a reliable source of throughput data and available capacity across the consolidated network of pipelines and storage facilities doing business in NYCA. In gauging congestion patterns over the defined historic period, LAI has also considered the daily variances in available capacity attributable to maintenance or unplanned outages.

The study period encompasses a diverse range of market conditions, including: hotter-than-normal temperatures that occurred during Summer 2010 and Summer 2013; the mild temperature conditions during Winter 2011-12; and the cold snap that occurred in the third week of January 2013.[34]

A number of macroeconomic and operational factors varied significantly over the study period as well. These include the financial crisis and subsequent economic recovery, gas price volatility, and, most importantly, the commercialization of significant new pipeline and storage facilities to accommodate production from Marcellus. The exponential growth of shale gas production over the last five years coupled with increased gas use for power generation in NYISO, PJM and ISO-NE have resulted in major facility improvements in Pennsylvania and New York, as well as many new pipeline projects presently under construction or in development in PJM and across NYCA. The impact of these infrastructure improvements on congestion events is observed over

[33] The daily posting of Operationally Available Capacity data is required by FERC.

[34] LAI's scope of work defined the relevant historic period through October 2012, but was extended during the course of this analysis to capture throughput patterns in January 2013.

the recent historic period as many of the facility improvements were commercialized in 2011 and 2012.

Pipeline utilization rates are defined as the ratio of throughput to available capacity for the final daily nomination cycle. While most pipelines posted data on their EBBs for the entire study period, there were exceptions. Some pipelines, but not all, also post the daily operating capacity at mainline points such as compressor stations. Where daily operating capacities were not available, the operational capacity was assumed to be equal to the maximum throughput during the study period. Absent a pipeline's posting of mainline throughput capacity, we have noted each instance where LAI has relied instead on the maximum throughput over the time series. We note that there is no one clear definition or industry convention regarding what constitutes congestion as operational and market factors differ across NYCA. Therefore we have formulated statistical benchmarks in order to calibrate the operating conditions that expose non-firm shippers to restrictive conditions potentially limiting the use of natural gas for power generation.

In conducting this analysis, pipeline congestion is synonymous with high utilization levels across the segments of relevance to the Capital District, LHV, NYC or Long Island. LAI has identified the number of days when pipeline utilization exceeded 90% and 95% of the available capacity. When pipeline utilization rates approach 95% of available capacity levels, the pipeline is likely, but not certain, to post Critical Notices or Flow Day Alerts, thereby requiring gas-fired generators to schedule ratably or otherwise incur costly penalties for unauthorized gas use and/or daily imbalances.[35] While the posting of critical notices rarely affects firm transportation entitlement holders, except perhaps in cases of *force majeure* events, a pipeline's issuance of such a notice is likely to constrain the scheduling of secondary firm transportation both in- and out-of-the-path, as well as any interruptible transportation volumes across the market area. From an operational standpoint, restrictions to the scheduling of non-firm transportation under capacity release arrangements or interruptible transportation can occur at lower or higher levels of utilization depending on the pipeline, location, and seasonal factors affecting storage withdrawals at Leidy, Ellisburg, Oakford and the Dawn storage hub in Ontario. LAI's use of the 90% and 95% statistical benchmarks demarcates the operational and market conditions that are most likely to constrain the flow of natural gas to non-firm shippers in the relevant zones. LAI has compiled the critical notices issued by each pipeline for the relevant segments over the study period in order to assess the causes of congestion.

Pipeline utilization rates have been derived for the following pipeline segments:

[35] Ratable takes are when the pipelines require shippers to take gas deliveries at a uniform hourly volume over a 24 hour period.

Table 4. Pipeline Segments Analyzed

Pipeline	Location(s)
Algonquin	Hanover, Stony Point, Southeast (Figure 24)
Empire	Empire Connector (Figure 34)
Iroquois	Brookfield, Waddington (Figure 39)
Millennium	Ramapo (Figure 48)
Texas Eastern	Lambertville, Linden (Figure 66)
Tennessee	Station 224, Station 245, Station 345 (Figure 54)
Transco	Linden (Figure 74)

Each of these locations represents a key point along the consolidated network of pipelines serving power loads in NYCA. Flow restrictions may adversely affect the availability of non-firm transportation service to generators in one or more zones. When pipeline restrictions result in the posting of critical notices or operating flow orders, gas-fired generation may switch to oil in storage. Some gas-fired steam turbine generators can use low sulfur RFO held at on-site tanks. Some combined-cycle plants or peakers use distillate oil or ULSD in order to operate when restrictions are placed on the scheduling of non-firm transportation service.[36] The sustainability of plant generation on RFO or ULSD requires knowledge of oil inventory levels, an inquiry which is outside the scope of this analysis.

In addition to EBB data, LAI reviewed a variety of other data sources, listed in Table 5.

Table 5. Data Sources

Data	Source	Description
NYC Load	NYISO	Hourly electric loads for Zone J from NYISO
Temperature	Bloomberg LP	Daily mean temperatures, Heating Degree Days and Cooling Degree Days in NYC
Fuel Prices	Bloomberg LP	Daily spot prices for natural gas, distillate oil, and residual fuel oil deliverable to NYC
Market Information	Platts	Various market information in Platts Gas Daily, other
Swaps Quotes	CME	Closing prices for basis swaps for gas deliverable to NYC

2.2 Algonquin Gas Transmission System

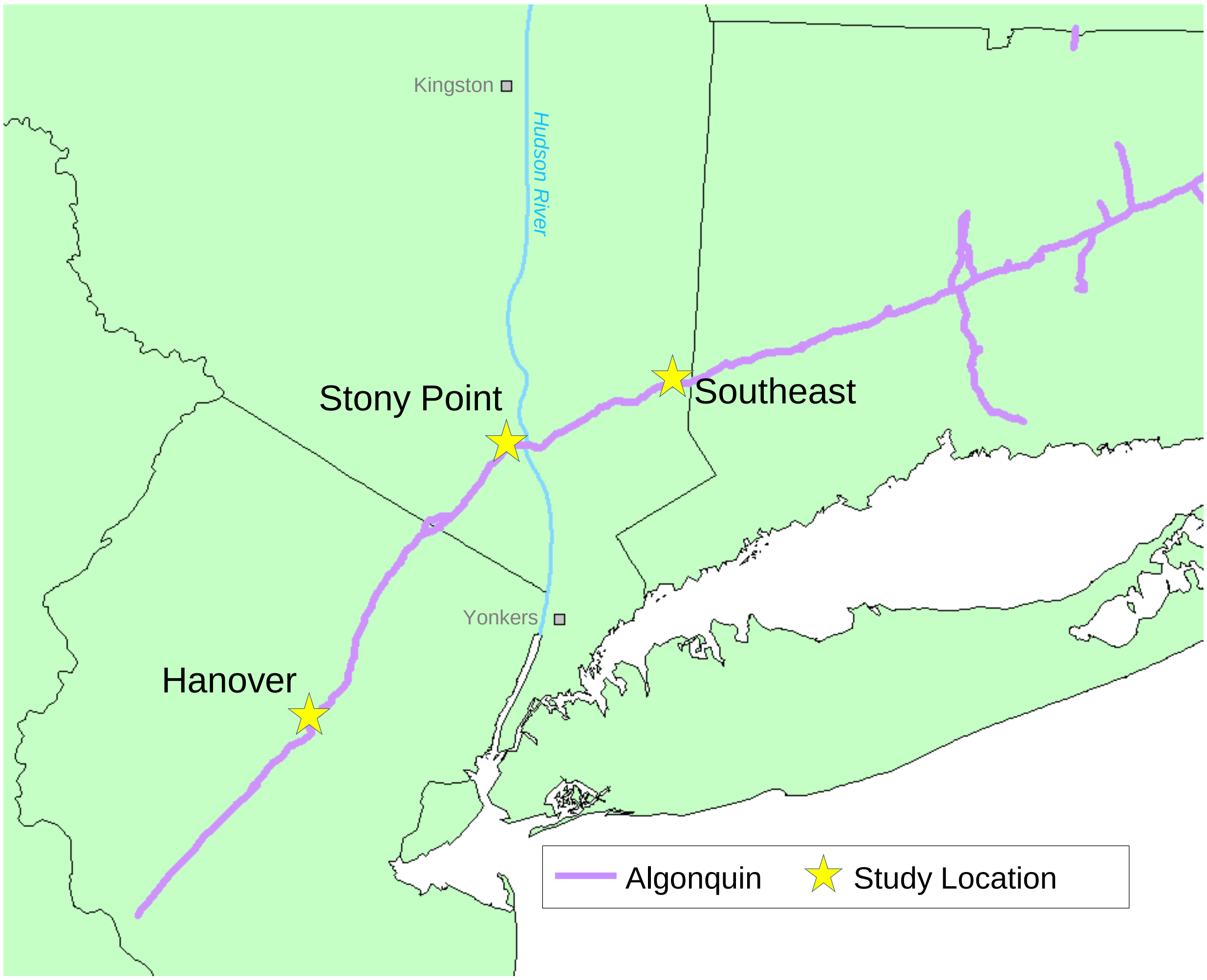
Algonquin, a subsidiary of Spectra Energy and regulated affiliate of its sister pipeline, Texas Eastern, serves parts of northern New Jersey and downstate New York, and, is one of two primary pathways into southern New England. Algonquin's certificated capacity is 2.4 Bcf/d over an extensive 1,100-mile pipeline, including many pipeline laterals serving local distribution companies (LDCs) and generators in Connecticut and Massachusetts. The system extends from an interconnection with Texas Eastern at Lambertville, New Jersey to the southern terminus of

[36] Non-firm transportation service includes secondary firm transportation arrangements and interruptible transportation.

Maritimes & Northeast (M&N) in northeastern Massachusetts. Historically, Algonquin has received gas sourced from the Gulf of Mexico through Texas Eastern. During the study period, however, Marcellus gas production supplanted large traditional volumes from the Gulf of Mexico for redelivery into the LHV and New England.[37] In order to identify periods of congestion on Algonquin, LAI analyzed throughput at the Hanover (NJ), Stony Point (NY), and Southeast (NY) compressor stations – all potential bottlenecks for transportation service to downstate New York.

Figure 24 shows the location of these compressor stations on Algonquin. Pipeline congestion events along the Algonquin mainline have a direct bearing on gas supply availability in the LHV. While Algonquin does not directly serve NYC or Long Island, Iroquois receives significant volumes from Algonquin at the Brookfield interconnection in Connecticut that are subsequently delivered to downstate customers. Therefore congestion on Algonquin can impact the supplies feeding the New York Facilities System.

Figure 24. Algonquin Pipeline



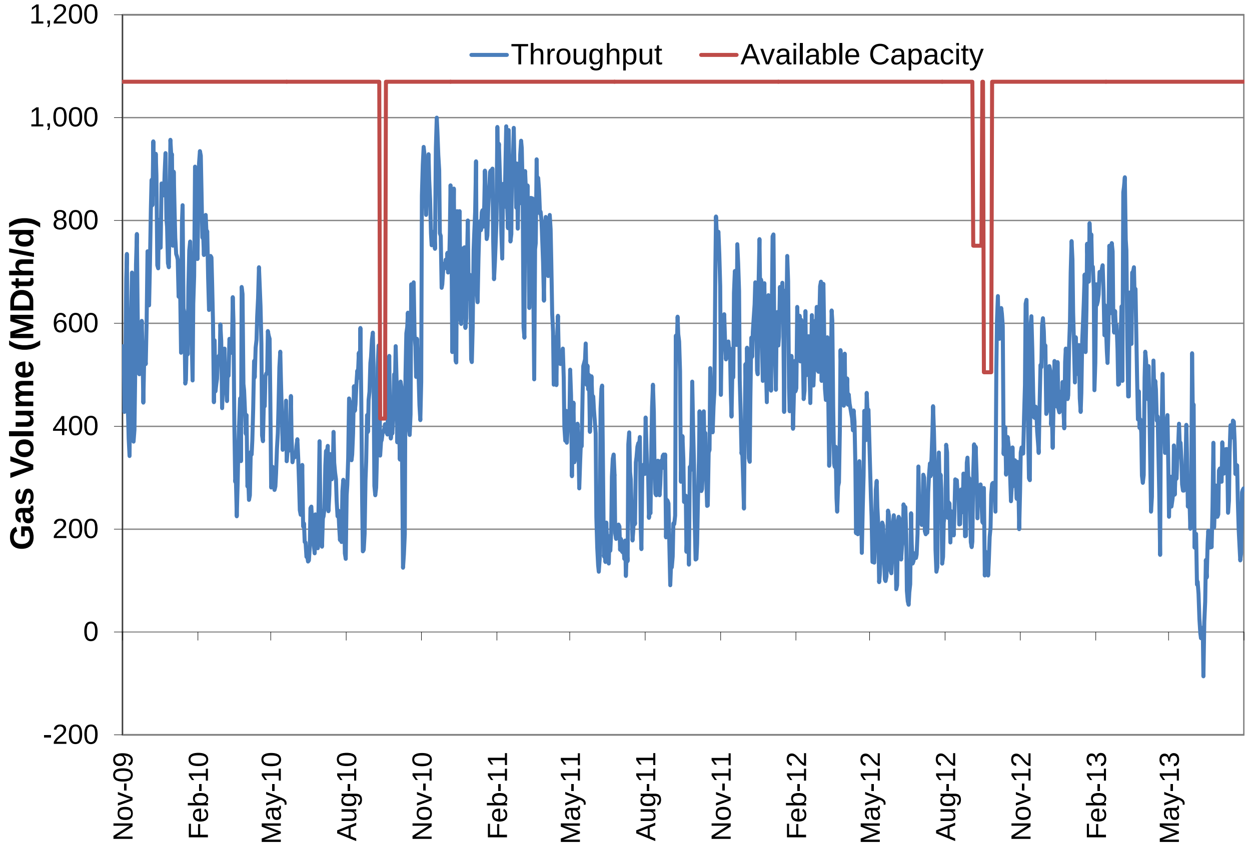
[37] Canadian gas out of Sable Island and regasified LNG from Canaport in New Brunswick can also be delivered to Algonquin via M&N. Gas from Atlantic Canada exclusively serves loads in the Maritimes and New England.

2.2.1 Hanover

The maximum available capacity at the Hanover compressor station during the study period was 1,070 MDth/d. The capacity was available for this segment on 1,341 days, about 98% of the study period. On the 28 days when full capacity was not available, scheduled maintenance – almost always performed during the cooling season – resulted in capacity de-rates. Scheduled maintenance reduced Algonquin capacity at Hanover to 415 MDth/d from September 11 to September 17, 2010, to 751 MDth/d from September 4 to September 14, 2012, and to 505 MDth/d from September 17 to September 26, 2012.

Figure 25 shows gas throughput and available capacity at Hanover for each day in the study period.

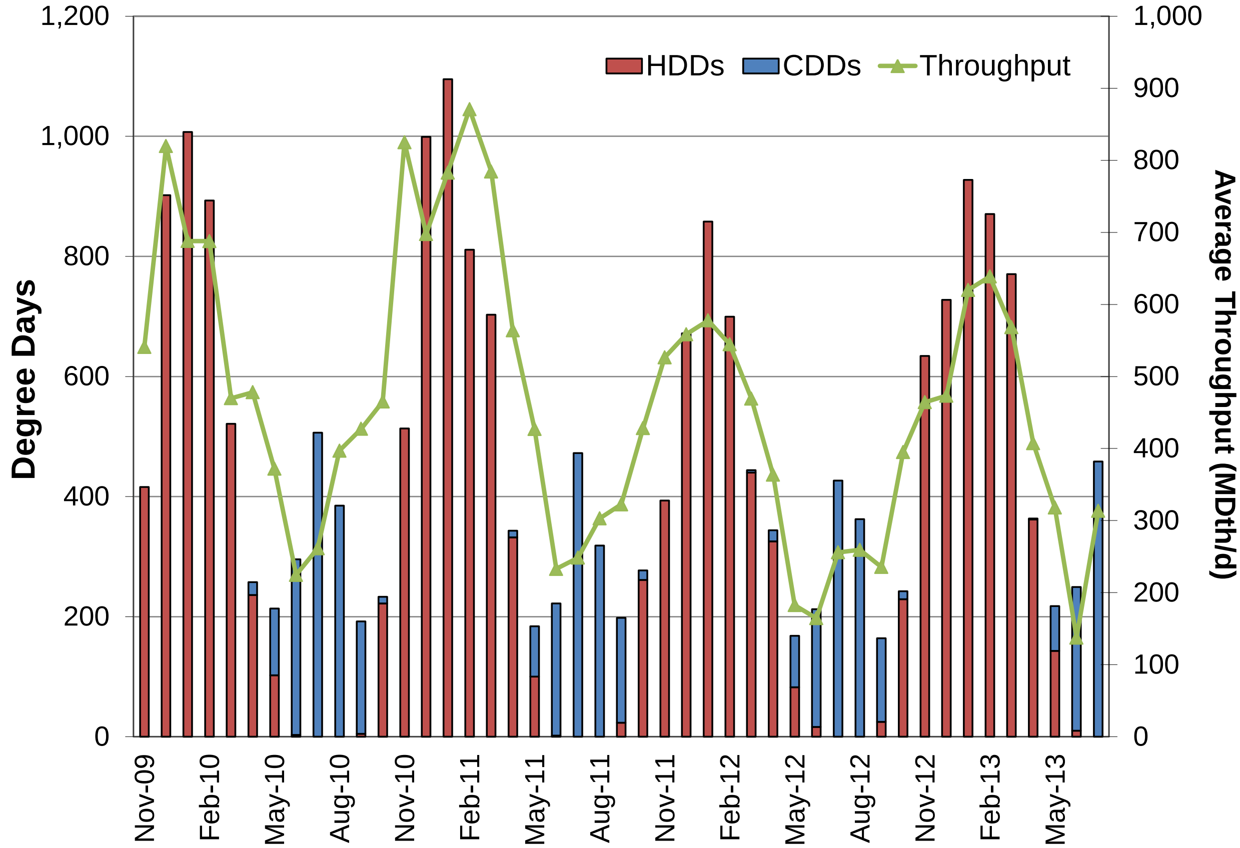
Figure 25. Daily Available Capacity and Throughput at Hanover



With the exception of the maintenance related capacity de-rates in September 2010 and September 2012, flows on the Hanover segment did not approach the available capacity.

Figure 26 shows the comparison of throughput to temperature aggregated on a monthly basis. Temperature is indicated as Heating Degree Days (HDDs) and Cooling Degree Days (CDDs).[38] The data show the relationship between heating demand and throughput.

Figure 26. Comparison of Temperature and Throughput for Hanover



These data show that periods of cold weather are characterized by high throughput at Hanover. Extreme cooling degree days during heat storms have only a moderate impact on throughput. Neither the HDD nor the CDD months during the study period resulted in congestion events at Hanover.

Examination of historical congestion patterns on Algonquin indicates that there has been substantial slack deliverability along the Hanover segment throughout the peak cooling season, June through August. Adjusted for maintenance cycles, there has been substantial slack deliverability during the shoulder seasons as well.

[38] For any given day, the number of HDDs is calculated as 65 degrees minus the daily mean temperature. CDDs are the daily mean temperature minus 65 degrees. If the difference is negative, the number of HDDs or CDDs for the day is zero.

Table 6. Monthly Pipeline Utilization Statistics at Hanover

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Days w/ 95% or greater util.	0	0	0	0	0	0	0	0	1	0	0	0
Days w/ 90% or greater util.	0	4	0	0	0	0	0	0	4	0	2	0

During the study period, there were ten days where utilization of the daily available capacity at Hanover exceeded 90%. Only on one day did pipeline utilization levels exceed 95%. Most of these days were associated with scheduled maintenance during the September outages. The day with a utilization rate greater than 95% occurred in September 2010. Other days when utilization exceeded 90% at Hanover involved comparatively moderate temperatures which occurred in November or February. The Hanover segment has experienced limited congestion events that would negatively impact generators holding non-firm transportation service on Algonquin. Maximum utilization during the summer months was observed at levels well below the threshold for congestion.

2.2.2 Stony Point

During the study period, the maximum available capacity at the Stony Point compressor station was 1,450 MDth/d. The segment operated at full capacity about 55% of the study period. Available capacity at Stony Point was less than the maximum capacity for a large number of days relative to other measured segments across Algonquin. The causes of the capacity de-rates at Stony Point are shown in Table 3.

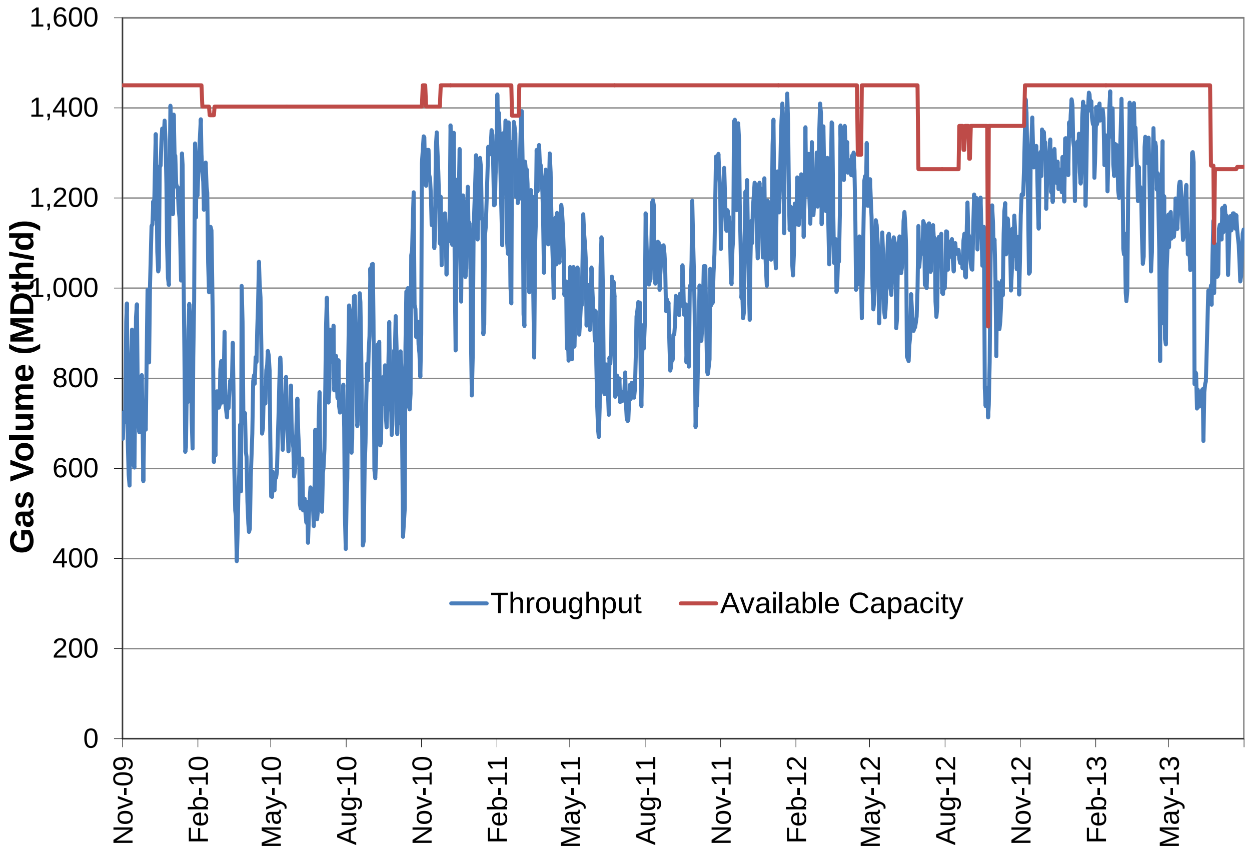
Table 7. Causes of De-rates at Stony Point

Date	Capacity (MDth/d)	Cause
2/6/10-11/23/10	1,403	Cause not reported in EBB critical notices[39]
2/15/10-2/20/10	1,384	Outage at the Stony Point compressor station
2/19/11-2/27/11	1,383	Outage at the Stony Point compressor station
4/16/12-4/20/12	1,296	Planned maintenance at Stony Point compressor station
6/29/12-10/31/12	Various	Maintenance associated with the results of the DOT Pipeline Integrity Program.
9/22/12	915	
6/21/13-7/31/13	Various	Maintenance / inspection

Figure 27 shows gas throughput and available capacity at Stony Point for each day in the study period:

[39] The cause of reduction in capacity that persisted for much of 2010 from 1,450 MDth/d to 1,MDth /d was not reflected in Algonquin's EBB postings nor reported in the trade press.

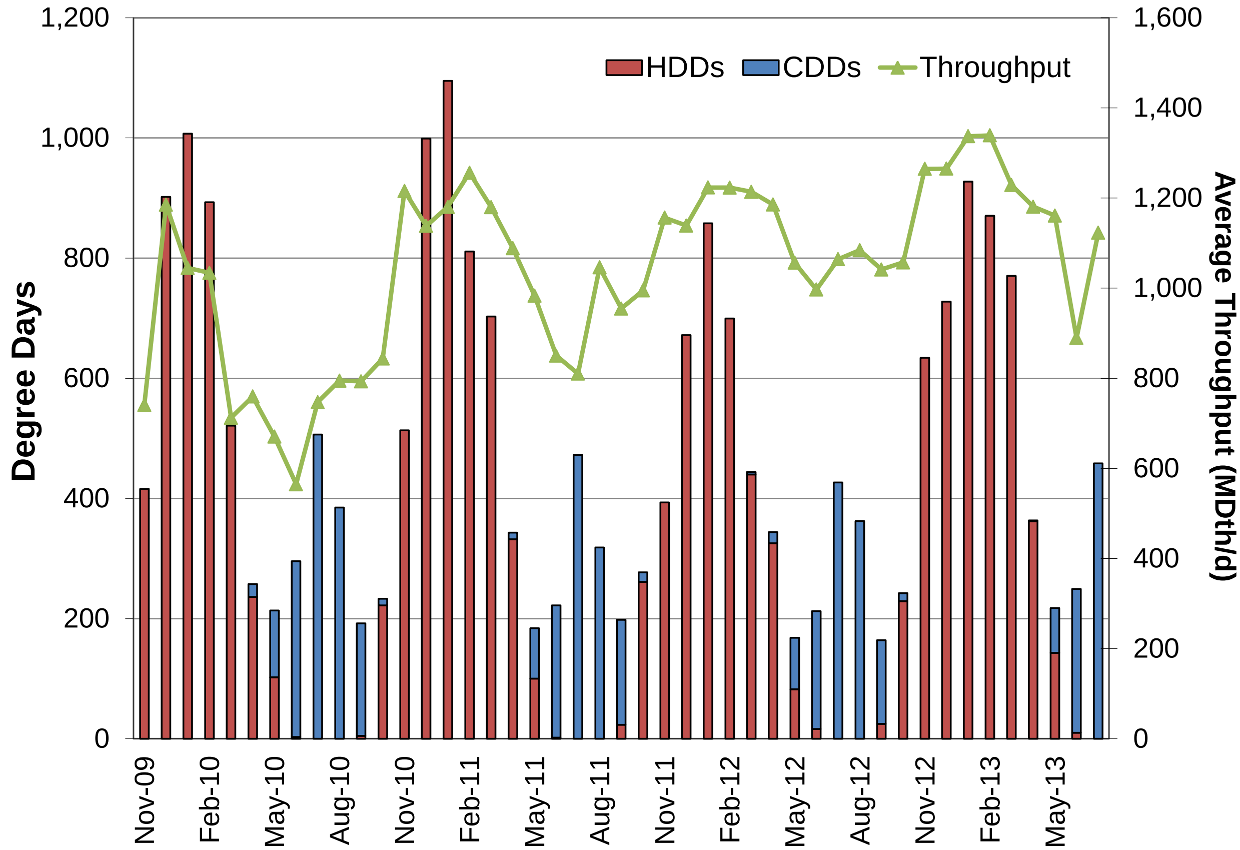
Figure 27. Daily Capacity and Throughput at Stony Point



The Stony Point segment shows a trend of increasing throughput and higher utilization rates during the second half of the study period in response to high production from Marcellus and shifting market preferences that affected flows through Tennessee, Texas Eastern and Algonquin. Available capacity was reduced significantly due to the various maintenance related capacity de-rates. The increased frequency of constrained capacity coupled with growing throughput increased utilization rates. Throughput across the Southeast segment increased, particularly during the last two years, as core and non-core loads, primarily in New England, have increased daily nominations across Algonquin from south-to-north, reflecting high utilization of the upstream Texas Eastern link from Marcellus to Lambertville. Increased throughput across Algonquin was also impacted by increased flows into Millennium at the Ramapo interconnect with Algonquin.

Stony Point, unlike Hanover, is situated downstream of the Ramapo interconnect with Millennium. The commercialization of the Laser and Bluestone gathering systems and other improvements on Millennium have resulted in higher flows from Millennium to Algonquin at the Ramapo interconnect. On a seasonal basis, throughput at Stony Point is influenced by HDDs as shown in Figure 28, and has remained relatively high from November 2011 through January 2013, also reflecting strong shipper demand for generation requirements during the cooling season in New England.

Figure 28. Comparison of Temperature and Throughput for Stony Point



Maximum utilization rates on the Stony Point segment were 90% or greater for all of the aggregated months, except May, August, September and October. Average utilization rates were 83% for January and 85% for February, while average utilization rates were 71% in July and 71% in August. As shown in Table 8, there were 183 days on the Stony Point segment with utilization rates of 90% or greater, with 151 of the days occurring during the winter months.

Table 8. Monthly Pipeline Utilization Statistics for Stony Point

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Days w/ 95% or greater util.	16	17	9	0	0	0	0	0	0	0	4	1
Days w/ 90% or greater util.	39	40	23	12	0	2	18	0	0	0	27	22

Utilization rates were significantly higher for all months during the second half of the study period. From November 2009 through September 2011, pipeline utilization was greater than 90% on 54 days. From October 2011 through July 2013, pipeline utilization was greater than 90% on 129 days. In response to broader market interest from Marcellus, most of the high pipeline utilization levels during the cooling season occurred during the last year. All eighteen July days with pipeline utilization levels greater than 90% occurred in July 2012 and July 2013. Tracking the pattern of accelerated production and delivery from Marcellus over the study period, all but two of the 47 days where utilization was 95% or greater occurred after the start of the 2010-11 heating season. 29 of the 47 days with 95% or higher utilization levels occurred in January through March 2013.

2.2.3 Southeast

The Southeast segment had a maximum available capacity of 1,418 MDth/d. The segment operated at full capacity for 1,015 days, about 74% of the study period. Capacity de-rates of various magnitudes on the remaining 403 days corresponded to pipeline safety and maintenance requirements. The explanations for the capacity de-rates on the Southeast segment are shown in Table 9, below:

Table 9. Causes of De-rates at Southeast

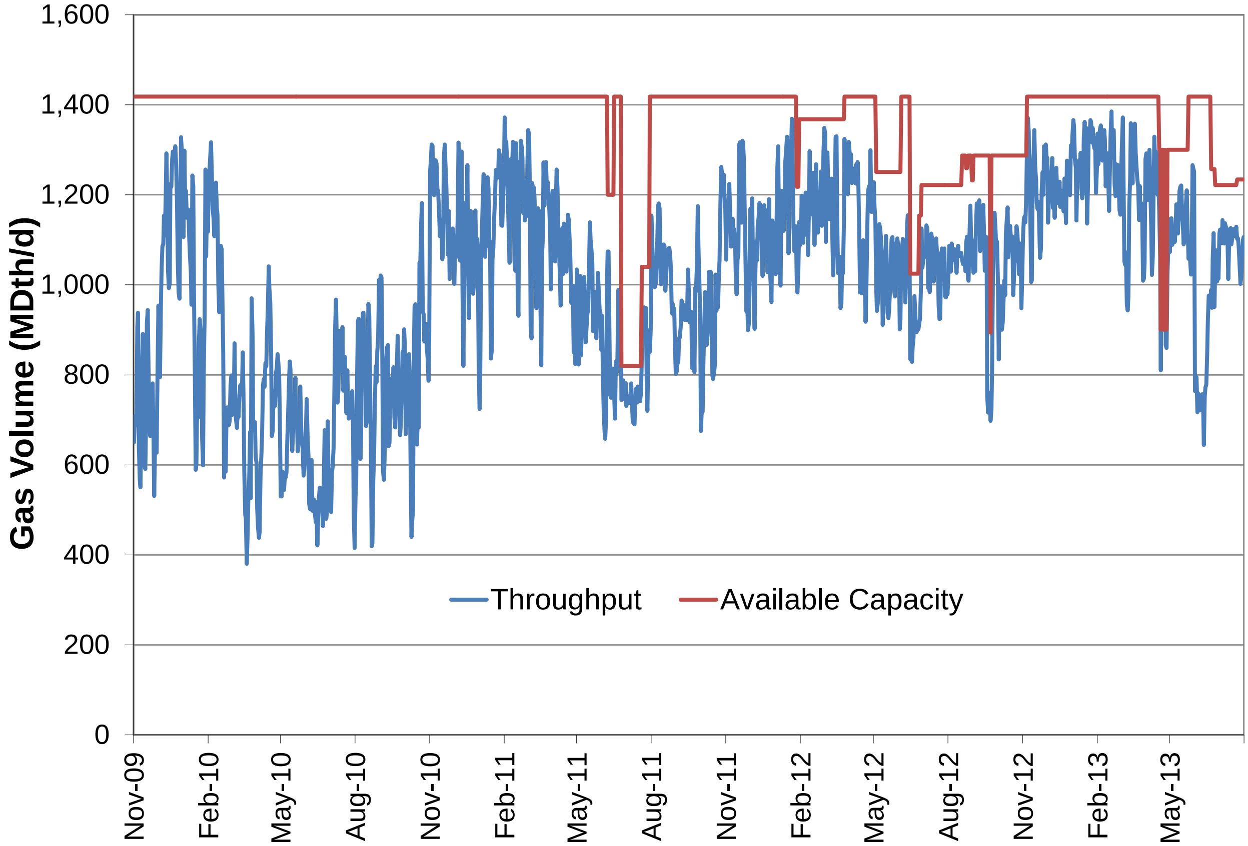
Date	Capacity (MDth/day)	Cause
6/8/11-6/15/11	1,200	Outage at the Oxford compressor station
6/25/11-7/19/11 7/20/11-7/29/11[40]	820 1,040	Maintenance between Southeast and Stony Point stations associated with the DOT Pipeline Integrity Program.[41]
1/27/12-1/29/12 1/30/12-3/25/12	1,218 1,368	Outage at the Southeast compressor station
August 2012-October 2012	Various	Maintenance between Southeast and Cornwall associated with the results of the DOT Pipeline Integrity Program.
4/18/13-5/23/13	Various	Maintenance / inspection
6/21/13-7/31/13	Various	Maintenance / inspection

Figure 29 shows throughput and available capacity at Southeast for each day in the study period.

[40] Separate dates in the same cell of the table indicate that pipeline capacity was restored incrementally. For example, this entry indicates that capacity at Southeast was de-rated to 820 MDth/d on June 25, 2011. On June 20, 2011, some capacity was restored, bringing the capacity along this segment to 1,040 MDth/d. Full capacity was restored beginning July 30, 2011.

[41] The DOT requires periodic review of pipeline safety procedures.

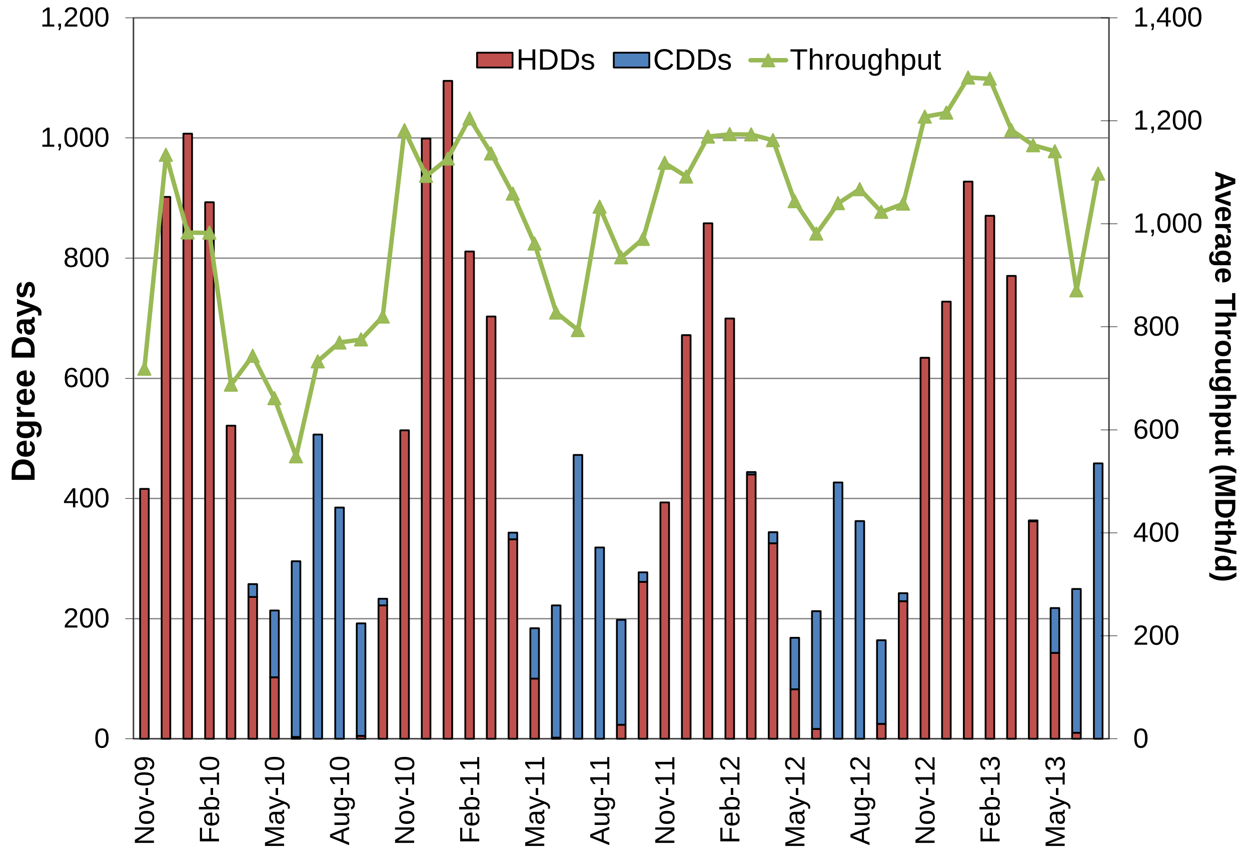
Figure 29. Daily Capacity and Throughput at Southeast



Improved deliverability from Marcellus into Algonquin and Millennium is evident in the review of throughput. From November 2009 through 2010, flows from Millennium were relatively low each month, especially during the cooling season. Thereafter, increased interconnect flows from Millennium into Algonquin are much higher, but still variable from month to month (see Figure 49 on page 68). A comparison of flows to temperature for Southeast shows that seasonal effects have been tempered in response to high demand across Algonquin in response to core send-out during the heating season and non-firm generation loads in New England throughout the year. System improvements across Millennium have reduced seasonal throughput variations on Algonquin and boosted the pipeline's ability to serve core and non-core loads in the LHV and New England.

Figure 30 provides a comparison for the Southeast segment of average daily throughput and temperature as measured by HDDs and CDDs.

Figure 30. Comparison of Temperature and Throughput for Southeast



Statistical analysis of utilization rates aggregated by month for the study period shows that maximum utilization exceeded 90% in each aggregated month at some point. Average utilization rates exceeded 80% for January and February. For July and August, the average utilization rates were 78% and 71%, respectively. Comparing the maximum and average utilization for the aggregated monthly data at Southeast with like statistics for Hanover, shows significantly higher utilization levels at Southeast, a segment more likely to experience flow day restrictions. As shown in Table 10, there were 191 days where pipeline utilization was 90% or greater relative to only ten days of like utilization levels for the Hanover segment. On the Southeast segment, 117 of these days occurred during the heating season.

Table 10. Monthly Pipeline Utilization Statistics for Southeast

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Days w/ 95% or greater util.	8	3	7	4	0	3	1	0	0	0	1	0
Days w/ 90% or greater util.	31	31	20	16	8	9	34	1	5	1	20	15

There were many days when Algonquin de-rated available capacity at Southeast. During the second half of the study period, de-rates contributed significantly to the number of days with 90% or greater pipeline utilization for the Southeast segment. For example, of the 34 days with 90% or greater utilization that occurred in July, ten days occurred between July 2 and July 19, 2011, when available capacity at Southeast was reduced to 820 MDth/d. On six days in July

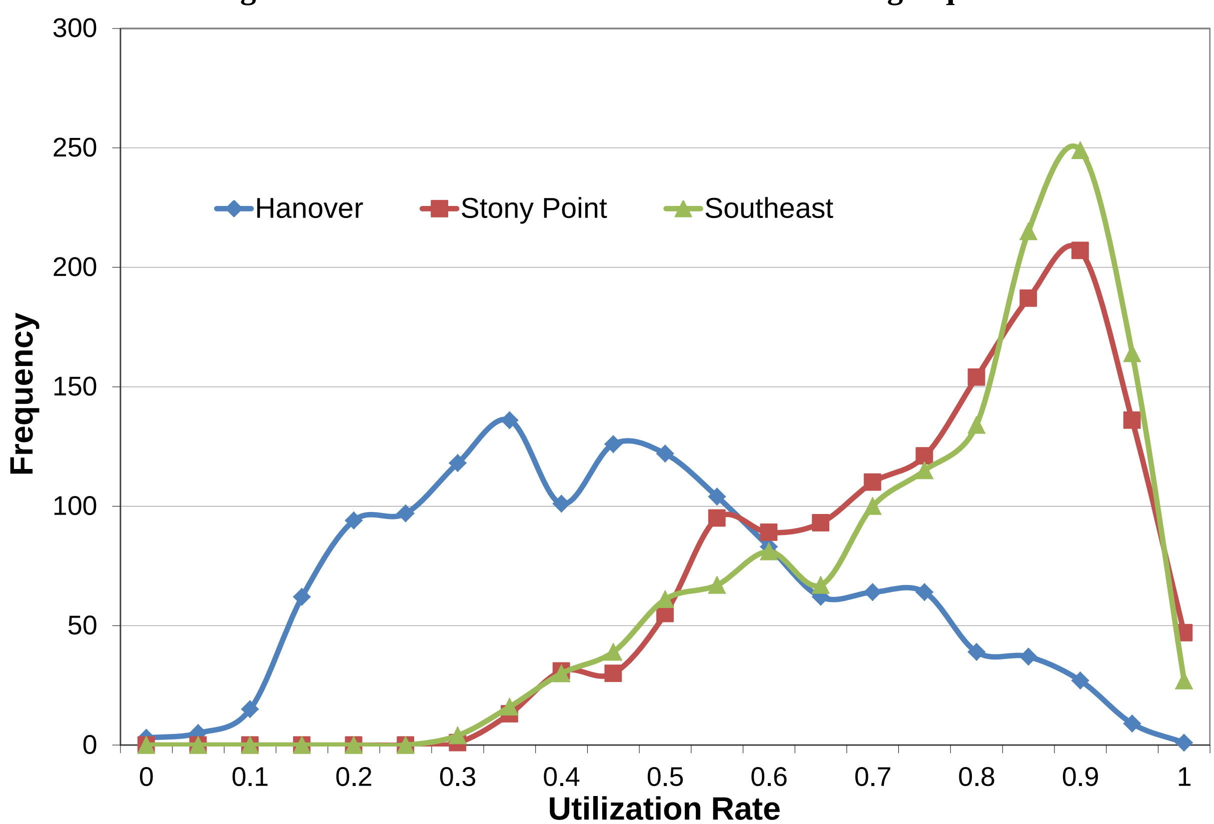
2012 and 16 days in July 2013, utilization exceeded 90% while available capacity was reduced to 1,222 MDth/d. These de-rates were associated with scheduled maintenance.

The market penetration of Marcellus supply has increased shipments from Millennium into Algonquin, and explains congestion patterns on Algonquin for south-to-north shipments into the LHV and New England. From November 2009 through September 2011, throughput exceeded 90% on 52 days, or 7%. From January 2011 through July 2013, there were 1397 days when pipeline utilization exceeded 90%, about 21%. According to Spectra Energy, gas supply input from Millennium more than tripled from 124 MDth/d in August 2009 to 389 MDth/d in July 2012. Likewise, Marcellus gas production into Texas Eastern increased eight-fold during this period from 90 MDth/d to 763 MDth/d. High pipeline utilization rates across this key segment reflect shifting market preference for shale gas to serve core and non-core customers alike in PJM MAAC, New York and New England.

2.2.4 Utilization Distributions

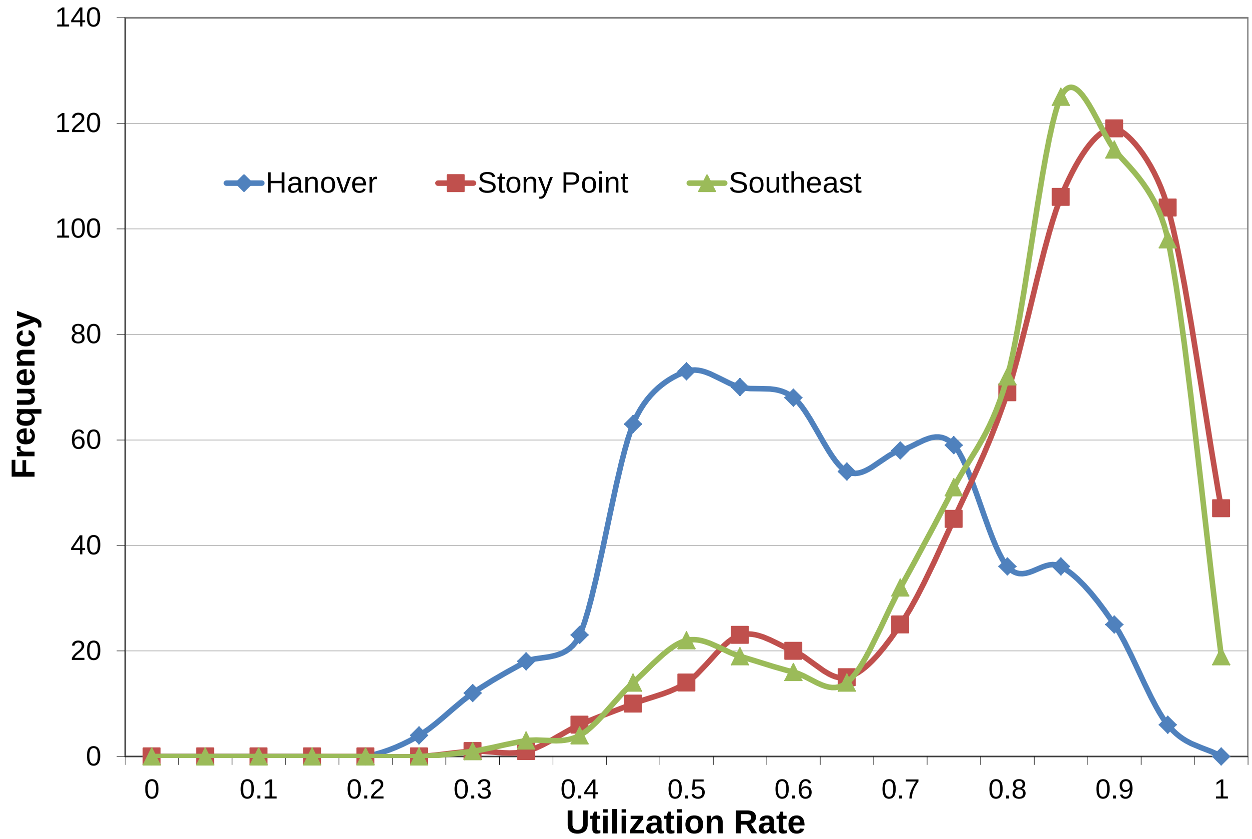
A side-by-side comparison of the statistical distributions for daily utilization shows that the incidence of days with high rates of utilization is greater on the Southeast and Stony Point segments than at Hanover. Spatial effects explain this dynamic, namely, Southeast and Stony Point are located downstream of the Millennium interconnect at Ramapo, while Hanover is located upstream of this key interconnect point. Frequencies are shown in Figure 31; note, the y-axis is the number of days for each rate of utilization.

Figure 31. Distribution of Utilization Rates on Algonquin



Repeating the frequency analysis using data limited to winter months shifts all three distributions to the right, indicating higher utilization rates during the winter, but shows the same pattern, with more frequent high utilization days at Southeast and Stony Point than Hanover. The descriptive statistics show that Southeast and Stony Point operate within a much narrower range of utilization rates relative to Hanover, an unconstrained point on the Algonquin system.

Figure 32. Distribution of Utilization Rates on Algonquin, Winter Only



2.2.5 High Congestion and Flow Days

The tables below show the top congestion days for Hanover, Southeast, and Stony Point, as measured by pipeline utilization rate. Also shown are the top throughput days. For each day, the pipeline segment's available capacity and daily temperature are reported. Daily temperature is the daily mean temperature at NYC, compiled by Bloomberg LP.

Table 11. Top Utilization and Throughput Days for Hanover

Top Utilization Days					Top Throughput Days				
Date	Capacity *MDth*	Throughput *MDth*	% util.	Temp *°F*	Date	Capacity *MDth*	Throughput *MDth*	% util.	Temp *°F*
9/17/2010	415	404	97.3%	65	11/19/2010	1,070	1,000	93.5%	44
9/16/2010	415	394	94.9%	65	2/12/2011	1,070	983	91.9%	35
9/15/2010	415	390	94.0%	65	2/1/2011	1,070	982	91.8%	28
11/19/2010	1,070	1,000	93.5%	44	2/21/2011	1,070	980	91.6%	31
9/14/2010	415	387	93.3%	68	2/15/2011	1,070	976	91.2%	31
2/12/2011	1,070	983	91.9%	35	11/20/2010	1,070	973	90.9%	48
2/1/2011	1,070	982	91.8%	28	12/29/2009	1,070	957	89.4%	24
2/21/2011	1,070	980	91.6%	31	3/2/2011	1,070	955	89.3%	39
2/15/2011	1,070	976	91.2%	31	12/8/2009	1,070	954	89.2%	39
11/20/2010	1,070	973	90.9%	48	2/3/2011	1,070	949	88.7%	29

The top utilization days for Hanover are primarily the result of maintenance-related capacity derates, while the top throughput days are mostly due to cold weather.

Table 12. Top Utilization and Throughput Days for Stony Point

Top Utilization Days					Top Throughput Days				
Date	Capacity *MDth*	Throughput *MDth*	% util.	Temp *°F*	Date	Capacity *MDth*	Throughput *MDth*	% util.	Temp F°
2/18/2013	1,450	1,437	99.1%	26	2/18/2013	1,450	1,437	99.1%	26
2/21/2011	1,383	1,369	99.0%	31	1/23/2013	1,450	1,434	98.9%	16
1/23/2013	1,450	1,434	98.9%	16	1/21/2012	1,450	1,432	98.8%	26
1/21/2012	1,450	1,432	98.8%	26	2/1/2011	1,450	1,430	98.6%	28
2/1/2011	1,450	1,430	98.6%	28	1/24/2013	1,450	1,430	98.6%	17
1/24/2013	1,450	1,430	98.6%	17	3/4/2013	1,450	1,420	97.9%	35
2/22/2011	1,383	1,360	98.3%	26	11/7/2012	1,450	1,419	97.9%	36
3/4/2013	1,450	1,420	97.9%	35	1/2/2013	1,450	1,419	97.9%	28
11/7/2012	1,450	1,419	97.9%	36	1/26/2013	1,450	1,415	97.6%	21
1/2/2013	1,450	1,419	97.9%	28	1/16/2013	1,450	1,414	97.5%	35

For the Stony Point segment, eight of the top ten utilization and throughput days are coincident. All of these days and the two highest throughput days not included in the top ten utilization days reflected the impact of cold weather.

Table 13. Top Utilization and Throughput Days for Southeast

Top Utilization Days					Top Throughput Days				
Date	Capacity *MDth*	Throughput *MDth*	% util.	Temp *°F*	Date	Capacity *MDth*	Throughput *MDth*	% util.	Temp *°F*
4/24/2013	900	900	100.0%	57	2/18/2013	1,418	1,385	97.7%	26
4/23/2013	1,300	1,294	99.5%	47	2/1/2011	1,418	1,372	96.8%	28
3/1/2012	1,368	1,349	98.6%	39	3/4/2013	1,418	1,372	96.8%	35
2/18/2013	1,418	1,385	97.7%	26	11/7/2012	1,418	1,371	96.7%	36
3/2/2012	1,368	1,335	97.6%	38	1/21/2012	1,418	1,369	96.5%	26
3/16/2012	1,368	1,330	97.2%	47	1/2/2013	1,418	1,366	96.3%	28
3/15/2012	1,368	1,329	97.1%	48	1/23/2013	1,418	1,366	96.3%	16
2/1/2011	1,418	1,372	96.8%	28	1/16/2013	1,418	1,362	96.1%	35
3/4/2013	1,418	1,372	96.8%	35	1/24/2013	1,418	1,362	96.1%	17
11/7/2012	1,418	1,371	96.7%	36	3/14/2013	1,418	1,359	95.8%	35

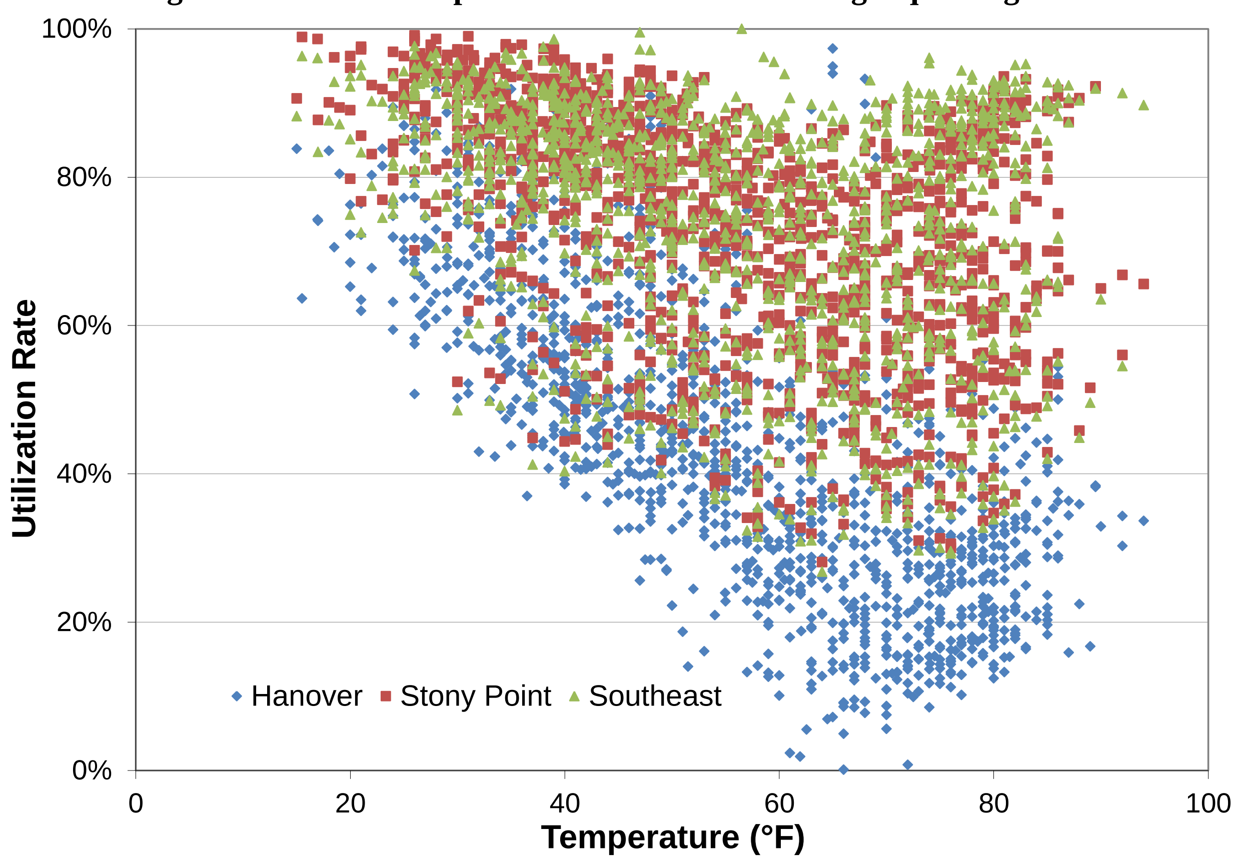
On Southeast, four out of ten of the top utilization days and highest throughput days were coincident. The days with highest throughput did not always correspond to days of colder-than-normal temperature conditions or extreme cold, but revealed utilization rates consistently greater than 95%.

2.2.6 Conclusions

Throughput on Algonquin reached a maximum during the heating season, with average utilization increasing downstream from Hanover at Stony Point and Southeast. Across the three segments, all top ten throughput days occurred in the winter, with the earliest observation occurring on November 7th (Stony Point & Southeast) and the latest occurring on March 14th (Southeast). At Hanover, there were only ten days during the study period when utilization rates were 90% or greater. In contrast, at Stony Point and Southeast there were 183 days and 191 days, respectively, when utilization rates were 90% or greater. Using the 90% utilization level as an indication of when pipelines *may* post critical notices affecting the scheduling of out-of-the-path secondary firm transportation or interruptible transportation, the statistical analysis shows that the Hanover segment rarely constitutes a chokepoint on the system and high utilization days are explained largely by scheduled pipeline maintenance, whereas the Stony Point and Southeast segments are often delivery-constrained. The extent to which Algonquin can bolster deliverability into New England through downstream interconnect flows to serve non-firm shippers is not part of this analysis, however.

Figure 33 shows a scatter plot of temperature and pipeline utilization for each segment on Algonquin.

Figure 33. Plot of Temperature vs. Utilization on Algonquin Segments

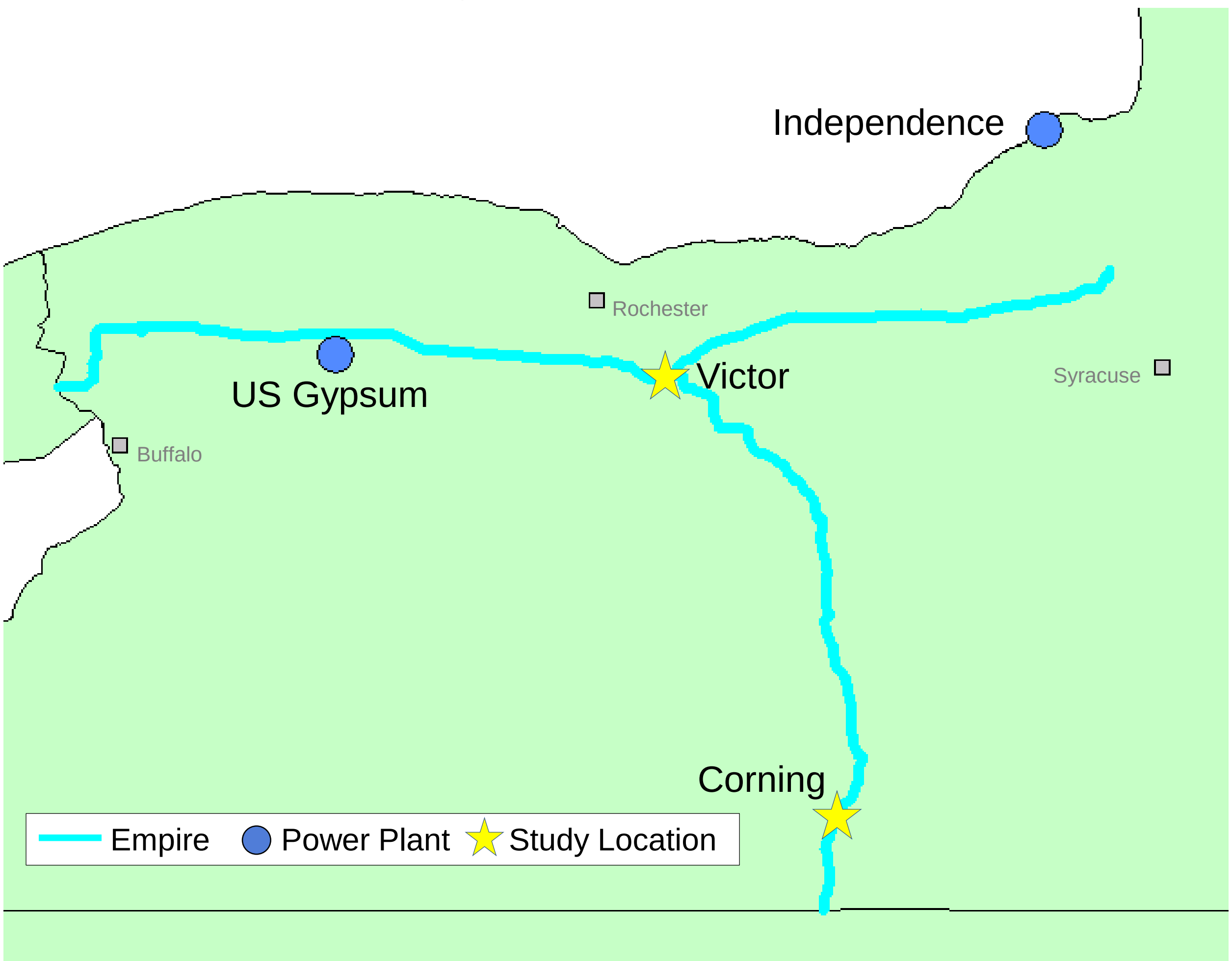


The scatter diagram shows that the Hanover segment utilization is generally driven by seasonal conditions. Most of the higher utilization days occurred during periods of high HDDs. The data for both Stony Point and Southeast show that higher utilization levels are distributed more evenly throughout the year, providing additional evidence that shippers with non-firm service across these segments are exposed to flow day restrictions.

2.3 Empire Pipeline

Empire, a subsidiary of NFG, is an intrastate pipeline owned by NFG that extends 249 miles from an interconnection with TransCanada at Chippawa, NY to Tioga County, PA. Empire has an interconnection with Millennium at Corning, near the southern end of its system. Empire serves northwestern New York via a separate segment that terminates near Syracuse. Sithe Independence is located in Scriba, New York, and depends on deliveries through Empire to a dedicated lateral operated by Niagara Mohawk. Empire also serves the US Gypsum plant near Oakfield, shown in Figure 34.

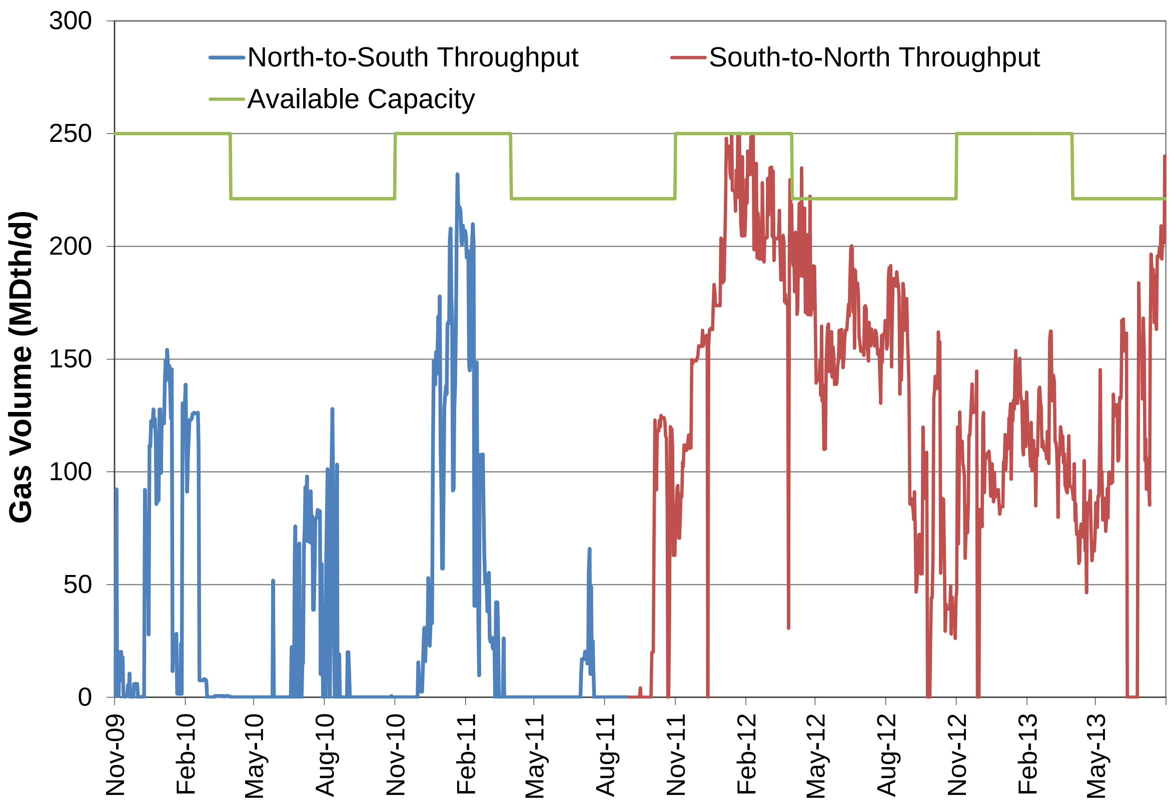
Figure 34. Empire Pipeline



Empire was originally designed to deliver western Canadian gas via TransCanada primarily to provide firm service in upstate New York. Production and transport from the Alberta border were later supplanted by Rocky Mountain gas production transported from Rockies Express to Chicago, for redelivery through the Vector pipeline into Ontario. The Empire Connector was commercialized in 2008 to connect these Canadian supplies to NYC via Millennium, Algonquin and Iroquois. Despite the relatively high cost of gas into Empire at Chippawa relative to natural gas sourced from Marcellus or the Gulf Coast, flows from TransCanada into Empire are still net positive, although the volumes have greatly decreased over the study period, offset by receipts from Millennium and Marcellus producers at the southern end of Empire's system.[42] Reflecting the multitude of hydraulic improvements in New York to accommodate shale gas production, flows on the Empire Connector are now moving south-to-north for re-delivery on Empire's west-to-east mainline.[43] As receipts at the southern end of Empire from Millennium and Marcellus producers continue to increase, market conditions may support the reversal-of-flow across Empire into Ontario.[44]

LAI has analyzed flow conditions on the Empire Connector. As reported in Empire's FERC application for the Connector, capacity on this segment varies seasonally: 250 MDth/d from November to March and 221 MDth/d from April to October. Empire's EBB does not provide daily differentiated capacity. Figure 35 shows gas throughput and available capacity for the segment for each day in the study period, differentiated by the direction of flow.

Figure 35. Daily Available Capacity and Throughput for the Empire Connector



[42] In contrast, flows at the Tennessee interconnection with TransCanada at Niagara are now reversed, that is, Niagara is now a delivery point into TransCanada.
[43] LAI has not attempted to identify the null point – point of no flow – on the Empire mainline.
[44] This dynamic is discussed further in section 3.2.2.

The data show a strong seasonality pattern. Driven by heating demand, pipeline utilization has approached 100% during the 2011-12 heating season. Notably, segment capacity was not approached during the January 2013 cold snap.

Prior to 2012, cooling season utilization of the segment had been low, punctuated with spikes in utilization during the peak cooling season. Following the flow reversal, utilization remained well above 50% most of the year; the high 2012 and 2013 cooling season throughput reflects the increased market penetration of shale gas for redelivery to upstate New York.

South-to-north flows on the Empire Connector were closely related to cold weather through the 2011-12 and 2012-13 heating seasons. Figure 36 shows the comparison of flows and weather on the segment.

Figure 36. Comparison of Temperature and Throughput for the Empire Connector

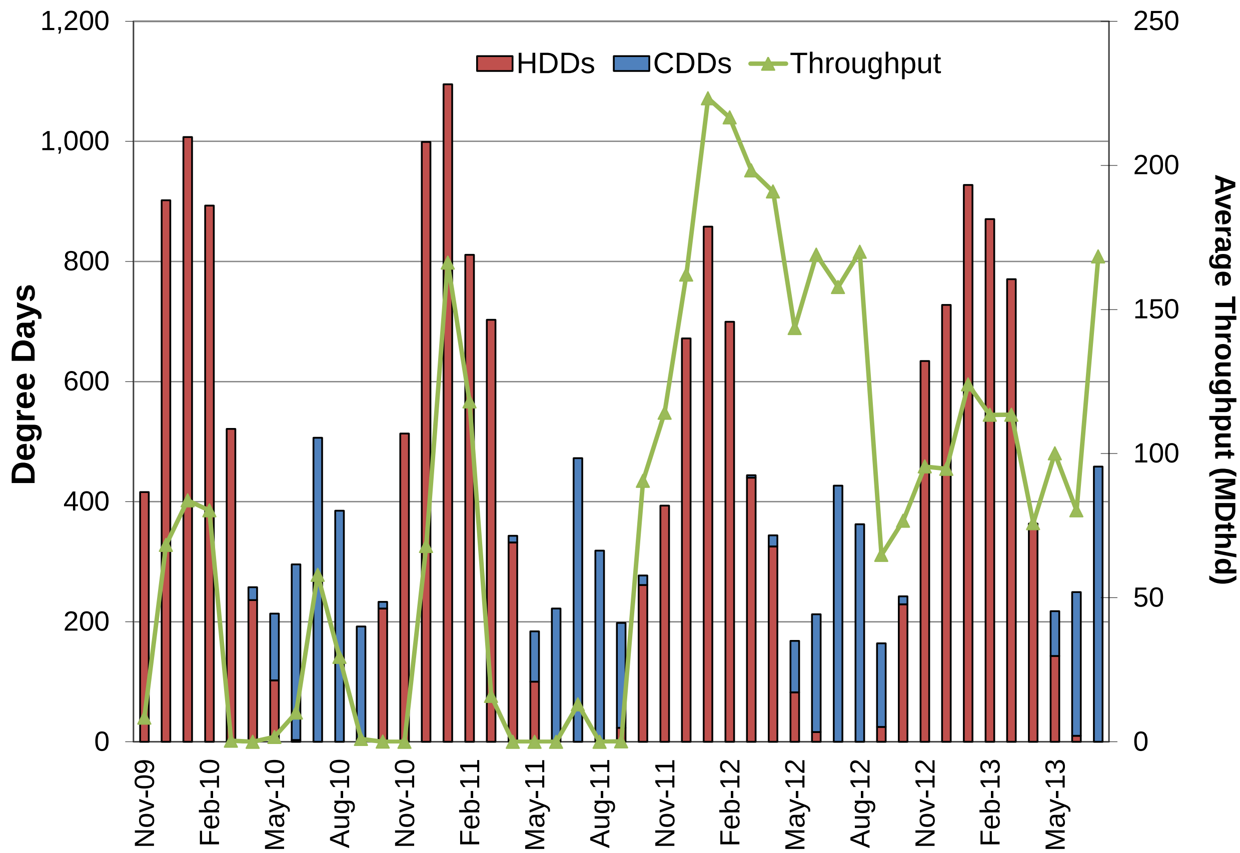


Table 14 shows that there were 49 days when utilization exceeded 90%, most of which occurred during the winter. A few days of high pipeline utilization across this segment occurred during the cooling season, including one day in June 2012 and even days in July 2013.[45] On 21 of these days utilization exceeded 95%, with only six such days occurring during non-winter months.

[45] The last two weeks in June 2012 saw atypically high flows on Empire, which peaked on June 17, 2012, when 200.3 MDth flowed over the Victor to Corning segment, a utilization rate of 90.5%.

Table 14. Monthly Pipeline Utilization Statistics for the Empire Connector

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Days w/ 95% or greater util.	10	5	0	4	0	0	2	0	0	0	0	0
Days w/ 90% or greater util.	15	12	5	9	0	1	7	0	0	0	0	0

2.3.1 Utilization Distributions

These data indicate that pipeline utilization levels vary widely. Descriptive statistics show comparatively erratic usage patterns over the study period, but recent market trends portend more significant use of the system on a reversal-of-flow basis to transport Marcellus gas to delivery points across the Empire mainline and into Canada.

Table 15. Month-by-Month Utilization on the Empire Connector

Month	Average	Max	Min
November 2009	3.3%	36.9%	0.0%
December 2009	27.3%	51.1%	0.0%
January 2010	33.5%	61.6%	0.6%
February 2010	32.1%	55.5%	3.0%
March 2010	0.1%	0.2%	0.0%
April 2010	0.0%	0.0%	0.0%
May 2010	0.8%	23.5%	0.0%
June 2010	4.6%	34.3%	0.0%
July 2010	26.2%	44.3%	0.0%
August 2010	13.3%	57.8%	0.0%
September 2010	0.5%	9.0%	0.0%
October 2010	0.0%	0.3%	0.0%
November 2010	0.0%	0.0%	0.0%
December 2010	27.2%	71.1%	1.0%
January 2011	66.5%	92.8%	22.8%
February 2011	47.2%	83.9%	3.9%
March 2011	6.4%	22.1%	0.0%
April 2011	0.0%	0.0%	0.0%
May 2011	0.0%	0.0%	0.0%
June 2011	0.0%	0.0%	0.0%
July 2011	5.9%	29.8%	0.0%
August 2011	0.0%	0.0%	0.0%
September 2011	0.1%	1.9%	0.0%

Month	Average	Max	Min
October 2011	41.0%	56.5%	0.0%
November 2011	45.7%	60.4%	28.2%
December 2011	64.8%	81.5%	0.0%
January 2012	89.3%	100.0%	73.5%
February 2012	86.6%	100.0%	77.2%
March 2012	79.3%	94.0%	12.2%
April 2012	86.4%	106.2%	76.7%
May 2012	64.9%	74.9%	49.8%
June 2012	76.4%	90.6%	66.1%
July 2012	71.4%	78.6%	59.0%
August 2012	76.9%	86.6%	60.8%
September 2012	29.3%	54.2%	0.0%
October 2012	34.7%	73.3%	11.8%
November 2012	38.2%	57.9%	0.0%
December 2012	37.9%	50.5%	30.3%
January 2013	49.6%	61.5%	38.7%
February 2013	45.4%	55.0%	34.0%
March 2013	45.4%	65.0%	31.9%
April 2013	34.3%	47.5%	21.0%
May 2013	45.3%	65.8%	33.3%
June 2013	36.3%	83.2%	0.0%
July 2013	76.2%	108.6%	38.6%

Figure 37 shows the distribution of utilization rates for the Empire segment over the study period. Figure 38 shows the same distribution, but only for the winter days. Because flows on this segment are highly seasonal, the distribution of utilization rates for winter days is considerably higher across the curve and, to a limited extent, is bimodal. Even during winter months there were many days when throughput was low.

Figure 37. Distribution of Utilization Rates on Empire

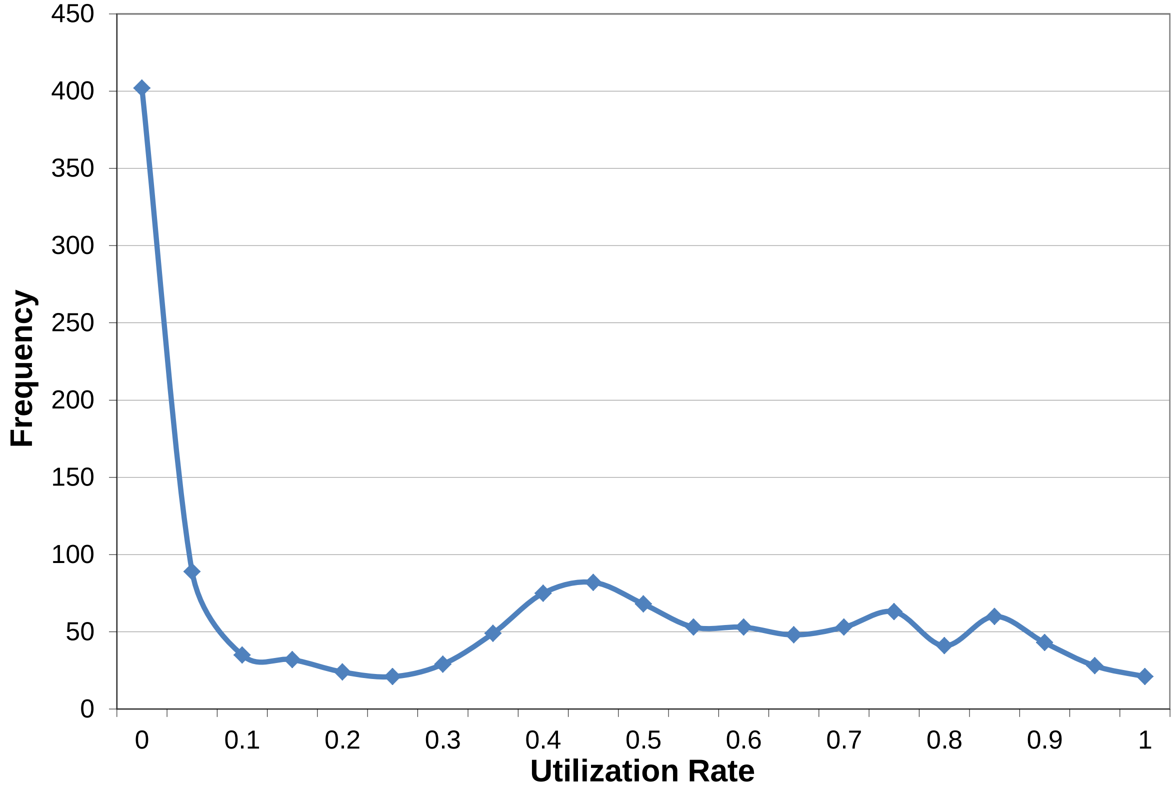
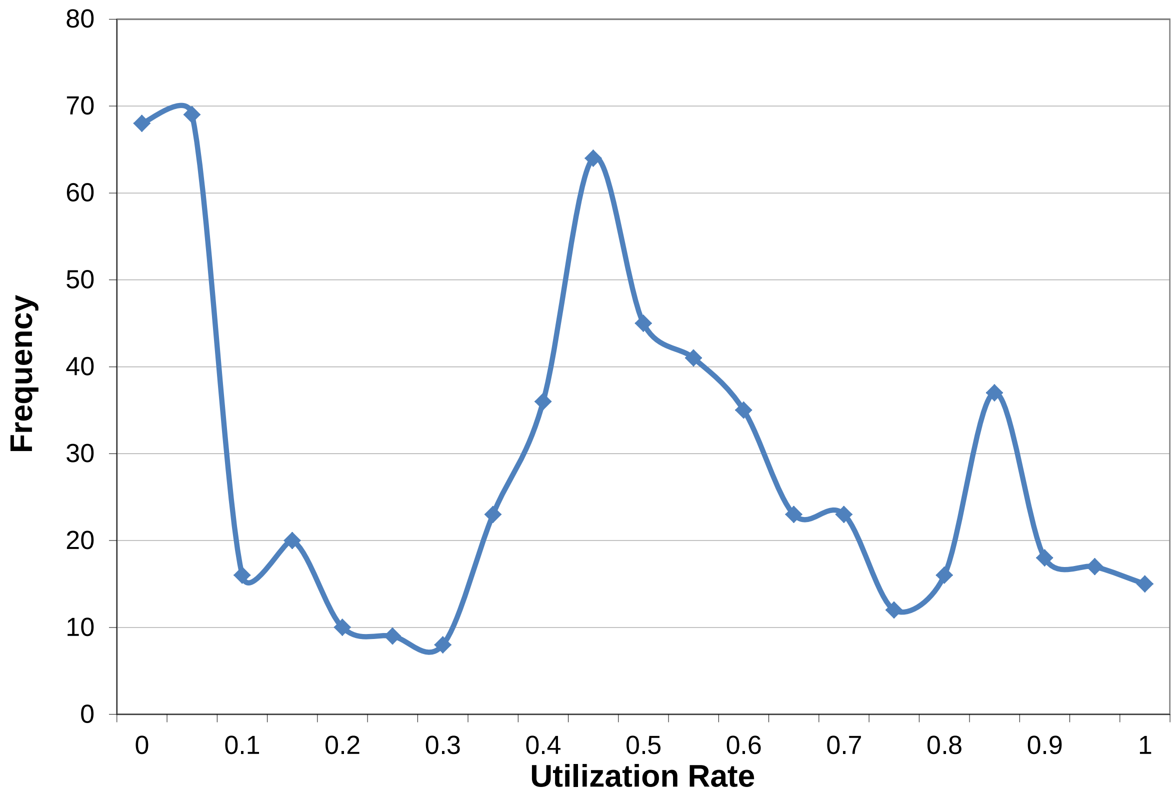


Figure 38. Distribution of Utilization Rates on Empire, Winter Only



2.3.2 High Congestion and Flow Days

Table 16 shows the top utilization and throughput days for the Empire Connector. The segment's available capacity and the daily temperature are shown for each day.

Table 16. Top Utilization and Throughput Days for the Empire Connector

Top Utilization Days					**Top Throughput Days**				
Date	**Capacity** *MDth*	**Throughput** *MDth*	**% util.**	**Temp** *°F*	**Date**	**Capacity** *MDth*	**Throughput** *MDth*	**% util.**	**Temp** *°F*
7/30/2013	221	240	108.6%	54	1/22/2012	250	250	100.0%	26
4/13/2012	221	235	106.2%	50	1/23/2012	250	250	100.0%	44
4/24/2012	221	222	100.6%	26	2/9/2012	250	250	100.0%	39
7/31/2013	221	222	100.3%	44	1/21/2012	250	250	100.0%	26
1/22/2012	250	250	100.0%	39	1/13/2012	250	250	99.9%	39
1/22/2012	250	250	100.0%	26	2/10/2012	250	249	99.7%	40
2/9/2012	250	250	100.0%	39	2/7/2012	250	249	99.4%	44
1/21/2012	250	250	100.0%	40	1/6/2012	250	248	99.1%	44
1/13/2012	250	250	99.9%	44	1/10/2012	250	245	97.8%	40
2/10/2012	250	249	99.7%	44	2/3/2012	250	242	96.9%	37

The top ten throughput days all occurred during the heating season, but not necessarily on the coldest days. The top utilization days include several cooling season days with higher than 100% utilization, this overage is a result of the assumption regarding the relative seasonal capacities of the Empire Connector. Although the days have throughput higher than the cooling season capacity reported in Empire FERC application, the throughput is not higher than the heating season capacity.

2.3.3 Conclusions

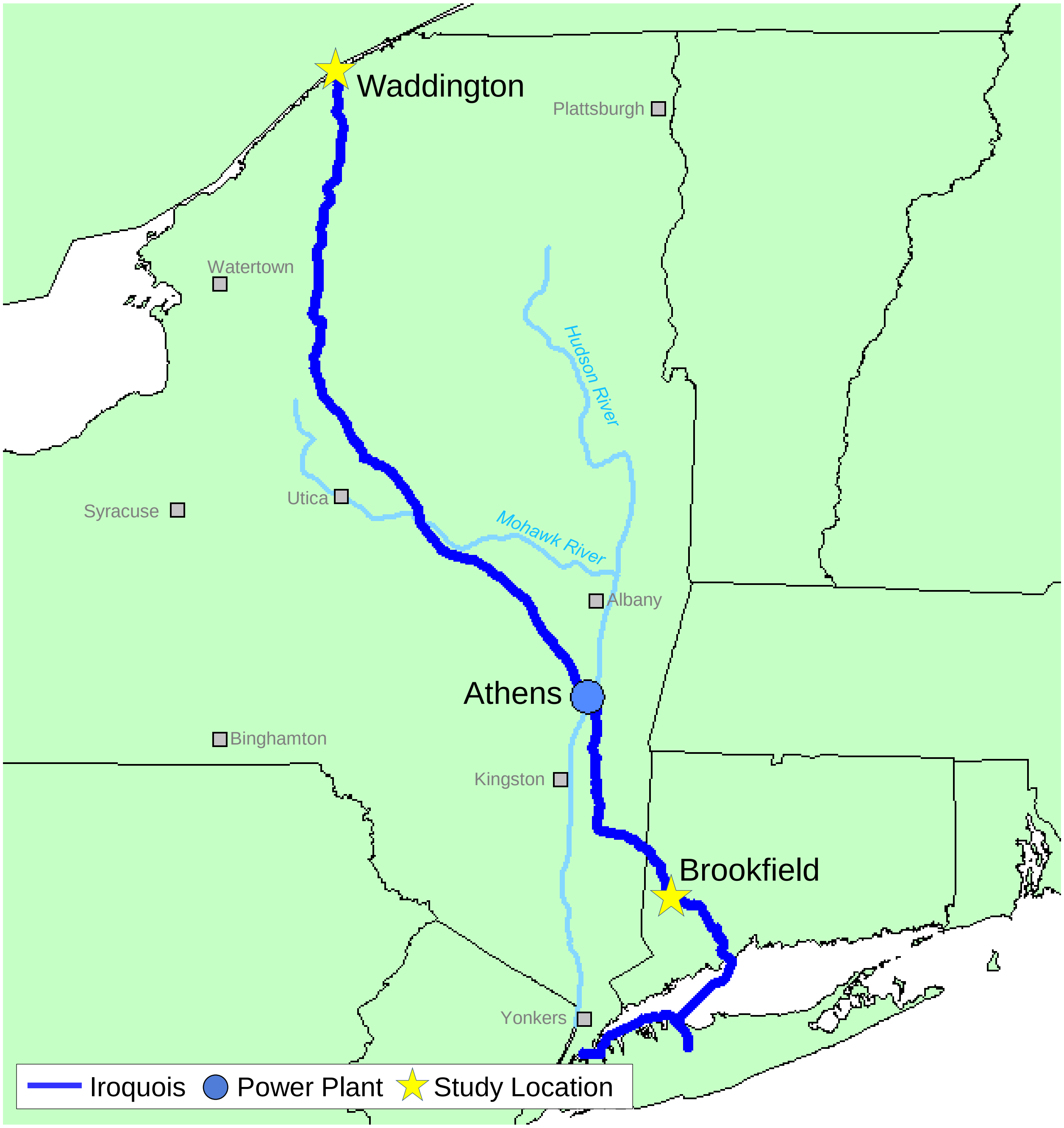
Six of the top ten utilization days and all ten of the top throughput days occurred during the 2011-12 heating season, a relatively mild winter. Beginning in 2012, flows across Empire increased significantly reflecting the reversal at the Corning interconnection. Notably, even during the winter peaks there is almost always significant additional capacity to serve non-core loads. Slack deliverability on Empire during the summer was previously pronounced, but following the reversal of the Corning interconnection, cooling season throughput has been increasing. The higher 2013 cooling season throughput is a result of increased throughput on Millennium following new producer connections and other system expansions.

2.4 Iroquois

Iroquois, which is owned by TransCanada, Dominion Resources, KeySpan Corporation, New Jersey Resource Corporation, and Energy East Corporation, runs slightly more than 400 miles from the Canadian border at Waddington across New York State and into southwestern New England, Long Island and NYC. The system has a capacity of roughly 1,200 MDth/d and has interconnections with Algonquin, Dominion, Tennessee and TransCanada.

For context, LAI analyzed flows at the Waddington receipt point at the Canadian border as well as the Brookfield compressor station and interconnection with Algonquin in southern Connecticut, which is upstream of the heart of the market on Long Island and the terminus of Iroquois's EastChester lateral to Hunts Point, NYC. Brookfield is also the key interconnect point with Algonquin. Gas flow data were available for both points on a daily basis for the period November 1, 2009 to January 31, 2013.

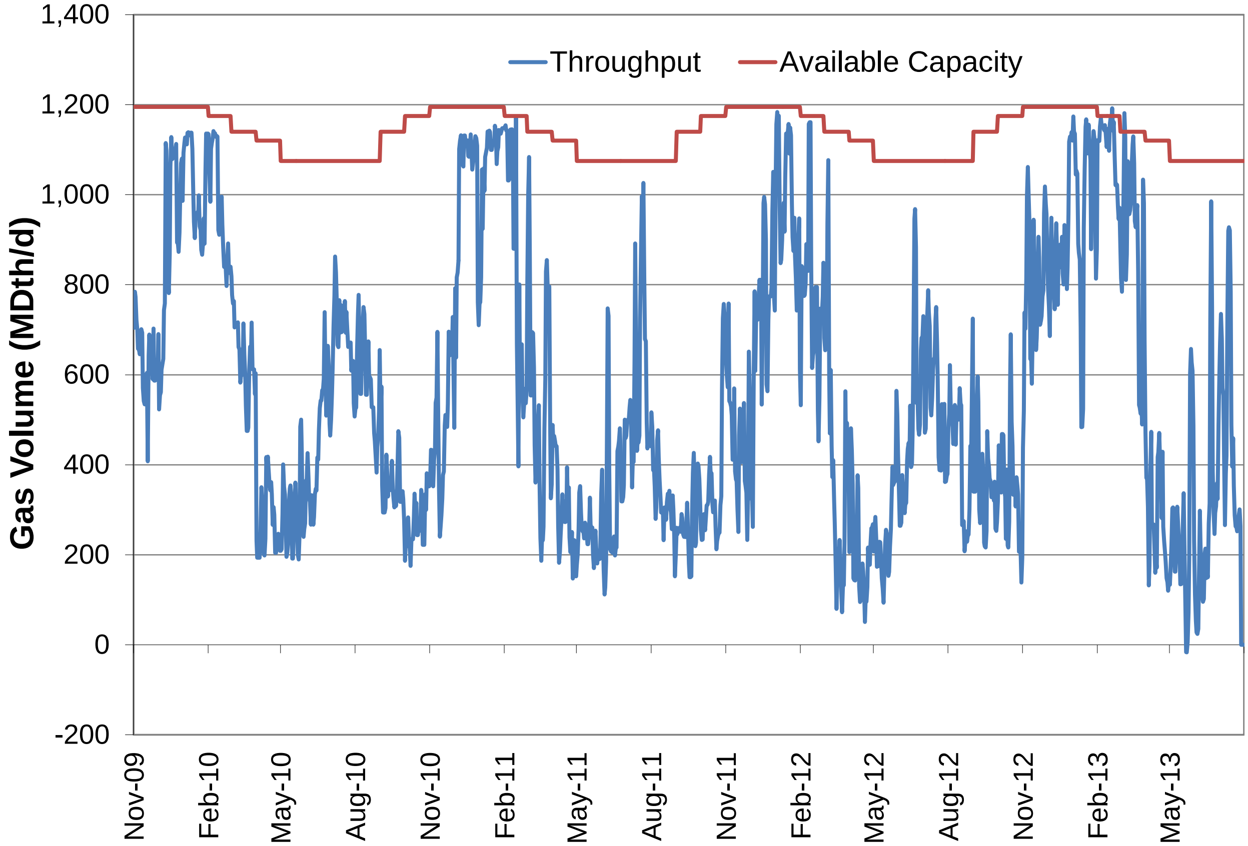
Figure 39. Iroquois Pipeline



2.4.1 Waddington

Daily pipeline capacity values were only available for Iroquois from November 1, 2012. Based on the available data, we have assumed the historical capacity and values shown in Figure 40.[46]

Figure 40. Daily Available Capacity and Throughput at Waddington

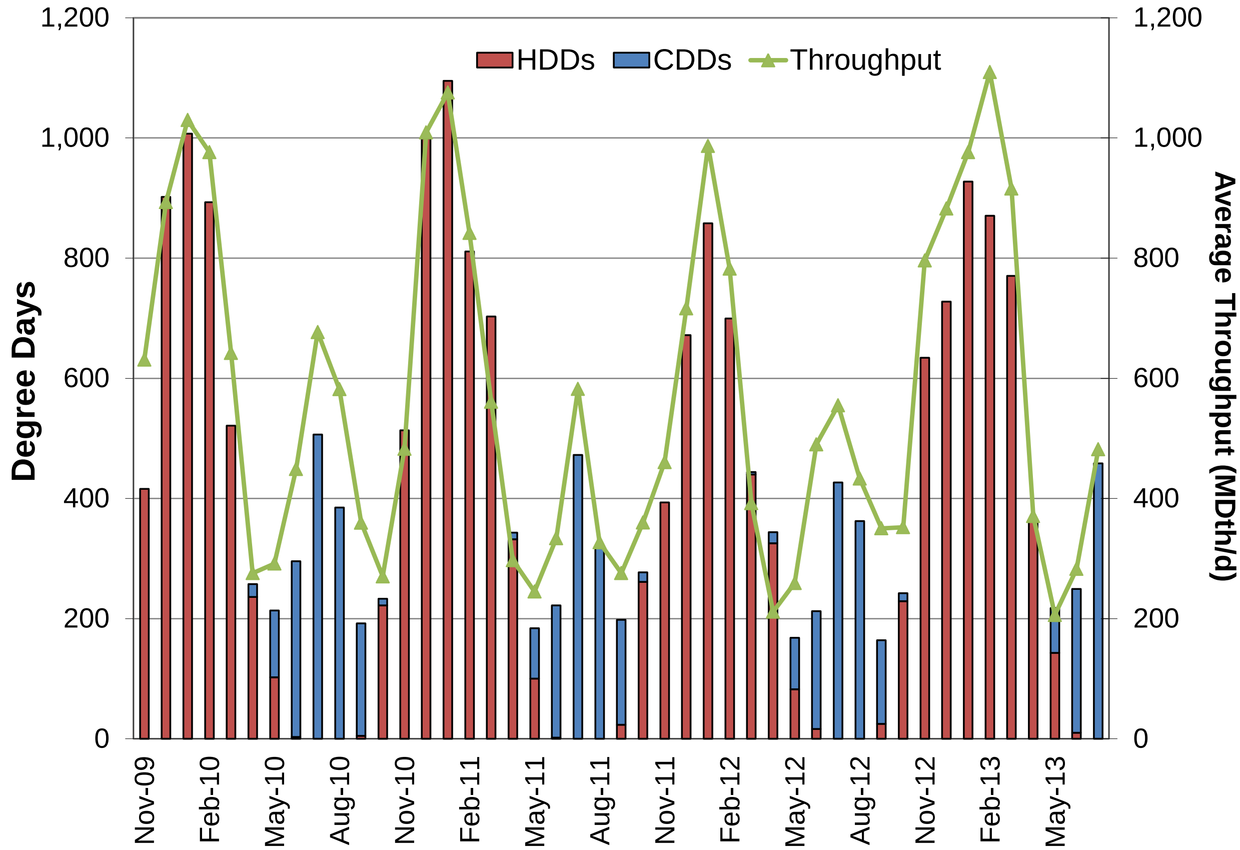


The data indicate a high degree of seasonality, with throughput at Waddington approaching receipt point capability during the premium heating season. Pronounced peaks in throughput also occurred during the summer, albeit at a lower level. Receipts during the shoulder season are low, reflecting Iroquois's ability to obtain lower cost gas through various pipeline interconnections with Dominion, Tennessee, and Algonquin for redelivery to the LHV, Long Island and NYC.

Figure 41 compares measures of temperature to throughput on an average monthly basis.

[46] The assumed capacity values do not include any maintenance- or contingency-related reductions prior to November 1, 2012.

Figure 41. Comparison of Temperature and Throughput for Waddington



Monthly average throughput showed strong relationships to both HDDs and CDDs.

The number of days for which utilization reached or exceeded 90% at Waddington in each month is shown in Table 17.

Table 17. Days with Pipeline Utilization at 90% or Greater for Waddington

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Days w/ 95% or greater util.	36	37	5	0	0	0	1	0	0	0	0	1
Days w/ 90% or greater util.	62	44	11	1	0	2	2	0	0	0	0	33

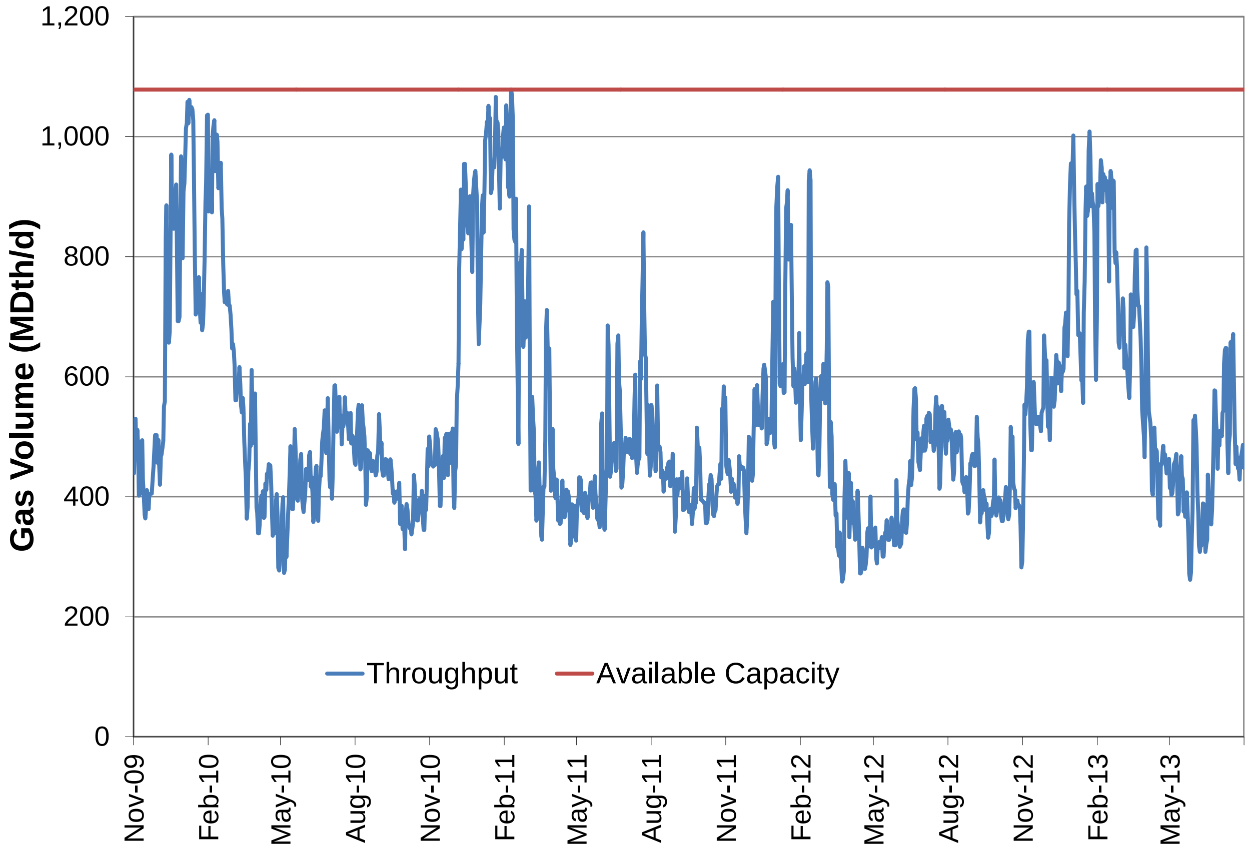
Utilization at Waddington reached or exceeded 90% for 155 days during the study period. All of these days occurred during heating season, except November. More than one-half of these days exceeded 95% utilization. Thus, congestion conditions developed on 79 days during the winter months when utilization was 95% or greater.

2.4.2 Brookfield

Iroquois has interconnections with Dominion at Canajoharie and Tennessee at Wright. From an operational standpoint, only the Brookfield interconnection with Algonquin is capable of accepting physical receipts south of the primary receipt point at Waddington. The other interconnections are delivery-only due to Iroquois's high operating pressure. Nevertheless, Iroquois can schedule receipts by displacement at Canajoharie and Wright when operating / market conditions warrant. The Brookfield Compressor Station was placed into service in Q4 2008, allowing the interconnection between Algonquin and Iroquois to become bi-directional.

Daily mainline throughput and capacity at Brookfield are not available on Iroquois's EBB. The maximum flow during the study period at Brookfield was 1,078 MDth, which occurred on February 9, 2011. Figure 42 shows throughput compared to the assumed available capacity for each day over the study period.

Figure 42. Daily Available Capacity and Throughput at Brookfield



The data are highly seasonal with flows at Brookfield regularly approaching system limitations during the winter. Figure 43 shows the relative volumes of gas flowing into Brookfield from upstream on Iroquois and from Algonquin. Figure 44 compares temperature conditions to average monthly throughput at Brookfield.

Figure 43. Sources of Gas Flowing Through Brookfield

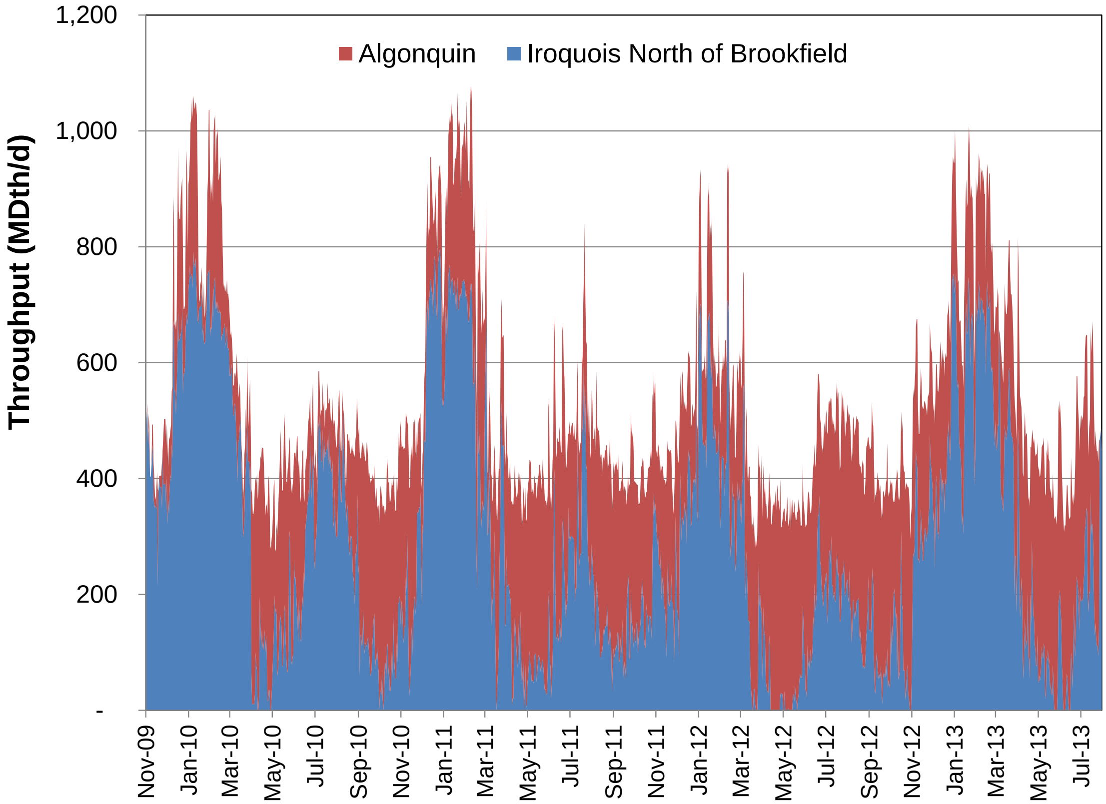
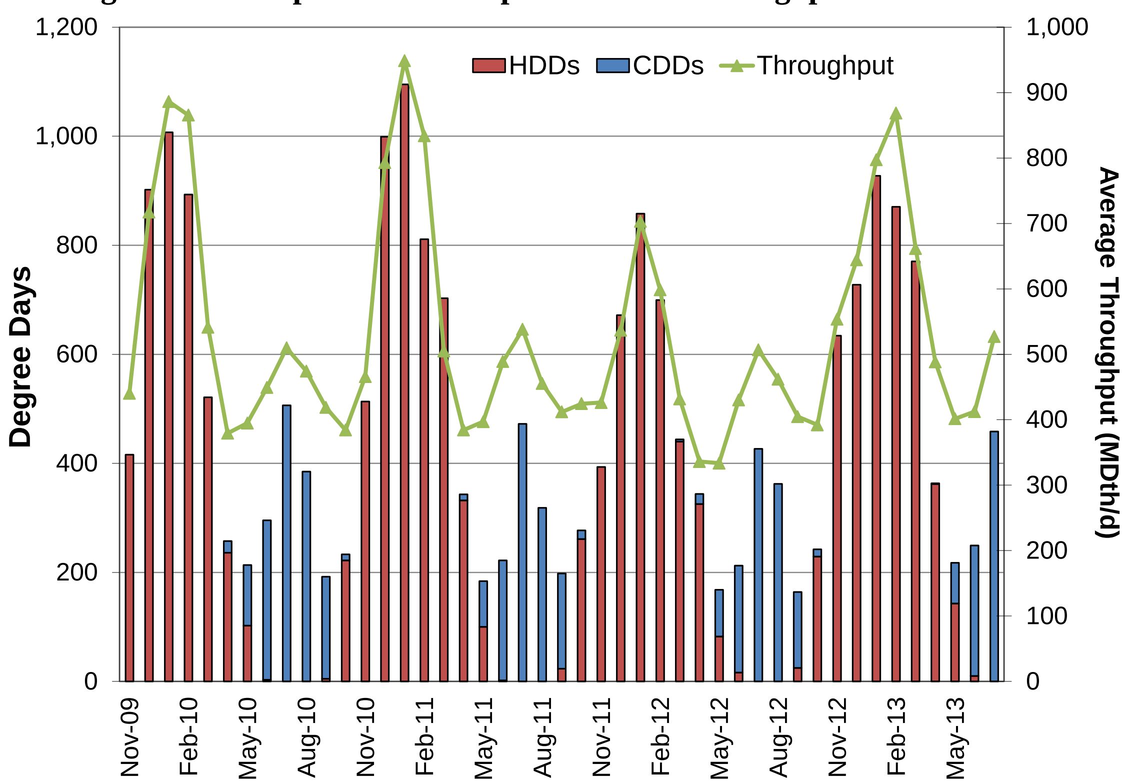


Figure 44. Comparison of Temperature and Throughput for Brookfield



Throughput appears to be highly correlated to temperature, with both winter and summer peaks generally matching the peaks in HDDs and CDDs. Table 18 identifies the number of days for which utilization reached or exceeded 90% at Brookfield.

Table 18. Days Pipeline Utilization Reached or Exceeded 90% at Brookfield

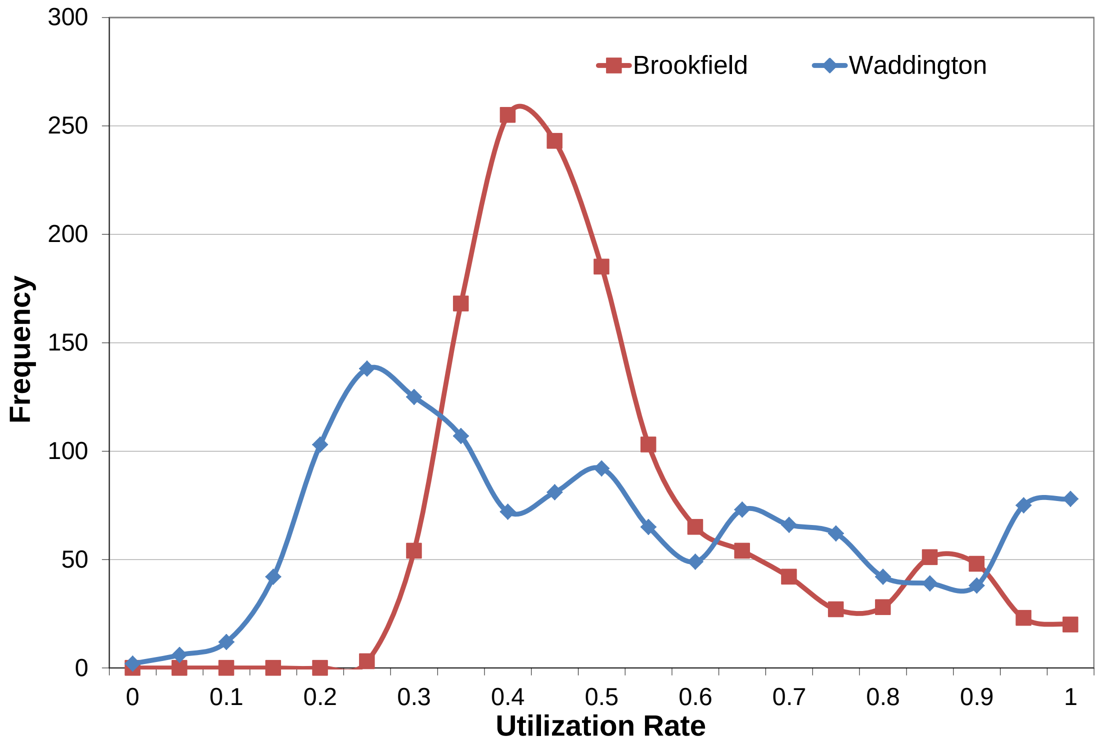
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Days w/ 95% or greater util.	14	6	0	0	0	0	0	0	0	0	0	0
Days w/ 90% or greater util.	30	13	0	0	0	0	0	0	0	0	0	0

In total, there were 43 days in which utilization exceeded 90%, all of which occurred in the peak heating season, January and February. Utilization exceeded 95% on almost half of these days.

2.4.3 Utilization Distributions

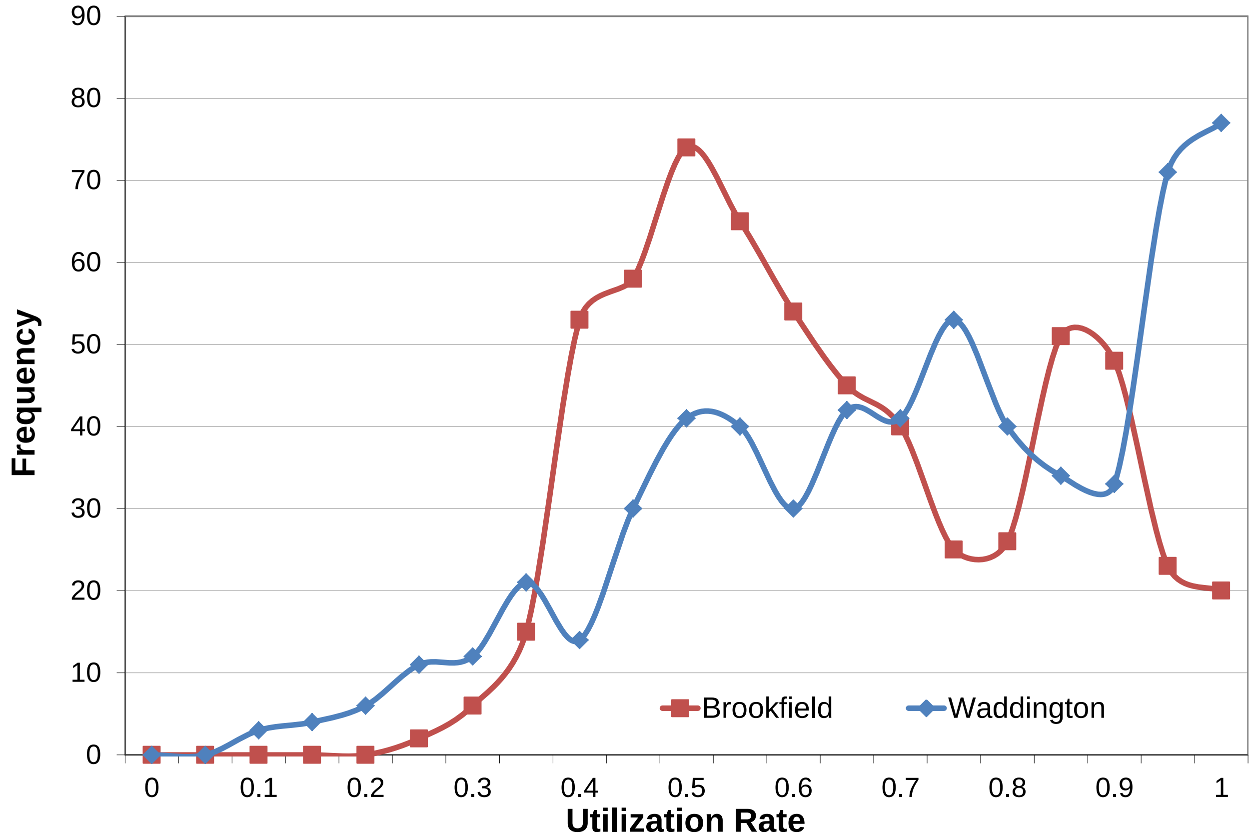
Figure 45 shows the distribution of utilization rates at Brookfield and Waddington. The mean around which each distribution is centered is similar, around 50%. Generally flows at Brookfield were more consistent reflecting the steady high demand for natural gas at power plants in the LHV, southern Connecticut, Long Island, and, to a lesser extent, behind the Hunts Point meter in Queens. There are few very low flow days and a significant, but not predominant number of high flow days in the distribution. On a majority of days, utilization rates were between 30% and 60%. For Waddington, on the other hand, flows were much more diverse reflecting the increased challenge associated with utilization of the Waddington receipt point during the cooling season – many observations ranged from 15% to 80%.

Figure 45. Distribution of Utilization Rates on Iroquois



Restricting the data to only winter months and repeating the analysis shows that utilization rates at Brookfield remained more centrally located while utilization rates at Waddington were more widely distributed.

Figure 46. Distribution of Utilization Rates on Iroquois, Winter Only



2.4.4 High Congestion and Flow Days

The following tables show the highest utilization and throughput days for the Iroquois points.

Table 19. Top Utilization and Throughput Days for Waddington

Top Utilization Days					Top Throughput Days				
Date	Capacity *MDth*	Throughput *MDth*	% util.	Temp *°F*	Date	Capacity *MDth*	Throughput *MDth*	% util.	Temp *°F*
3/6/2013	1,140	1,181	103.6%	40	2/19/2013	1,175	1,192	101.5%	41
2/19/2013	1,175	1,192	101.5%	41	1/3/2012	1,195	1,184	99.1%	24
2/15/2011	1,175	1,174	99.9%	31	3/6/2013	1,140	1,181	103.6%	40
2/17/2013	1,175	1,171	99.7%	25	1/5/2012	1,195	1,175	98.3%	34
2/5/2013	1,175	1,170	99.6%	30	1/2/2013	1,195	1,174	98.3%	28
2/18/2013	1,175	1,168	99.4%	26	2/15/2011	1,175	1,174	99.9%	31
3/21/2013	1,140	1,130	99.1%	35	2/17/2013	1,175	1,171	99.7%	25
1/3/2012	1,195	1,184	99.1%	24	2/5/2013	1,175	1,170	99.6%	30
2/21/2013	1,175	1,162	98.9%	29	2/18/2013	1,175	1,168	99.4%	26
2/12/2012	1,175	1,161	98.8%	26	1/18/2013	1,195	1,168	97.7%	30

Table 20. Top Utilization and Throughput Days for Brookfield

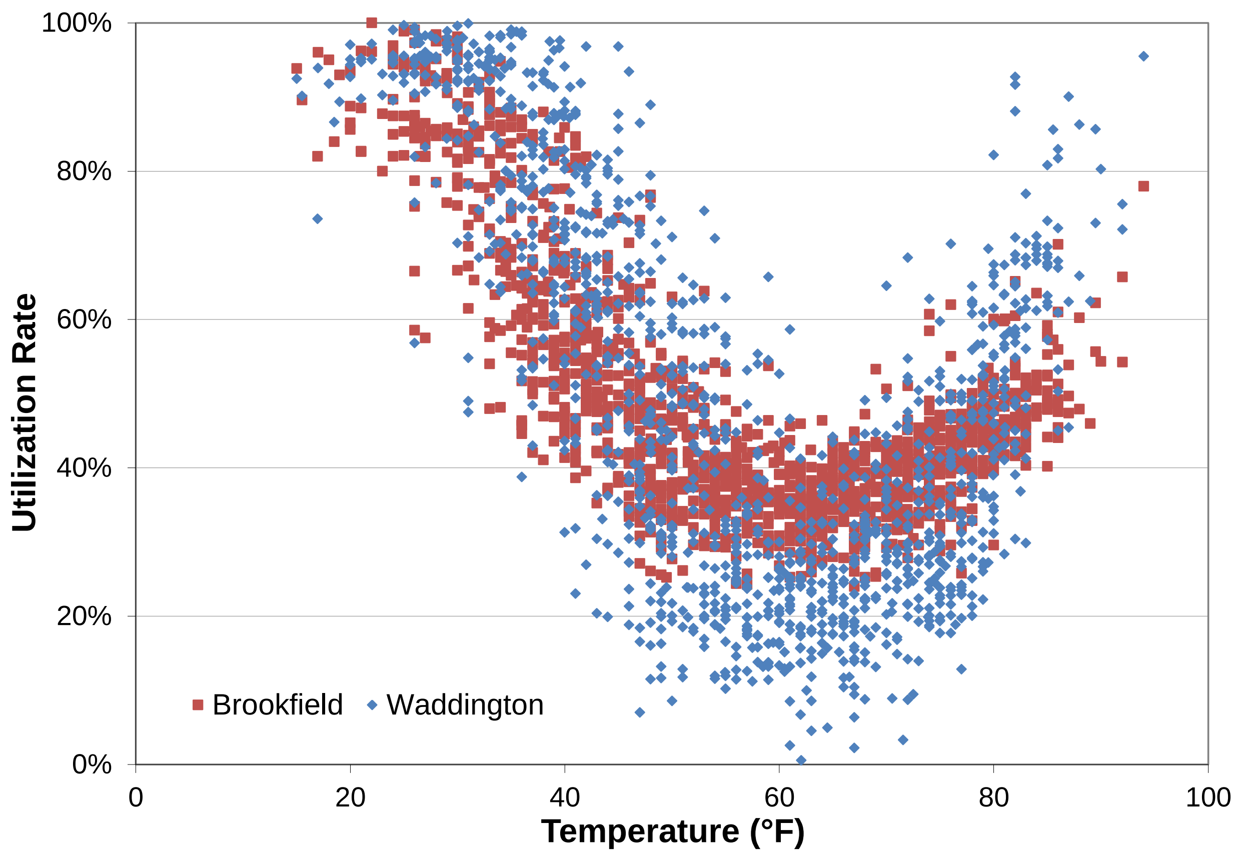
Top Utilization Days					Top Throughput Days				
Date	Capacity *MDth*	Throughput *MDth*	% util.	Temp *°F*	Date	Capacity *MDth*	Throughput *MDth*	% util.	Temp *°F*
2/9/2011	1,078	1,078	100.0%	22	2/9/2011	1,078	1,078	100.0%	22
2/10/2011	1,078	1,068	99.1%	26	2/10/2011	1,078	1,068	99.1%	26
1/21/2011	1,078	1,066	98.9%	25	1/21/2011	1,078	1,066	98.9%	25
1/8/2010	1,078	1,061	98.4%	28	1/8/2010	1,078	1,061	98.4%	28
1/6/2010	1,078	1,058	98.1%	30	1/6/2010	1,078	1,058	98.1%	30
2/3/2011	1,078	1,052	97.6%	29	2/3/2011	1,078	1,052	97.6%	29
1/12/2011	1,078	1,052	97.5%	28	1/12/2011	1,078	1,052	97.5%	28
1/11/2010	1,078	1,049	97.3%	26	1/11/2010	1,078	1,049	97.3%	26
1/12/2010	1,078	1,046	97.0%	30	1/12/2010	1,078	1,046	97.0%	30
1/9/2010	1,078	1,045	96.9%	24	1/9/2010	1,078	1,045	96.9%	24

For both locations, the top ten throughput and utilization days occurred in January, February and March. Seven of the top ten Waddington throughput days occurred during early 2013. For Brookfield, five of the top ten throughput and utilization days were observed between January 6, 2010 and January 12, 2010.

2.4.5 Conclusions

The plot of temperature vs. utilization for Brookfield and Waddington in Figure 47 shows a "U" shaped pattern that indicates that cold weather is the prominent driver of pipeline utilization.

Figure 47. Plot of Temperature vs. Utilization on Iroquois

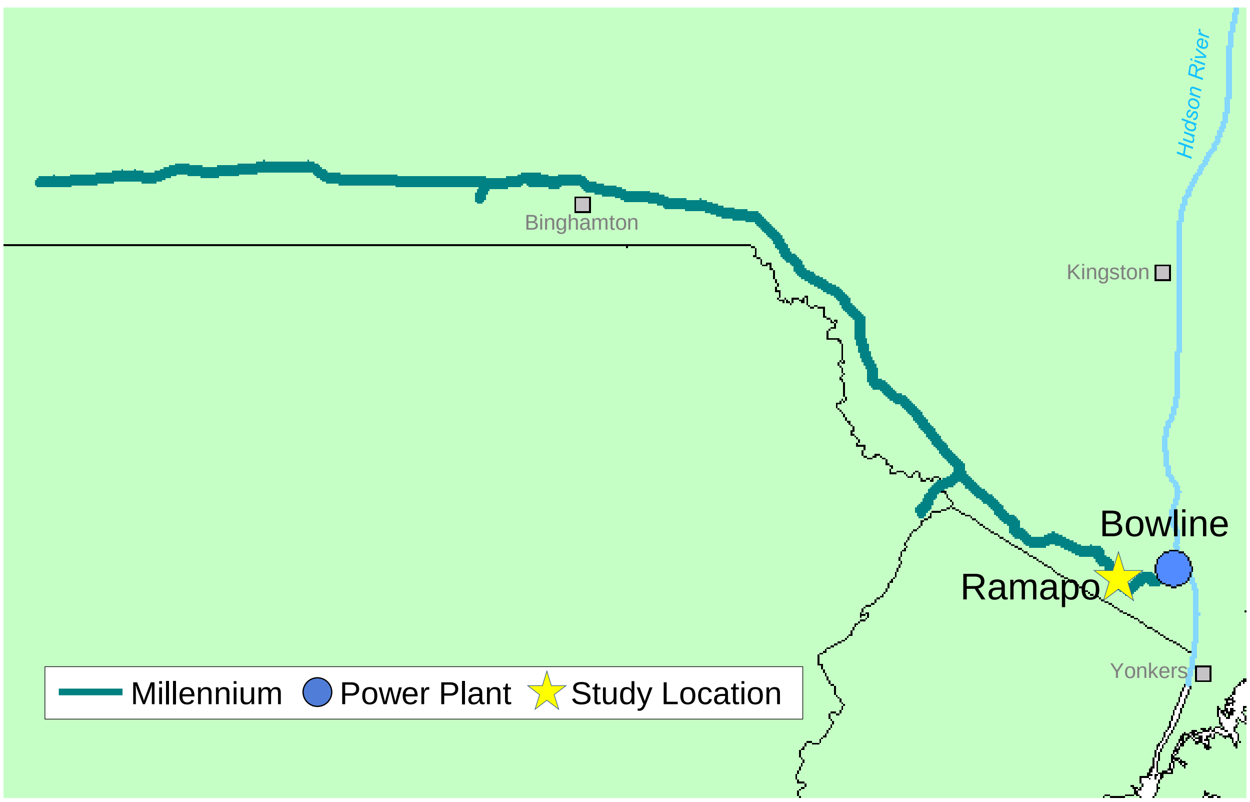


Gas flows at both Brookfield and Waddington approach full utilization during extreme cold. Relative to most other pipeline segments across NYCA, utilization rates are high on Iroquois during the summer months as well. The decline of the Waddington receipt point utilization during the cooling season over the study period reflects the steady growth of Marcellus shale gas in New York and New England, including increased flows of shale gas onto Iroquois through the interconnection with Algonquin. This recent trend has displaced western Canadian gas at Waddington.

2.5 Millennium

Millennium runs across New York from Independence, NY in the west through Corning, where it interconnects with Empire, and then to Ramapo in the east, where it interconnects with Algonquin. Millennium, which is jointly owned by DTE Energy, NGrid and NiSource, has a certificated capacity of 525 MDth/d. The pipeline entered service in late 2008 through acquisition of existing Columbia Gas facilities. Millennium is connected to significant production fields, which will be addressed in more detail in Section 3.3.1.2 on page 134.

Figure 48. Millennium Pipeline



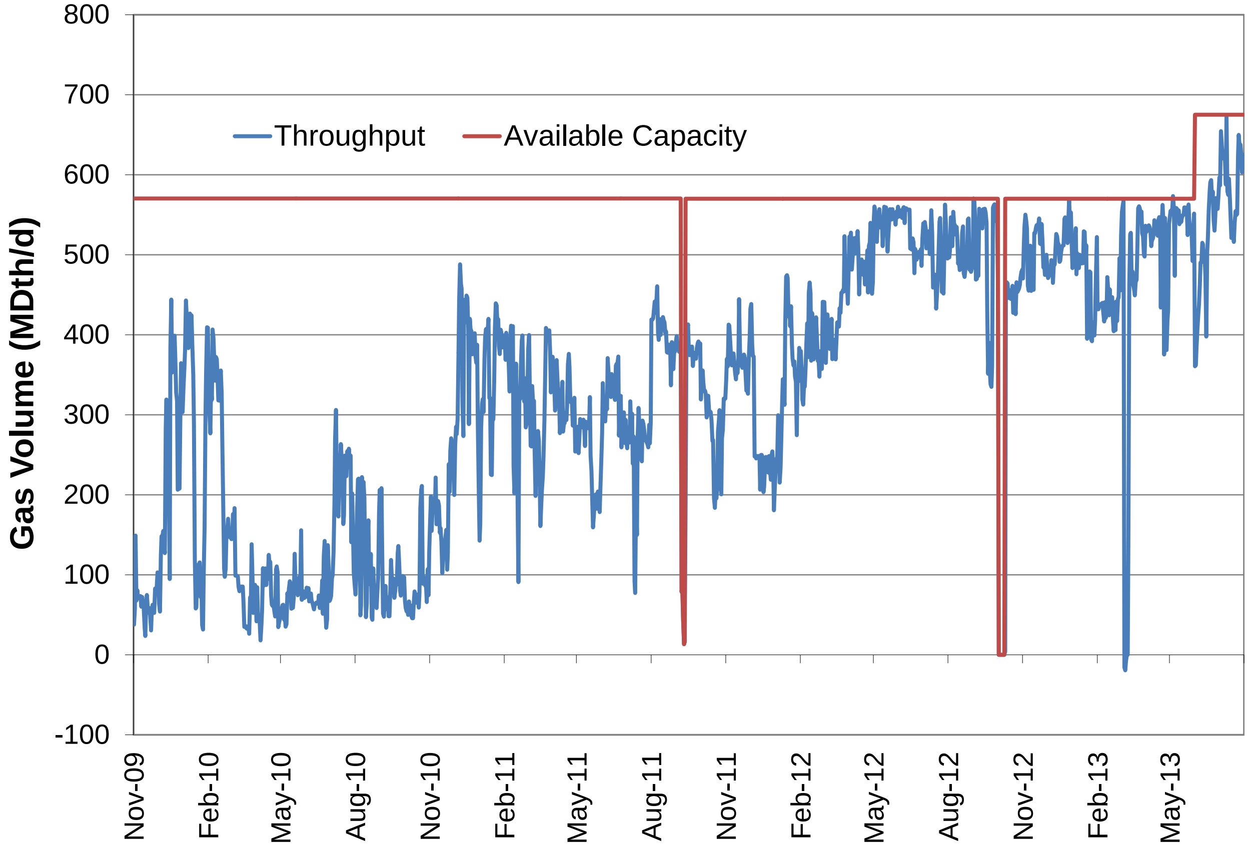
LAI analyzed flows through the Ramapo interconnection, where gas enters the Algonquin mainline for redelivery to the LHV and New England. Data were available for Ramapo on a daily basis for the period November 1, 2009 to January 31, 2013.

2.5.1 *Ramapo*

Although Millennium reports daily capacity for certain segments of its system, the available data set does not line up with the Ramapo location. Therefore, LAI assumed that prior to commercialization of the Minisink Compressor Station the segment's available capacity was equal to the maximum flow of 570 MDth/d, which occurred on September 1, 2012.[47] Following the commercialization of the Minisink Compressor Station, the capacity increased to 675 MDth/d. A review of OFOs posted on Millennium's EBB identified two significant outages occurred during the study period. The first was in September 2011, when a *force majeure* was declared at the Stagecoach high deliverability storage facility in Pennsylvania due to severe flooding and electrical outages, which lasted four days. The second outage occurred in October 2012, when hydrostatic testing and maintenance were conducted at Ramapo. Millennium did not specify how much pipeline capacity was lost during the maintenance event. In conducting this study, LAI has made the simplifying assumption that <u>no</u> gas flowed over the Ramapo interconnect during either of these periods.

Figure 49 shows throughput at Ramapo for the study period.

Figure 49. Millennium Daily Available Capacity and Throughput at Ramapo

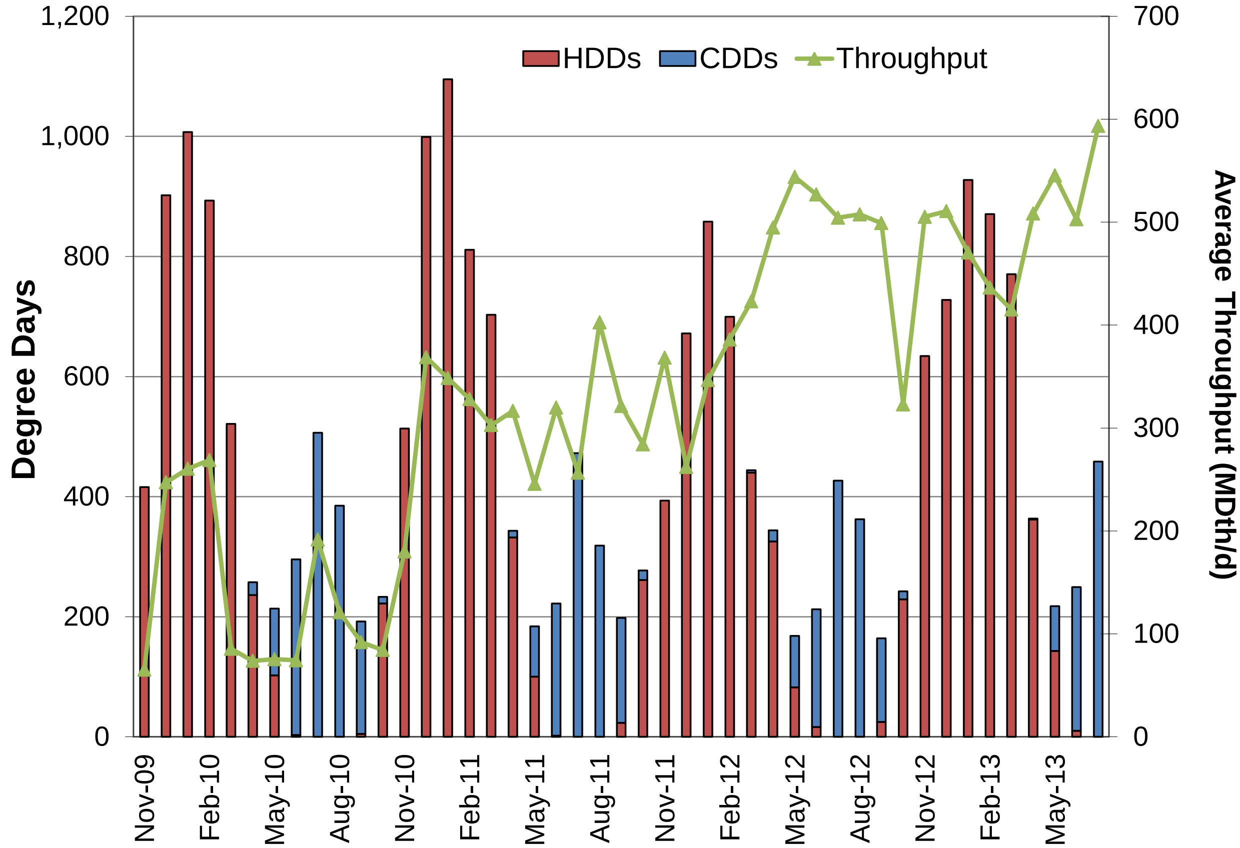


[47] Ramapo is the only segment analyzed whose maximum flow day occurred during a non-winter month.

Throughput increased significantly during the study period due to commercialization of the Laser Northeast Gathering System and the Bluestone Gathering System, which significantly increased producers' ability to move gas from the Marcellus shale into Millennium for delivery to eastern New York. [48]

Figure 50 compares flows to temperatures for this segment.

Figure 50. Comparison of Temperature and Throughput for Ramapo



During the first half of the study period, flows were highly seasonal, driven in large part by HDDs. Beginning in late 2011, throughput at Ramapo increased and remained at much higher levels through the summer of 2012, reflecting increased gas production from Marcellus and the start-up of Laser, and later Bluestone. Days where utilization rates at Ramapo reached or exceeded 90% are shown in Table 31.

Table 21. Days Pipeline Utilization Exceeded 90% for Ramapo

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Days w/ 95% or greater util.	0	0	8	6	44	13	7	4	16	0	3	7
Days w/ 90% or greater util.	5	0	14	33	58	17	28	12	19	0	15	13

[48] Millennium's production receipts are discussed in more detail in Section 3.3.1.2 on page 147.

Utilization reached or exceeded 90% at Ramapo on 214 days during the study period. Most of the high utilization days occurred during the months of April through September. All of the days on which utilization was 90% or greater occurred after February 2012.

2.5.2 Utilization Distributions

In Figure 51, the distribution of utilization rates for all days is plotted, revealing broad dispersion. Figure 52 shows the same analysis using only winter data. The median and mode are shifted to the right, indicating that utilization at Ramapo is affected by cold weather.

Figure 51. Distribution of Utilization Rates on Millennium

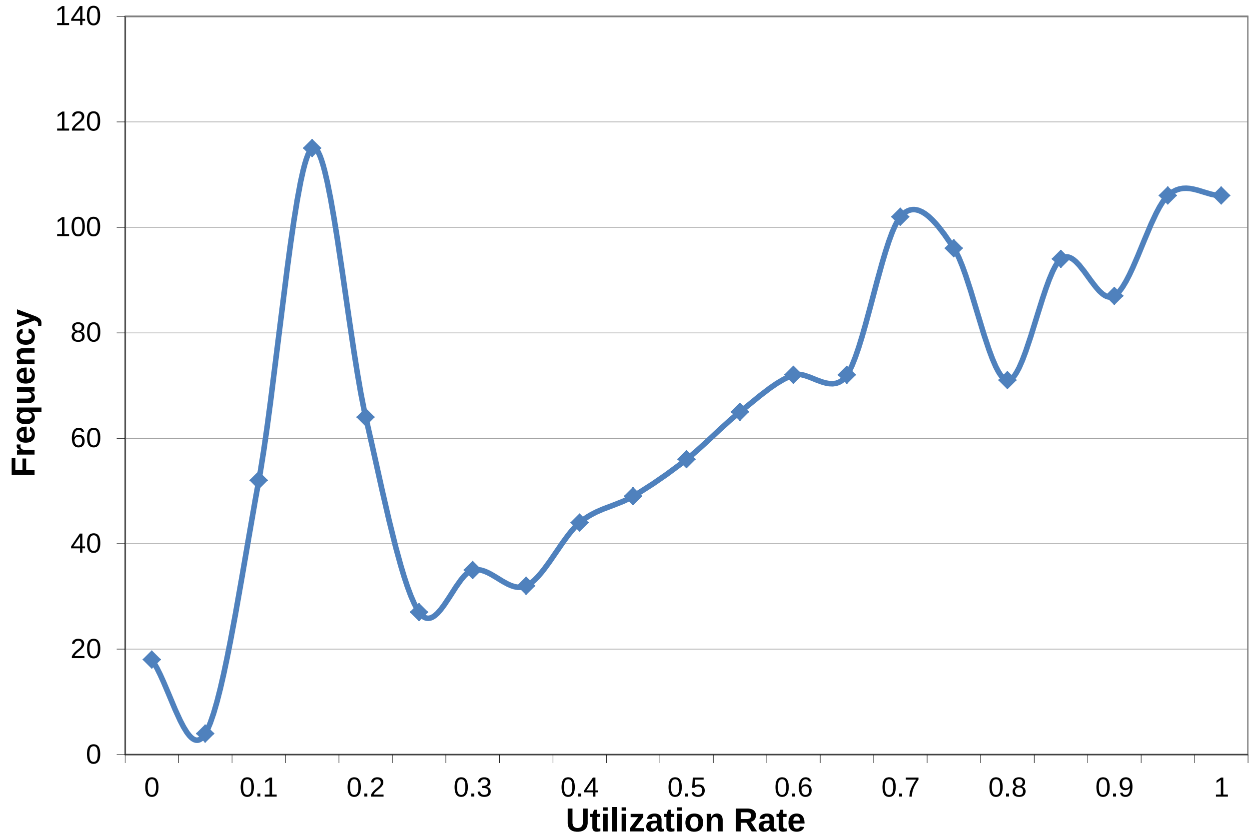
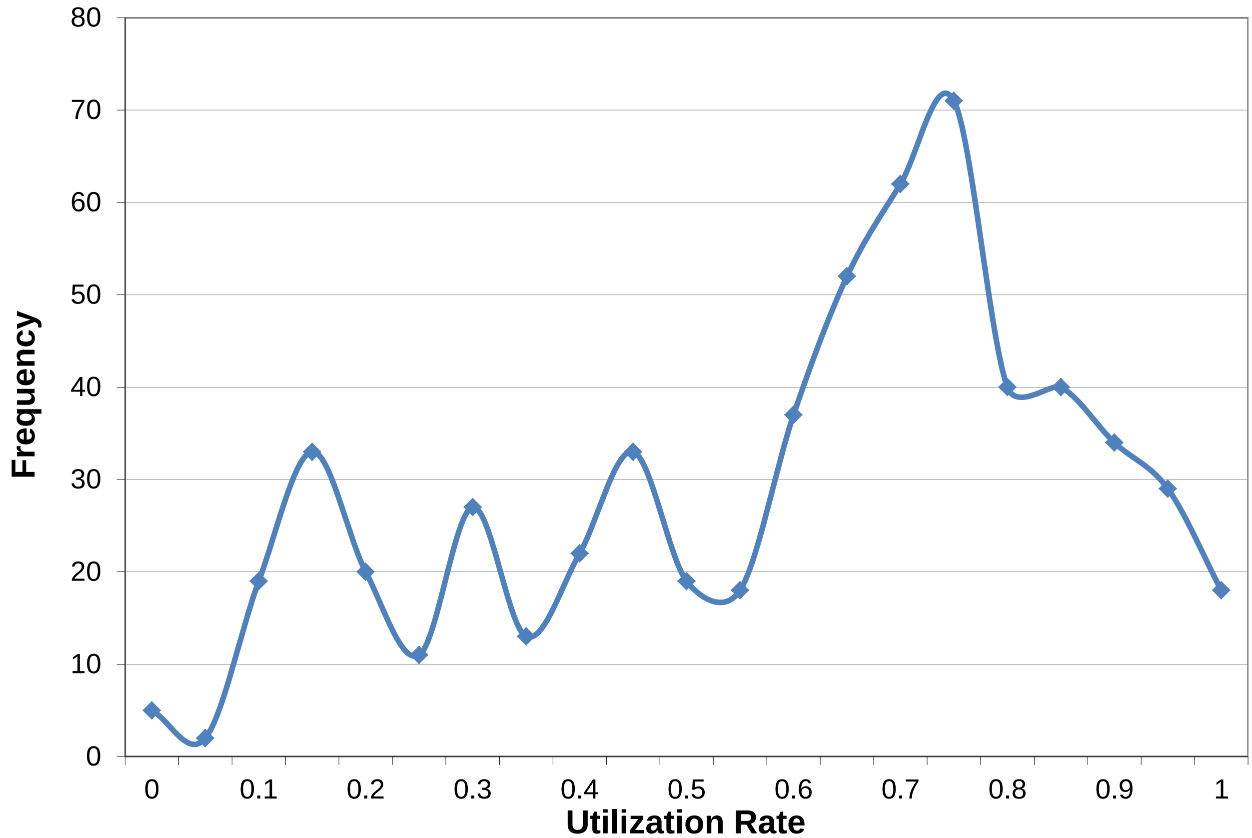


Figure 52. Distribution of Utilization Rates on Millennium, Winter Only



2.5.3 High Congestion and Flow Days

The top utilization and throughput days for Ramapo are shown in Table 22. Due to the capacity increase associated with the startup of the Minisink Compressor Station, the top ten throughput days all occur during the summer 2013.

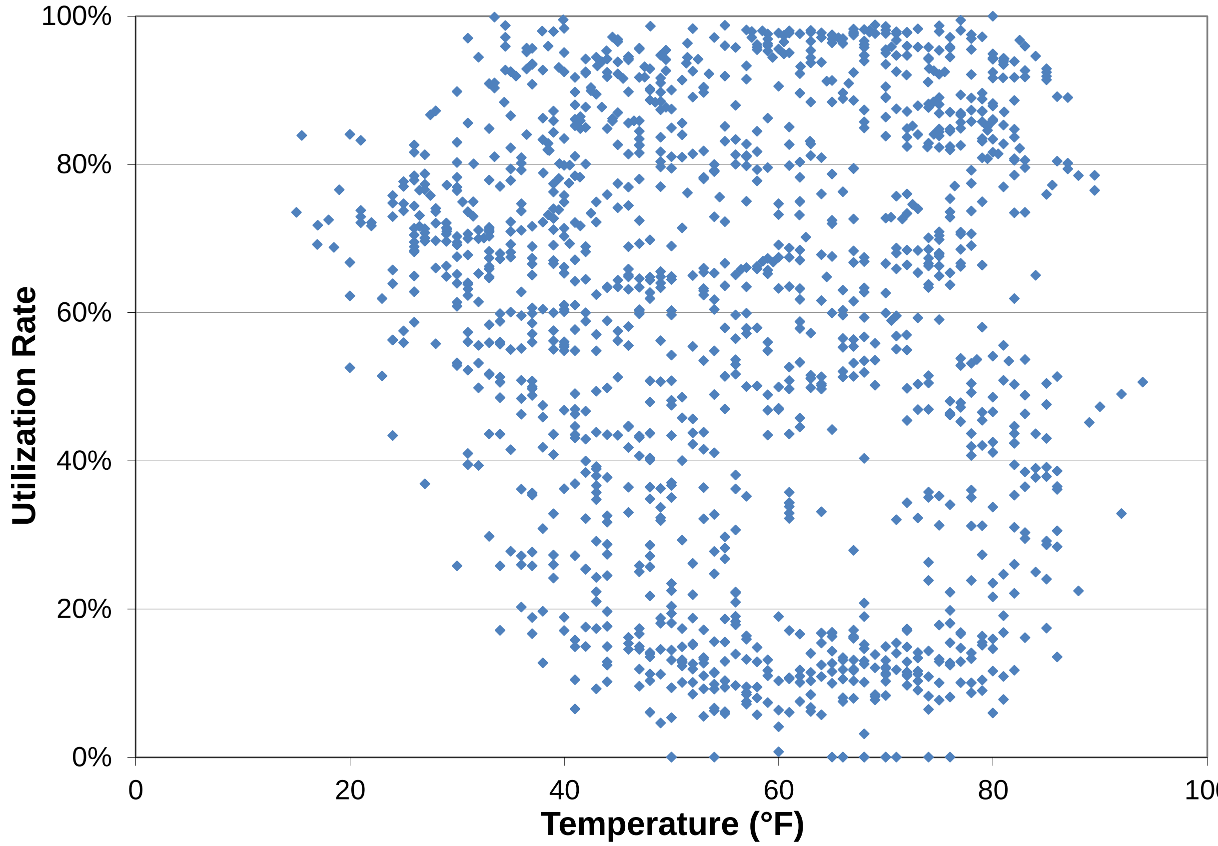
Table 22. Top Utilization and Throughput Days for Ramapo

Top Utilization Days					**Top Throughput Days**				
Date	**Capacity** *MDth*	**Throughput** *MDth*	**% util.**	**Temp** *°F*	**Date**	**Capacity** *MDth*	**Throughput** *MDth*	**% util.**	**Temp** *°F*
5/5/2013	570	573	100.6%	55	7/10/2013	675	675	100.0%	80
9/1/2012	570	570	100.1%	83	7/3/2013	675	655	97.0%	78
7/10/2013	675	675	100.0%	80	7/25/2013	675	650	96.3%	66
12/28/2012	570	569	99.9%	34	7/27/2013	675	638	94.5%	76
3/5/2013	570	567	99.5%	40	7/4/2013	675	636	94.2%	81
9/2/2012	570	567	99.5%	77	7/26/2013	675	636	94.2%	74
9/27/2012	570	563	98.8%	69	7/28/2013	675	627	92.9%	74
5/24/2013	570	563	98.8%	55	7/5/2013	675	625	92.6%	83
3/4/2013	570	563	98.7%	35	7/31/2013	675	625	92.6%	75
7/28/2012	570	563	98.7%	75	7/24/2013	675	624	92.5%	76

2.5.4 Conclusions

The high concentration of gas-fired generation on Algonquin in New England sustains a high level of pipeline utilization at the Ramapo interconnection. That temperature variations are not a key driver of high throughput across Millennium during the cooling season is shown in Figure 53. The lack of correlation between temperature and utilization is explained by power loads in the LHV and New England.

Figure 53. Temperature vs. Utilization on Millennium



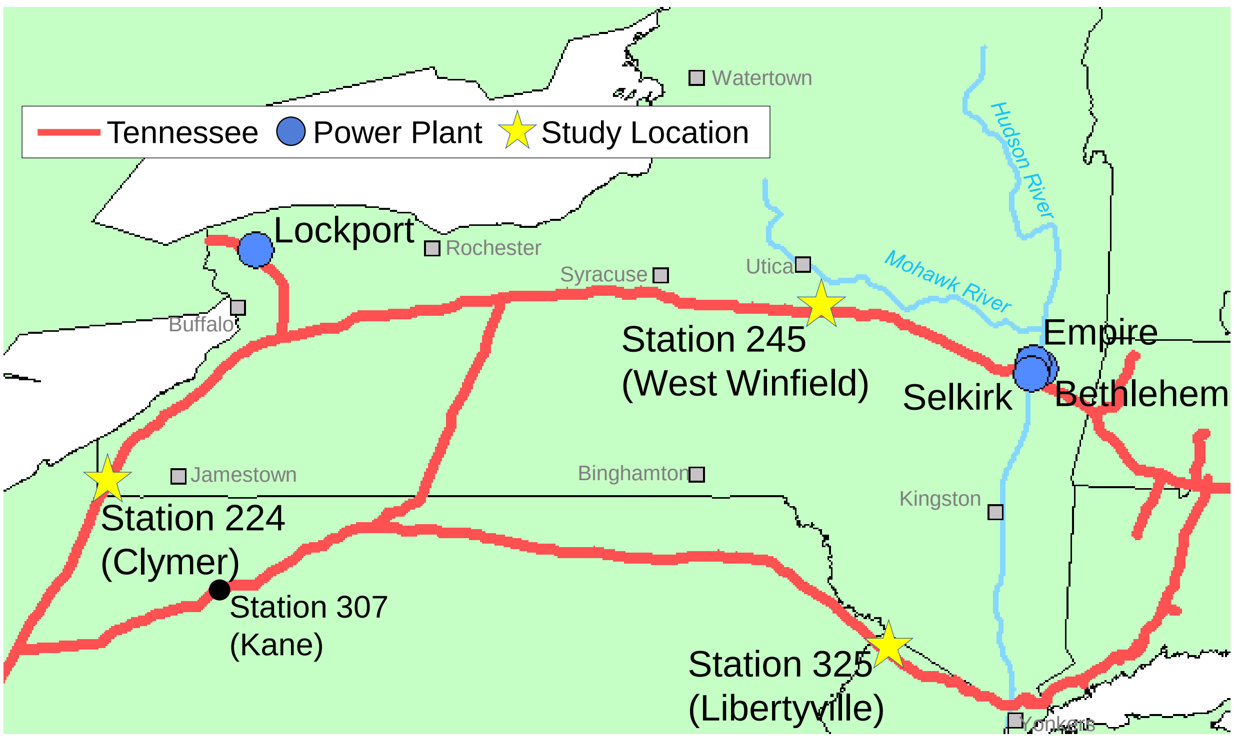
In the first half of the study period, there was significant slack capacity at Ramapo. Upon commercialization of Laser, Bluestone, and the Minisink Compressor Station, slack deliverability at Ramapo dissipated, reflecting the more complete use of the Algonquin mainline for downstream deliveries. Since early 2012, utilization rates on this segment of the Millennium system have been consistently high year-round.

2.6 Tennessee Gas Pipeline

Tennessee is now owned by Kinder Morgan. Tennessee is a 14,000-mile pipeline network with a total capacity of 6.7 Bcf/d extending from the Gulf Coast to New England. Tennessee and Algonquin are the primary long-haul pipelines transporting Marcellus shale gas to New England. Key interconnects of relevance in New York are with Algonquin, Dominion, and NFG. Historically, Tennessee sourced natural gas from the Gulf Coast by way of Leidy and Ellisburg, Pennsylvania, but also from western Canada through its interconnection with TransCanada at Niagara into Line 200 across upstate New York. While the Niagara import point with TransCanada is now a delivery point for export into Ontario, Tennessee's system wide improvements from western Pennsylvania into New York accommodate shale gas to supply customers throughout New York and New England.

As shown in Figure 54, Tennessee's route system consists of two distinct pipeline corridors across New York into New England. Line 200 follows a northern path that bisects central New York, running past Buffalo and near Syracuse, Utica, and through the Capital District, providing direct service to several generators. LAI analyzed data for Station 224 and Station 245 on Line 200. The 300 Line runs parallel to the New York-Pennsylvania border and is the superhighway linking Marcellus with Westchester County, as well as southern New England, where Lines 200 and 300 converge near the Connecticut-Massachusetts border. LAI analyzed data at Station 325, which is located on Line 300 in northern New Jersey along the path into White Plains. Insofar as the two Tennessee lines serve different markets, throughput and utilization patterns differ significantly.

Figure 54. Tennessee Pipeline



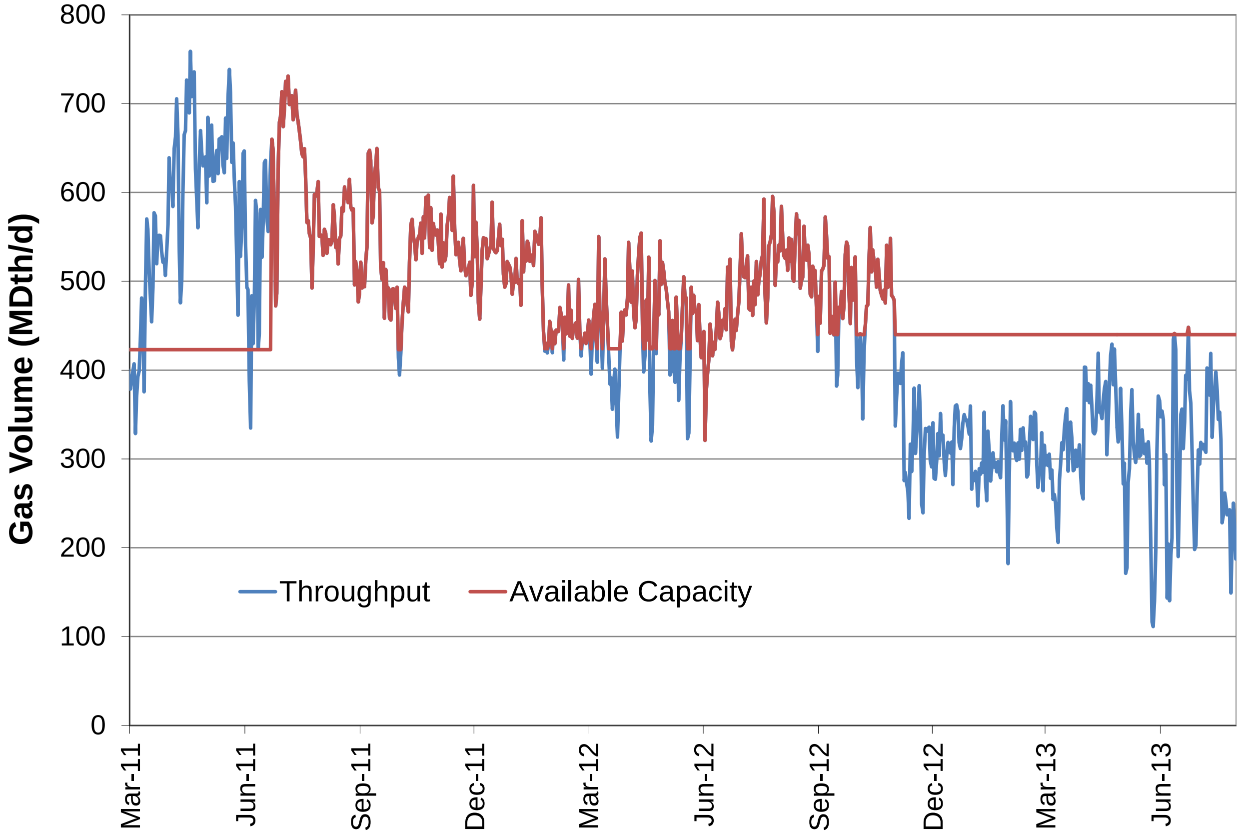
Mainline throughput data were available for the Tennessee segments on a daily basis for the period February 17, 2011 to July 31, 2013, a total of 896 days.[49]

2.6.1 Station 224

For the majority of days in the available dataset, the reported daily pipeline capacity values for Station 224 were equal to the throughput, potentially indicative of reverse flow through the station. There were no significant service outages that reduced capacity on this segment during the study period. The figure below shows gas throughput compared to the assumed available capacity for each day of the study period.

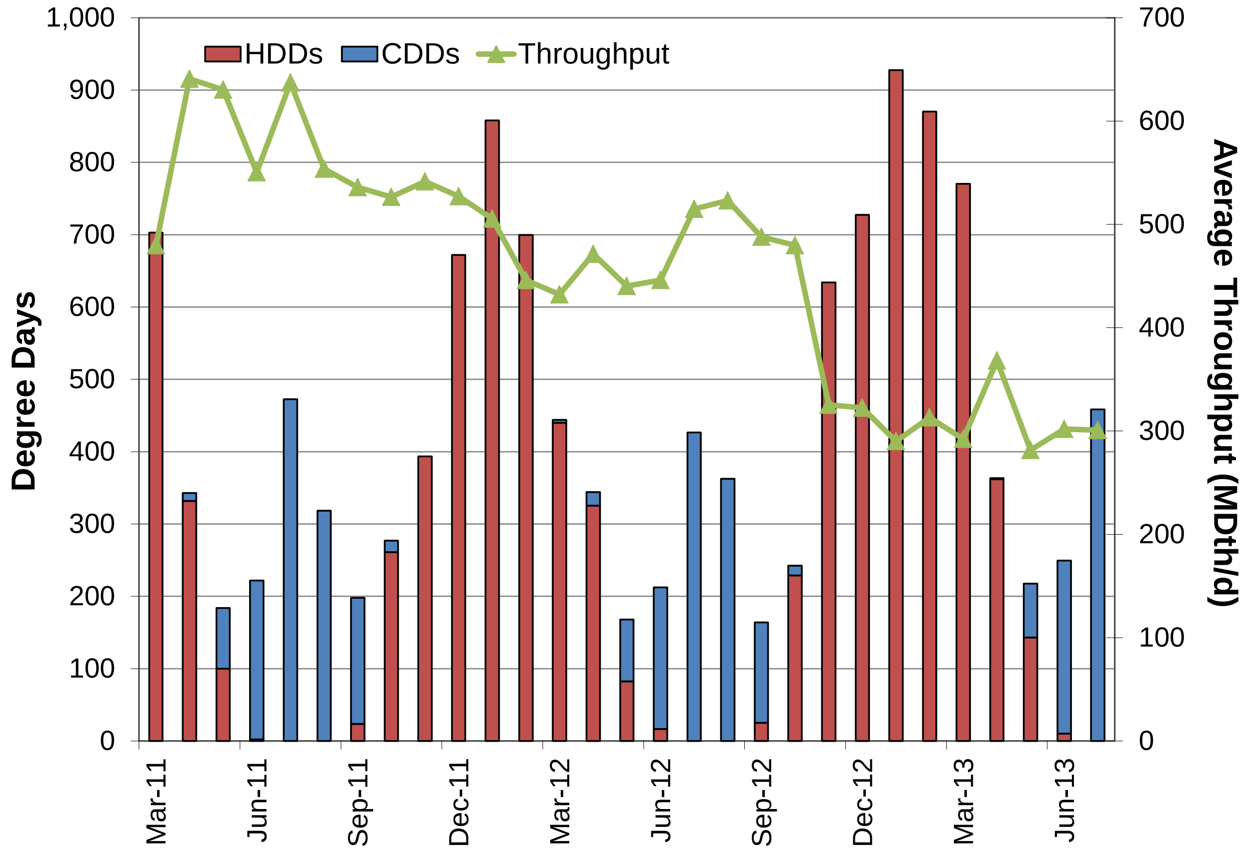
[49] Although earlier EBB data is available, Tennessee only started reporting mainline throughput at selected points on February 17, 2011.

Figure 55. Daily Available Capacity and Throughput at Station 224



Following commercialization of the infrastructure improvements associated with the flow reversal at Niagara in November 2012, flows through Station 224 were reduced. Throughout the study period, as shown in Figure 56, strong seasonal variations were not observed.

Figure 56. Comparison of Temperature and Throughput for Station 224



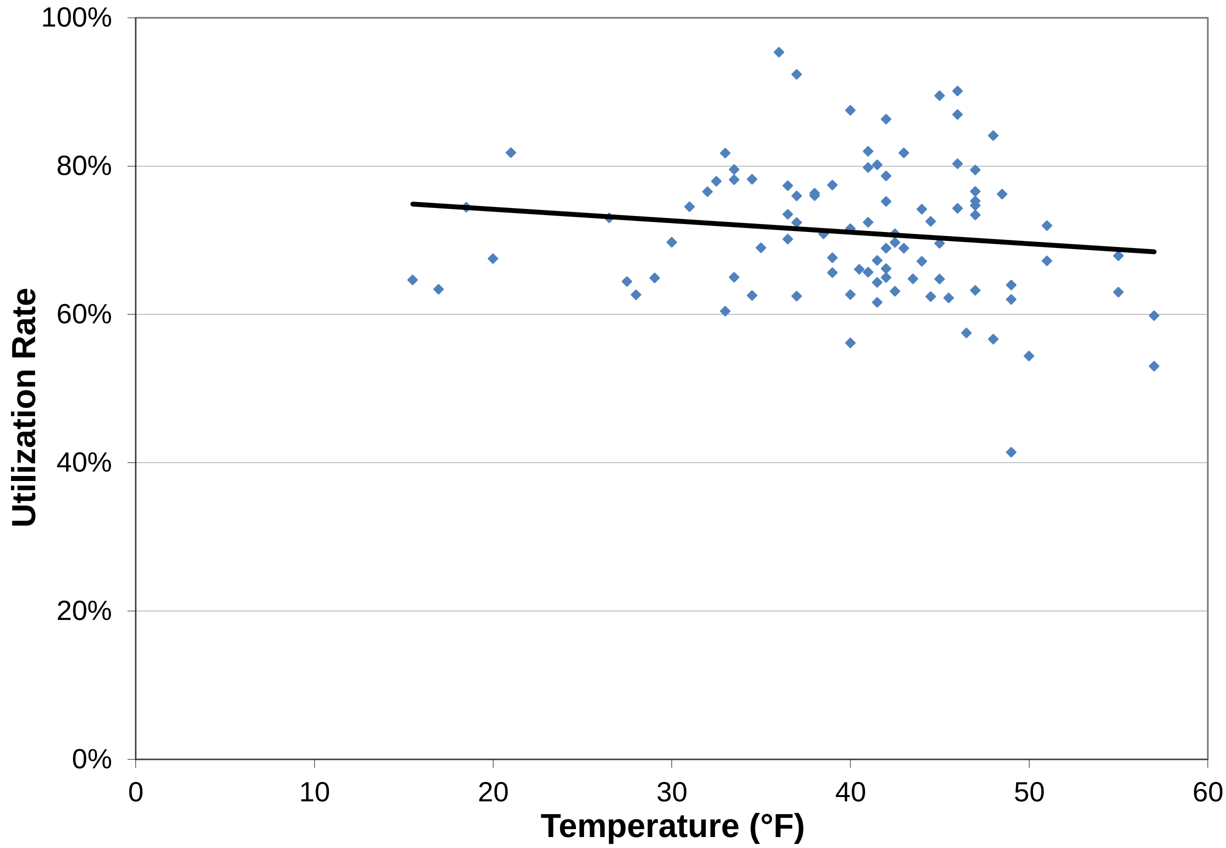
Gas volumes on Tennessee's Line 200 flow through the Capital District and into New England. Line 200 volumes do not flow into NYC, and are therefore not particularly sensitive to swings associated with seasonal throughput patterns caused by core customers' demand for heating.

Table 23. Monthly Pipeline Utilization Statistics for Station 224

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Days w/ 95% or greater util.	31	35	44	59	55	62	63	62	58	56	31	31
Days w/ 90% or greater util.	31	39	54	64	59	63	66	62	58	60	33	31

These utilization statistics are skewed due to the period in 2011 and 2012 with high capacity values. Therefore we have also plotted pipeline utilization against daily average temperature for the period from November 1, 2011 through July 31, 2013, shown in Figure 57 along with a linear trend line for that dataset. There appears to be a slight negative correlation between temperature and utilization; however, there is broad dispersion around the trend line, indicating a weak relationship between pipeline use and temperature is moderate not strong.

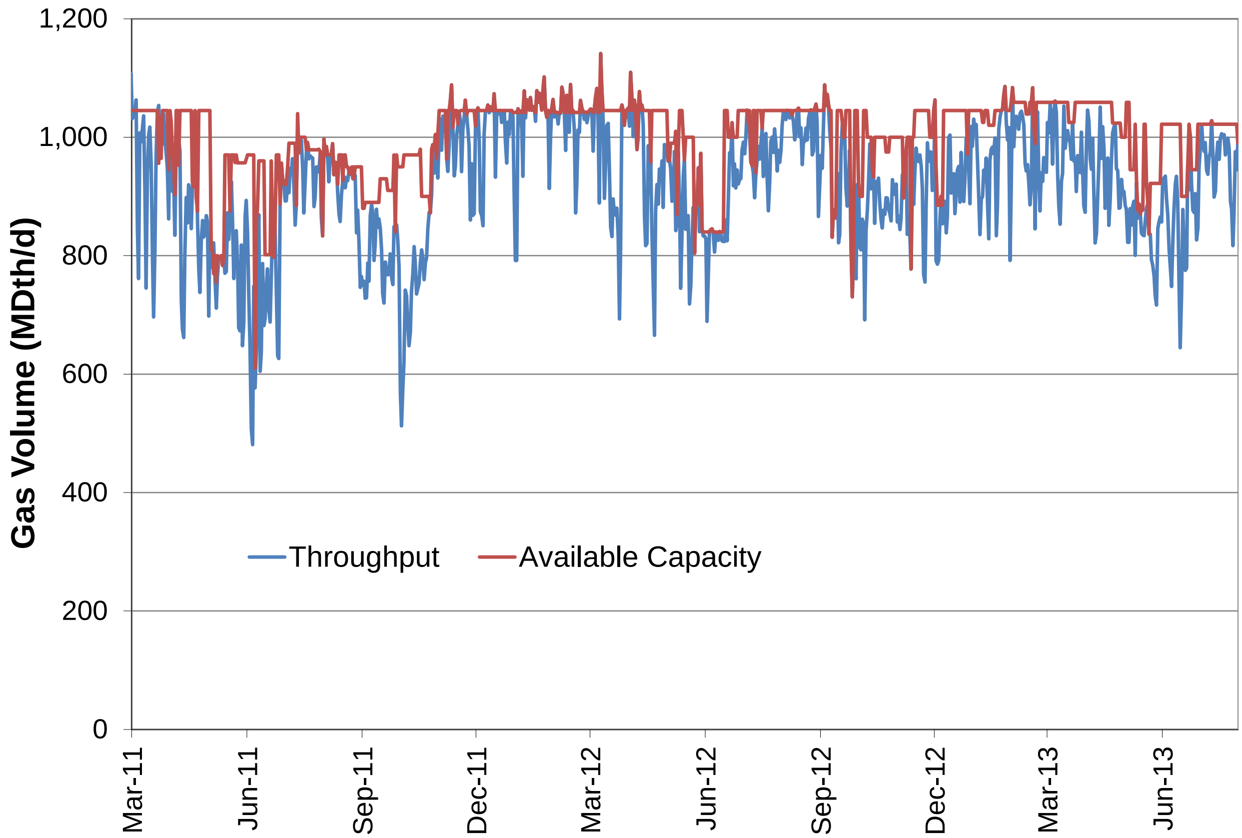
Figure 57. Plot of Temperature vs. Utilization at Station 224



2.6.2 Station 245

The posted daily capacity data for Station 245 did not exhibit a consistent profile, instead showing spikes to match throughput when Tennessee was able to exceed the design capacity of the compressor station to meet operational demand. The maximum flow at Station 245 was 1,141 MDth, which occurred on March 9, 2012. Volumes flowing through Station 245, were sourced from Marcellus via Line 200 and Line 400, which flows south-to-north through central New York, and via the Empire Connector at Hopewell.

Figure 58. Daily Available Capacity and Throughput at Station 245



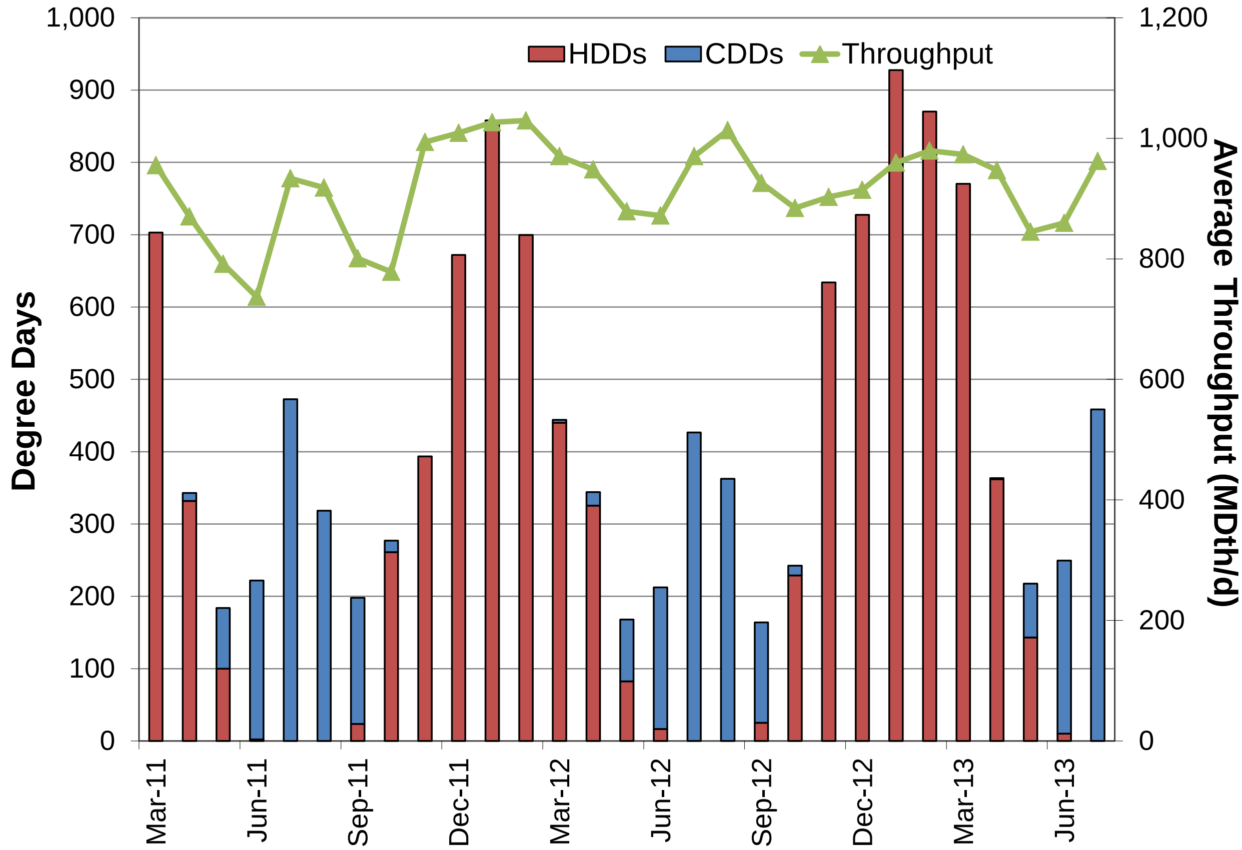
Far more gas flows through Station 245 on a year-round basis than Station 224. Station 245 is the principal bottleneck on Line 200, which causes deliveries on Tennessee downstream of Station 245 to be valued at the Tennessee Zone 6 pricing point, an index that is highly correlated with the Algonquin Citygates pricing point.

Table 24. Monthly Pipeline Utilization Statistics for Station 245

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Days with 95% or greater util.	43	49	46	26	36	30	51	47	23	11	25	32
Days with 90% or greater util.	47	56	63	50	53	47	79	54	30	27	42	40

Station 245 experienced pipeline utilization rates of 90% or greater on 588 days during the truncated time series, distributed roughly equally between the heating and cooling seasons. Reflecting the market penetration of shale gas in New York and New England as well as the high concentration of gas-fired generation served directly by Tennessee in New England, flow patterns at Station 245 exhibits a relatively low degree of seasonality. Average utilization was 80% or greater. Average flows were relatively constant and at high levels throughout the year. Figure 59 provides a comparison of temperature and throughput at Station 245.

Figure 59. Comparison of Temperature and Throughput for Station 245



As with Station 224, the data in Figure 59 do not suggest a strong correlation between temperatures and throughput. LAI has concluded that flows across this segment are relatively insensitive to weather conditions, reflecting New England's dependence on gas-fired generation served directly by Tennessee throughout the year.

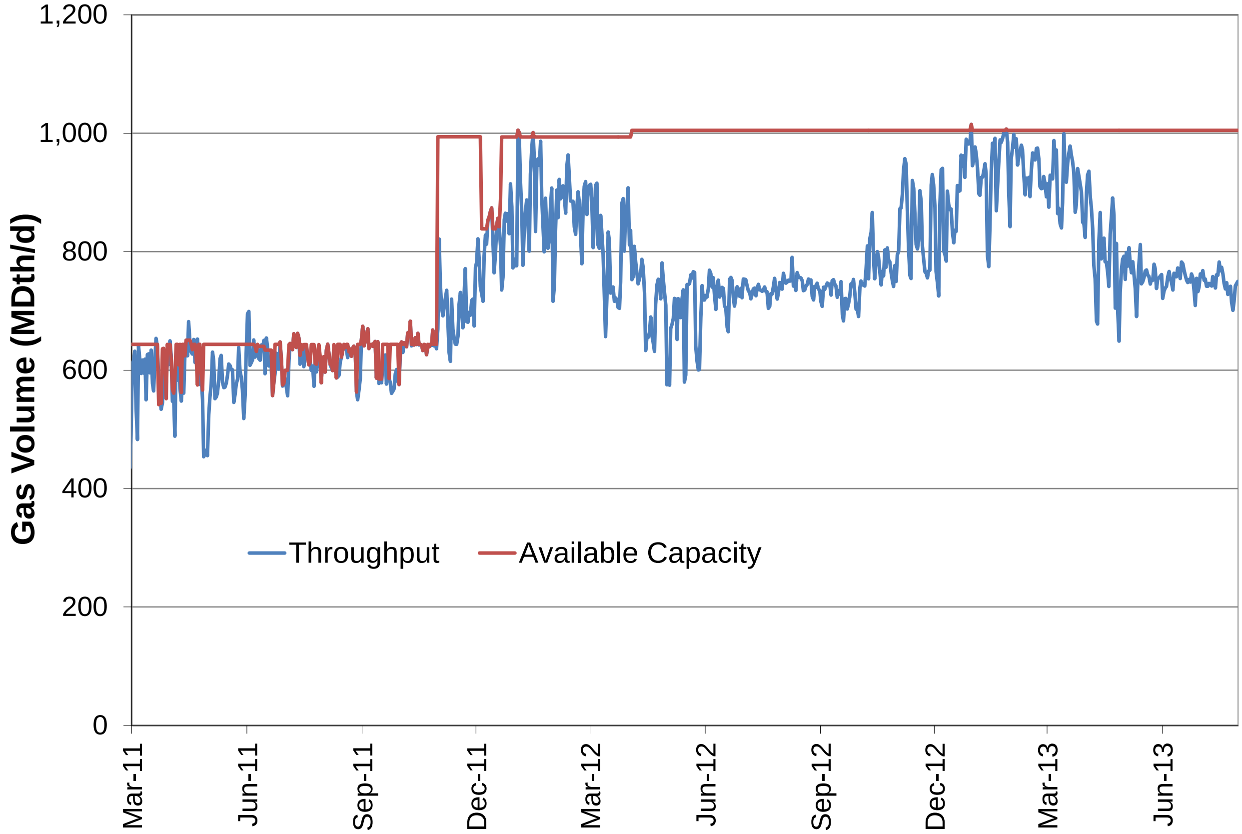
2.6.3 Station 325

The baseline capacity of Station 325 changed over the study period, due to infrastructure additions associated with Tennessee's Line 300 Project. From 2/17/11 through 10/29/11, with some oscillation, the capacity is 644 MDth/d; from 10/30/11 through 4/2/12, the capacity is 994 MDth/d; and from 4/2/12 through 1/31/13, the capacity is 1,005 MDth/d.[50]

The maximum flow at Station 325 was 1,015 MDth, which occurred on December 30, 2012. There was one significant service outage that reduced capacity on this segment during the study period, with a reduction of 155 MDth/d from December 5 to 20, 2011 due to an efficiency problem at the upstream Station 323. The figure below shows gas throughput compared to EBB-reported available capacity from March 2011 through July 2013. The instances where throughput is higher than capacity are indicative of the system's ability to meet peak loads for short periods of time.

[50] The transition from 644 MDth/d to 994 MDth/d coincides with the in-service date of Line 300 Project.

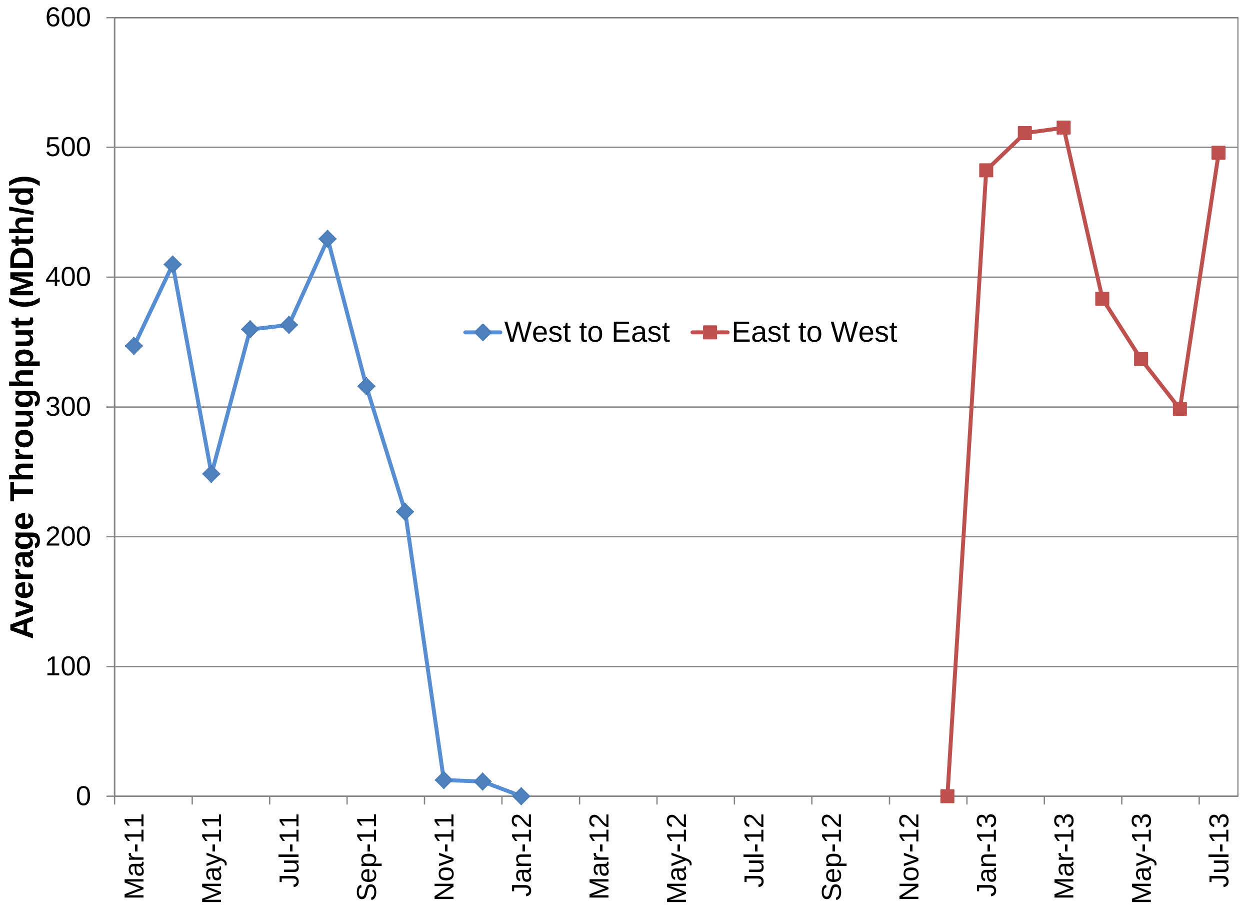
Figure 60. Daily Available Capacity and Throughput at Station 325



The flows at Station 325 show seasonality following the capacity increase in late 2011. Flows approached segment capacity during the 2011-12 and 2012-13 heating seasons.

Historically, both Line 200 and Line 300 have flowed gas sourced from the Gulf Coast, with additional Canadian imports flowing on Line 200. As Marcellus receipts on Line 300 have increased, Gulf Coast- and Canada-sourced flows have been displaced. A review of compressor station throughput and directionality on Line 300 shows that Station 307 (location shown in Figure 54), which previously flowed gas from west to east, is now flowing gas east-to-west, after a period of no flow, as illustrated in Figure 61. Market dynamics have since rationalized the reversal-of-flow, including the conversion of Niagara from a receipt point to a delivery point into Ontario.

Figure 61. Average Monthly Throughput at Station 307

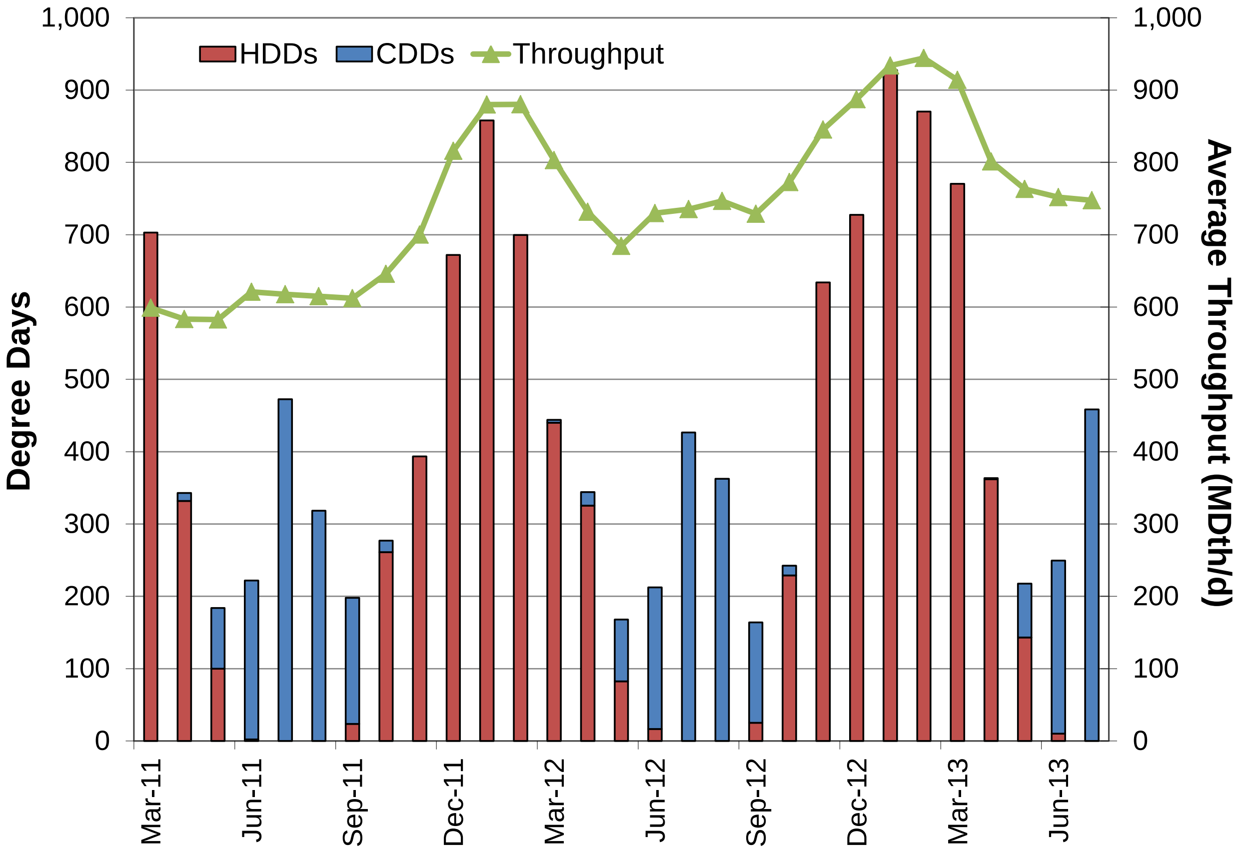


Similar data for Station 219, Line 200 and Line 300 indicate that no gas is flowing into the region from the south. Instead, Marcellus gas is flowing to the west on Line 300 and then onto Line 200 for export to Ontario. This flow dynamic is supported by the increased Marcellus receipts into Tennessee shown in Figure 14.

The changing flow dynamics on Line 300 Line mean that gas flowing through Station 325 en route to New York is now sourced exclusively from Marcellus. How daily volumes are scheduled for eastward flow through Station 325 is driven primarily by the magnitude of the power loads in Ontario versus New England.

Comparing throughput to temperature measures confirms that flows at Station 325 have been responsive to temperature swings during the last two winters, as shown in Figure 62.

Figure 62. Comparison of Temperature and Throughput for Station 325



These data indicate that over the study period, throughput at Station 325 reflected the impact of heating demand. Throughput peaked during the 2011-12 heating season and has remained elevated during the 2012-13 heating season.

Table 25 shows the number of days for which utilization at Station 325 reached or exceeded 90%.

Table 25. Monthly Pipeline Utilization Statistics for Station 325

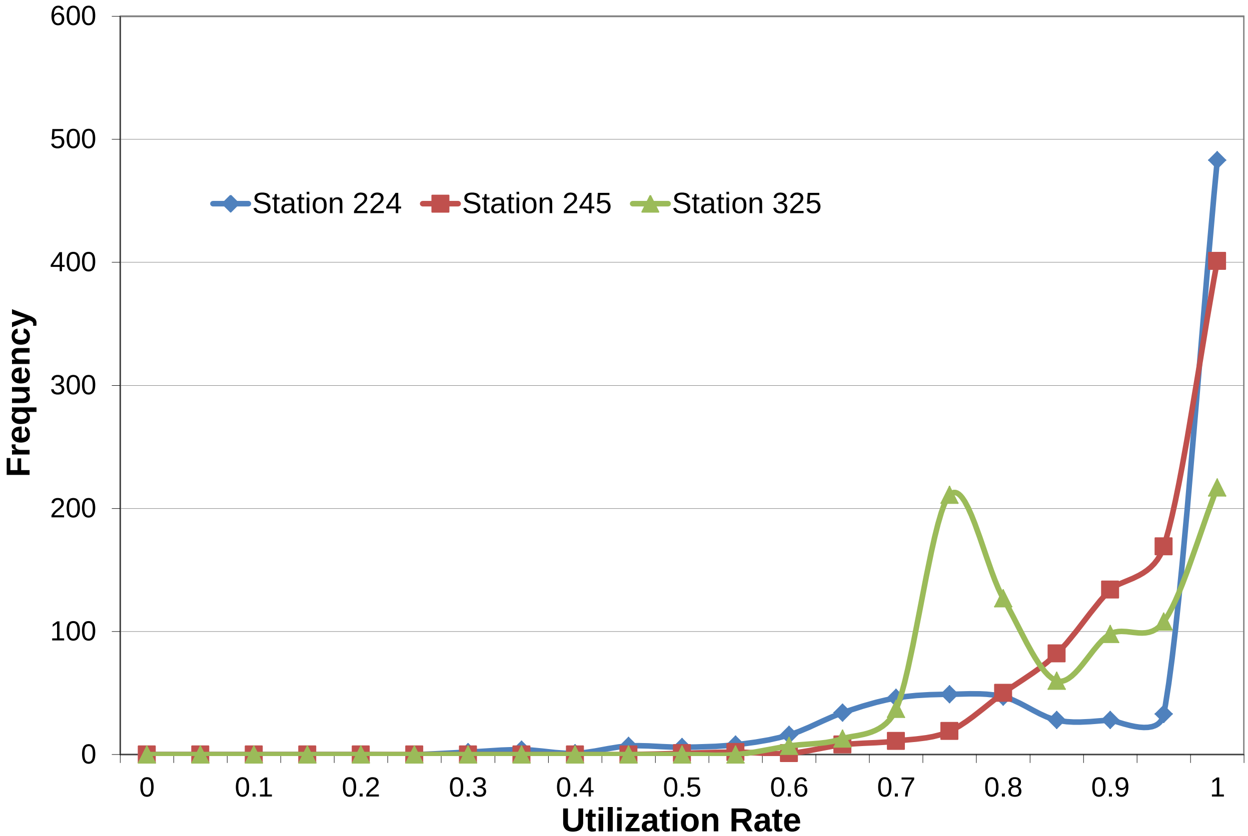
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Days with 95% or greater util.	22	16	28	19	6	25	25	26	20	30	1	17
Days with 90% or greater util.	35	40	48	23	16	30	30	29	26	30	8	28

Station 325 experienced 343 days with utilization at 90% or greater, and 235 days at 95% or greater. The cooling season days with high utilization occurred prior to Tennessee placing the 300 Line Project facilities in-service, suggesting a significant degree of seasonality for the expansion capacity.

2.6.4 Utilization Distributions

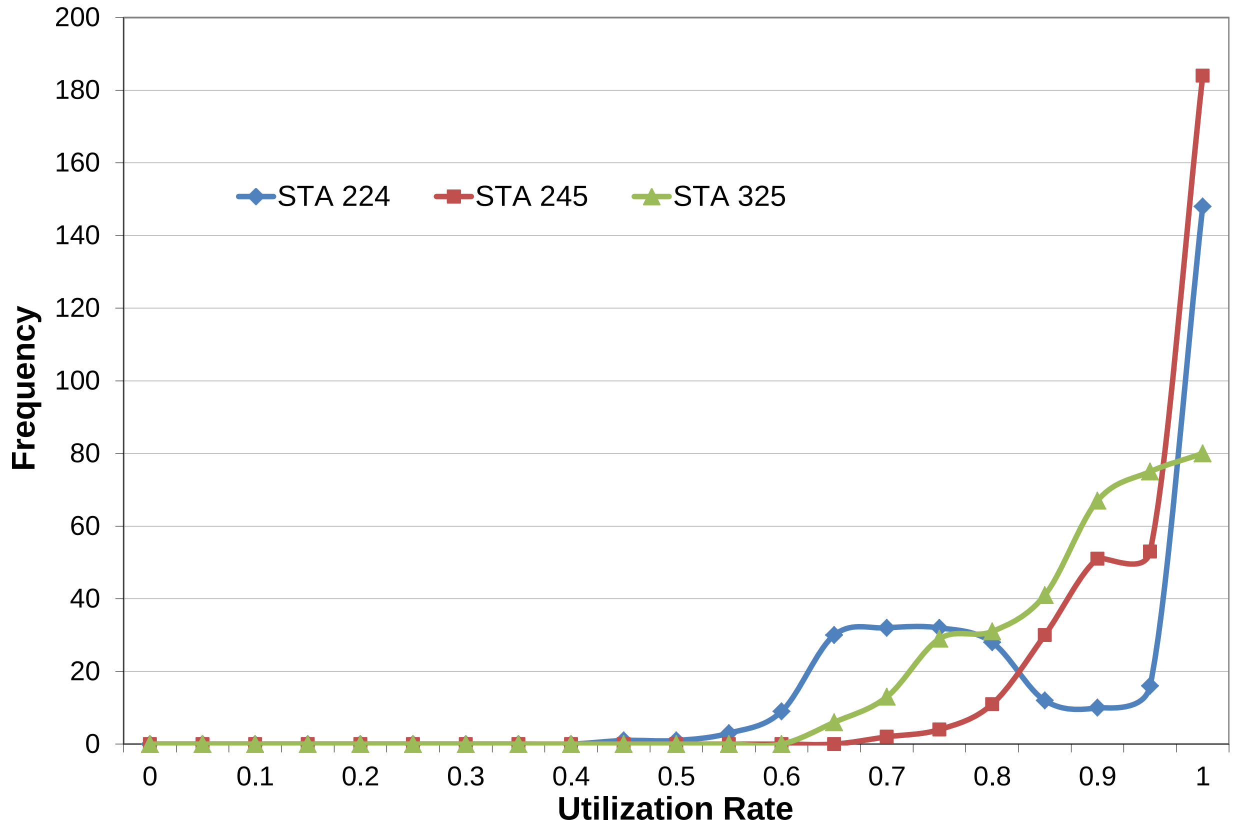
The data shown by the frequency distribution plots in Figure 63 and Figure 64 indicate that all three compressor stations operate with high utilization factors. In the Station 224 dataset, the local peak between utilization rates of 0.6 and 0.9 is associated with the period since November 2, 2012.

Figure 63. Distribution of Utilization Rates on Tennessee



Frequency distribution curves for the same three points using only winter month data are shown in Figure 64.

Figure 64. Distribution of Utilization Rates on Tennessee, Winter Only



2.6.5 High Congestion and Flow Days

The next three tables show the top throughput days for Station 224, Station 245 and Station 325. Given Tennessee's operational practice of regularly exceeding the EBB-reported design capacity of the compressor stations, we have not reported the top utilization days.

Table 26. Top Throughput Days for Station 224[51]

Top Throughput Days				
Date	**Capacity** *MDth*	**Throughput** *MDth*	**% util.**	**Temp** *°F*
4/18/2011	423	759	179.4%	55
5/19/2011	423	739	174.6%	68
4/21/2011	423	736	174.0%	53
7/5/2011	731	731	100.0%	79
4/15/2011	423	727	171.8%	49
7/3/2011	725	725	100.0%	72
4/20/2011	423	717	169.5%	55
7/11/2011	715	715	100.0%	83
6/30/2011	713	713	100.0%	74
5/20/2011	423	713	168.5%	61

[51] The top three throughput days, in April and May 2011, show very high utilization rates because Tennessee consistently reported a capacity of 423 MDth/d during this period, independent of the scheduled flow volumes, as shown in Figure 55.

Table 27. Top Throughput Days for Station 245

Top Throughput Days				
Date	Capacity *MDth*	Throughput *MDth*	% util.	Temp *°F*
3/9/2012	1,141	1,141	100.0%	51
2/25/2011	1,045	1,112	106.4%	46
4/2/2012	1,110	1,110	100.0%	49
2/28/2011	1,045	1,108	106.0%	50
1/24/2012	1,102	1,102	100.0%	48
2/21/2011	1,045	1,092	104.5%	31
2/23/2011	1,045	1,090	104.3%	31
2/14/2012	1,089	1,089	100.0%	42
11/11/2011	1,088	1,088	100.0%	45
9/4/2012	1,088	1,088	100.0%	75

Table 28. Top Throughput Days for Station 325

Top Throughput Days				
Date	Capacity *MDth*	Throughput *MDth*	% util.	Temp *°F*
12/30/2012	1,015	1,015	100.0%	31
1/27/2013	1,007	1,007	100.0%	27
1/3/2012	1,005	1,005	100.0%	24
1/4/2012	1,001	1,001	100.0%	20
1/15/2012	1,001	1,001	100.0%	21
1/25/2013	1,005	1,001	99.6%	19
3/14/2013	1,005	1,000	95.1%	35
2/2/2013	1,005	998	95.1%	24
1/26/2013	1,005	997	99.2%	21
1/18/2013	1,005	991	98.6%	30

For Station 224, all of the top throughput days occurred during the non-winter months, prior to November 1, 2012. Four of these occurred during the period April 15-21, 2011, when Tennessee reported "seasonable weather," but Station 224 still experienced high throughput.

Eight of the top ten throughput days for Station 245 occurred during winter months. However, most of the top days for Station 245 were relatively mild. On March 9, 2012, for example, the day on which the maximum flow over the segment was observed, the mean temperature in NYC was 51ºF. The average for Station 245's top 10 days is approximately 47ºF.

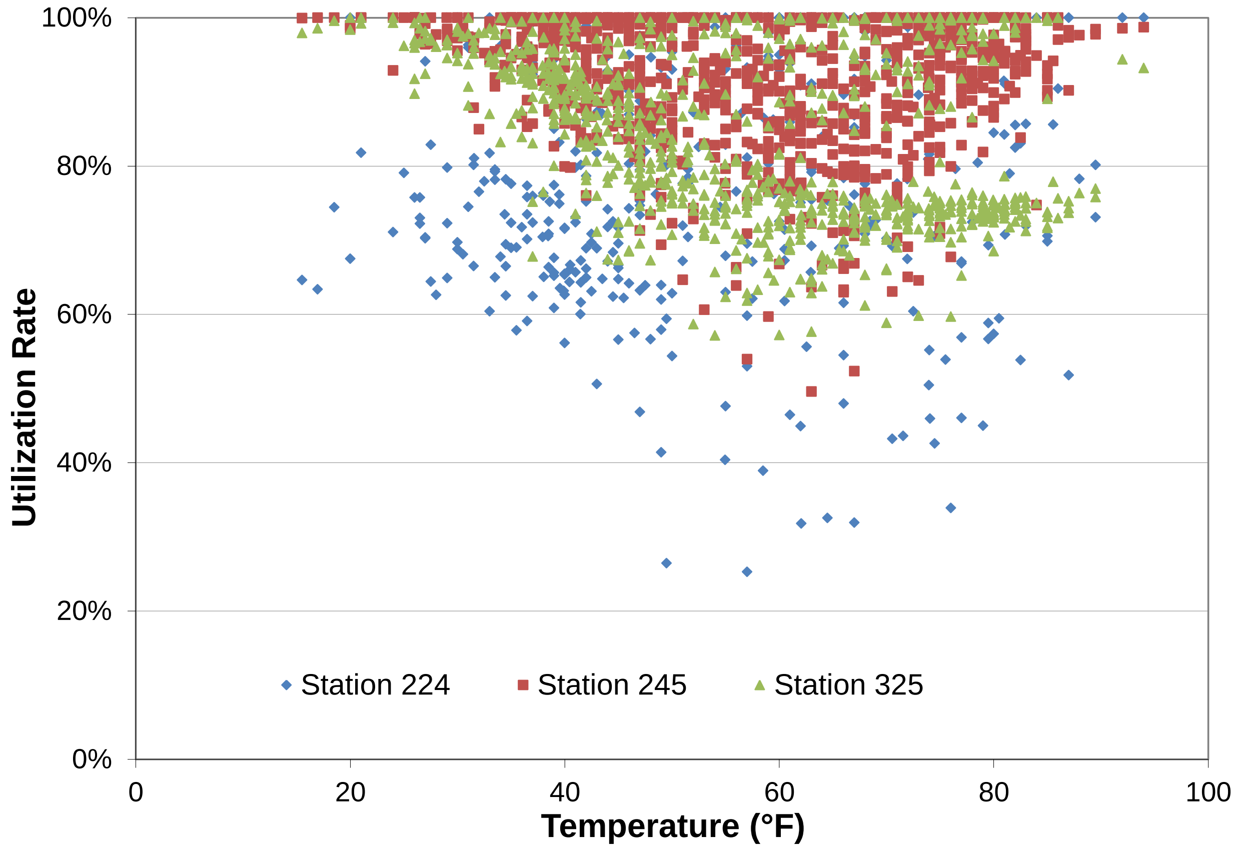
Six of the top ten throughput days for Station 325 occurred during January, February and March 2013, and all are associated with cold weather.

2.6.6 Conclusions

The Tennessee segments vary widely in terms of the market areas they serve and, as a result, the market factors that affect utilization and throughput. Station 325, which lies on Line 300 serving White Plains, follows a pattern of utilization consistent with other pipeline segments serving NYC. Hence, pipeline congestion events are driven by HDDs.

Throughput and utilization at Station 224 and Station 245 exhibit different patterns less affected by seasonality. Figure 65 compares temperature and utilization for Station 224, Station 245 and Station 325. The data for Station 325 exhibits limited seasonality, whereas the data for Station 224 and Station 245 reveal much less seasonality.

Figure 65. Plot of Temperature vs. Utilization on Tennessee



A recent presentation by Tennessee underscores the preponderance of flow day restrictions due to nominations in excess of capacity.[52] Tennessee reports restrictions at Station 245 having occurred on 96% of the days during winter 2010-11, 99% of the days in the winter 2011-12, and 100% of the days in winter 2012-13 due to nominations in excess of capacity.[53] Tennessee reports that restrictions were also implemented for 79% of the days during the summer of 2011, 92% of the days during the summer of 2012, and 96% of the days during April through July of 2013.[54] The imposition of restrictions is not necessarily synonymous with curtailments or interruptions to non-firm loads, depending on the amount by which nominations exceed capacity, which is not reported, and the character of service of the generator nominations. If generators are relying on released capacity or secondary firm nominations for gas transportation, those nominations would be scheduled at a higher priority than interruptible nominations which are typically bumped in accordance with Tennessee's tariff provisions.

Growing volumes from Marcellus are flowing on Line 300 to markets in downstate New York and into New England. Based on the available EBB data, throughput at Station 325 is increasing. However, Tennessee reports that the frequency of restrictions at Station 325

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[52] Tennessee Gas Pipeline, 2013 Shipper Meeting. http://tebb.elpaso.com/TgpLookup/Presentations/08191312-111713-081913112518-2013%20Shipper%20Meeting%20Presentation.pdf

[53] Ibid, page 12.

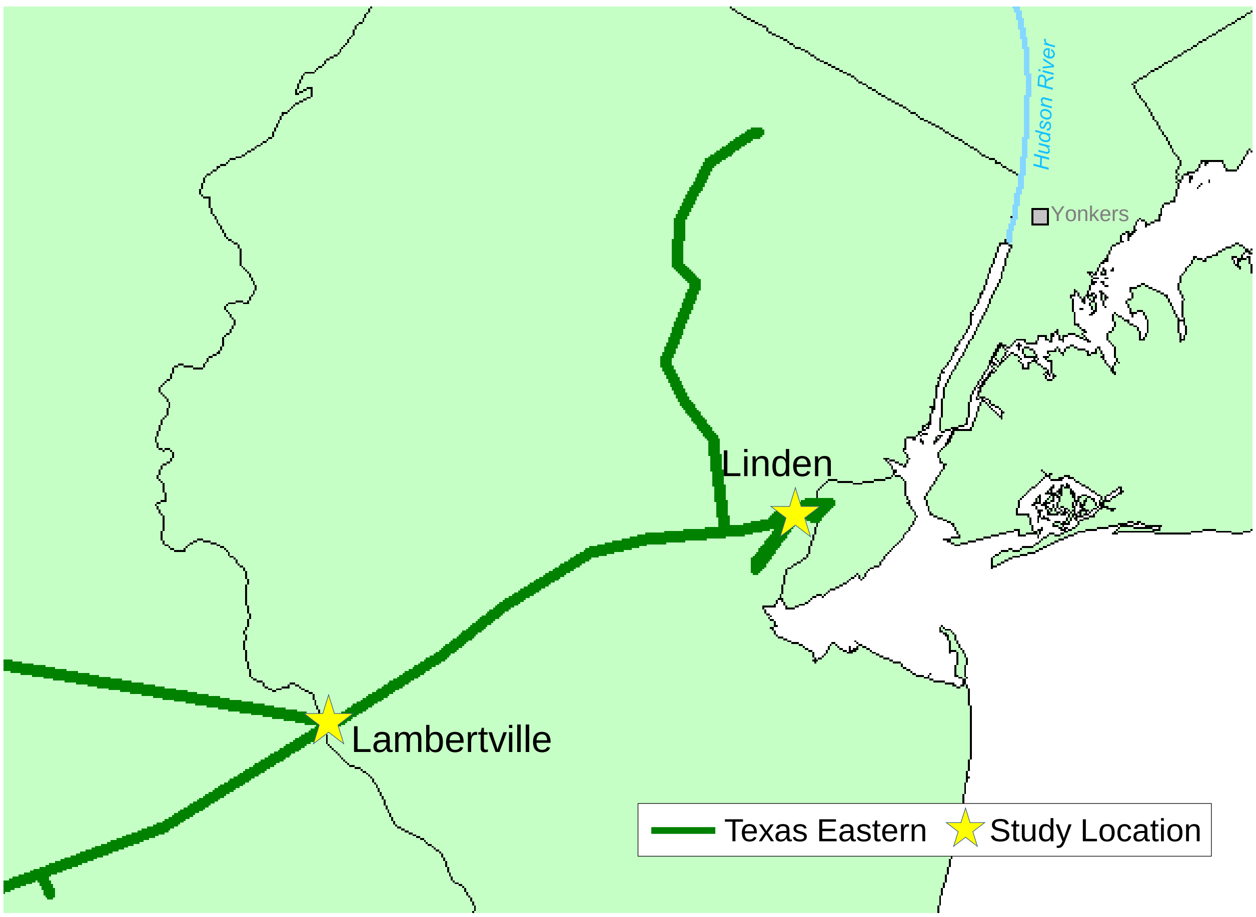
[54] Ibid, page 11.

dropped from 87% in the winter of 2010-11 to 7% for the winter of 2011-12, and 0% for the winter of 2012-13 following commercialization of the 300 Line Project in November 2011.[55]

2.7 Texas Eastern

Texas Eastern, a Spectra Energy subsidiary, is a 10,200 mile pipeline system that extends from the Gulf of Mexico to New Jersey. Texas Eastern has a total peak day capacity of 8 Bcf/d as well as 75 Bcf of conventional storage resources, primarily at Leidy, Pennsylvania.[56] The key compressor stations of relevance to NYC are in Lambertville and Linden, New Jersey. Texas Eastern has interconnections with Algonquin at Lambertville and Hanover, New Jersey, as well as other interconnection points with other pipelines serving downstate New York. Texas Eastern's current terminus is Staten Island.

Figure 66. Texas Eastern Pipeline



Texas Eastern links NYC with natural gas from the Gulf Coast and Marcellus. Gas from Marcellus has increasingly displaced gas sourced from the Gulf of Mexico. As previously mentioned, in Q4-2013 Spectra expects to commercialize the New Jersey – New York Expansion

[55] Ibid, page 12.
[56] Annual Peak Day Capacity Report, filed with FERC on February 25, 2013.

Project, which will add 800 MDth/d into New Jersey as well as the new gate station in Manhattan. Production from Marcellus coupled with the start-up of this project may obviate the need for long haul transportation on Texas Eastern to serve core and non-core shipper requirements in NYC.

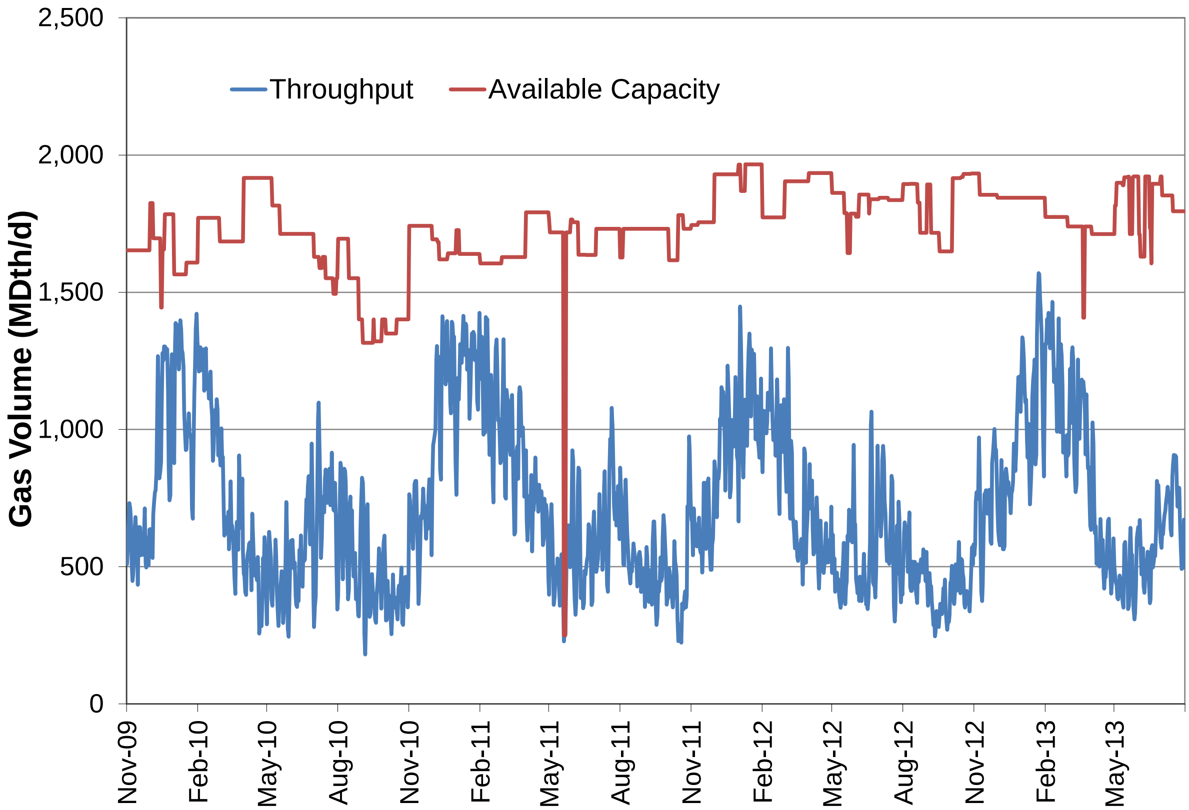
As shown in Figure 66, Lambertville is located at the Pennsylvania-New Jersey border, where the northern and southern lines through Pennsylvania converge. The Lambertville interconnection point is the main receipt point onto Algonquin.

2.7.1 Linden

Linden is located on the New Jersey side of the Hudson River upstream of Texas Eastern's terminus on Staten Island. For the study period, capacity at Linden averaged 1,753 MDth/d during the winter and 1,733 MDth/d during the non-winter months. Over the study period, there were two significant capacity reductions. On May 20, 2011, available capacity plummeted to 250 MDth and remained at that level for three days due to pipeline integrity and safety inspections. In September 2011, maintenance of the (upstream) Chambersburg compressor station reduced capacity across all downstream points, including Lambertville and Linden.

Figure 67 shows throughput and available capacity at Linden for each day in the study period.

Figure 67. Daily Available Capacity and Throughput at Linden (Texas Eastern)



These data indicate there is substantial spare capacity at Linden, with the lowest utilization rates occurring during the shoulder and, to a lesser extent, summer months. Throughput is seasonal and is highest during the winter. Figure 68 shows the comparison of flows and temperature for the study period.

Figure 68. Comparison of Temperature and Throughput at Linden (Texas Eastern)

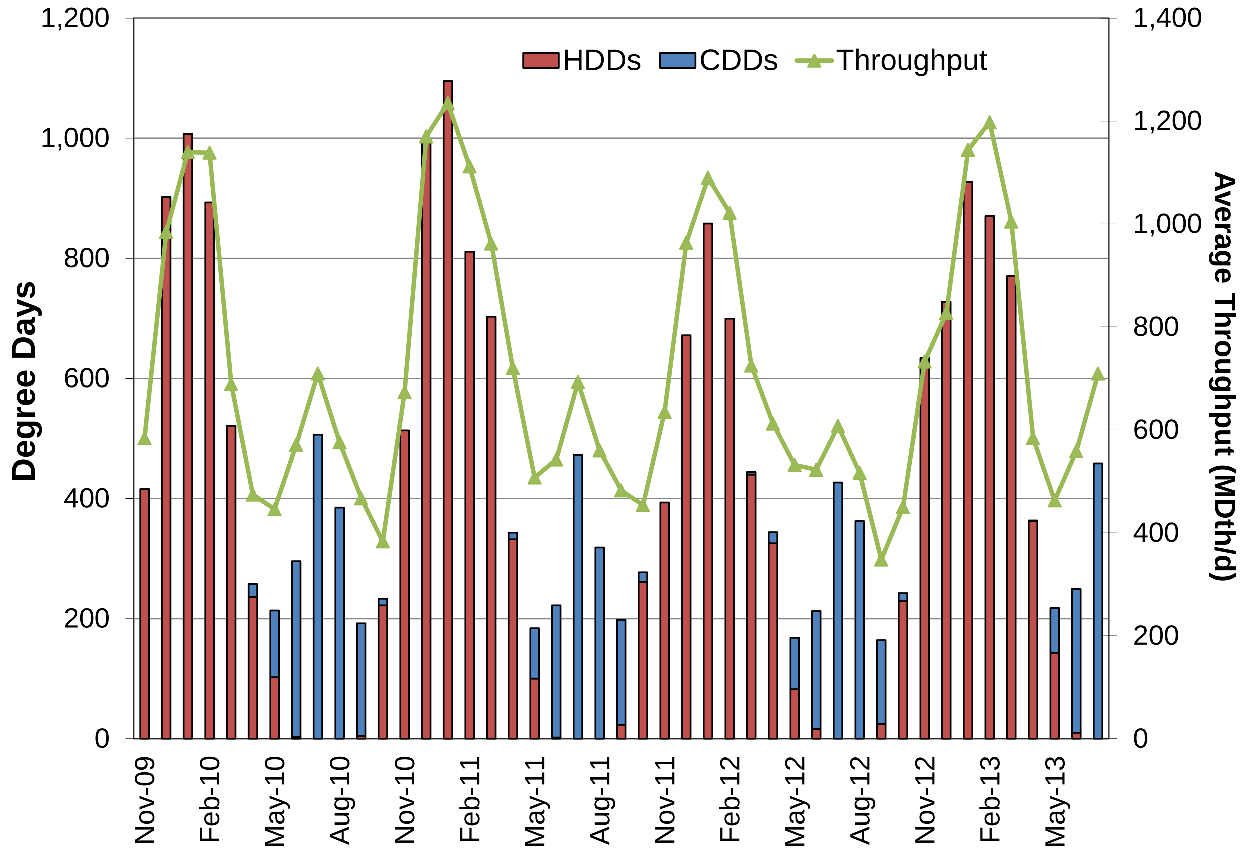


Table 29 shows the number of days at Linden for which utilization rates exceed 90% and 95%.

Table 29. Days of High Pipeline Utilization at Linden (Texas Eastern)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Days w/ 95% or greater util.	0	0	0	0	2	0	0	0	0	0	0	0
Days w/ 90% or greater util.	0	0	0	0	3	0	0	0	0	0	0	0

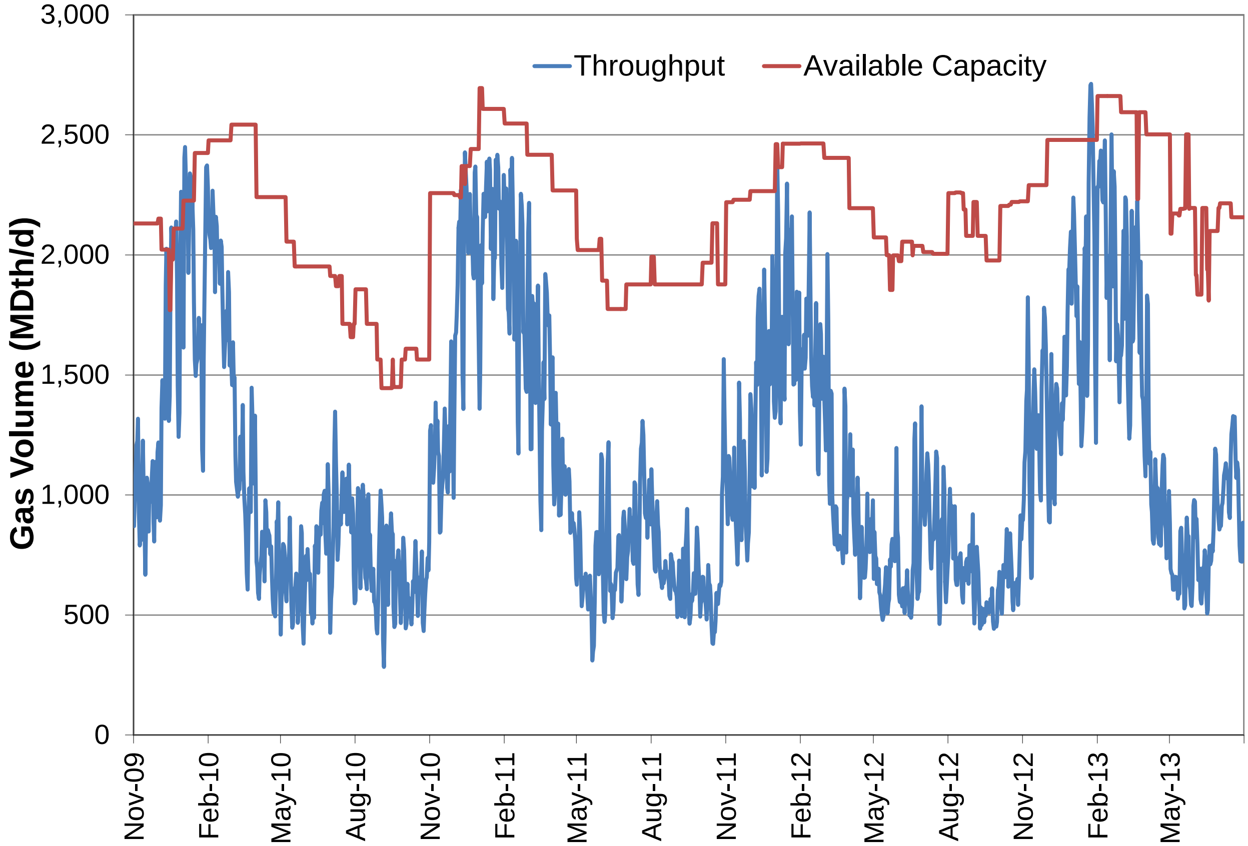
During the study period, there were only three days when utilization exceeded 90%; on two of these days, utilization exceeded 95%. The three days all occurred in May 2011 during the pipeline outage described above.

2.7.2 Lambertville

Operationally available capacity at Lambertville varied significantly over the study period. Capacity at Lambertville averaged 2,399 MDth/d during the winter months and 2,008 MDth/d during the summer months. The September 2010 outage at Chambersburg was the only significant capacity reduction at Lambertville.

Figure 69 shows gas throughput and available capacity at Lambertville for each day in the study period.

Figure 69. Daily Available Capacity and Throughput at Lambertville



The data indicate that while there was some unused capacity during the non-winter months, Lambertville was highly constrained during the winter, with utilization exceeding 100% at least once per winter throughout the study period.[57] Critical for gas utility loads in New Jersey, throughput exhibited a high degree of seasonality – predictably, high utilization rates in the winter followed by a seasonal trough in the spring, a smaller peak in the summer, followed by another seasonal trough in the fall. Figure 70 shows the comparison of flows to temperature at Lambertville.

[57] The highest calculated throughput during the study period (2,713 MDth/d) is slightly higher than the highest capacity level during the study period (2,695 MDth/d). Texas Eastern is able to exceed daily operating capacity for short durations.

Figure 70. Comparison of Temperature and Throughput for Lambertville

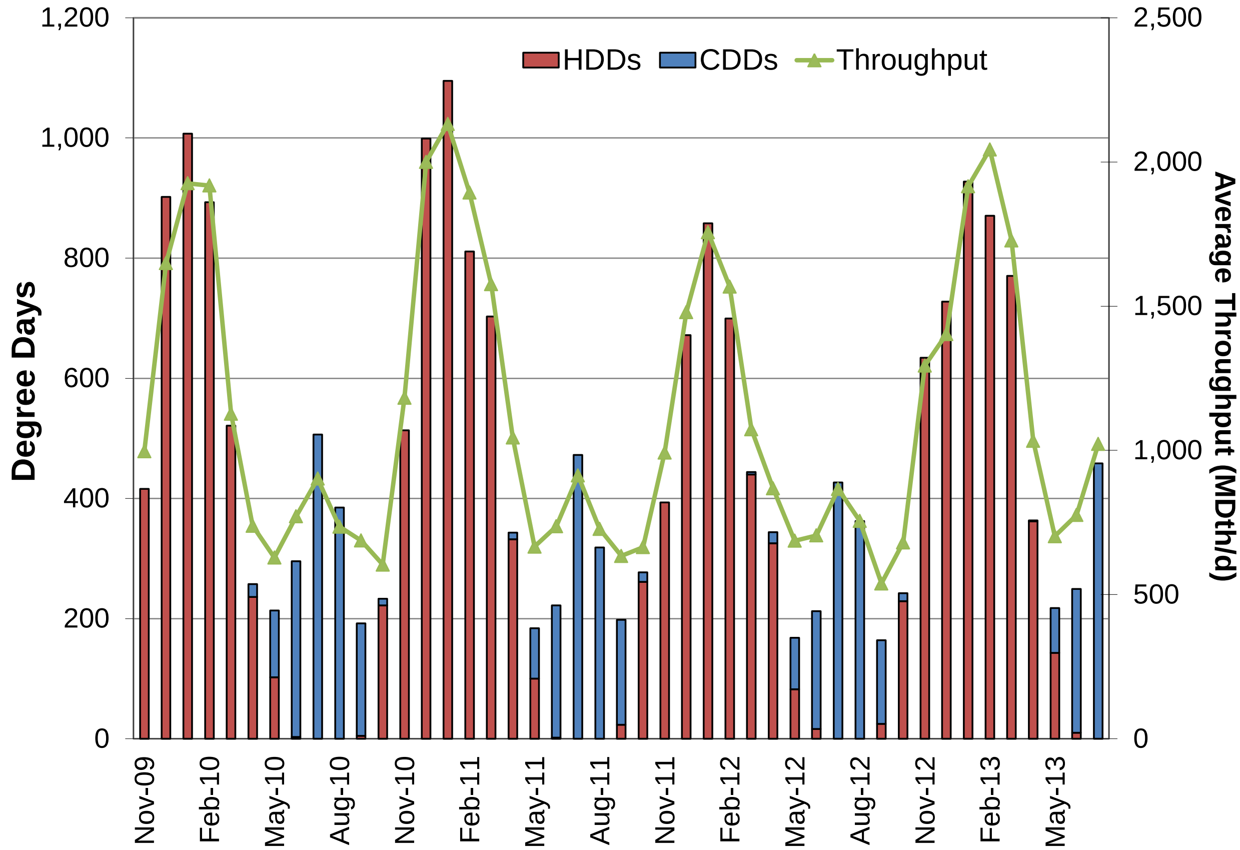


Table 30 shows the number of days on which utilization rates reached or exceeded 90%.

Table 30. Monthly Pipeline Utilization Statistics for Lambertville

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Days w/ 95% or greater util.	18	0	1	0	0	0	0	0	0	0	0	18
Days w/ 90% or greater util.	31	6	3	0	0	0	0	0	0	0	0	26

On 66 days utilization exceeded 90%; on 37 of those 61 days utilization exceeded 95%. All occurred during the winter. The majority of these days occurred in December and January.

2.7.3 Utilization Distributions

A comparison of the distribution of utilization rates (Figure 71) indicates that for both locations, median utilization is around 30%, with the Lambertville curve showing somewhat higher overall rates and a higher median. Lambertville also exhibits a "fat tail" to the right side of the curve, indicating that there are a significant number of days when utilization is high, but the preponderance of these days occur in the winter. Repeating the frequency analysis using data limited to winter months (Figure 72) shows that Linden is bi-modal with a large number of observations that fall between 35% and 50%, and another large number of observations between 60% and 65%.

Figure 71. Distribution of Utilization Rates on Texas Eastern

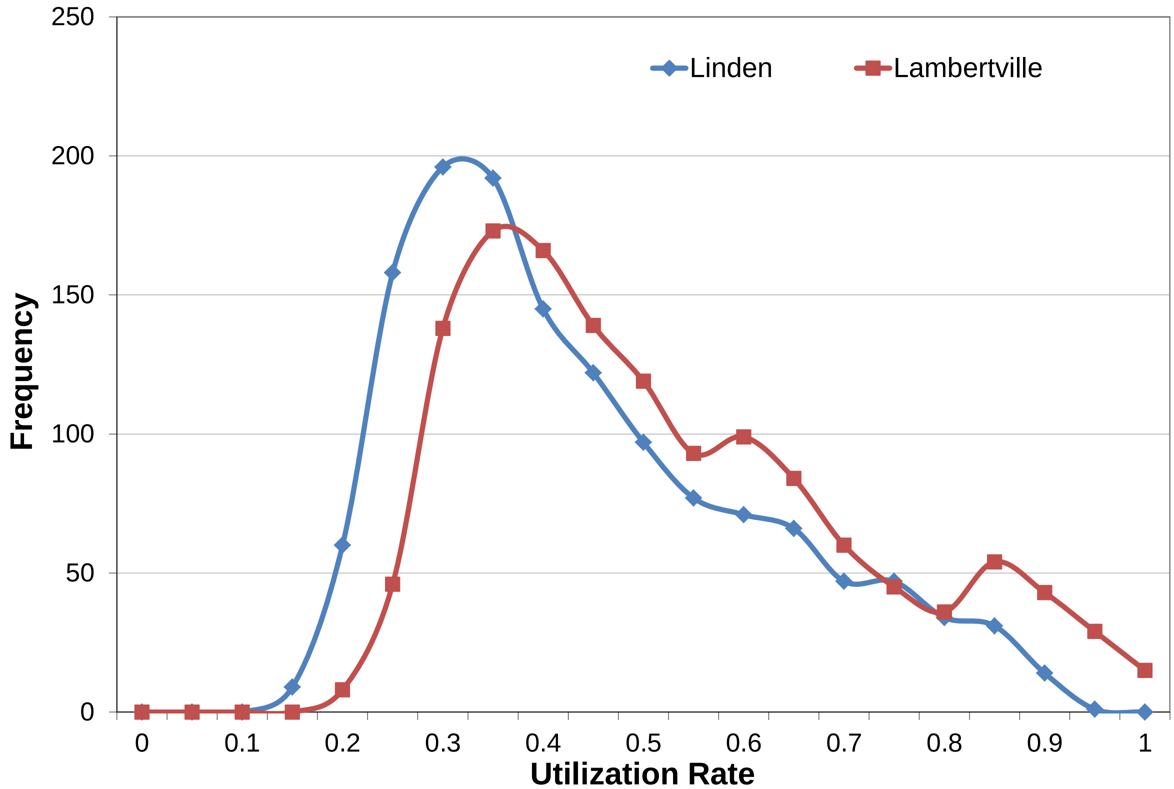
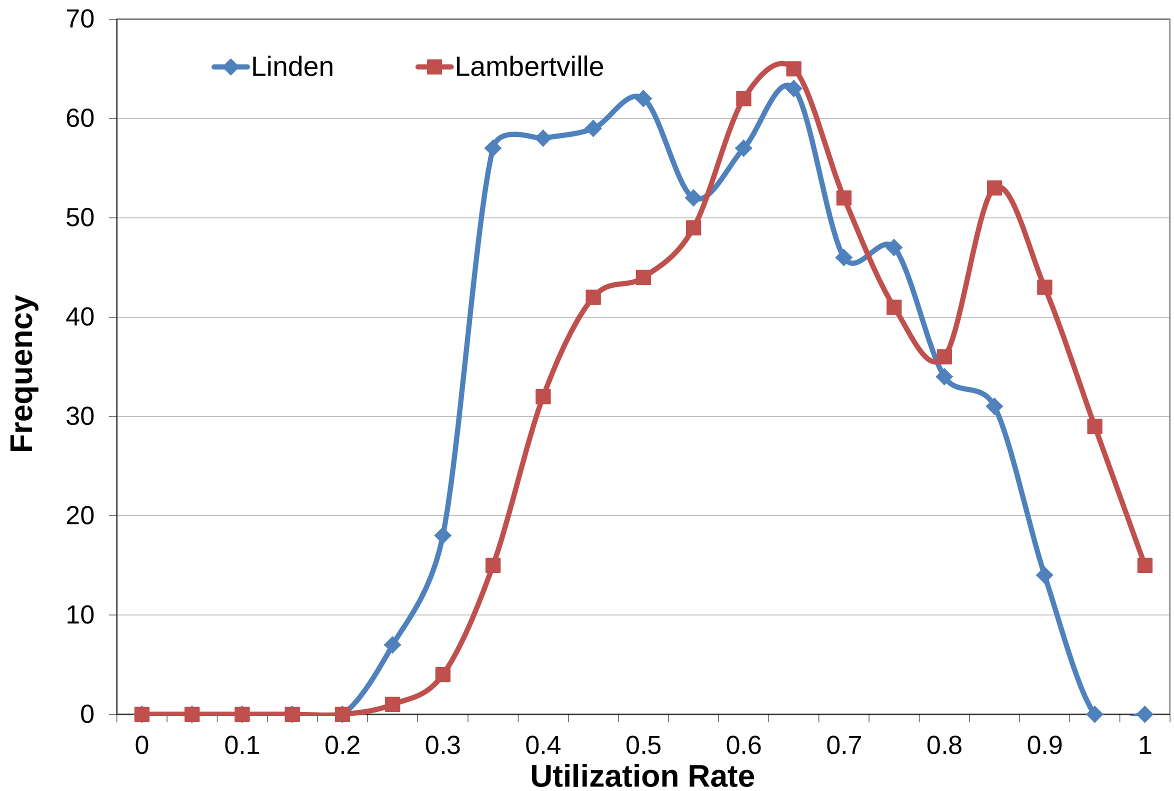


Figure 72. Distribution of Utilization Rates on Texas Eastern, Winter Only



2.7.4 High Congestion and Flow Days

The tables below show the top congestion days for Linden and Lambertville, as measured by pipeline utilization rate. Also shown are the top throughput days.

Table 31. Top Utilization and Throughput Days for Linden (Texas Eastern)

Top Utilization Days					Top Throughput Days				
Date	Capacity *MDth*	Throughput *MDth*	% util.	Temp *°F*	Date	Capacity *MDth*	Throughput *MDth*	% util.	Temp *°F*
5/22/2011	250	255	102.0%	56	1/23/2013	1,844	1,570	85.1%	16
5/21/2011	250	254	101.6%	67	1/24/2013	1,844	1,566	84.9%	17
5/20/2011	250	228	91.2%	61	1/22/2013	1,844	1,487	80.6%	20
1/9/2010	1,565	1,398	89.3%	24	1/25/2013	1,844	1,476	80.0%	19
1/3/2010	1,565	1,388	88.7%	20	2/9/2013	1,774	1,465	82.6%	27
1/30/2010	1,608	1,422	88.4%	17	1/3/2012	1,965	1,448	73.7%	24
1/5/2010	1,565	1,381	88.2%	25	1/26/2013	1,844	1,429	77.5%	21
2/8/2011	1,605	1,410	87.9%	30	1/31/2011	1,640	1,425	86.9%	27
2/10/2011	1,605	1,402	87.4%	26	1/31/2011	1,640	1,425	86.9%	27
12/14/2010	1,620	1,413	87.2%	21	1/30/2010	1,608	1,422	88.4%	17

Table 32. Top Utilization and Throughput Days for Lambertville

Top Utilization Days					Top Throughput Days				
Date	Capacity *MDth*	Throughput *MDth*	% util.	Temp *°F*	Date	Capacity *MDth*	Throughput *MDth*	% util.	Temp *°F*
1/3/2010	2,226	2,450	110.1%	20	1/24/2013	2,479	2,713	109.4%	17
1/24/2013	2,479	2,713	109.4%	17	1/23/2013	2,479	2,707	109.2%	16
1/23/2013	2,479	2,707	109.2%	16	1/25/2013	2,479	2,620	105.7%	19
1/2/2010	2,226	2,405	108.0%	26	1/22/2013	2,479	2,573	103.8%	20
12/29/2009	2,110	2,263	107.3%	24	1/26/2013	2,479	2,530	102.1%	21
12/17/2009	1,981	2,114	106.7%	26	2/17/2013	2,662	2,502	94.0%	25
12/14/2010	2,295	2,427	105.8%	21	2/9/2013	2,662	2,477	93.1%	27
1/25/2013	2,479	2,620	105.7%	19	1/3/2010	2,226	2,450	110.1%	20
12/19/2009	1,981	2,089	105.5%	26	2/4/2013	2,662	2,435	91.5%	27
1/9/2010	2,226	2,340	105.1%	24	12/14/2010	2,295	2,427	105.8%	21

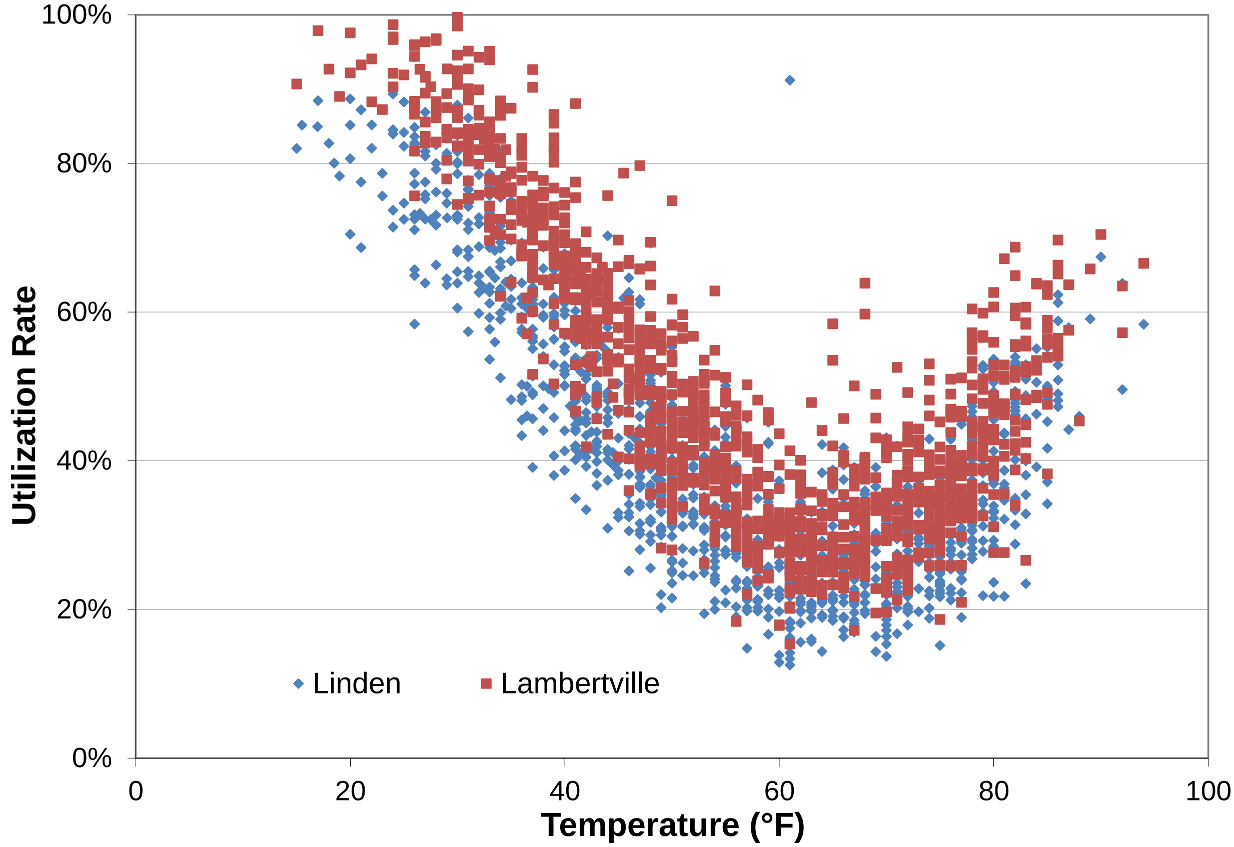
With the exception of three days in May 2011 at Linden, the top utilization days for both segments occurred during the winter, primarily in the peak heating season. Likewise, nearly all of the top throughput days at both locations occur in January.

2.7.5 Conclusions

There is slack capacity at Linden throughout the year. Excluding contingency periods, the maximum utilization rate during the study period at Linden was 89%. Unlike Linden, capacity at Lambertville is highly utilized throughout the heating season and is often constrained during the peak heating season.

Figure 73, a plot of temperature vs. utilization rates, highlights this relationship: The plot shows that utilization is highest for low temperatures, decreases for moderate temperatures in shoulder months and then increases with high temperatures.

Figure 73. Temperature vs. Utilization Levels on Texas Eastern



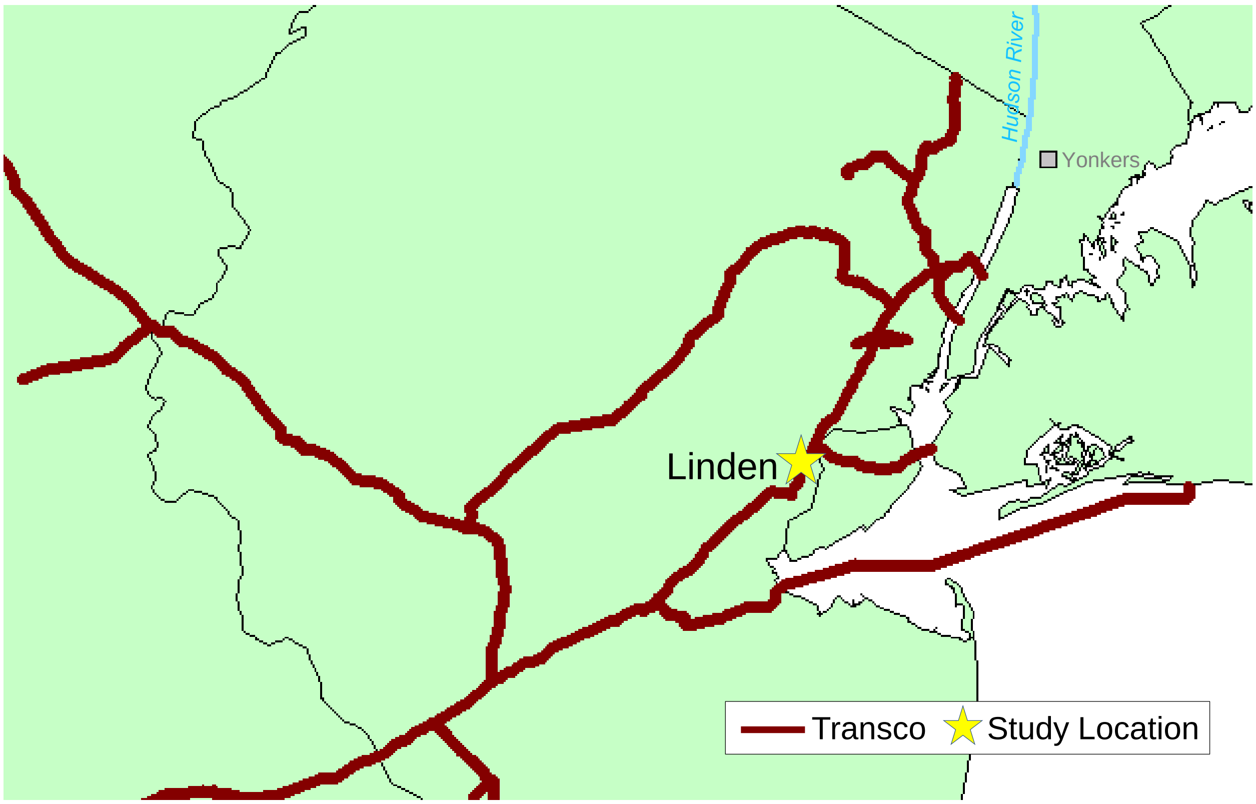
There is no excess capacity at Lambertville that can be reasonably relied upon to promote fuel assurance for non-firm shippers during the heating season. The demand for non-firm transportation service in the downstate market coupled with the increased market penetration rate of shale gas destined for New England results in frequent congestion events at Lambertville throughout the heating season. This congestion will be partially alleviated by the TEAM 2014 Project facilities, which will increase capacity to Lambertville by 300 MDth/d.

The high concentration of gas utility loads in New Jersey and NYC results in very high capacity utilization levels throughout the heating season, but a material decline in pipeline utilization levels during the cooling season. Slack deliverability during the spring, summer and fall has the potential to promote gas use by generators in NYC, but would likely necessitate expensive local infrastructure additions on the New York Facilities System in order to bolster flow from Staten Island to the market center in Brooklyn, Queens and Manhattan. Spectra's new pipeline into Manhattan represents a more efficient pathway for shale gas to capture market share in NYC for core and non-core loads alike.

2.8 Transco

Transco is a 10,200 mile pipeline system, owned by Williams, that originates on the Gulf Coast and extends into the Northeast, terminating in northern New Jersey and NYC. The gas transported on Transco is primarily sourced from the Gulf Coast and Marcellus, and provides access to 200 Bcf of conventional storage facilities in Pennsylvania. In 2012, Transco could deliver 5,494 MDth/d to Zone 6, which begins in Maryland and continues to NYC. Transco's northern terminus is illustrated in Figure 42. Key interconnections on Transco are with Texas Eastern and Columbia. Transco is the primary pipeline supplier of natural gas into the New York Facilities System for power generation in-City and on Long Island, and has also recently constructed a lateral in New Jersey to serve the Bayonne Energy Center, which is electrically dedicated to NYC.

Figure 74. Transco Pipeline



LAI analyzed flows across a point just downstream of Transco's Linden interconnection with Texas Eastern.

2.8.1 Linden

The daily operational capacity reported at Linden on Transco's EBB tracks very closely with throughput; therefore we have analyzed throughput relative to the design capacity of Linden, as shown in Figure 75. No significant service outages were reported that reduced capacity on this segment during the study period.

Throughput at Linden follows a strong seasonal pattern. Over the last twelve months of the study period, Linden experienced the highest flows during the winter (January 2013). Throughput during the cooling season remains high as well, but peaks at lower levels than during the heating season. Figure 76 compares throughput on an average monthly basis HDDs and CDDs.

Figure 75. Daily Available Capacity and Throughput at Linden (Transco)

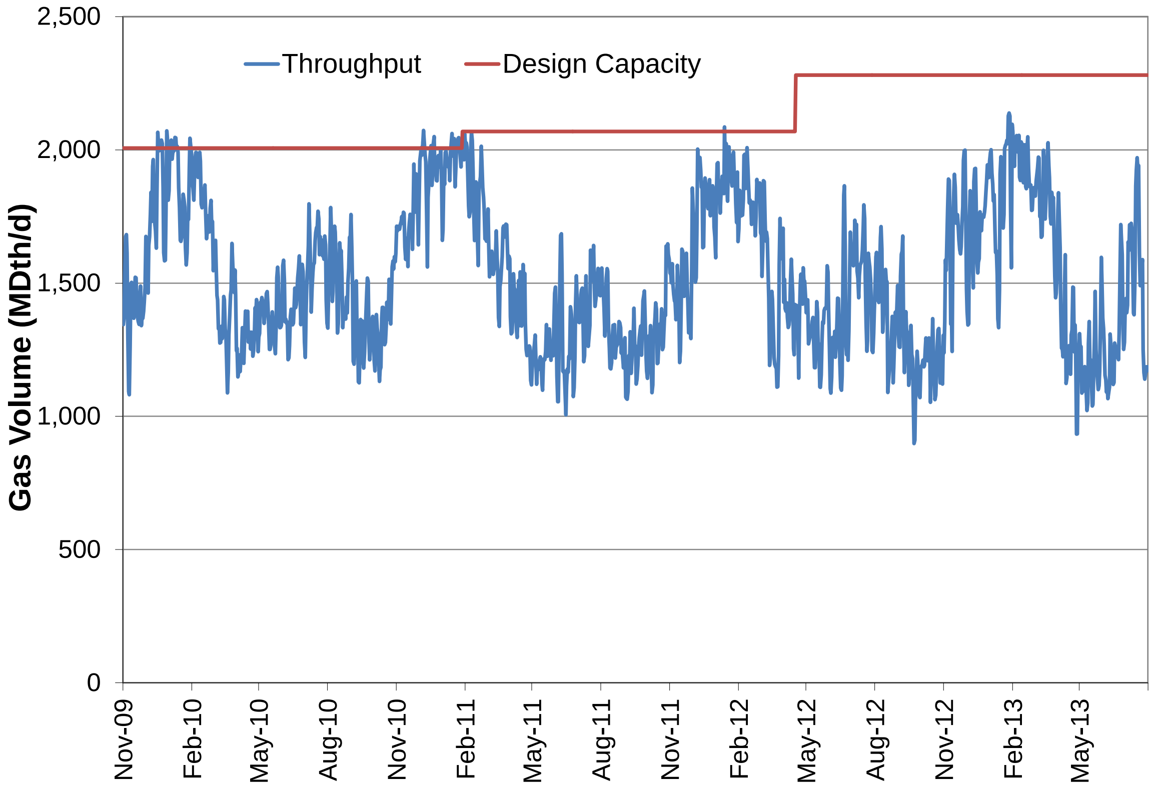


Figure 76. Comparison of Temperature and Throughput for Linden (Transco)

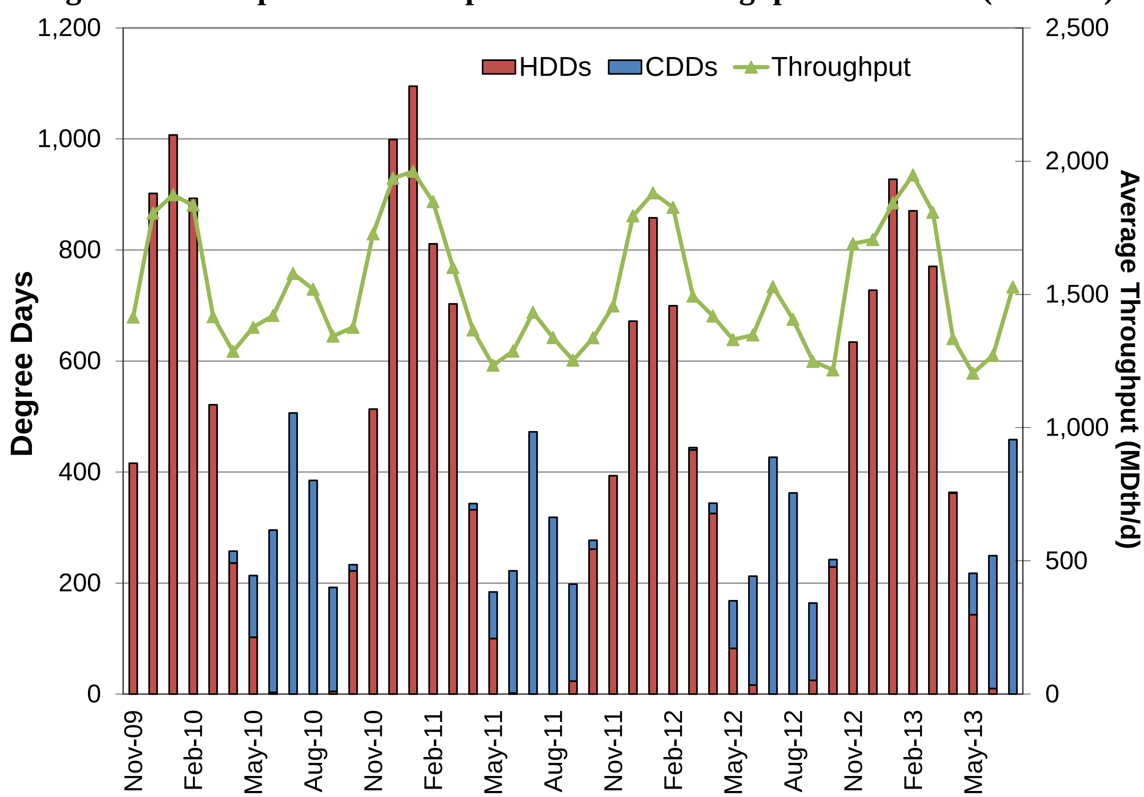


Table 33 shows the number days that the utilization rate reached or exceeded 90% at Linden.

Table 33. Number Days Pipeline Utilization Exceeded 90% for Linden (Transco)

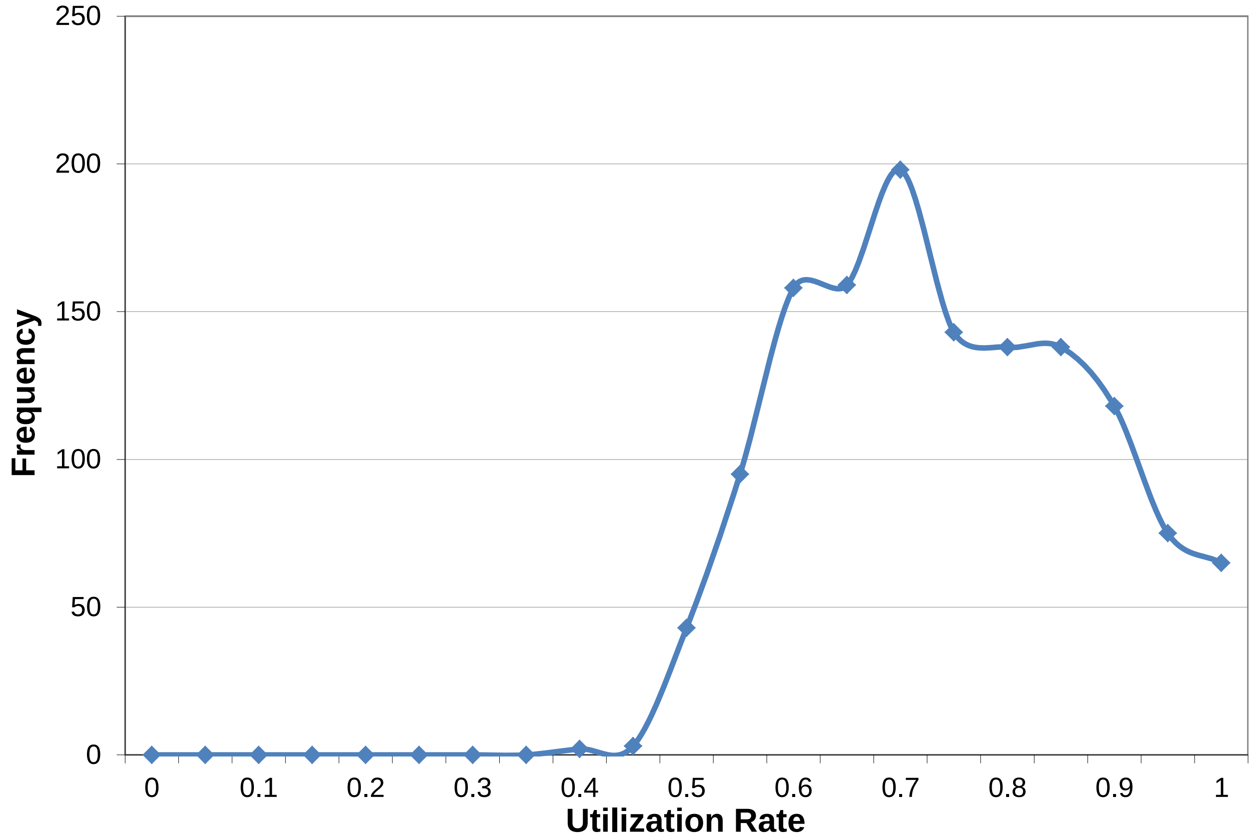
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Days w/ 95% or greater util.	46	17	0	0	0	0	0	0	0	0	2	34
Days w/ 90% or greater util.	74	41	2	0	0	0	0	0	0	0	3	54

Utilization at Linden was 90% or greater for 174 days, all occurring during the winter. Transco is the primary pipeline serving NYC and Long Island, as well as much of the gas utility load in New Jersey. Most days when pipeline utilization exceeded 95% occurred in December and January. Five days of high pipeline utilization levels occurred during the January 2013 cold snap.

2.8.2 Utilization Distributions

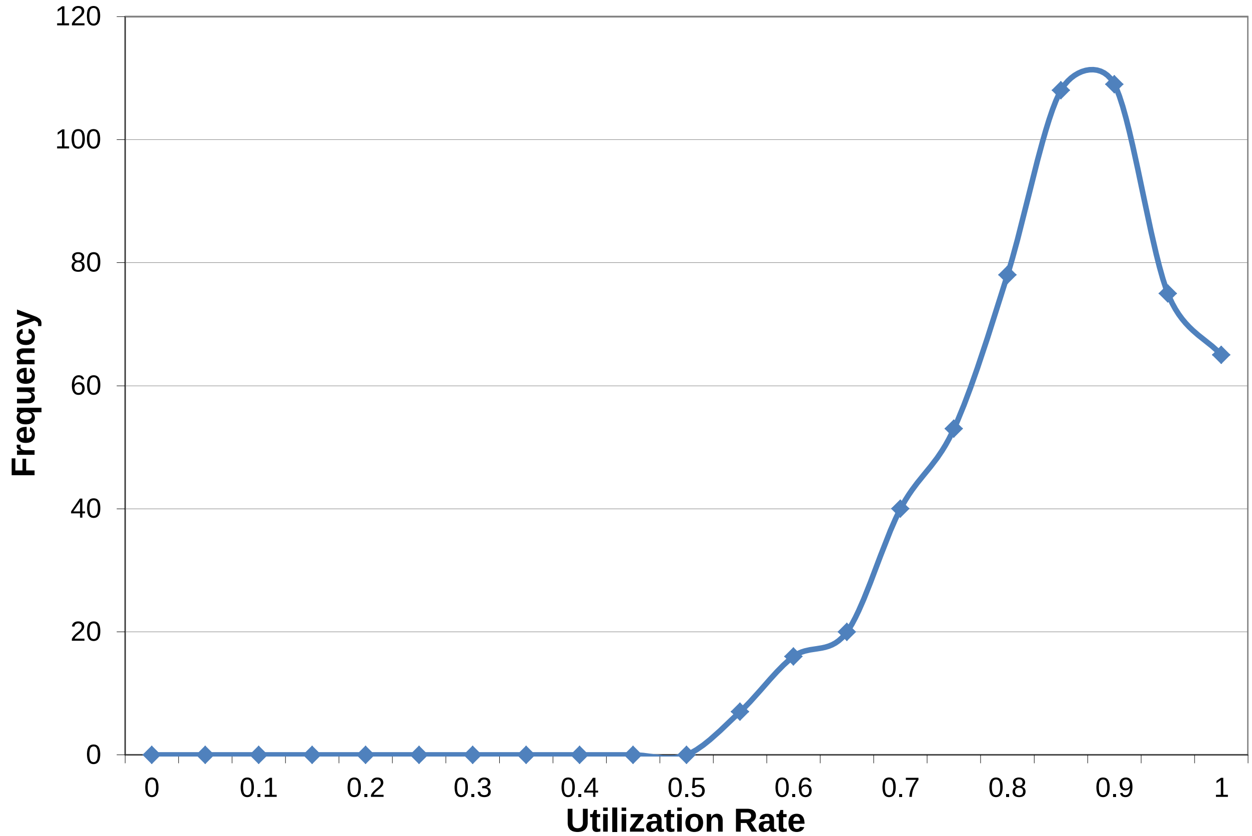
An analysis of the distribution of utilization rates at Linden indicates a set of observations that are tightly clustered around the median, which is around 70%. On roughly 70% of all days the utilization rate was between 60% and 85%. Most observations outside that range were for the highest utilization rates that generally occurred on the coldest days.

Figure 77. Distribution of Utilization Rates on Transco



The distribution of utilization rates using only winter month data is shown in Figure 78.

Figure 78. Distribution of Utilization Rates on Transco, Winter Only



2.8.3 High Congestion and Flow Days

Table 34 shows the top utilization and throughput days for Linden. While all of the top utilization days occurred during the period with the lowest design capacity (prior to 1/28/11), half of the top ten throughput days occurred during the period with the highest design capacity level (since 4/16/12).

Table 34. Top Utilization and Throughput Days for Linden (Transco)

Top Utilization Days					Top Throughput Days				
Date	Capacity *MDth*	Throughput *MDth*	% util.	Temp *°F*	Date	Capacity *MDth*	Throughput *MDth*	% util.	Temp *°F*
12/7/2010	2,007	2,073	103.3%	33	1/27/2013	2,281	2,139	93.8%	27
12/29/2009	2,007	2,071	103.2%	24	1/26/2013	2,281	2,128	93.3%	21
12/17/2009	2,007	2,066	102.9%	26	1/28/2013	2,281	2,126	93.2%	33
1/14/2011	2,007	2,061	102.7%	24	1/31/2013	2,281	2,096	91.9%	46
12/21/2010	2,007	2,050	102.1%	33	1/13/2012	2,069	2,086	100.8%	39
1/9/2010	2,007	2,047	102.0%	24	12/7/2010	2,007	2,073	103.3%	33
1/23/2011	2,007	2,046	102.0%	18	12/29/2009	2,007	2,071	103.2%	24
1/10/2010	2,007	2,045	101.9%	21	2/1/2013	2,281	2,070	90.8%	28
1/29/2010	2,007	2,044	101.8%	20	12/17/2009	2,007	2,066	102.9%	26
1/22/2011	2,007	2,043	101.8%	19	2/9/2011	2,069	2,066	99.8%	22

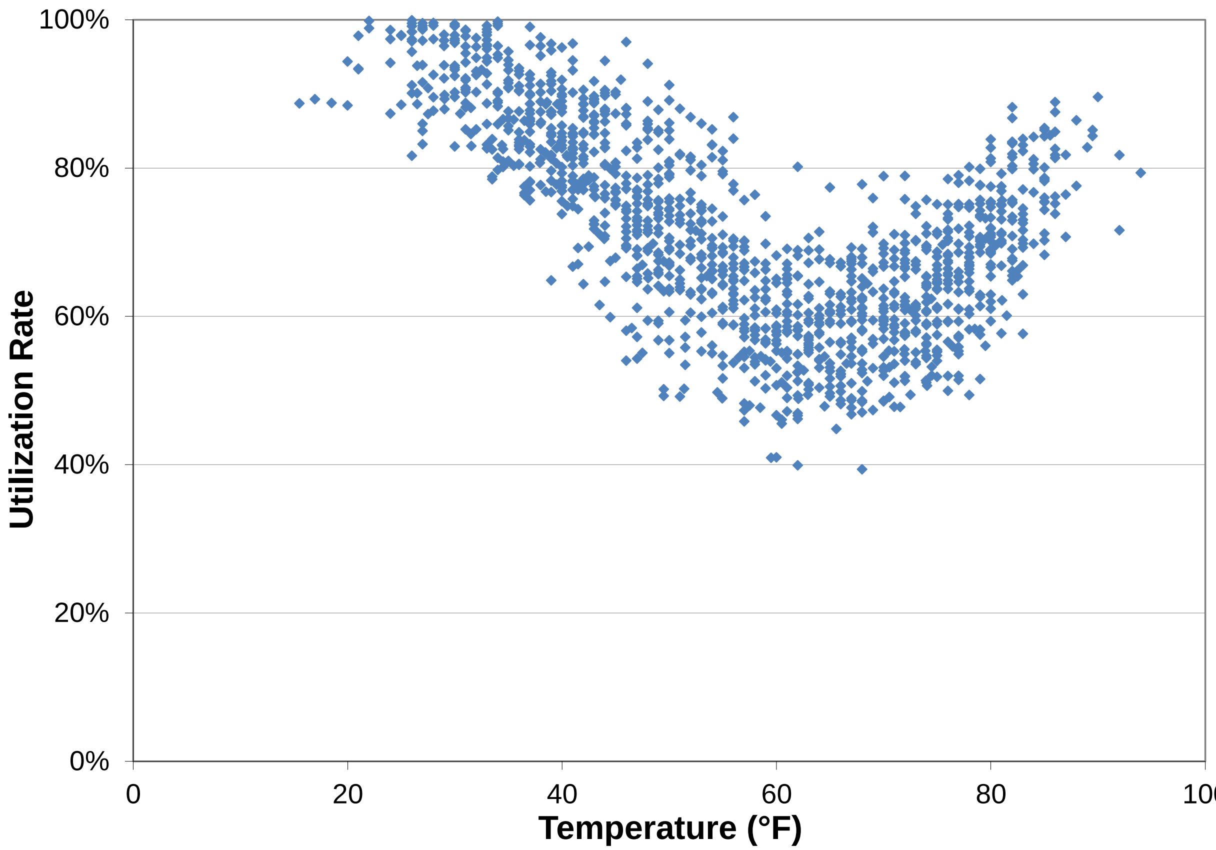
The top utilization and throughput days at Linden occurred during cold weather. The January 2013 cold snap accounts for the top four throughput days.

2.8.4 Conclusions

The utilization levels at Linden peak during cold weather and, to a lesser extent, during hot weather. All of the days for which utilization reached or exceeded 90% occurred in November, December, January, February and March. Average monthly utilization levels range from a low of 61% for September to a high of 91% for January. The data indicate that Transco is fully utilized during the winter months when maximum utilization rates exceed 90% and average utilization rates are above 70%.

Figure 79 shows the scatter plat of utilization v. temperature at Linden.

Figure 79. Plot of Temperature vs. Utilization on Transco



Summer throughput rates increased over the latter part of the study period. During the hottest months of the summer of 2011, June through August, a total of 124,478 MDth flowed across the Transco Linden segment into NYC and Long Island. In those same months during the more mild summer of 2012, 131,406 MDth flowed into the New York Facilities System. Table 35 compares cooling demand and total throughput for the peak months of each of the past three summers and summer 2013 to-date, as well as the ratio of gas demand to CDDs. The increase in the ratio of gas use divided by cooling degree days represents an increase in the amount of gas transported by Transco into the New York Facilities System primarily for power generation, adjusted for weather effects.

Table 35. Comparison of Gas Demand and Temperature at Linden (Transco)

	MDth	CDDs	MDth / CDD
June 2010 – August 2010	138,648	1,184	117.1
June 2011 – August 2011	124,478	1,011	123.1
June 2012 – August 2012	131,406	985	133.4
June 2013 – July 2013	85,498	698	122.5

Adverse conditions constraining the flow of non-firm gas supply at or downstream of Linden occurred during the winter. While gas utilization intensity was increasing during the cooling seasons for each summer in the study period, none of the summer months contained days for which utilization reached 90%. If throughput on Transco were to continue to increase, congestion conditions would likely materialize during the summer months as well. However, the combination of Transco's and Texas Eastern's expansions into the New York Facilities System in Q4-2013 will likely ameliorate congestion patterns on Transco at Linden – at least over the short- to intermediate-term. Slack deliverability on Transco during the cooling and shoulder seasons, should therefore be available in order to improve the quality of non-firm transportation for generators in NYC and Long Island.

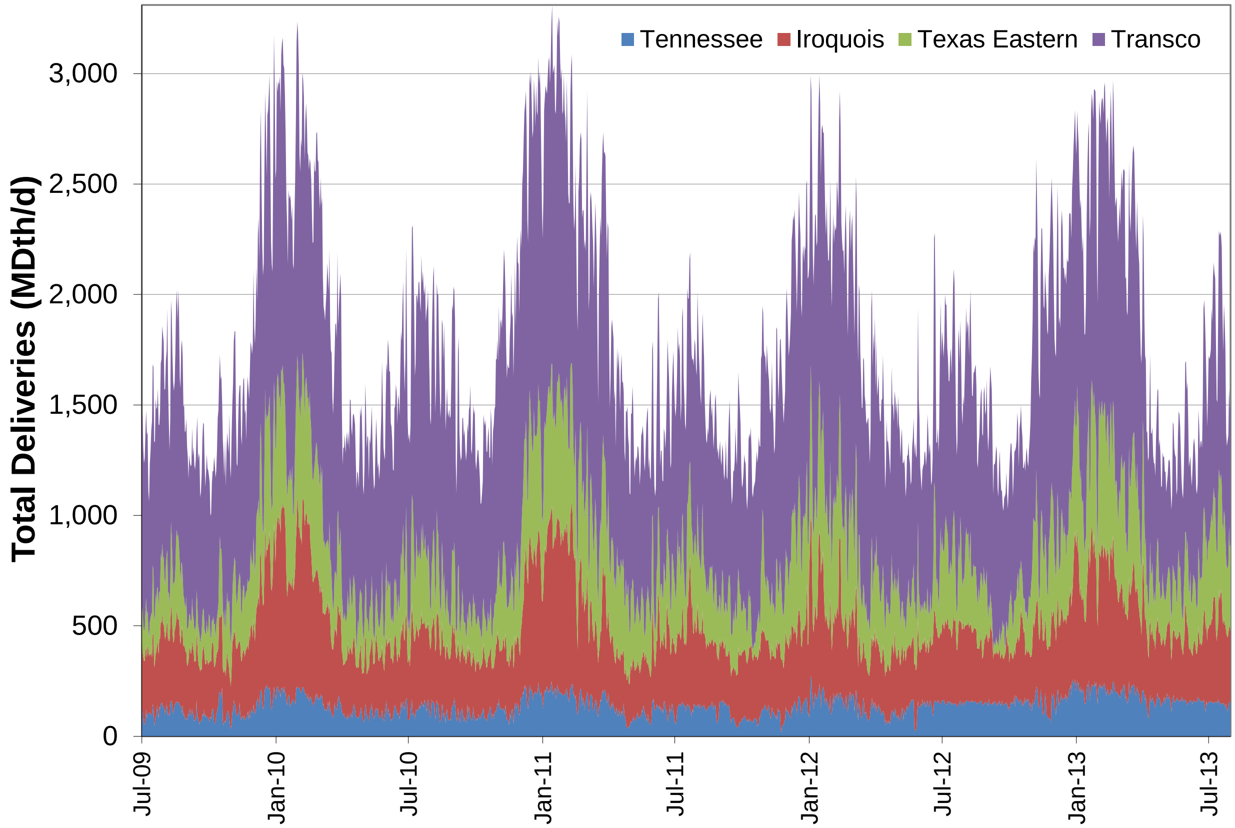
2.9 Conclusions and Observations

Some of the pipeline segments analyzed showed less than full capacity utilization including Tennessee Station 224 and Algonquin Hanover. On these segments, throughput typically does not follow the seasonal patterns of peak levels during the winter and somewhat lower throughput during the hot summer months, that is, these segments do not show the "U" shaped temperature versus utilization pattern. Segments that are either fully utilized or are close to fully utilized during the coldest months tend to follow strong seasonal throughput patterns.

Transco and Iroquois serve large core and power plant loads across the New York Facilities System, and show high utilization levels throughout the heating season, and limited slack deliverability during the peak cooling season. Iroquois's Brookfield segment, in particular, is often constrained during the heating and cooling seasons. Texas Eastern's Lambertville and Linden segments have slack deliverability, except during the peak heating season, but local deliverability conditions on the New York Facilities System may hinder increased use of gas flow across these segments to improve the quality of non-firm service in NYC. The extent to which Con Edison's in-City buildout to support oil-to-gas conversion objectives will improve operating flexibility across the New York Facilities System is outside the scope of this inquiry.

The key pipelines that serve NYC and Long Island are Transco, Texas Eastern, Tennessee, and Iroquois. Figure 80 shows total deliveries into the New York Facilities System during the study period. The top of the y-axis has been set at the maximum delivery level, therefore the "air" in this figure approximates the slack daily deliverability.

Figure 80. New York Facilities System Deliveries



High oil-to-gas price ratios and environmental restrictions have increased NYC's reliance on natural gas for electric generation during the summer. Table 35 shows that gas flowing per unit of cooling demand in NYC has increased at Linden. The table below expands this analysis to include flows at Lambertville and Brookfield, the constraint points on Texas Eastern and Iroquois, respectively. The pattern is the same, gas consumption per unit of cooling demand (measured in CDDs) increased every summer during the study period.

Table 36. Ratio of Key Flows and Temperature for NYC[58]

	Linden (Transco) (MDth)	Linden (Texas Eastern) (MDth)	Brookfield (MDth)	Total Flow (MDth)	CDDs	Ratio (MDth/CDDs)
June 2010 – August 2010	138,648	56,987	43,981	239,616	1,184	202.4
June 2011 – August 2011	124,478	55,117	45,461	225,056	1,011	222.6
June 2012 – August 2012	131,406	50,529	42,933	224,868	985	228.3
June 2013 – July 2013	85,498	38,756	28,711	152,965	698	219.1

[58] Flows across Station 325 were excluded because data were not available for 2010.

In the hot summer 2010, 202.4 MDth of gas flowed over these three pipeline segments per CDD in NYC. For summer 2012, gas flow increased to 228.3 MDth per CDD, a 13% increase.

A review of the daily operational capacity and OFO postings for each pipeline indicates that forced outages were rare and, when they occurred, were usually of short duration. Reductions in capacity due to scheduled maintenance were more common and, in some cases, longer lasting. Consistent with the pipelines' enviable record of performance across NYCA, these outages were scheduled during the shoulder months, both spring and fall, in order to avoid disruptions to firm entitlement holders, and minimize disruptions during the peak cooling season. In reviewing the results of this analysis, readers are reminded that congestion events are sometimes paradoxical as they reflect the material de-rate of the pipeline segment at the time when natural gas is either less likely to be needed for grid security requirements or pipeline "workarounds" can be coordinated with interconnected pipelines.

A summary of our observations regarding pipeline congestion and the potential slack deliverability for non-core customers in the winter versus summer by pipeline segment examined in this study is presented in Table 35.

Table 37. Potential Slack Pipeline Deliverability (Current Infrastructure)[59]

Pipeline	Location	NYCA Zones Served	Other Markets Served	Slack Deliverability	
				Winter	Summer
Algonquin	Hanover	G-H-I	NE	Moderate	High
	Stony Point	G-H-I	NE	Low	Moderate
	Southeast	G-H-I	NE	Low	Moderate
Empire	Empire Connector	B, C	Ontario	Moderate	Low
Iroquois	Brookfield	J, K	NE	Moderate	High
	Waddington	G-H-I, J, K	NE	Low	Moderate
Millennium	Ramapo	G-H-I	Ontario, NE	Low	Low
Tennessee	Station 224	A, B, C, E, F	Ontario, NE	Low	Low
	Station 245	F	NE	Low	Low
	Station 325	G-H-I, J	NE	Low	High
Texas Eastern	Lambertville	J	NE	Low	High
	Linden	J	N/A	Moderate	High
Transco	Linden	J, K	N/A	Moderate	Moderate

Figure 81 and Figure 82 illustrate pipeline congestion summarized in Table 37 for the heating and cooling season peak days, respectively, based on the existing infrastructure configuration.

[59] The classification of slack seasonal peak day deliverability is based on the peak utilization for each segment during winter 2012-13 (November through March) or summer 2013 (May through July). Segments with peak seasonal utilization less than or equal to 80% are categorized as having high slack deliverability, segments with peak seasonal utilization between 81% and 94% (inclusive) are categorized as having moderate slack deliverability, and segments with peak seasonal utilization greater than or equal to 95% are categorized as having low slack deliverability.

Figure 81. Heating Season Peak Day Pipeline Congestion (Current Infrastructure)

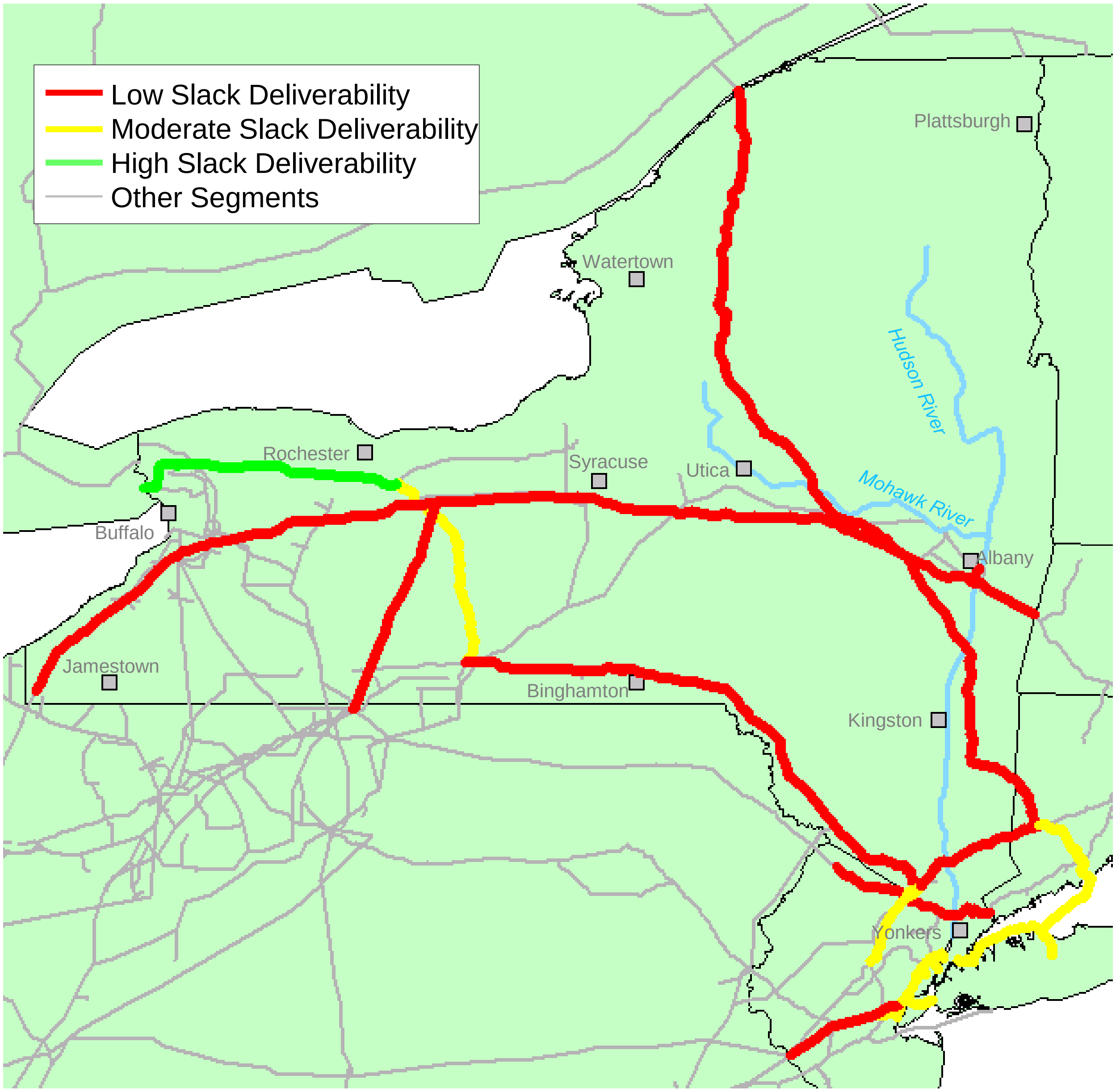
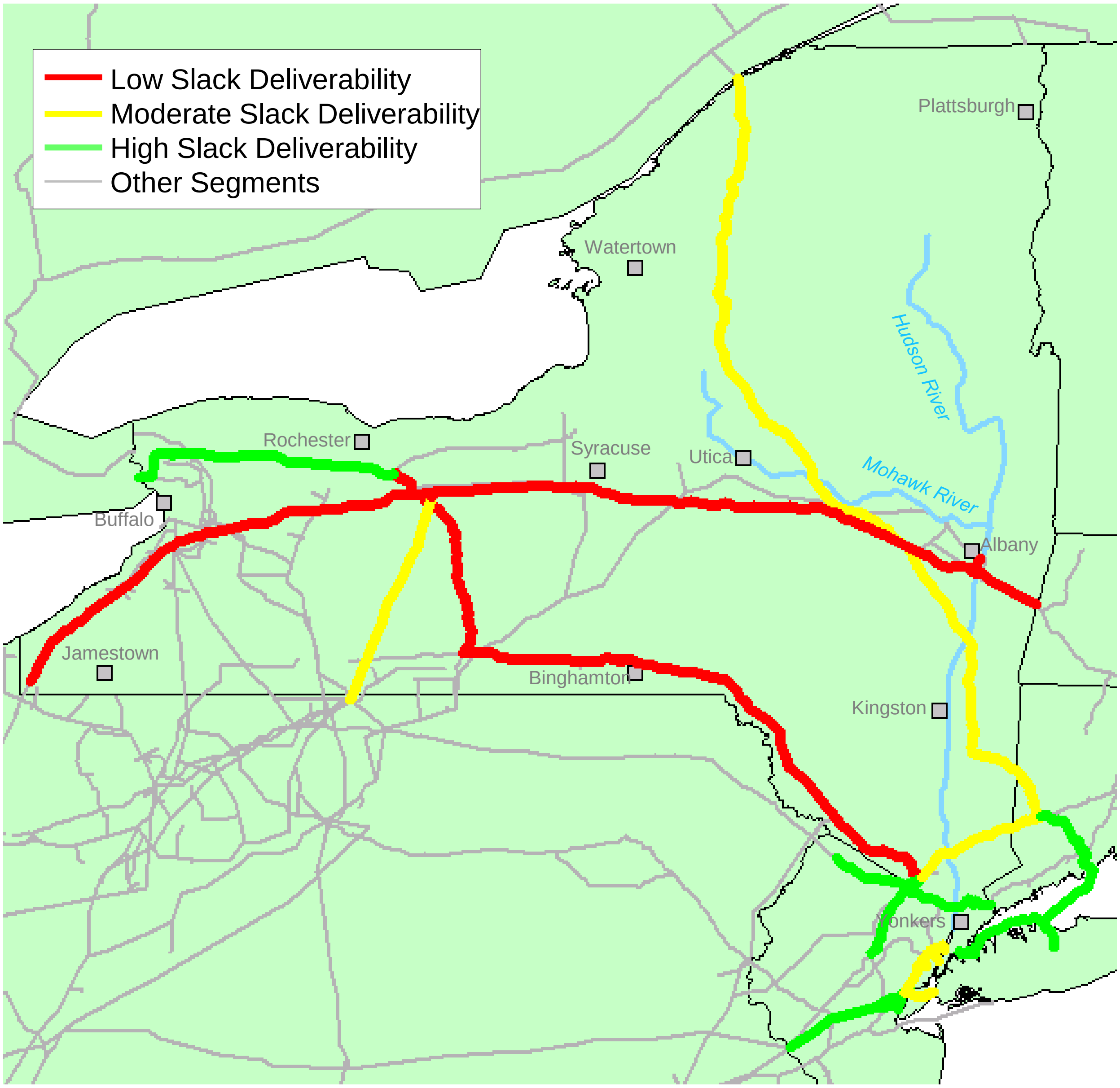


Figure 82. Cooling Season Peak Day Pipeline Congestion (Current Infrastructure)



3 FORECAST OF INFRASTRUCTURE ADEQUACY

The general framework of the flow balance approach utilized to forecast infrastructure adequacy over the five-year study horizon is to compare supply inputs (upstream boundary flows, in-state receipts from production fields and storage facilities) and demand inputs (downstream boundary flows, LDC core demand, generation non-core demand) to calculate whether there is sufficient infrastructure capability to meet *all* needs. Using this flow balance approach, LAI has calculated the amount of delivery capacity available for gas-fired generators. Relying on NYISO's forecast of gas demand for power generation over the study period, we have compared this amount to the forecast of non-core gas demand for electric generation. This flow balance approach provides a reasonable basis to determine whether shortfalls are likely to materialize, that is, insufficient gas supply delivered to those generators NYISO would otherwise call on in the Day Ahead Market or Real Time Market.[60] Based on the frequency and magnitude of the shortfalls, LAI is able to forecast the amount of unserved demand. Results are presented on a seasonal peak day basis.

3.1 Upstream Boundary Flows

Based on the historical throughput data used in the congestion analysis described previously, additional data from pipeline EBBs, and other sources as needed, LAI has determined the capability of each pipeline operating in NYCA to deliver gas to end-users in both the heating and cooling seasons. Planned infrastructure expansions – described previously in the Pipeline Infrastructure section of this report – will change the boundary flows over the study period. We have accounted for these facility additions where relevant.

Figure 83 and Figure 84 show the boundary points on pipelines delivering gas into upstate and downstate New York, respectively.[61] Dominion and NFG each have multiple points at which the pipeline crosses the state border. Boundary flows have not been modeled at each point. Instead we have calculated total net deliverability into NYCA. Hence, individual points are not marked in Figure 83. The gathering and storage systems that cross the Pennsylvania-New York border are modeled as in-state receipts and discussed in Section 3.3.

[60] Physical constraints can materialize within a 24-hour gas day that are not observable under the flow balance approach. Identification of intra-day flow limitations affecting non-core demand requires transient simulation analysis, which is outside the scope of this inquiry.
[61] Not all indicated points are inflow points throughout the study period.

Figure 83. Upstream Boundary Flow Points Into Upstate New York

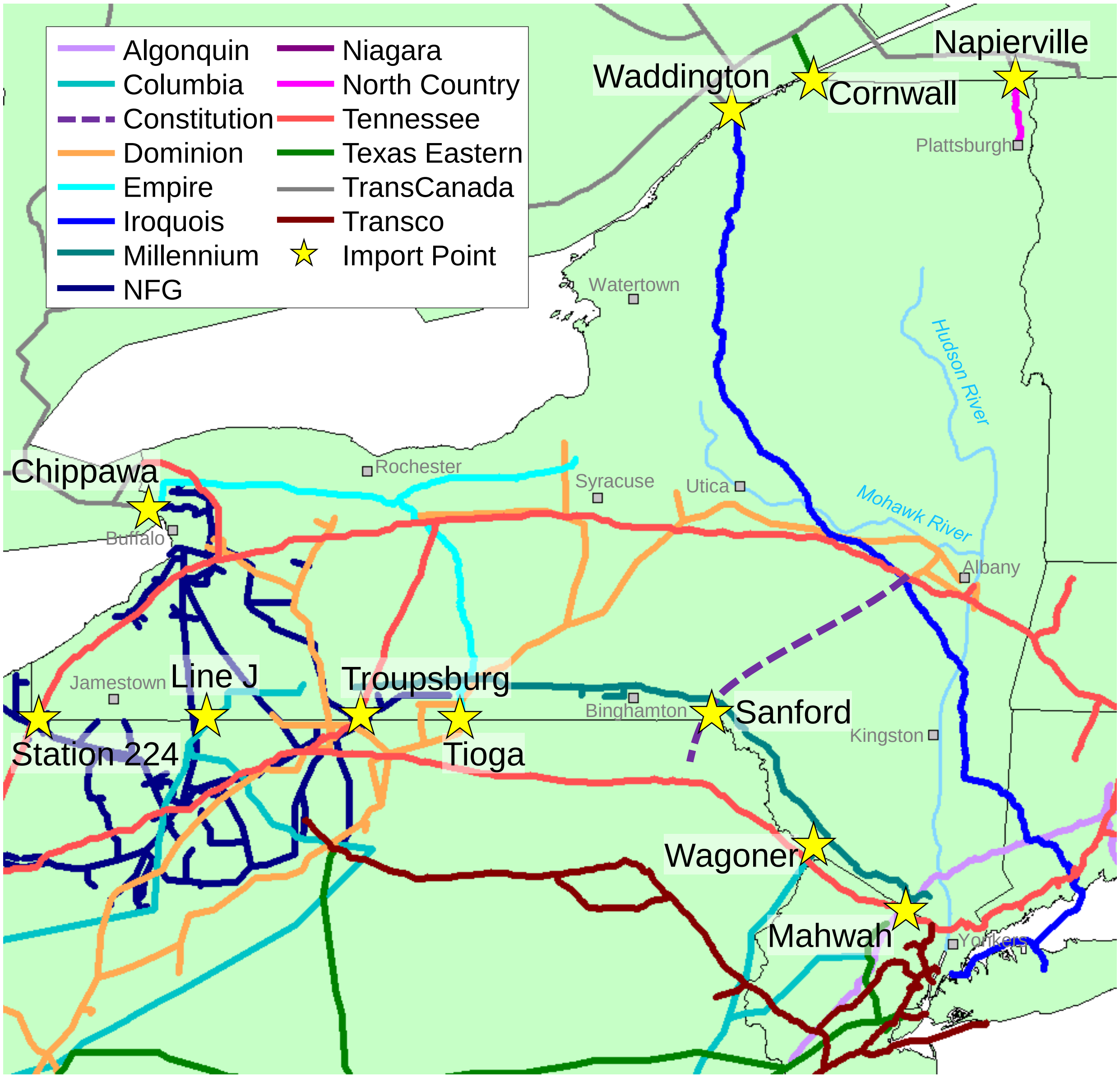


Figure 84. Upstream Boundary Flow Points Into Downstate New York

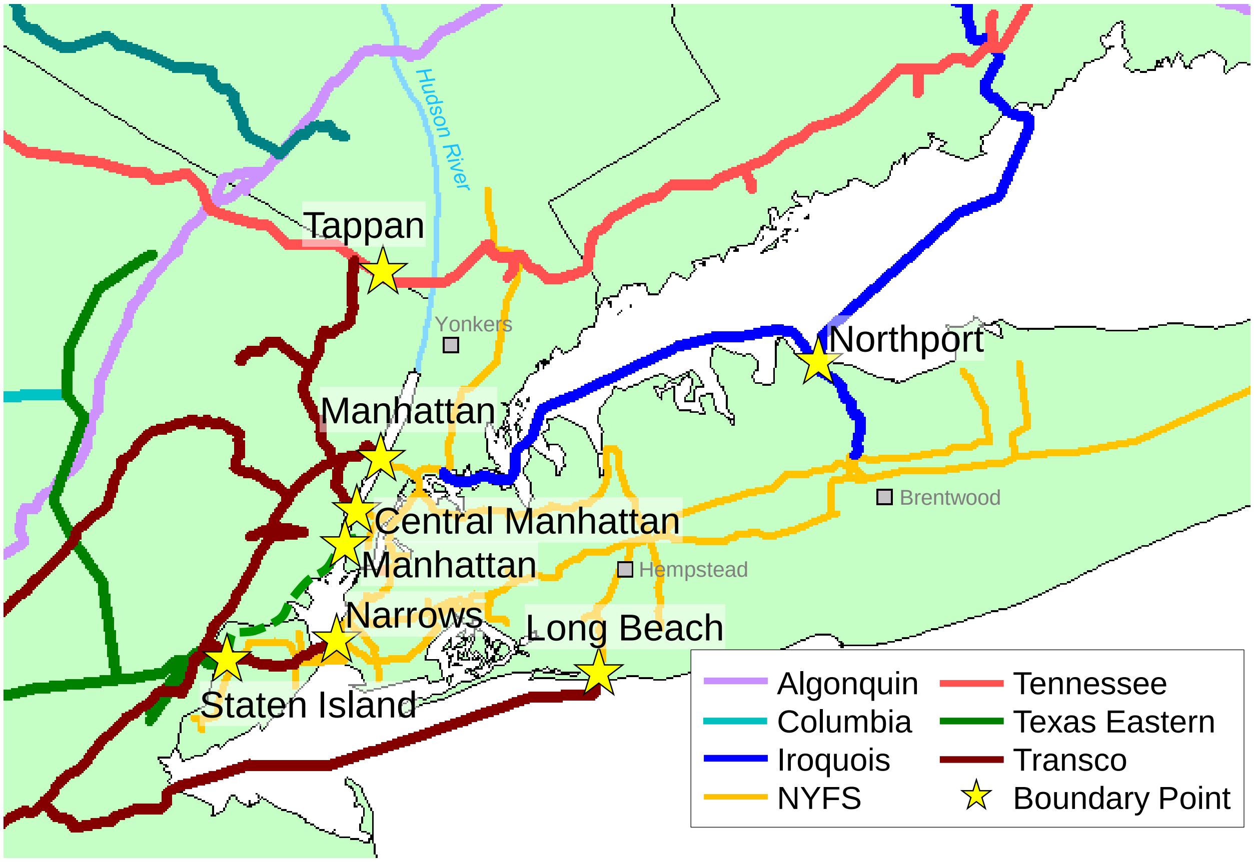


Table 38 and Table 39 summarize the inflow capacity modeled at each boundary point illustrated in the above figures for the heating and cooling seasons, respectively.

The following sections describe how the boundary flow capacities were derived at each point. The method for estimating capacity varies by point depending on the available data. If a pipeline reports daily capacity at the boundary flow point, the reported daily capacity has been used to reflect seasonal capacity differences. In the event that capacity at a boundary point is reported only on an overall basis, seasonal capacity has been calculated as the average of the top ten throughput days.[62] For purposes of calculating seasonal values, the heating season has been defined as November through March. The cooling season is May through September. The peak cooling season is July and August.

[62]The average-of-top-ten-days construct is used in order to approximate sustainable operating conditions. These averages have been calculated from LAI's historical database of daily EBB postings, and may include days prior to the period shown in the throughput figures.

Table 38. Upstream Boundary Flow Point Capacities (Heating Season, MDth/d)

Boundary Point	Winter 2012-13	Winter 2013-14	Winter 2014-15	Winter 2015-16	Winter 2016-17	Winter 2017-18
Algonquin @ Mahwah	1,144	1,144	1,144	1,144	1,144	1,144
Columbia @ Line J	21	21	21	21	21	21
Constitution @ Sanford	0	0	0	0	650	650
Dominion @ PA/NY Border	1,695	1,695	1,695	1,695	1,695	1,695
Empire @ Chippawa	101	51	1	1	1	1
Empire @ Tioga	250	300	350	350	350	350
Iroquois @ Waddington	1,195	1,195	1,195	1,195	1,195	1,195
Iroquois @ Northport	858	858	858	858	858	858
NFG @ PA/NY Border	626	626	626	626	626	626
Niagara @ Cornwall	41	41	41	41	41	41
North Country @ Napierville	105	105	105	105	105	105
Tennessee @ Station 224	440	440	440	440	440	440
Tennessee @ Troupsburg	560	560	560	560	560	560
Tennessee @ Tappan	412	412	412	412	412	412
Texas Eastern @ Staten Island	688	688	738	738	738	738
Texas Eastern @ Manhattan	0	800	800	800	800	800
Transco @ NYFS[63]	1,637	1,837	1,837	1,937	1,937	1,937
Total	9,773	10,773	10,823	10,923	11,573	11,573

Table 39. Upstream Boundary Flow Point Capacities (Cooling Season, MDth/d)

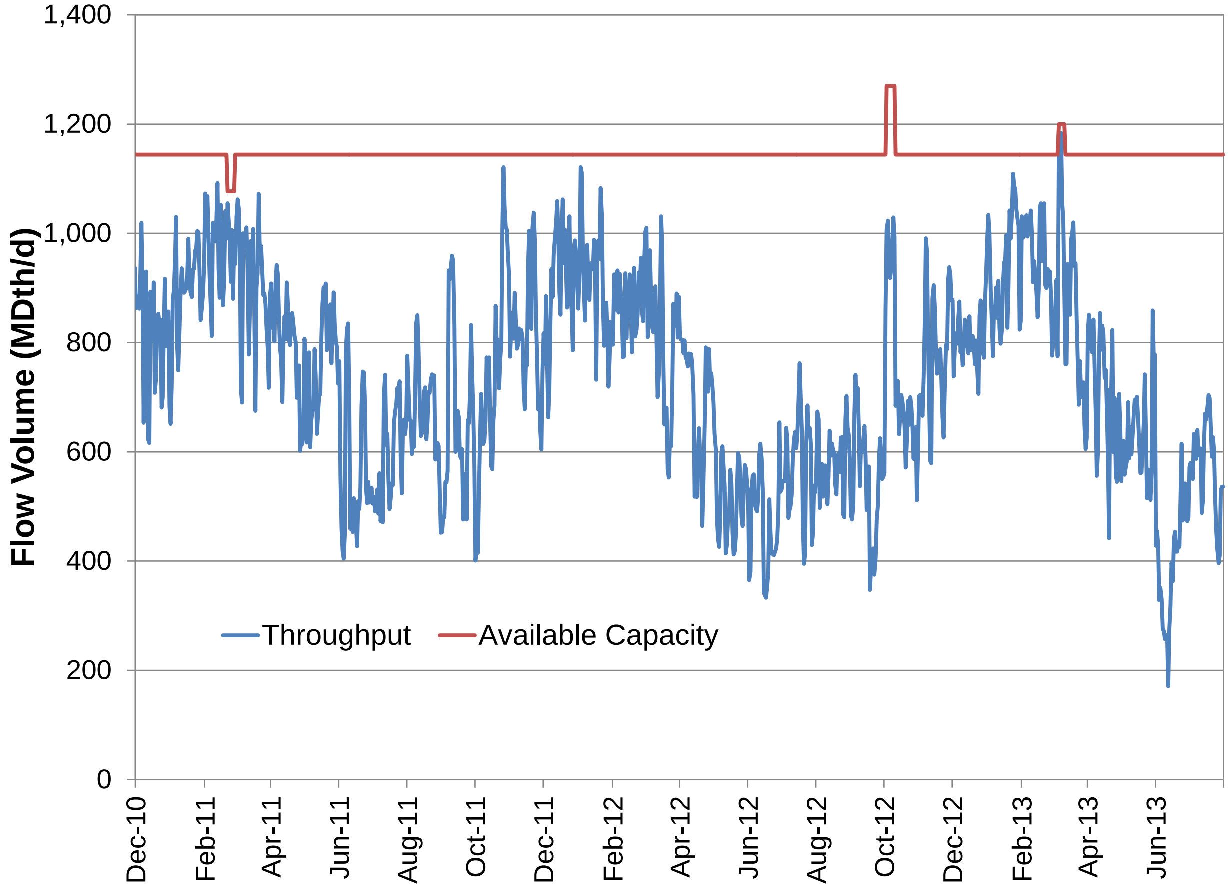
Boundary Point	Summer 2013	Summer 2014	Summer 2015	Summer 2016	Summer 2017
Algonquin @ Mahwah	1,144	1,144	1,144	1,144	1,144
Columbia @ Line J	14	14	14	14	14
Constitution @ Sanford	0	0	0	0	650
Dominion @ PA/NY Border	736	736	736	736	736
Empire @ Chippawa	62	12	0	0	0
Empire @ Tioga County	250	300	350	350	350
Iroquois @ Waddington	1,075	1,075	1,075	1,075	1,075
Iroquois @ Northport	694	694	694	694	694
NFG @ PA/NY Border	388	388	388	388	388
Niagara @ Cornwall	41	41	41	41	41
North Country @ Napierville	105	105	105	105	105
Tennessee @ Station 224	440	440	440	440	440
Tennessee @ Troupsburg	560	560	560	560	560
Tennessee @ Tappan	412	412	412	412	412
Texas Eastern @ Staten Island	578	578	628	628	628
Texas Eastern @ Manhattan	0	800	800	800	800
Transco @ NYFS	1,244	1,444	1,444	1,544	1,544
Total	7,743	8,743	8,331	8,931	9,581

[63] This data point consolidates deliveries into the Manhattan, Central Manhattan, Narrows and Long Beach points shown in Figure 84.

3.1.1 Algonquin

Algonquin reports flows across the New Jersey / New York border at the Mahwah mainline point. The design capacity at this point is 1,144 MDth/d, historical throughput and daily capacity, as reported on Algonquin's EBB, are shown in Figure 85. Because the daily capacity at the Mahwah mainline point and at the upstream Hanover compressor station (Figure 25) is constant year-round with infrequent reductions due to maintenance, the full 1,144 MDth/d capacity has been modeled as the year-round capacity.[64]

Figure 85. Capacity and Throughput on Algonquin at Mahwah[65]

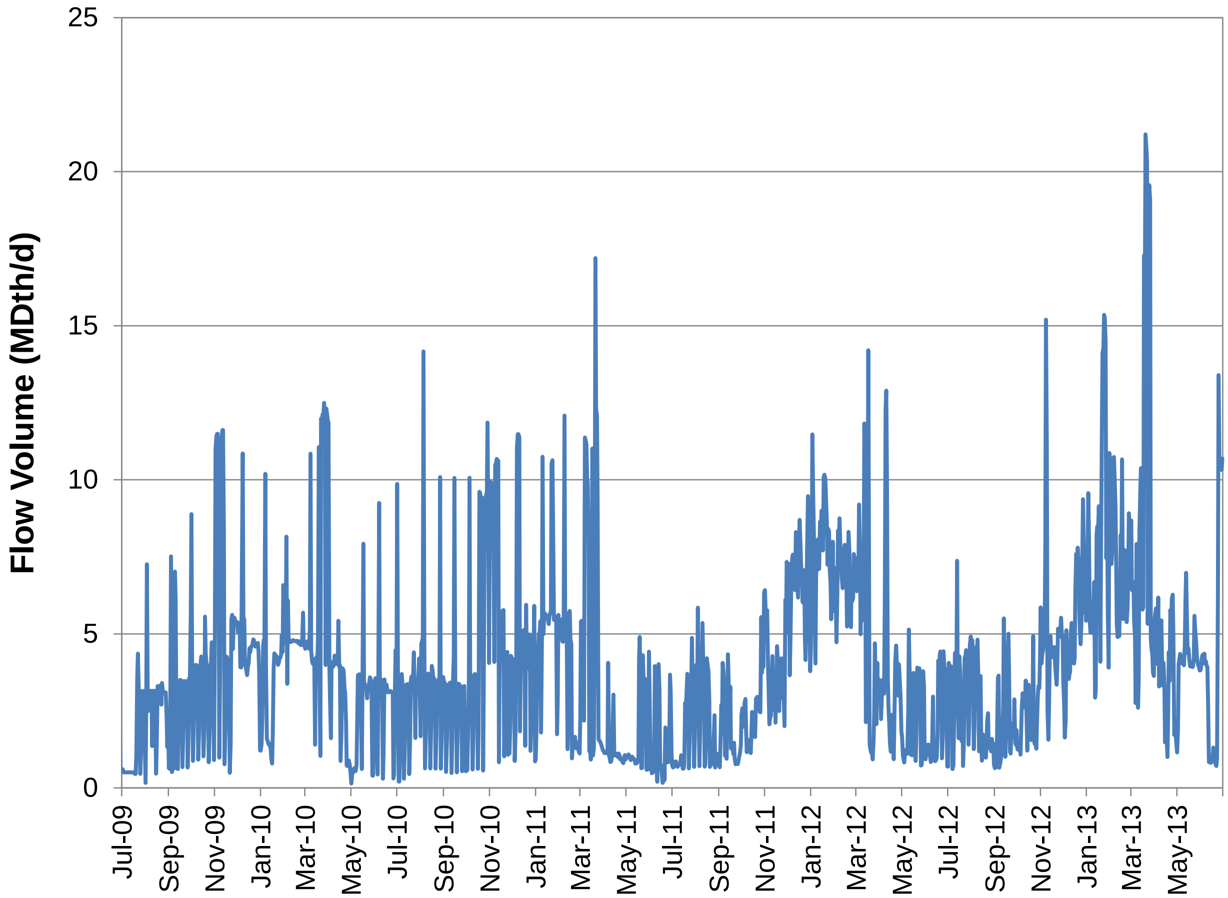


3.1.2 Columbia

Columbia also operates delivery meters on its Line J-2 in New York. Total flows are relatively small, as shown in Figure 86. Based on the highest delivery day for each season, as extracted from Columbia's EBB, we have modeled the heating season and cooling season capacities at 21 MDth/d and 14 MDth/d, respectively.

[64] An adjustment for temperature effects to each pipeline's seasonal capacity is outside the scope of this analysis.
[65] The brief period in March 2013 when flows exceeded 1,144 MDth/d was due to maintenance on Millennium that prevented deliveries into Algonquin at Ramapo, thereby heightening shippers' reliance on Algonquin to offset constraints on Millennium.

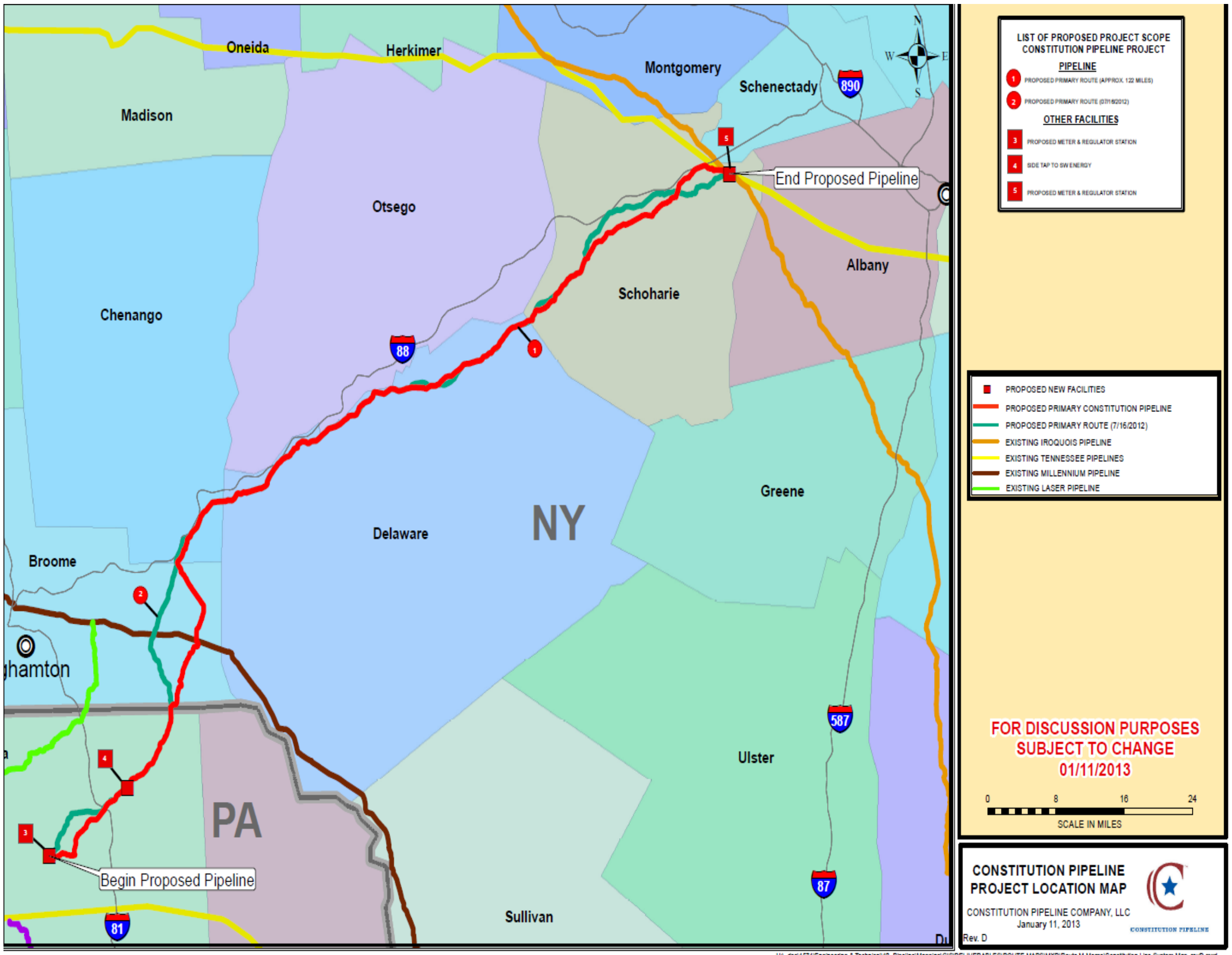
Figure 86. Columbia Line J Boundary Flow



3.1.3 Constitution

The current planned route of the proposed Constitution pipeline (Figure 87) shows that it will enter New York near Sanford Township. LAI has made the simplifying assumption that the full 650 MDth/d is included in the supply balance for both the heating and cooling seasons beginning Q4-2016.

Figure 87. Proposed Constitution Pipeline Route[66]



3.1.4 Dominion

Dominion does not report all receipts and deliveries on its EBB. Therefore the available daily data is insufficient to estimate the total deliverability in NYCA. Instead, we have modeled the boundary flow into New York based on the in-state receipts and deliveries listed in Dominion's current index of customers as filed with FERC. We have assumed that Dominion delivers all firm contract quantities on a peak day. Because many of Dominion's contracts have multiple possible paths, we have reduced the calculated differential between New York receipts and deliveries by 10% to account for operational factors, resulting in a boundary flow capability of 1,695 MDth/d.[67] Dominion has not announced any projects to increase transportation capacity into New York during the study period. Figure 88 illustrates receipt and delivery data posted to Dominion's EBB – it does not include all NYCA volumes. However, it does capture the high demand seasonality associated with throughput patterns on the Dominion system, which is linked to the extensive conventional storage facilities at Oakford.

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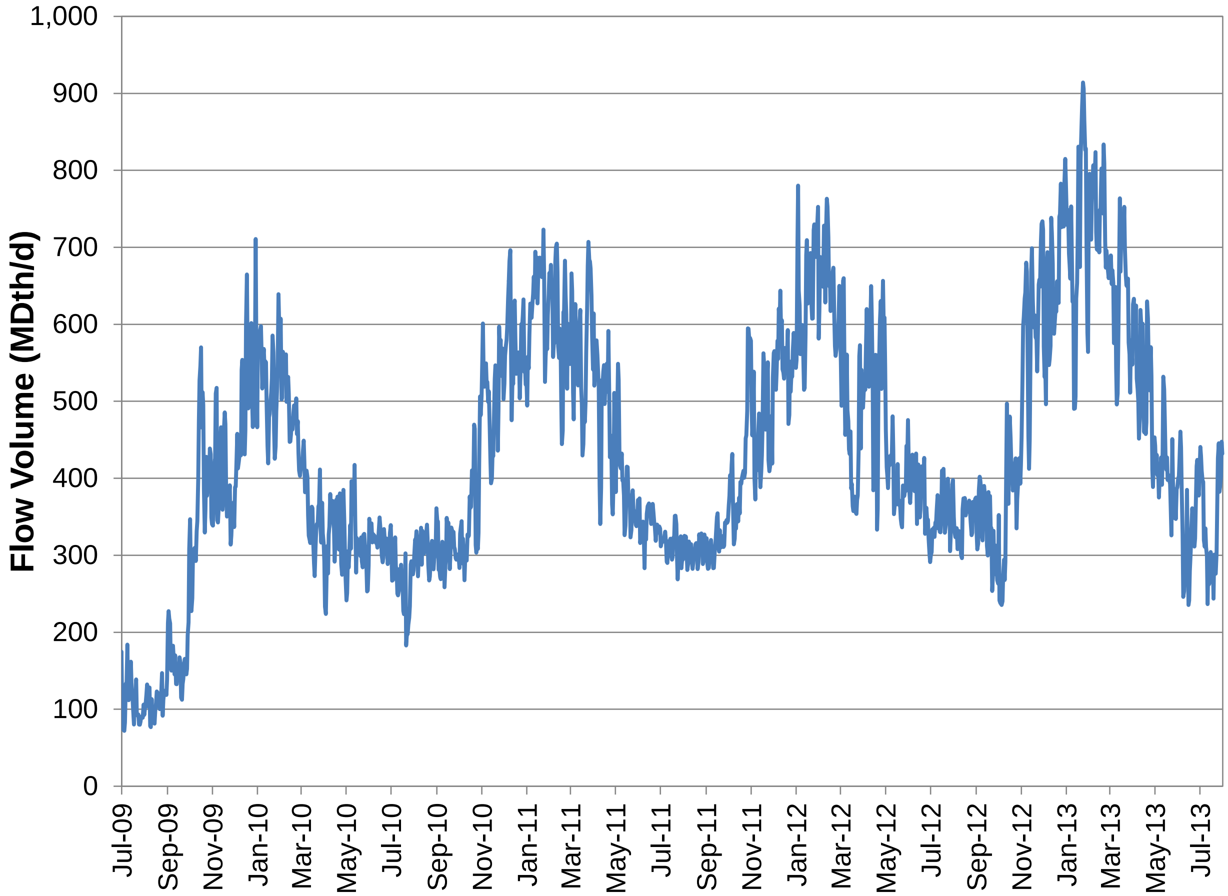
[66] Source: http://constitutionpipeline.com/maps/

[67] EIA state-to-state capacity report lists Dominion's Pennsylvania to New York capacity at 1,615 MDth/d.

Dominion depends on withdrawals from its Pennsylvania storage fields to bolster deliverability throughout the heating season. Therefore in order to estimate Dominion's summer deliverability in NYCA, we have removed the contracts that are sourced from storage – these volumes would not normally be withdrawn during the cooling season, except perhaps during gas outage contingencies. We have again reduced the net deliveries by 10% to account for operational factors, resulting in a summer boundary flow capacity of 736 MDth/d.

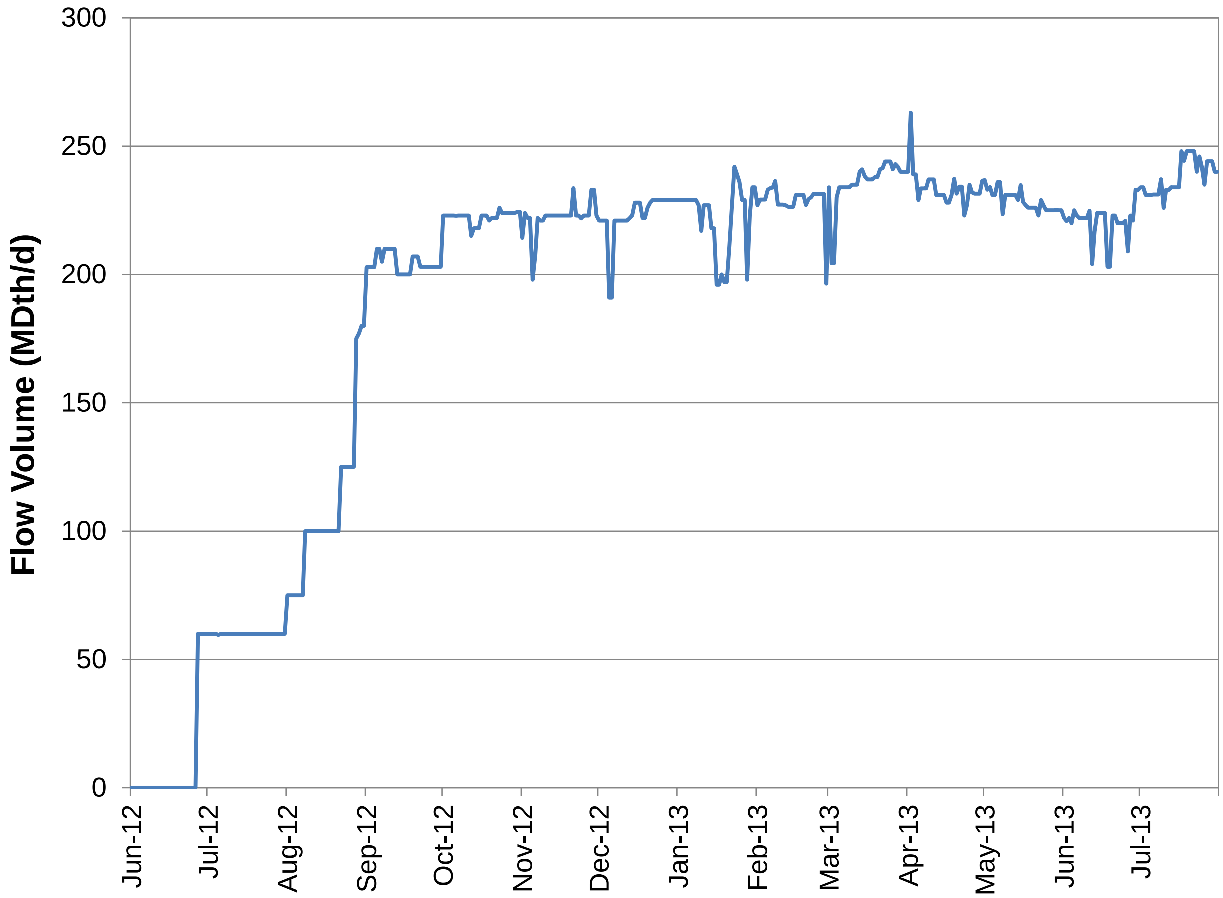
Figure 88. Net NYCA Deliveries Reported on Dominion's EBB



3.1.5 Empire

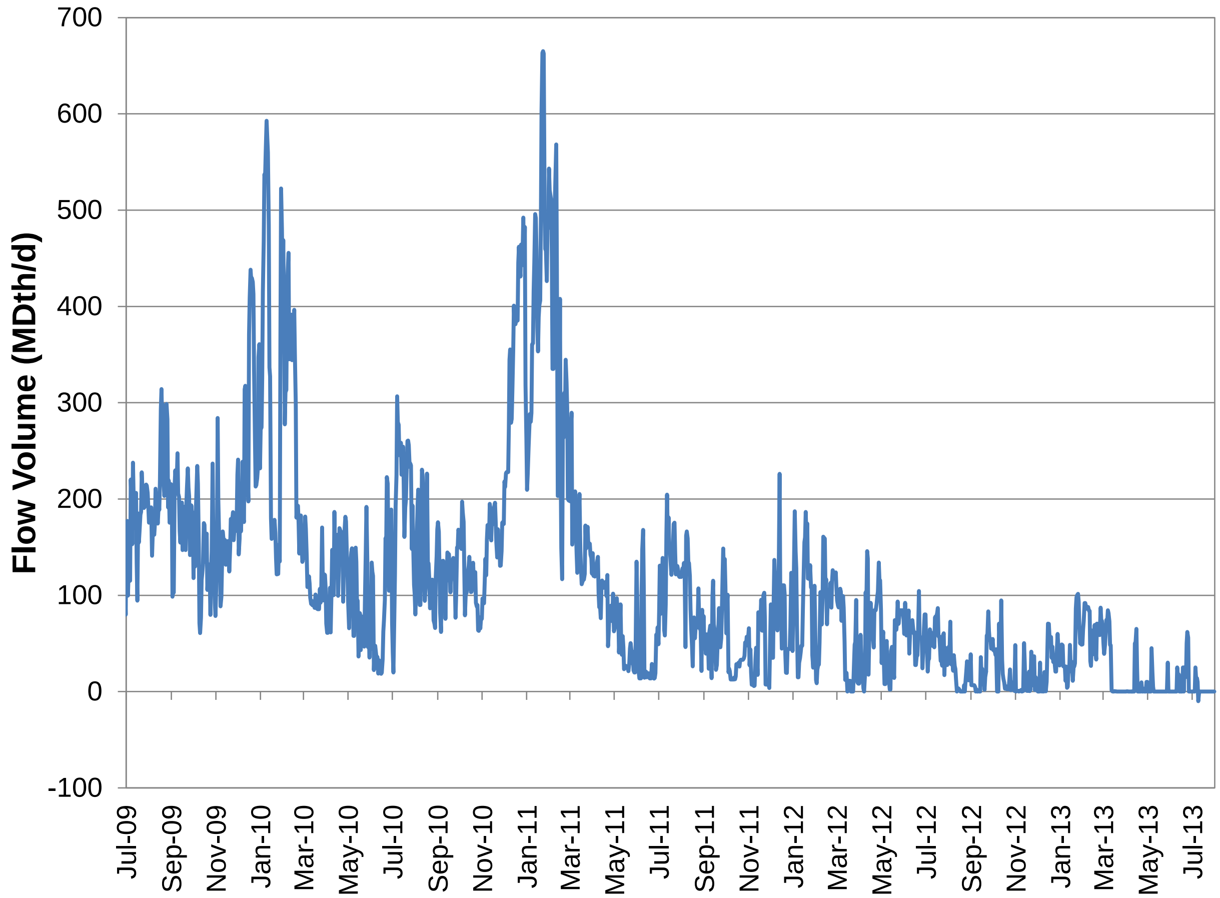
Following completion of the Tioga County Extension Project in November 2011, Empire now receives gas at both ends of its system, with gas from northern Pennsylvania production flowing into the southern end of its system. Receipts to-date at these production meters are shown in Figure 89. The Tioga County Extension Project was designed to receive up to 350 MDth/d. Increasing utilization to the full capacity of the new facilities is dependent on production levels, to date the total receipts have only exceeded 250 MDth/d on one day. Although the timing of expanded or re-directed production is uncertain, we have assumed that over the next two heating seasons the full intended capacity will be achieved. Therefore the 2013-14 heating season boundary flow is estimated at 300 MDth/d, and the 2014-15 heating season is estimated at 350 MDth/d. Because this boundary flow is directly linked to production, we have modeled the same capacity for the heating and cooling seasons.

Figure 89. Empire Production Receipts in Tioga County



Receipts from TransCanada at Chippawa are shown in Figure 90. While Chippawa has previously seen peak imports near 700 MDth/d, recent usage has been less than 100 MDth/d, even during the January 2013 cold snap. Because of the shift in operating paradigm, the modeled boundary flows at Chippawa are based on recent operational patterns rather than transportation capacity. Receipts ranged from 0 MDth/d to 101 MDth/d during the 2012-13 heating season and from -10 MDth/d (a net delivery) to 62 MDth/d during the 2013 cooling season to-date. We have modeled the maximum values for these seasons and staged the decrease in imports from Canada over the study horizon relative to the incremental production capacity from Tioga County. Based on this construct, the 2013-14 heating season will see a peak net imports of 51 MDth/d, the 2014 cooling season will see a peak net import of 12 MDth/d, the 2014-15 heating season will see a peak net import of 1 MDth/d, and the 2015 cooling season will see a net export of 38 MDth/d.

Figure 90. Empire's Net Receipts at Chippawa



3.1.6 Iroquois

Iroquois's primary receipt point is the Waddington, New York, interconnection with TransCanada, which has a design capacity of 1,195 MDth/d. Daily net receipts are shown in Figure 91 and operating capacity from November 1, 2012 is shown in Figure 92.[68] Based on the operating capacity data for the 2013 cooling season to-date, we have modeled the heating season capacity at 1,195 MDth/d and the cooling season capacity at 1,075 MDth/d.

[68] Iroquois changed their EBB reporting format to include operational capacity alongside scheduled capacity, but posts only the required 90 days of historical data. Therefore prior operational capacity could not be retrieved.

Figure 91. Net Receipts at Waddington

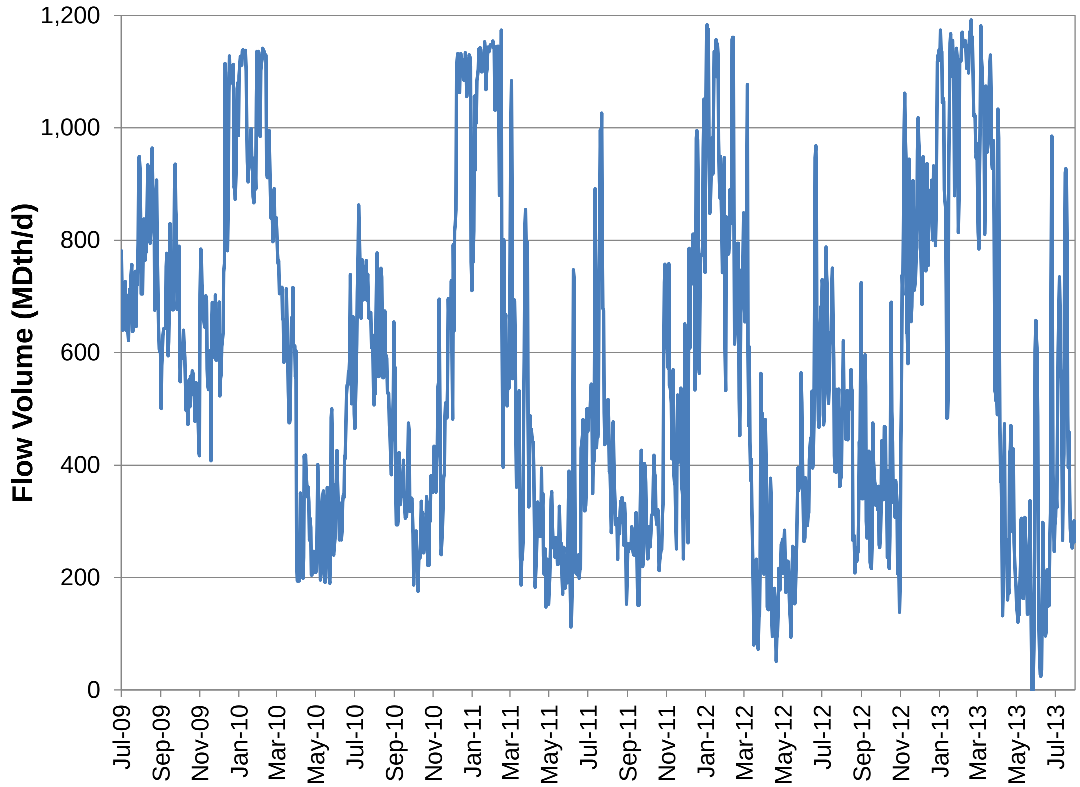
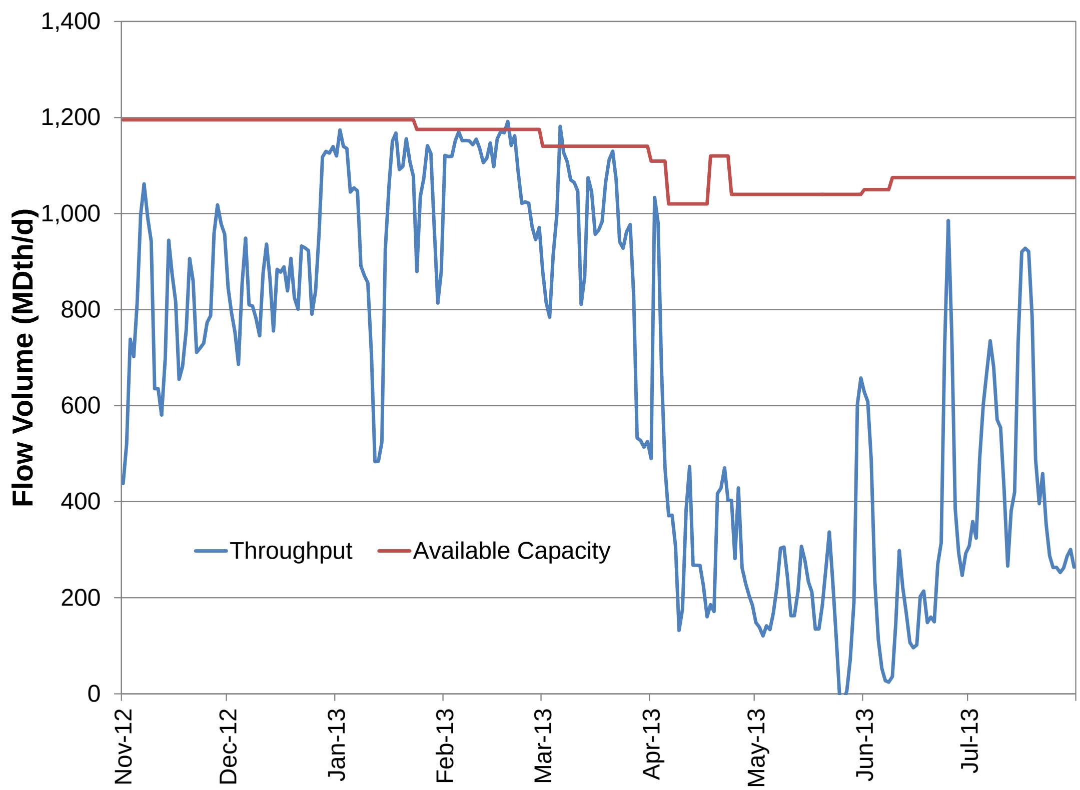


Figure 92. Operating Capacity at Waddington



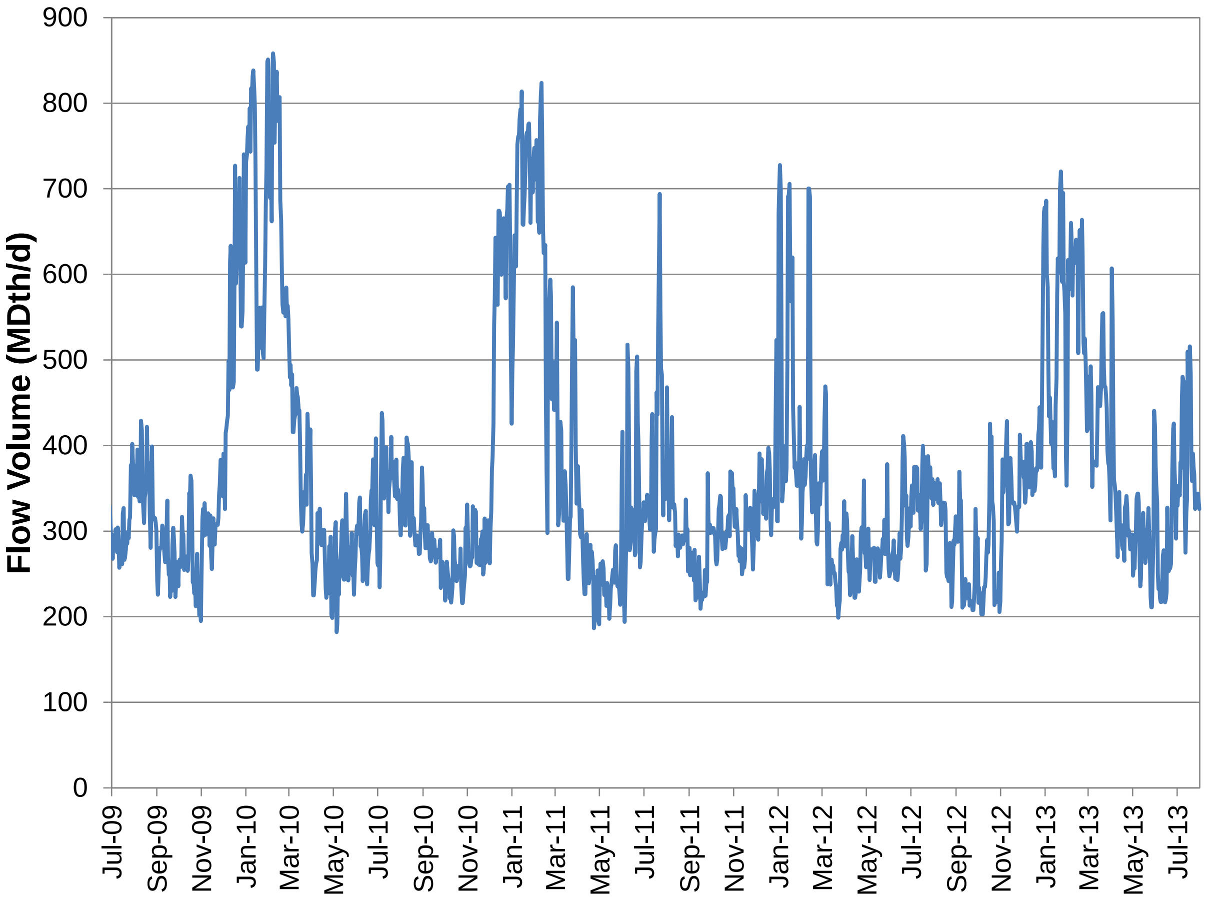
If the Constitution pipeline is commercialized, Iroquois will be able to receive up to 650 MDth/d at the modified Wright compressor station following construction of the Wright Interconnect Project. If the new facilities are fully utilized, there may be a number of low demand days, most likely during the shoulder months, when the Iroquois flow balance indicates that Waddington would become a new export point as volumes flow north from Wright to Waddington.[69]

Because Iroquois serves Connecticut, the pipeline has a downstream boundary point at the New York-Connecticut border (discussed on page 127) and then a second "upstream" boundary point under Long Island Sound as Iroquois re-enters New York before making landfall at NGrid's Northport station on Long Island.[70] Based on historical EBB data, we have calculated the mainline flows across Long Island Sound, as shown in Figure 93. The heating season peak day throughput is 858 MDth/d to serve downstate demand. Conducting the same calculation for the cooling season yields a throughput of 694 MDth/d. These peak throughput values are used as the seasonal capacity values for this segment. To the extent that downstate deliveries are flowing to non-firm shippers, the addition of new non-firm shippers in upstate New York or Connecticut could reduce the boundary flow available to serve the Northport, Port Jefferson and Caithness generation plants on Long Island, as well as other smaller generation plants in Suffolk County. For example, if Cricket Valley is constructed, flows that are currently available to downstate non-core shippers on a non-firm basis may instead serve upstate non-core demand, thereby reducing the availability of natural gas at Northport and South Commack, all other things being the same. However, due to the significant increases in New York Facilities System deliverability from Texas Eastern and Transco, this dynamic would not likely place incremental generation at risk in NYC.

[69] We have not modeled this change in directionality because the import capacity at Waddington will not be affected. Moreover, the reversal would likely not occur on peak NYCA demand days.

[70] Double counting is avoided for modeling purposes by subtracting the volumes flowing from New York to Connecticut and then adding the volumes flowing from Connecticut to New York.

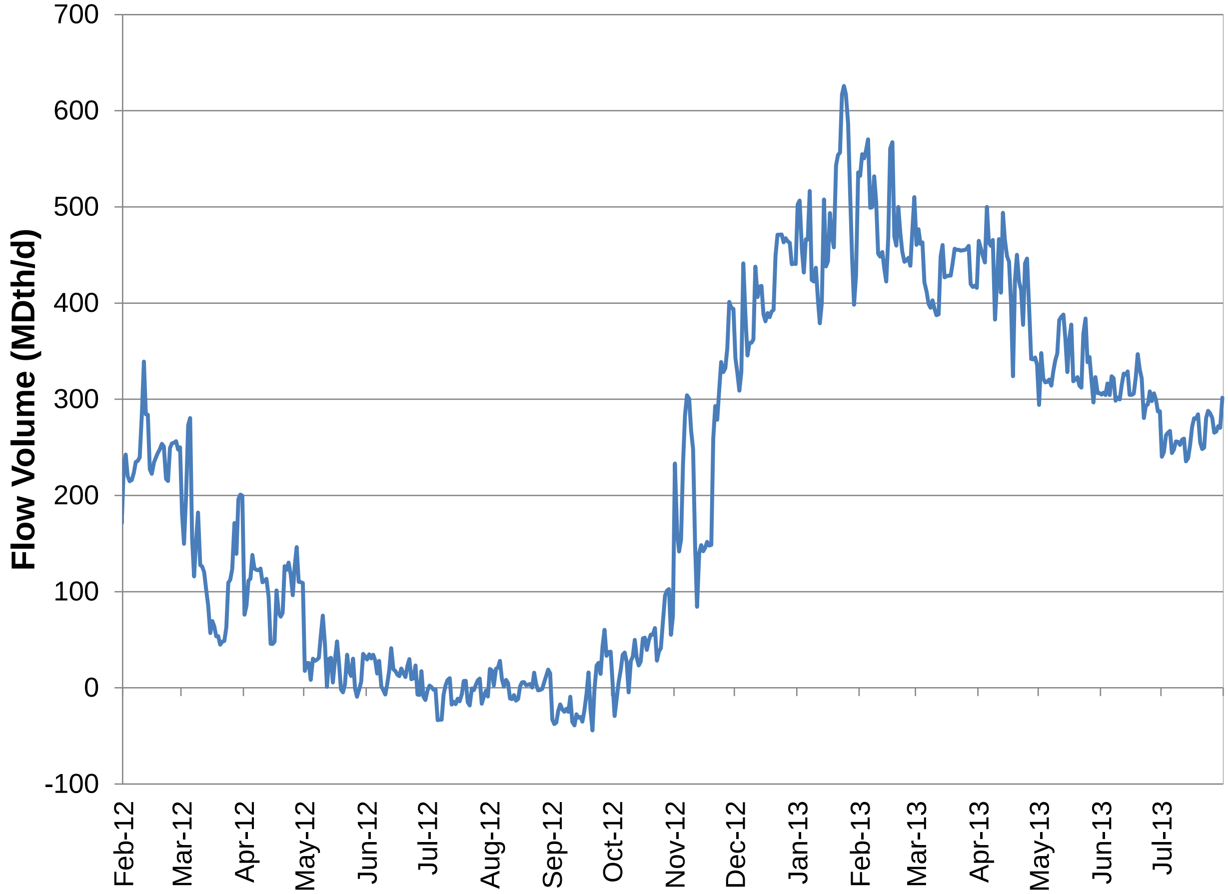
Figure 93. Throughput on Iroquois across Long Island Sound



3.1.7 National Fuel Gas

Upon commercialization of the Northern Access Project and related facilities on Tennessee the conversion of Niagara to a net export point drastically altered NFG's flow patterns in NYCA. We have therefore based our boundary flow capacity assumptions on data from the 2012-13 heating season and the 2013 cooling season to-date. The net flow into NYCA on NFG – calculated as deliveries at New York points less receipts at New York points – is shown in Figure 94. The peak in-flow during the 2012-13 heating season was 626 MDth/d. In contrast to the summer of 2012, which saw both positive and negative boundary flow values with an average of around 5 MDth/d, the summer of 2013 to-date has seen much higher positive boundary flow values, with a peak of 388 MDth/d. The seasonal capacity differential accommodates storage injections in Pennsylvania during the cooling season to support deliveries during the heating season.

Figure 94. Net Deliveries into NYCA on NFG

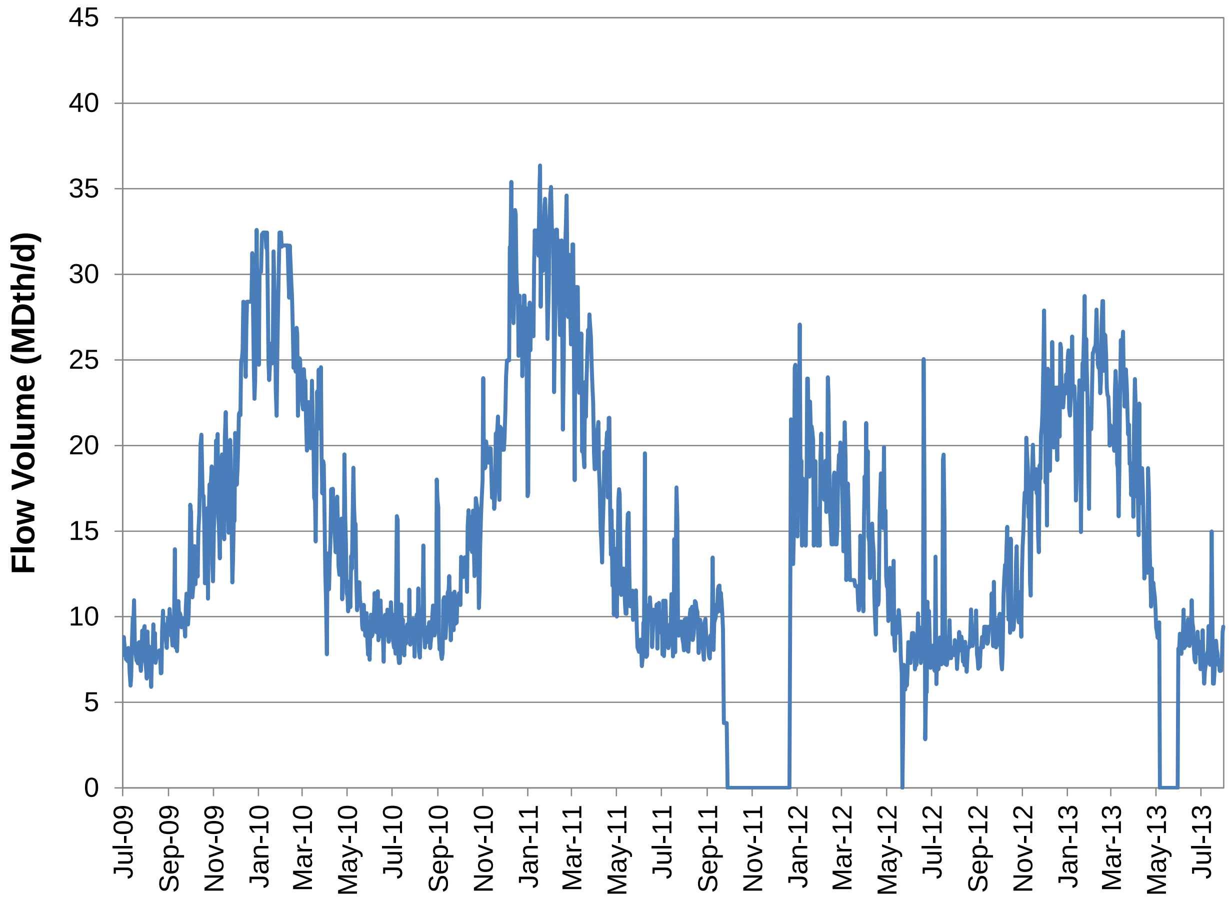


3.1.8 Niagara Gas

Niagara Gas is an Enbridge subsidiary delivering gas into upstate New York from Canada. Niagara Gas is the primary supplier to St. Lawrence Gas.[71] Although there are no publicly available data sources for the daily flow volumes from Niagara Gas into St. Lawrence Gas, TransCanada reports deliveries into Niagara Gas at Cornwall, and St. Lawrence Gas is the sole firm shipper on Niagara Gas. Therefore we have assumed that all gas delivered from TransCanada into the Niagara Gas system at Cornwall subsequently flows into New York for delivery to St. Lawrence Gas. TransCanada's Cornwall deliveries are shown in Figure 95. St. Lawrence Gas reported in its 2012-13 Winter Supply Review filing that it holds 41 MDth/d of firm capacity on Niagara Gas, therefore we have assumed that value for year-round import capacity.

[71] Additional deliveries to St. Lawrence Gas from Iroquois are discussed on page 183.

Figure 95. Niagara Gas Receipts at Cornwall[72]



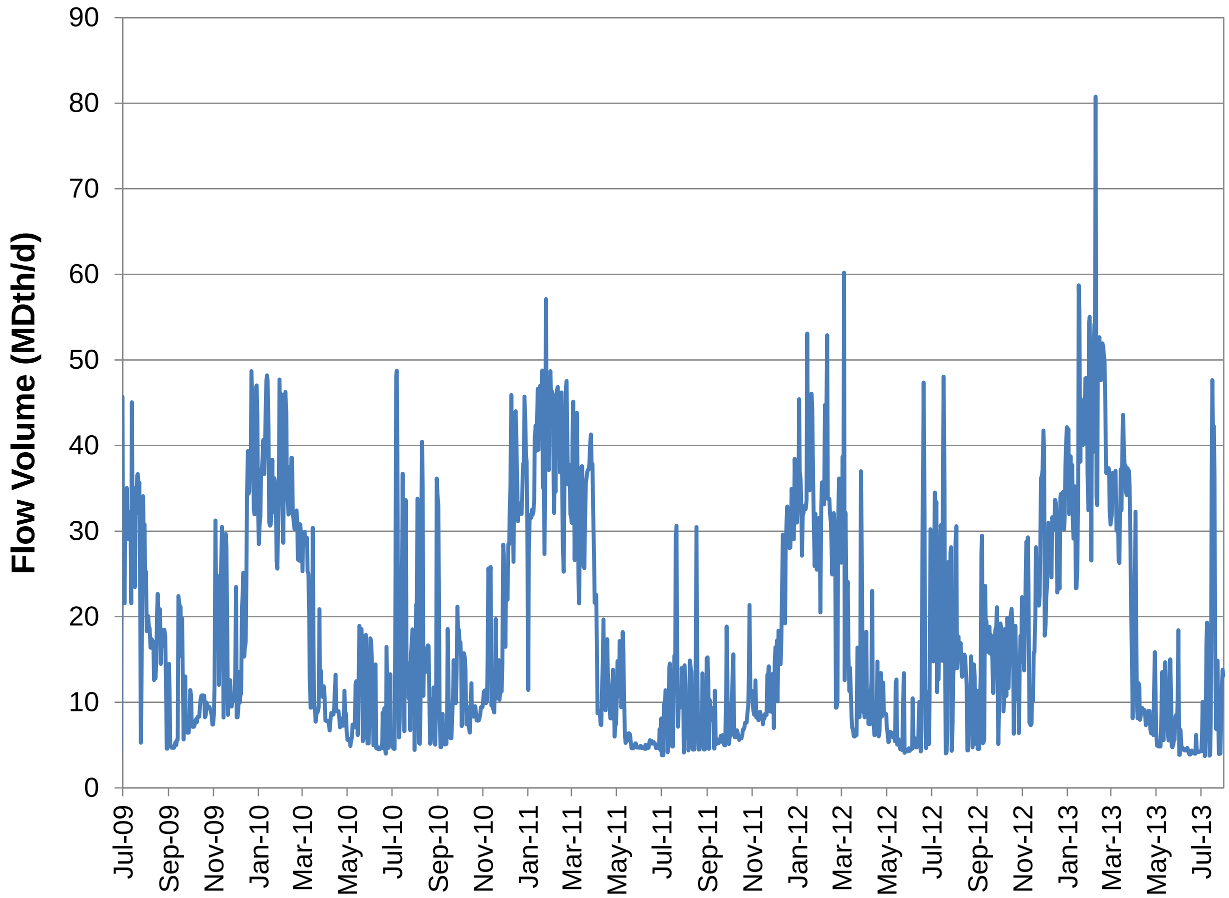
3.1.9 North Country

The North Country Pipeline is owned by TransAlta's Saranac power plant and also serves New York State Electric & Gas (NYSE&G). North Country imports gas from TransCanada at Napierville. TransCanada's reported daily deliveries are shown in Figure 96. The full capacity of the line is 105 MDth/d, which has been modeled as the boundary flow for both the heating and cooling seasons.[73]

[72] The period of no deliveries in Q4-2011 is a result of construction for the St. Lawrence River Pipeline Crossing Replacement Project. During this period, deliveries from Iroquois filled the gap to meet all of St. Lawrence Gas's needs, as shown in Figure 149 on page 185.

[73] NYPSC Declaratory Ruling in Case No. 92-M-0322.

Figure 96. North Country Receipts at Napierville

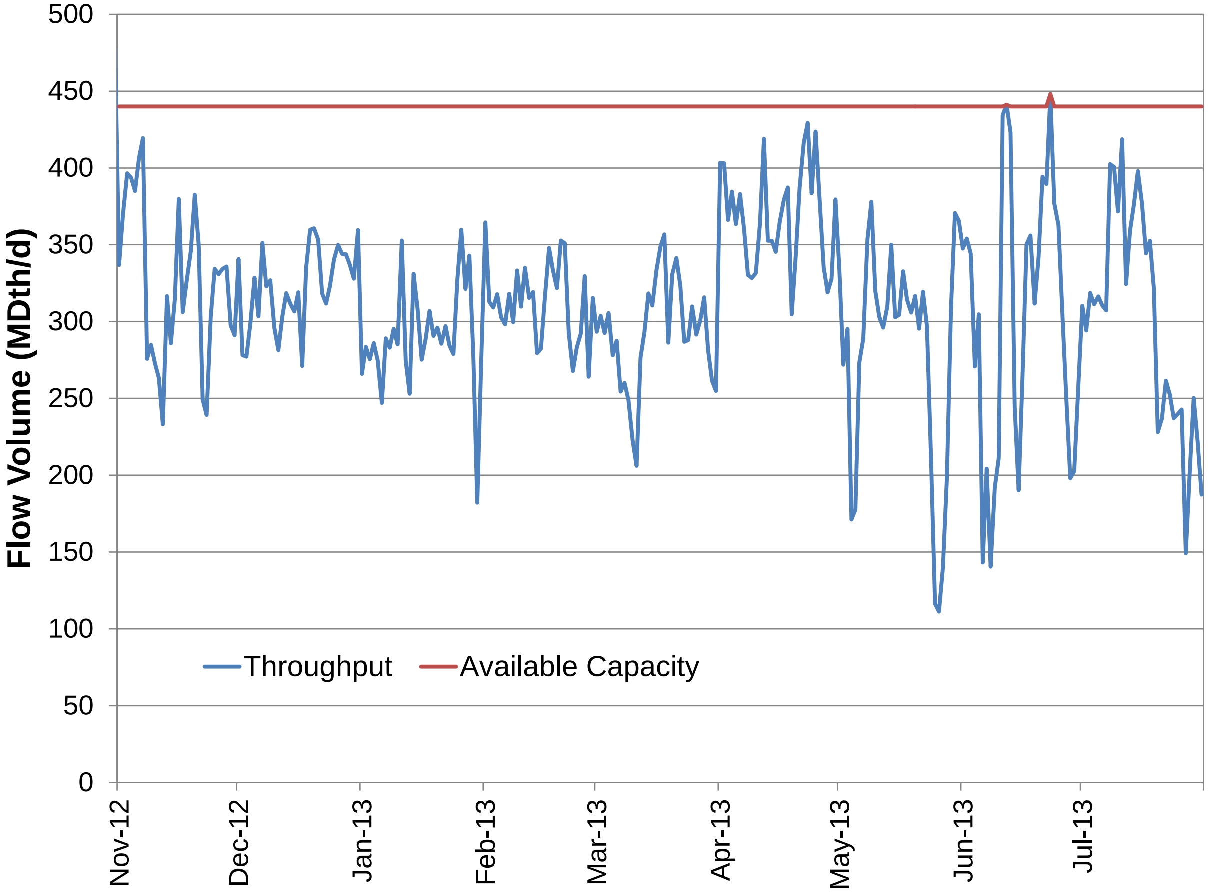


3.1.10 Tennessee

Historically, Tennessee has received imports from TransCanada at the Niagara interconnection. At the beginning of the 2012-13 heating season, Tennessee placed facility improvements into service that reversed the flow direction at Niagara. Therefore this is now a downstream boundary point, addressed on page 131.

This reconfiguration of Tennessee's system has also affected the boundary flows into New York from Pennsylvania on Tennessee's Line 200, represented by Station 224. Daily capacity and scheduled flows since Niagara exports commenced on November 1, 2012 are shown in Figure 97. Daily capacity has consistently been 440 MDth/d throughout the 2012-13 heating season and 2013 cooling season to-date. Therefore it has been modeled to remain at that level year-round going forward.

Figure 97. Throughput and Capacity on Tennessee at Station 224



Line 300 delivers Marcellus shale gas into New York from Pennsylvania via New Jersey. Daily capacity and scheduled flows through Station 325, the nearest upstream compressor station, are shown in Figure 98. The boundary flow across the state border near Tappan, is calculated based on the EBB-reported throughput at the compressor station less net deliveries in New Jersey downstream of the station. The capacity across the New Jersey-New York border is calculated by reducing the current capacity of Station 325 (1,005 MDth/d for both the heating and cooling seasons) by the current contracted deliveries at points between Station 325 and the state border (593 MDth/d) to yield a boundary flow limit of 412 MDth/d. This is consistent with the peak calculated boundary flow since Station 325 achieved its current capacity, shown in Figure 99. Tennessee's Northeast Upgrade Project will increase deliverability into Algonquin at Mahwah, NJ by 636 MDth/d. Since this delivery point is upstream of NYCA, we have not adjusted the boundary flow at the New York-New Jersey border. Similarly, Columbia's East Side Expansion Project is designed to deliver incremental gas into Tennessee at Milford, PA, but this is upstream of Station 325 in New Jersey. Tennessee has not announced improvements intended to increase Line 300 capacity downstream of Milford. Therefore no boundary flow changes are modeled.

Figure 98. Throughout at Tennessee Station 325

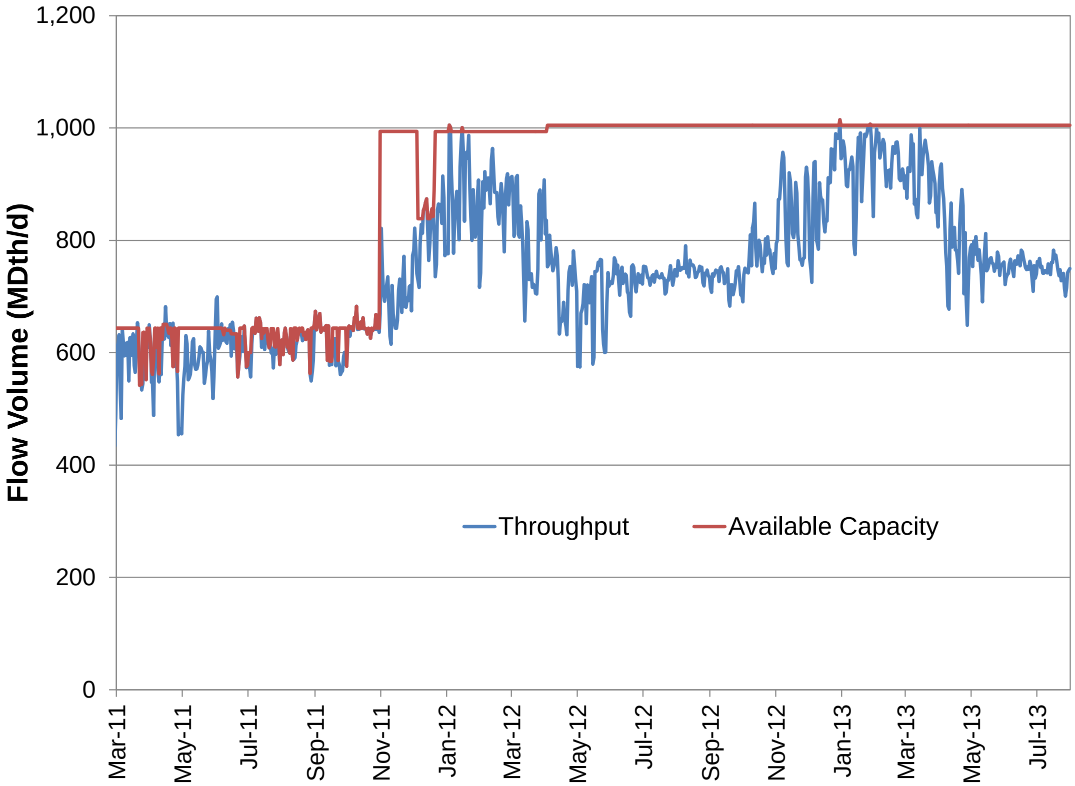
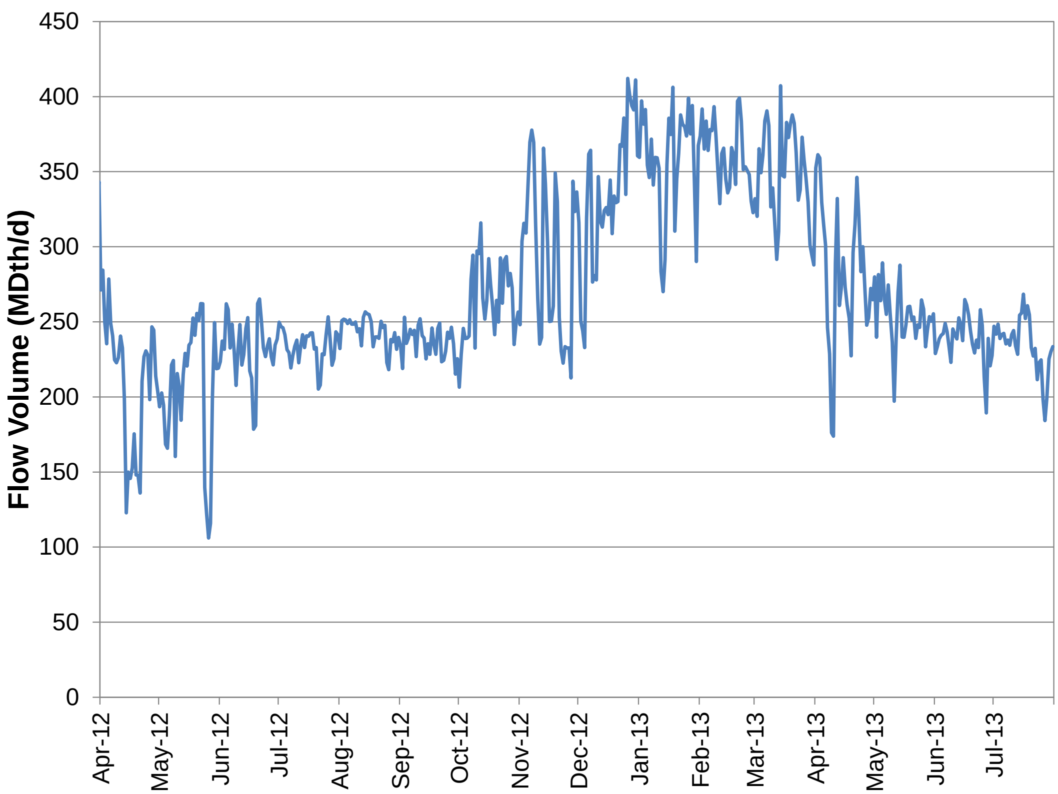
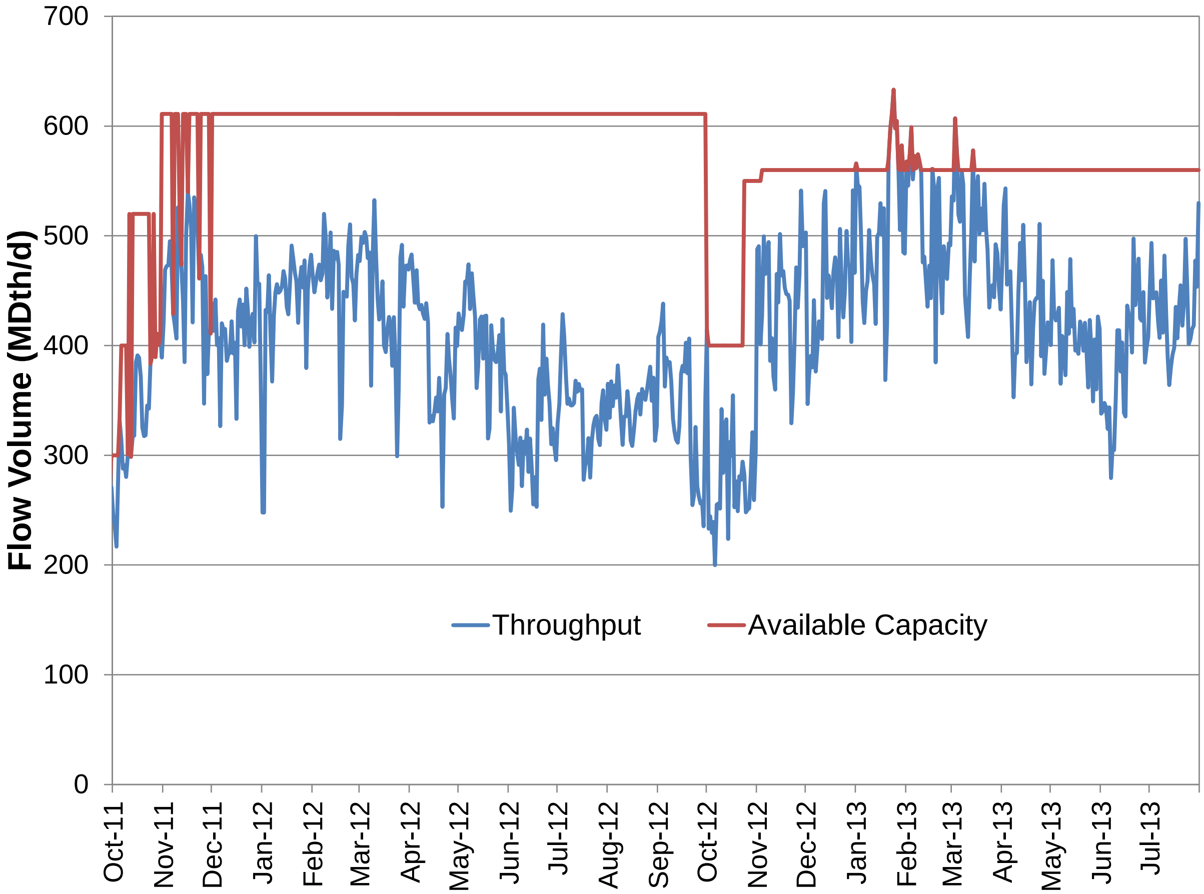


Figure 99. Throughput on Tennessee at Tappan



Tennessee's Line 400 traverses central New York, delivering Marcellus gas from Line 300 into Line 200. Tennessee's reported flows into New York on Line 400, which crosses the state border near the town of Troupsburg, are shown in Figure 100. The throughput capacity at this point is currently 560 MDth/d. Tennessee was able to boost the capacity during the January 2013 cold snap, but we have made the conservative assumption to model the capacity for both the heating and cooling seasons at the daily 560 MDth/d level.

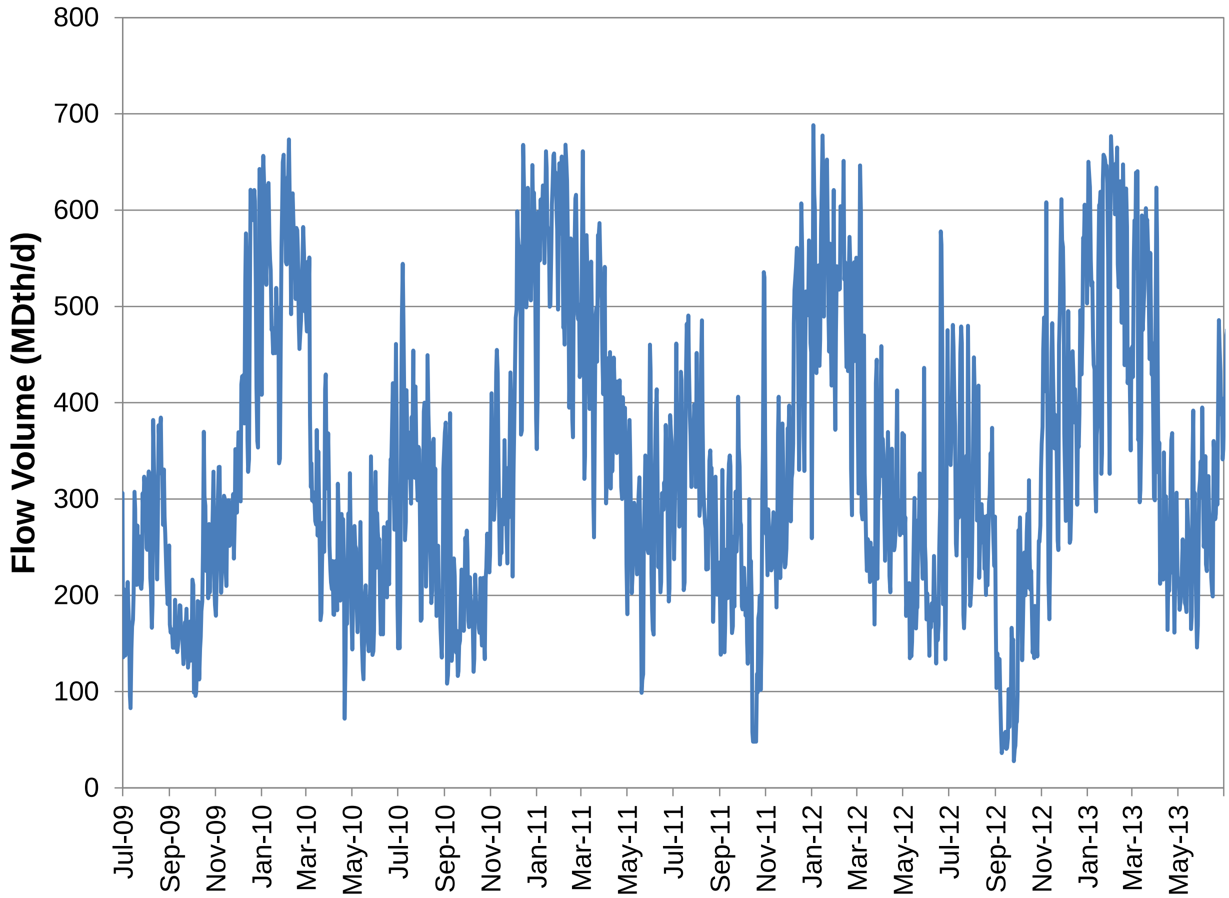
Figure 100. Throughput on Tennessee at Troupsburg



3.1.11 Texas Eastern

Texas Eastern currently has one delivery path into New York, which serves Staten Island, daily deliveries are shown in Figure 101. Based on the peak delivery days by season, we have estimated the heating season capacity of this boundary point to be 688 MDth/d, and the cooling season to be 578 MDth/d. The TEAM 2014 Project is designed to increase deliverability into Staten Island by 50 MDth/d for the 2014-15 heating season, therefore the modeled boundary flow capacities are increased by 50 MDth/d for all subsequent seasons.

Figure 101. Texas Eastern Deliveries at Staten Island



The full capacity of the New York – New Jersey Expansion Project – 800 MDth/d – is modeled as the boundary flow capacity at the new Manhattan gate station.[74]

3.1.12 Transco

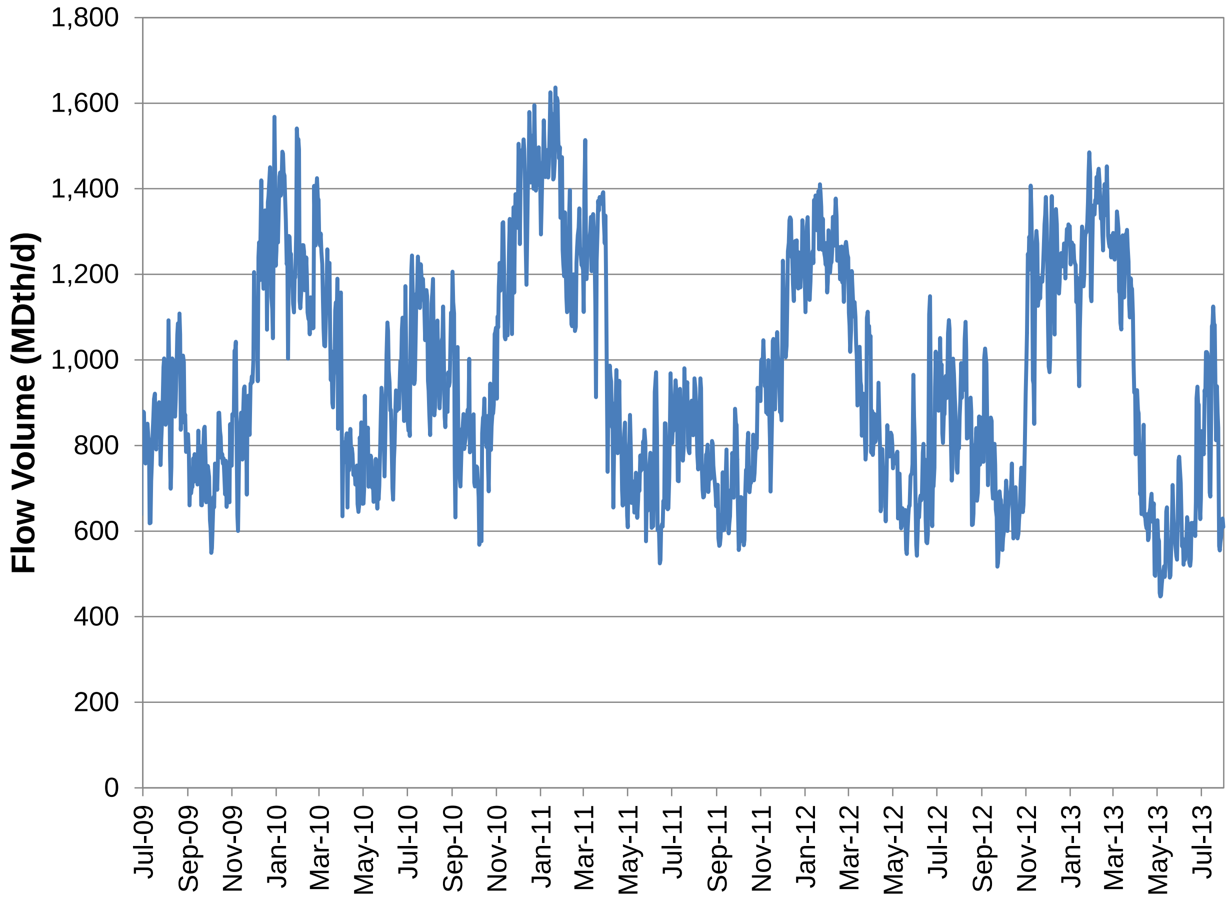
Transco's only delivery points in NYCA are directly into Zone J and Zone K. Transco reports all flows into the "New York Facilities Group" on a consolidated basis on their EBB, shown in Figure 102. Based on the seasonal peak delivery day, we have estimated Transco's ability to deliver into the New York Facilities System to be 1,637 MDth/d during the heating season and 1,244 MDth/d during the cooling season.[75] Transco is currently constructing facilities for the Northeast Supply Link Project, which will increase deliverability into NYC by 200 MDth/d for

[74] Because this capacity will also be available to new delivery points in New Jersey, the full 800 MDth/d may not flow into Manhattan.

[75] NGrid asserts in its 2012-13 Winter Supply Review filing that the 647 MDth/d proposed capacity of the pending Rockaway Delivery Lateral is equal to the existing delivery capacity at Long Beach (Transco's Zone K delivery point) plus 100 MDth/d, therefore the current design capacity of the Lower New York Bay Lateral is calculated to be 547 MDth/d to Long Beach, with the remainder Transco's NYCA capacity deliverable to the three gate stations in Zone J (Manhattan, Central Manhattan and Narrows).

the 2013-14 heating season.[76] The Northeast Connector and Rockaway Delivery Lateral Projects are currently undergoing FERC review, and will include 100 MDth/d of incremental deliverability on the Lower New York Bay Lateral into Long Beach and the new Rockaway delivery point. In this analysis, we have assumed a commercial operation date for the 2015-16 heating season.

Figure 102. Transco Deliveries into the NYFS



3.2 Downstream Boundary Flows

The amount of natural gas flowing to downstream markets in New England and Canada has been evaluated in order to account for demands in adjacent control areas.[77] There are complex operational effects on pipelines serving New York that are linked to downstream demand patterns in New England and Ontario, including potential reform of New England's Forward Capacity Market to facilitate fuel assurance objectives. Figure 103 shows the downstream boundary flow points into New England and Ontario.

[76] The remaining 50 MDth/d from the Northeast Supply Link Project will be deliverable to the Station 210 Pool in New Jersey.

[77] These boundary flows are not differentiated between core and non-core, nor have load growth factors been applied. Analysis of demand and/or wholesale market reforms in New England and Ontario affecting operational dynamics across NYCA is outside the scope of this inquiry.

Figure 103. Downstream Boundary Flow Points Out of NYCA

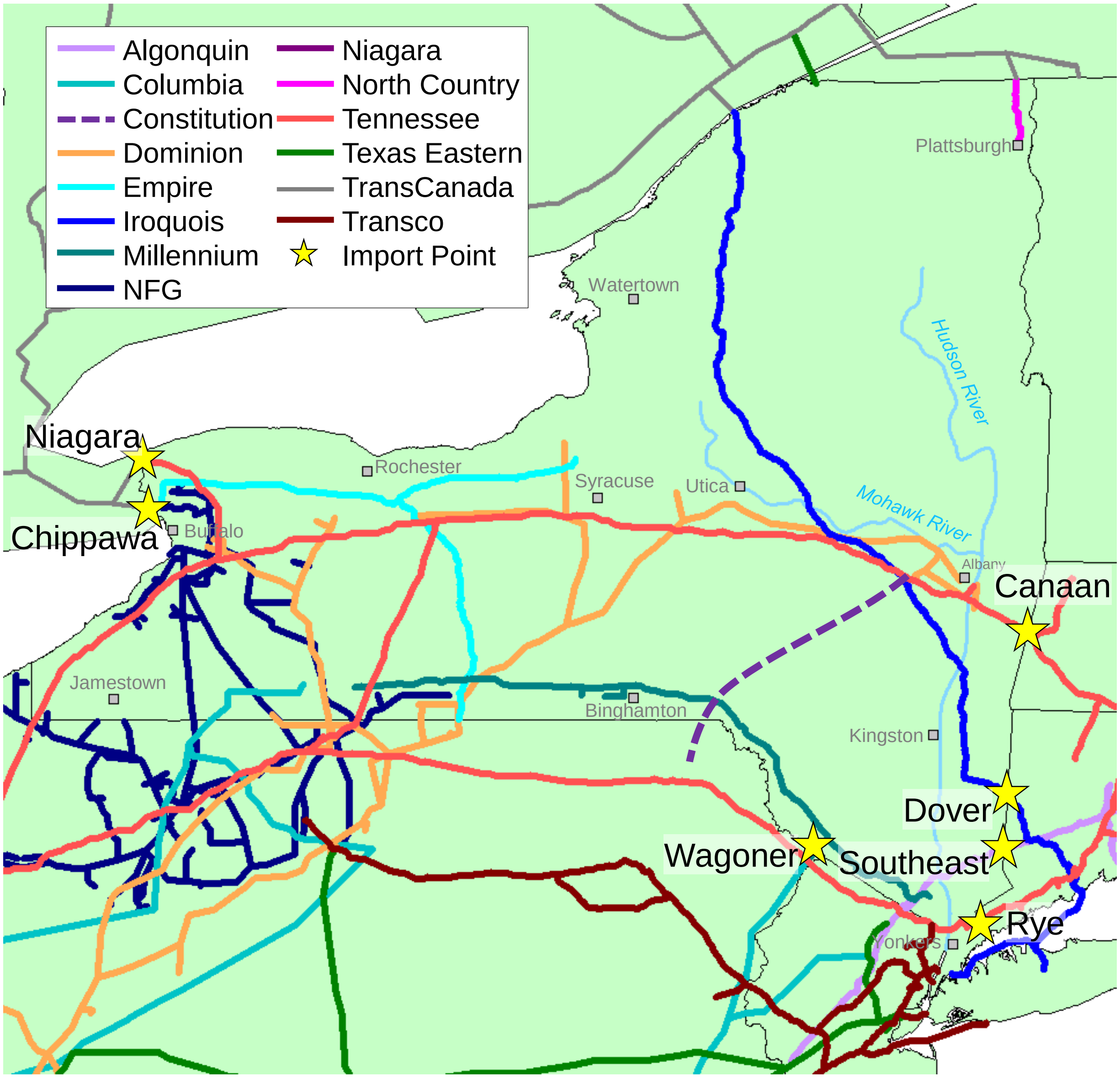


Table 40 and Table 41 summarize the flows out of NYCA at these points for the heating and cooling seasons, respectively.

Table 40. Downstream Boundary Flow Point Capacities (Heating Season, MDth/d)

Boundary Point	Winter 2012-13	Winter 2013-14	Winter 2014-15	Winter 2015-16	Winter 2016-17	Winter 2017-18
Algonquin @ Southeast	1,385	1,385	1,385	1,385	1,818	1,818
Empire @ Chippawa	0	0	0	0	0	0
Iroquois @ Dover	756	756	756	756	756	756
Millennium @ Wagoner	125	125	125	75	75	75
Tennessee @ Niagara	458	458	458	458	458	458
Tennessee @ Rye	224	224	224	224	224	224
Tennessee @ Canaan	1,266	1,266	1,266	1,266	1,338	1,338
Total	4,214	4,214	4,214	4,164	4,669	4,669

Table 41. Downstream Boundary Flow Point Capacities (Cooling Season, MDth/d)

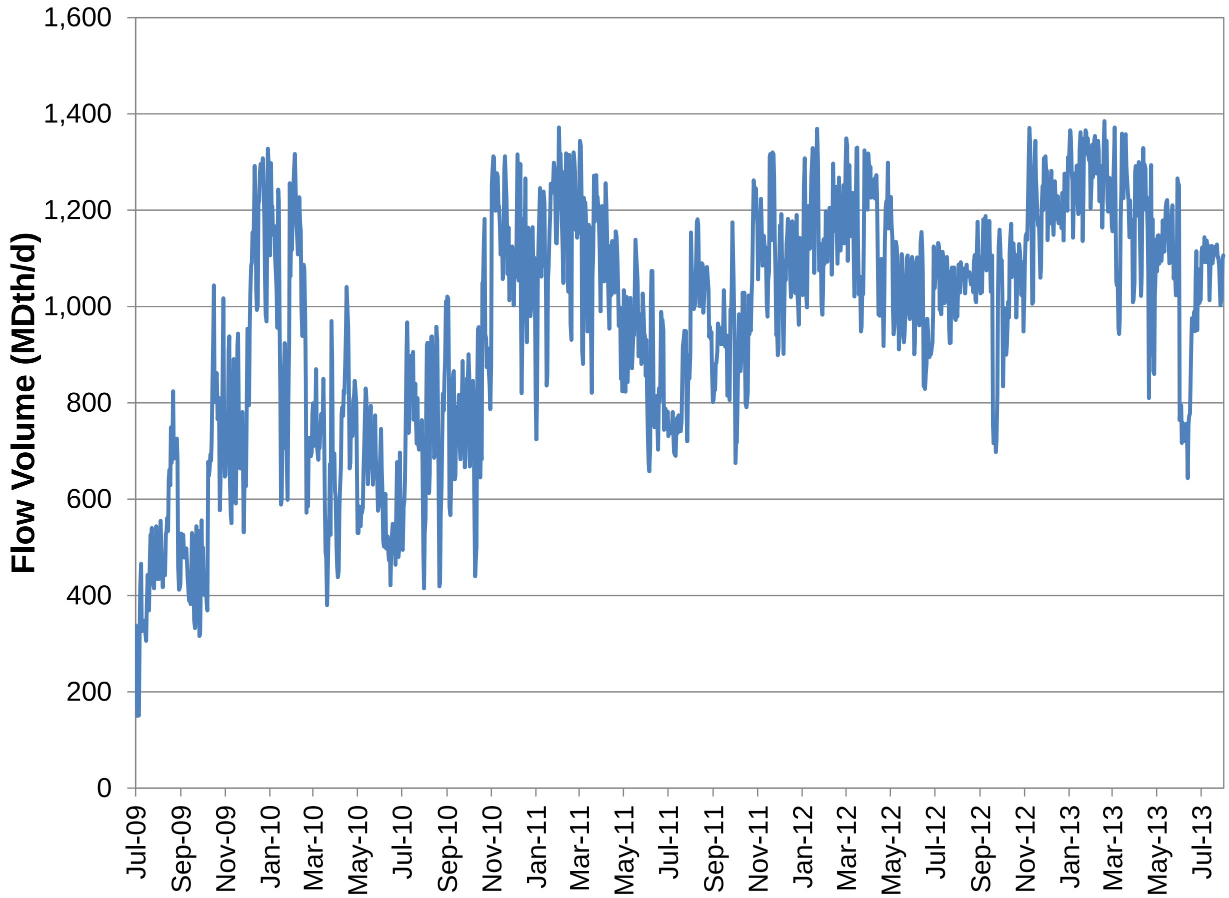
Boundary Point	Summer 2013	Summer 2014	Summer 2015	Summer 2016	Summer 2017
Algonquin @ Southeast	1,266	1,266	1,266	1,266	1,266
Empire @ Chippawa	0	0	38	38	38
Iroquois @ Dover	572	572	572	572	572
Millennium @ Wagoner	76	76	76	26	26
Tennessee @ Niagara	461	461	461	461	461
Tennessee @ Rye	111	111	111	111	111
Tennessee @ Canaan	1,034	1,034	1,034	1,034	1,106
Total	3,520	3,520	3,558	3,508	4,013

The derivation of the flows through these points is discussed in the following sections. Because downstream boundary flows are intended to reflect net demand in downstream markets, rather than capacity to serve downstream markets, we have modeled the downstream boundary flows at these points based on the peak seasonal deliveries, rather than mainline throughput capacity.

3.2.1 Algonquin

Throughput at the Southeast compressor station represents the downstream boundary flow to New England. The mainline throughout capacity at this point is 1,418 MDth/d. Based on the peak throughput day for each season, we have modeled the heating season boundary flow at 1,385 MDth/d and the cooling season flow at 1,266 MDth/d. Following completion of the Algonquin Incremental Project, capacity at this boundary point will increase by 433 MDth/d, because the utilization factor of the new capacity is not known, we have conservatively modeled the full capacity flowing downstream to New England on a peak day.

Figure 104. Throughput on Algonquin at Southeast



3.2.2 Empire

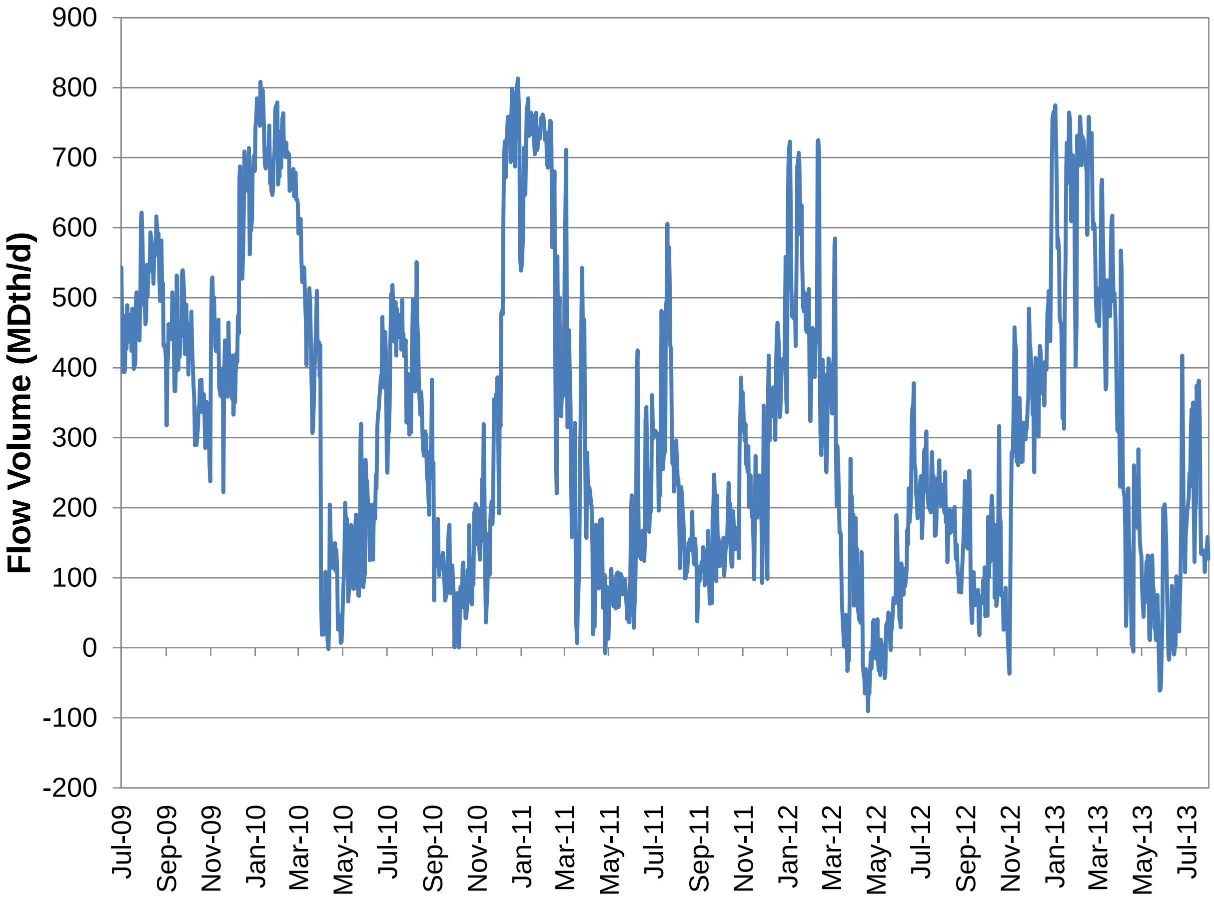
Based on assumptions regarding the timing of additional production capacity, described on page 111, we have estimated that Chippawa will become a cooling season export point starting in 2015, as the producer interconnections in Tioga County reach full output.

3.2.3 Iroquois

Iroquois has a midstream boundary point where the pipeline crosses the New York-Connecticut border near Dover; calculated throughput across this point is shown in Figure 105.[78] Flows at this point are closely linked to the boundary point where gas flows across Long Island Sound into downstate New York (discussed on page 116). The corresponding boundary flows from New York to Connecticut on the peak seasonal throughput days across Long Island Sound are 756 MDth/d and 572 MDth/d for the heating and cooling seasons, respectively.

[78] Negative scheduled volumes represent days on which deliveries in upstate New York exceeded receipts. Rather than indicating a reversal of flow north of Brookfield, the difference was made up by linepack.

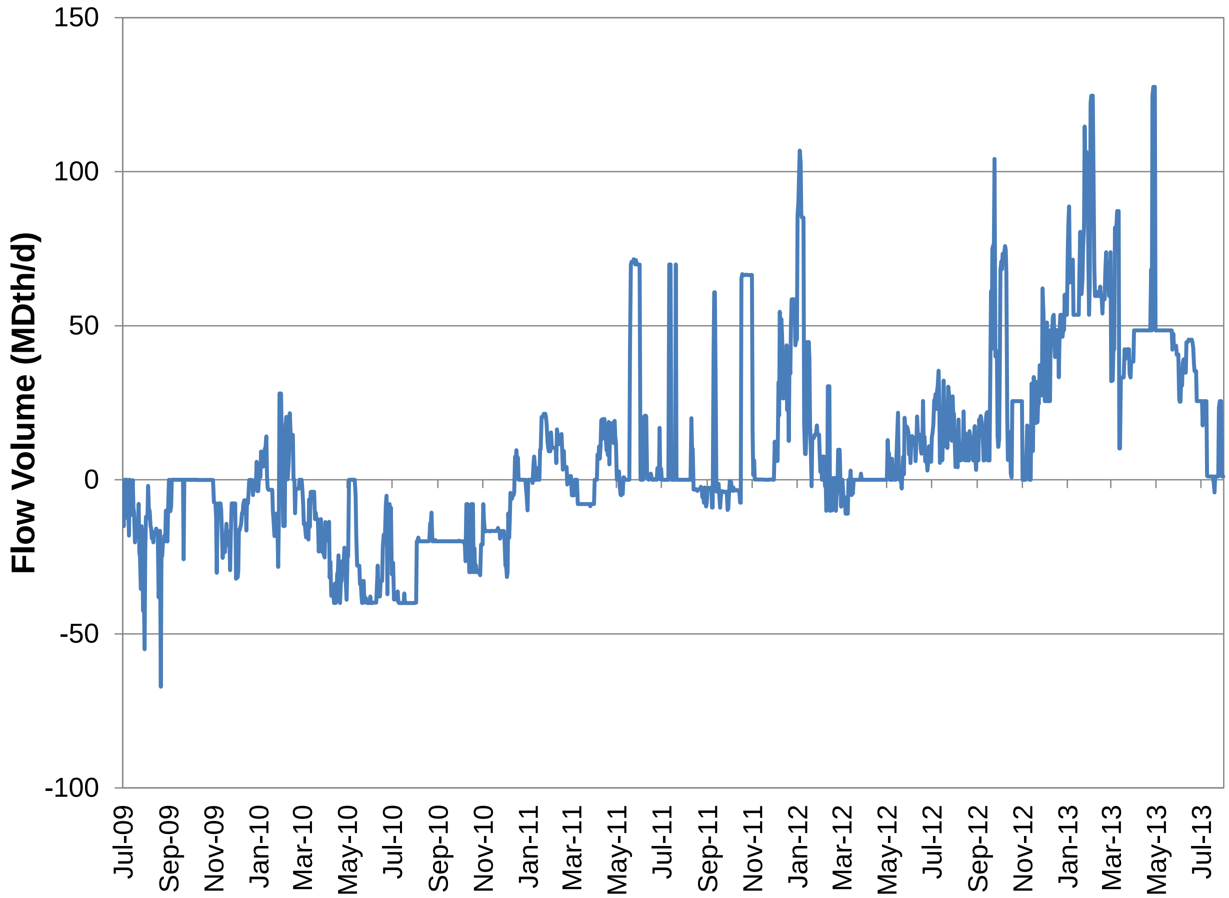
Figure 105. Calculated Throughput at the New York-Connecticut Border



3.2.4 Millennium

As on-system production has increased over the last three years, Millennium's interconnection with Columbia at Wagoner has become primarily a delivery point, as shown in Figure 106. Because of the changing flow patterns, we have based the boundary flow estimate on the period since Wagoner has become a Millennium delivery point (rather than a receipt point). The peak heating season day delivery is 125 MDth/d during the heating season. For the cooling season, the peak day is nearly 140% of the second highest day. Therefore we have used the second highest delivery day volume of 76 MDth/d as a more representative peak day value. Columbia's East Side Expansion will increase the transfer capacity from Columbia to Millennium by 50 MDth/d when commercialized in Q4-2015. Assuming that the net deliveries will be directionally adjusted by this expansion, Wagoner will remain an export point from New York, but with smaller volumes.

Figure 106. Net Deliveries from Millennium into Columbia at Wagoner



3.2.5 Tennessee

Tennessee has two downstream boundary points with New England – into Massachusetts on the 200 Line at Canaan (Figure 107) and into Connecticut on the 300 Line at Rye (Figure 108). Based on the peak throughput days, we have modeled the heating season boundary flow at 1,266 MDth/d and the cooling season at 1,034 MDth/d on Line 200. When Tennessee's Connecticut Expansion Project comes online for the 2016-17 heating season, boundary flows into Massachusetts will increase by 72 MDth/d. On Line 300, the heating season and cooling season boundary flows have been modeled at 224 MDth/d and 111 MDth/d, respectively.

Figure 107. Throughput at NY-MA Border (200 Line)

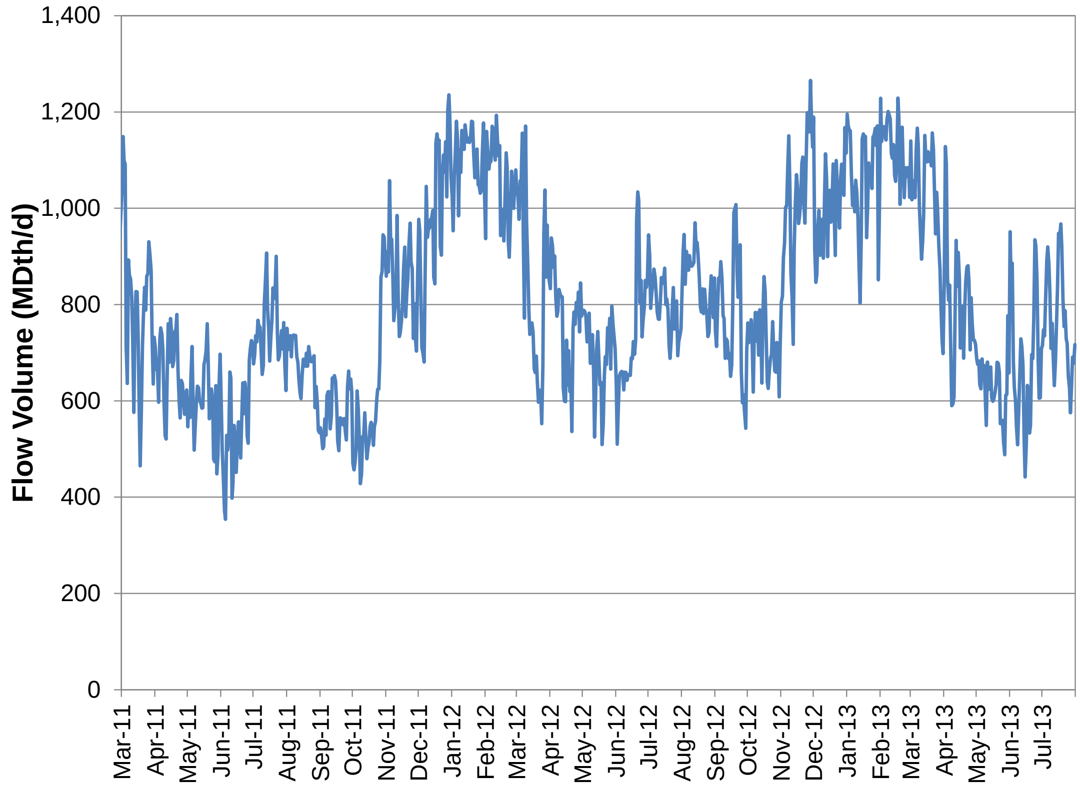
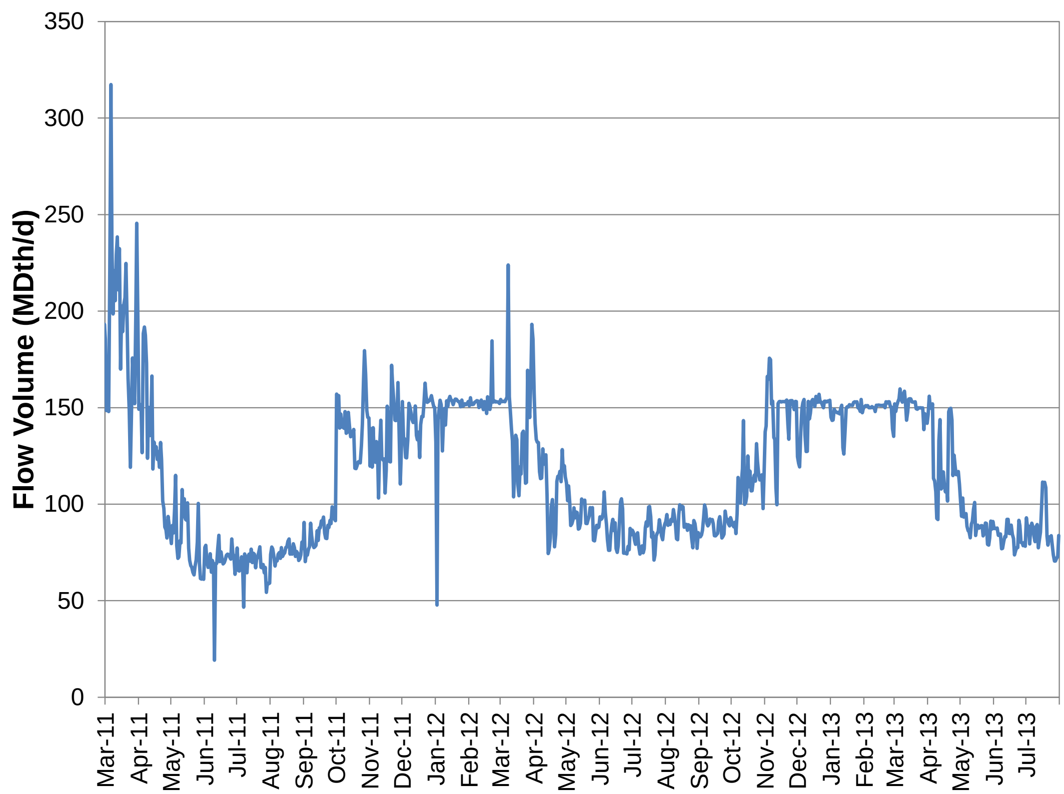
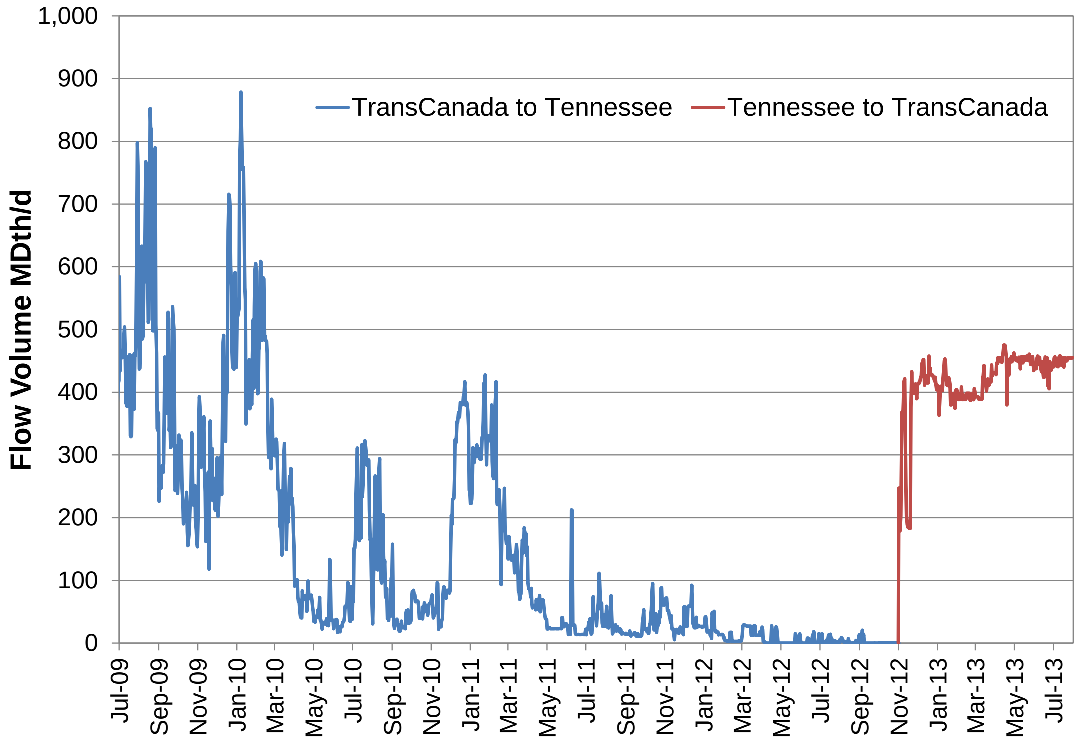


Figure 108. Throughput at NY-CT Border (300 Line)



With the massive expansion of Marcellus production on Tennessee, system flow dynamics in New York have seen significant recent changes. Most noteworthy for this study is the transition of the interconnection with TransCanada at Niagara from a net import point to a net export point, as shown in Figure 109. Tennessee has not announced any facility improvements to further expand deliverability to Niagara. Therefore we have assumed that exports will remain at levels similar to the 2012-13 heating season and 2013 cooling season over the study horizon. The heating and cooling season peak volumes since Niagara became an export point are 458 MDth/d and 461 MDth/d, respectively.

Figure 109. Exports to Canada at Niagara



3.3 In-State Receipts

In addition to receiving gas from upstream pipeline segments, several pipelines also receive gas from in-state producer interconnections and storage fields. Pipelines also receive gas at interconnections with other interstate pipelines, but as these flows have already been accounted for when they entered the state, they are not incremental supplies. LDCs also receive gas directly from local production and LNG storage. Table 42 and Table 43 summarize in-state receipts for the heating and cooling seasons, respectively. In these tables, the non-coincident peak values for the production and storage points are combined for each pipeline with negative values for the cooling season representing storage injections. While total state-wide gas production has been decreasing since 2006, with a 15% decline from 2011 to 2012 reported by the New York State Department of Environmental Conservation (NYSDEC), it is unclear whether peak day production capability has experienced a similar decrease.[79] The year-end

[79] NYSDEC, 2012 Annual Oil & Gas Production Data. http://www.dec.ny.gov/energy/36159.html.

proven reserves have remained relatively constant, and the number of gas wells has been increasing.[80] Based on these statistics and a review of the historical data, LAI believes that our assumption that production associated with Dominion, NFG, Tennessee, and the LDCs will remain constant over the study horizon is reasonable. If peak day production capability does decrease over the study horizon, the assumed values are sufficiently small that the impact on the state-wide flow balance will be minimal.

Table 42. In-State Receipts (Heating Season, MDth/d)

	Winter 2012-13	Winter 2013-14	Winter 2014-15	Winter 2015-16	Winter 2016-17	Winter 2017-18
Dominion Production	119	119	119	119	119	119
Millennium Production	200	430	530	625	675	683
NFG Production	8	8	8	8	8	8
Tennessee Production	3	3	3	3	3	3
Honeoye Storage	56	56	56	56	56	56
Seneca Lake Storage	140	140	140	140	140	140
Stagecoach Storage	770	770	770	770	770	770
Steuben Storage	60	60	60	60	60	60
Thomas Corners Storage	140	140	140	140	140	140
Wyckoff Storage	35	35	35	35	35	35
Dominion Storage	657	657	657	657	657	657
NFG Storage	806	806	806	806	806	806
LDCs – Production	52	52	53	53	53	53
LDCs – LNG Storage	561	561	561	561	561	561
Total	3,836	3,836	3,937	4,032	4,082	4,090

Table 43. In-State Receipts (Cooling Season)

	Summer 2013	Summer 2014	Summer 2015	Summer 2016	Summer 2017
Dominion Production	135	135	135	135	135
Millennium Production	385	485	585	655	683
NFG Production	7	7	7	7	7
Tennessee Production	5	5	5	5	5
Honeoye Storage	-40	-40	-40	-40	-40
Seneca Lake Storage	-72.5	-72.5	-72.5	-72.5	-72.5
Stagecoach Storage	770	770	770	770	770
Steuben Storage	-45	-45	-45	-45	-45
Thomas Corners Storage	-70	-70	-70	-70	-70
Wyckoff Storage	-40	-40	-40	-40	-40
Dominion Storage	-328.5	-328.5	-328.5	-328.5	-328.5
NFG Storage	-408	-408	-408	-408	-408
LDC Production	34	35	35	35	35
LDC LNG Storage	0	0	0	0	0
Total	-177	-77	23	93	121

80 NYSDEC, 10 Year Oil & Gas Summary Statistics. http://www.dec.ny.gov/energy/93184.html.

The derivation of these inputs by pipeline is described in the following sections.

3.3.1 Production Resources

3.3.1.1 Dominion

The primary producers connected to Dominion in NYCA are EOG Resources and Talisman Energy, as shown in Figure 110. Future production receipts are modeled as the sum of the expected peak production from each source. To account for potential production drop-off, future peak day production is based on the highest seasonal receipt volumes since the start of the 2012 heating season, as summarized in Table 44.

Figure 110. Dominion Production Receipts

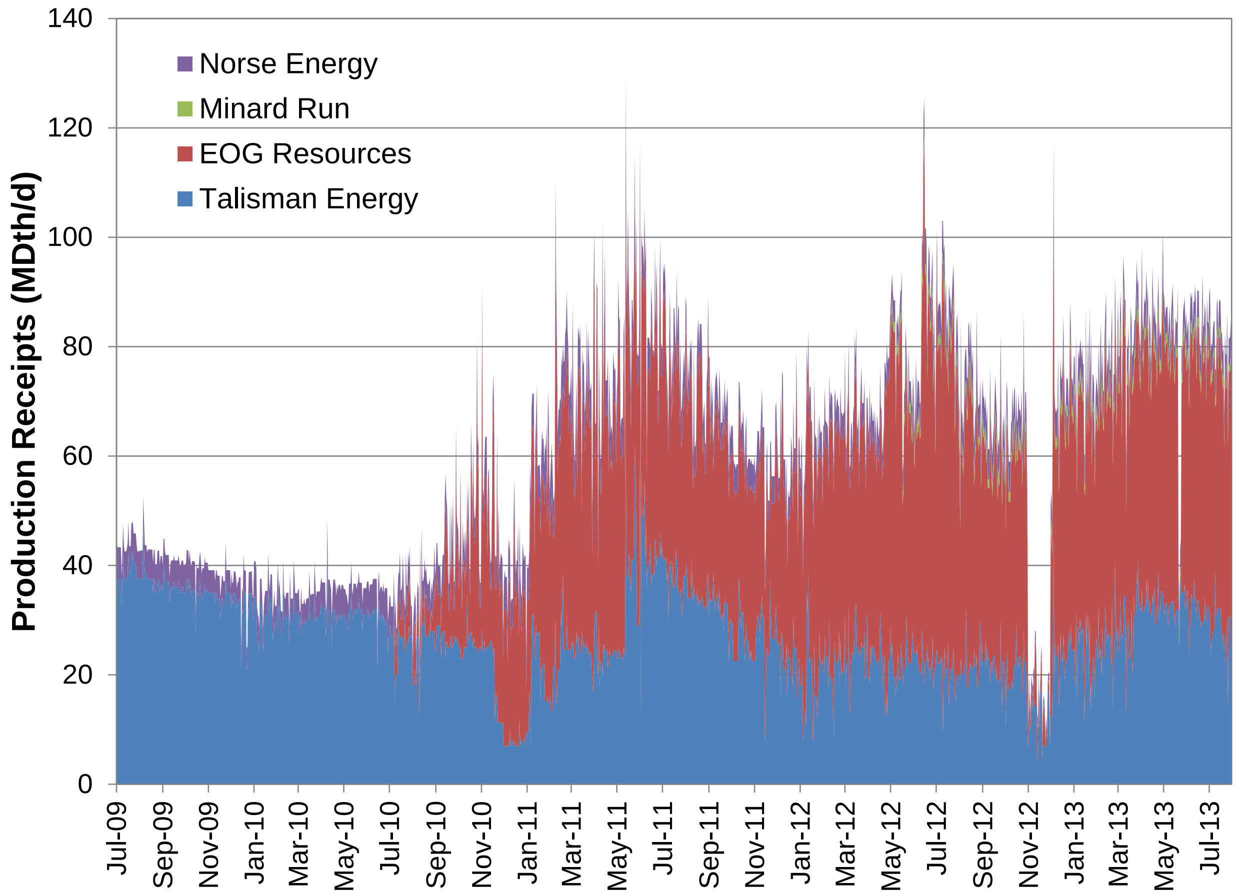


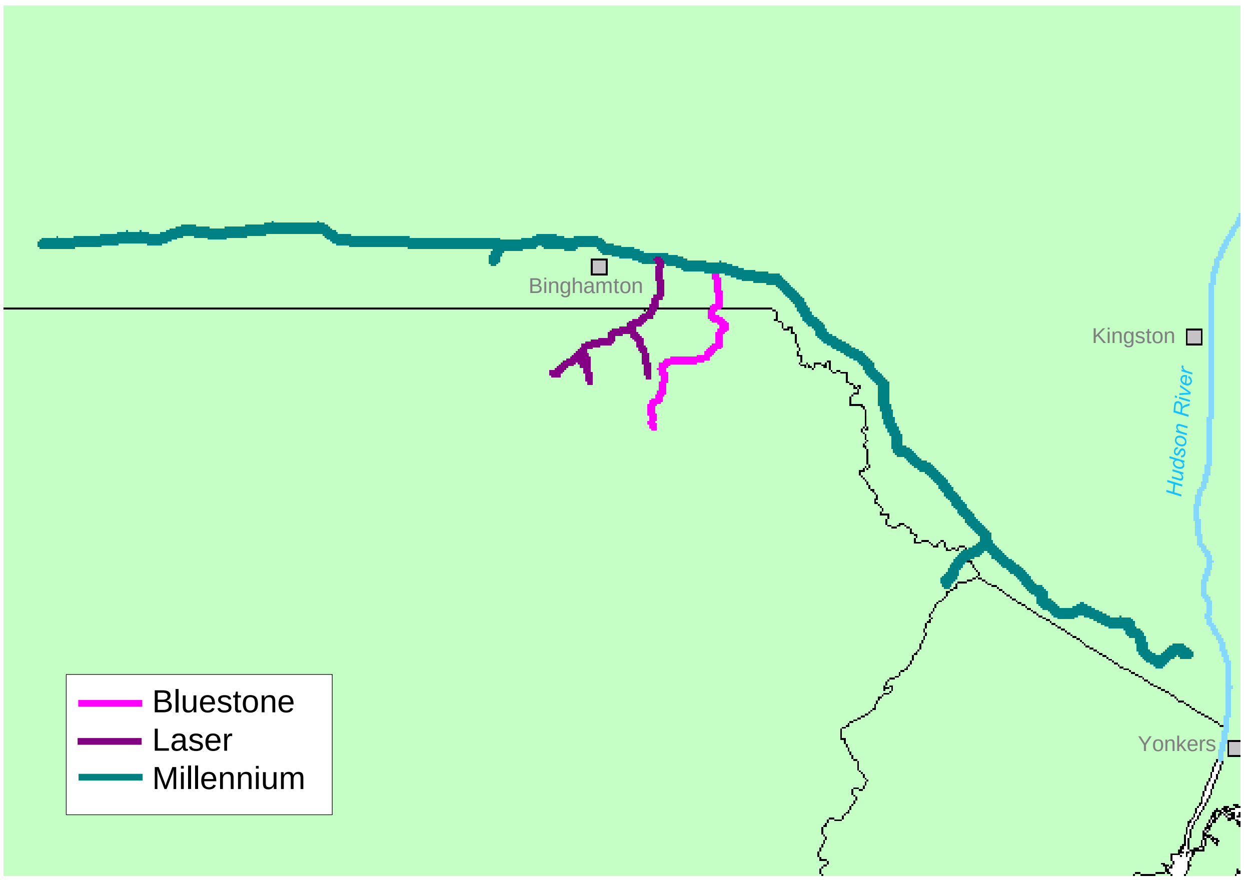
Table 44. Peak Dominion Production Receipts

Producer	Heating Season Peak Production (MDth/d)	Cooling Season Peak Production (MDth/d)
EOG Resources	65	86
Minard Run	2	2
Norse Energy	6	8
Talisman Energy	46	39

3.3.1.2 Millennium

Over the last two years, two major new gathering systems – Laser and Bluestone, described in Section 1.1 and illustrated in Figure 111 – have come online and interconnected with Millennium. Chesapeake Energy and Talisman Energy also operate production facilities in New York that deliver gas into Millennium.

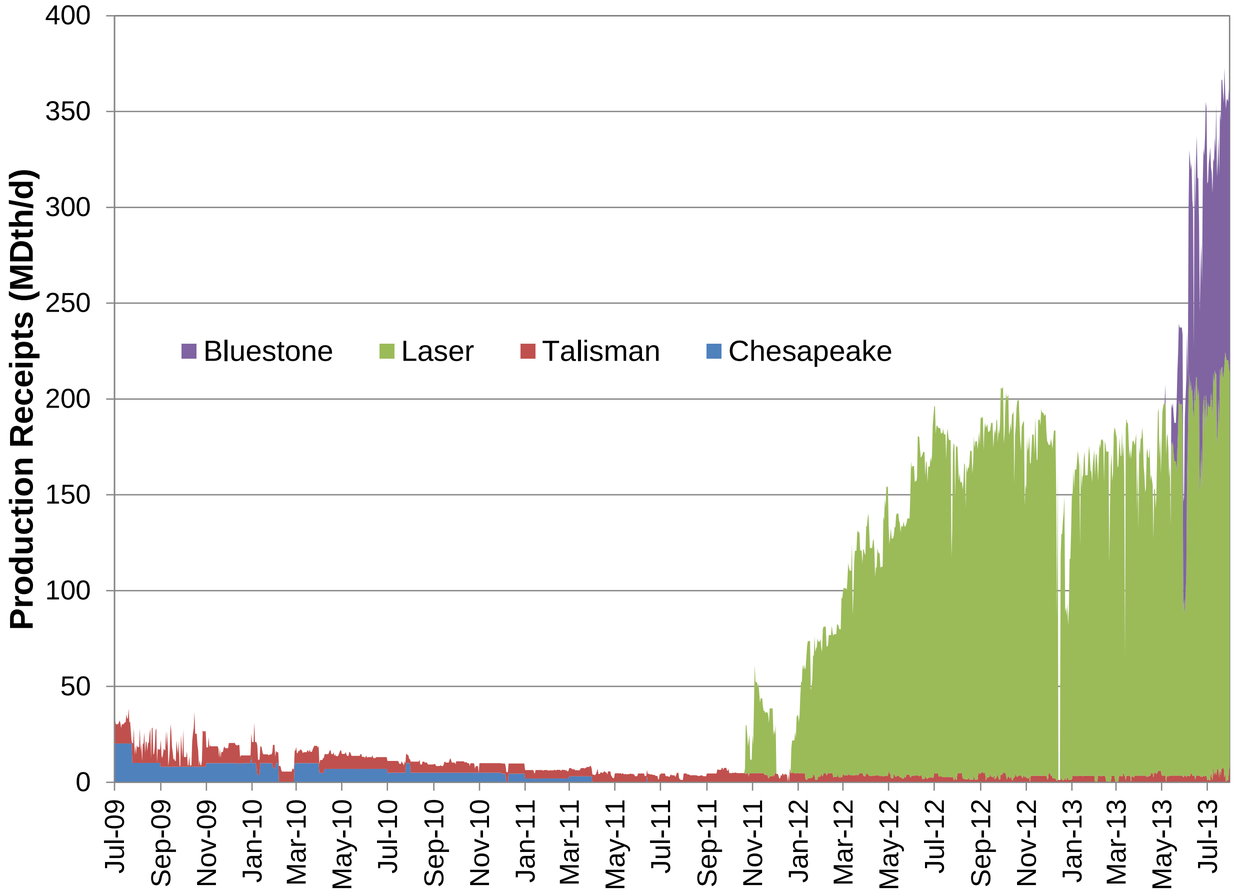
Figure 111. Millennium Production Resources



Laser has a production capacity of 400 MDth/d and Bluestone has a total production capacity of 600 MDth/d, of which 275 MDth/d can be delivered to Millennium. The receipts at all Millennium producer interconnections are shown in Figure 112, which shows that Laser and Bluestone are not yet operating at full capacity. Based on historical data, we have modeled staged increases as additional production capacity is brought online. To date, Laser's maximum utilization has been just over half of the system capacity – 222 MDth/d out of 400 MDth/d – we have therefore assumed this level for 2013 cooling season peak receipts; during the 2012-13 heating season the maximum utilization was 192 MDth/d. Using these values as a baseline, we have increased the seasonal peak receipts by 50 MDth/d each year until the full capability of 400 MDth/d is utilized. Bluestone's maximum utilization during the 2013 cooling season to-date has been 155 MDth/d; using this value as a baseline, we have assumed that production will increase by 25 MDth/d each season until the full capacity of 275 MDth/d is utilized. Talisman receipts have been relatively consistent since mid-2010, therefore we have assumed peak receipts of 8

MDth/d for each season over the study period. Millennium has not reported regular receipts from Chesapeake Energy since March 2011, therefore we have assumed no receipts in the future.

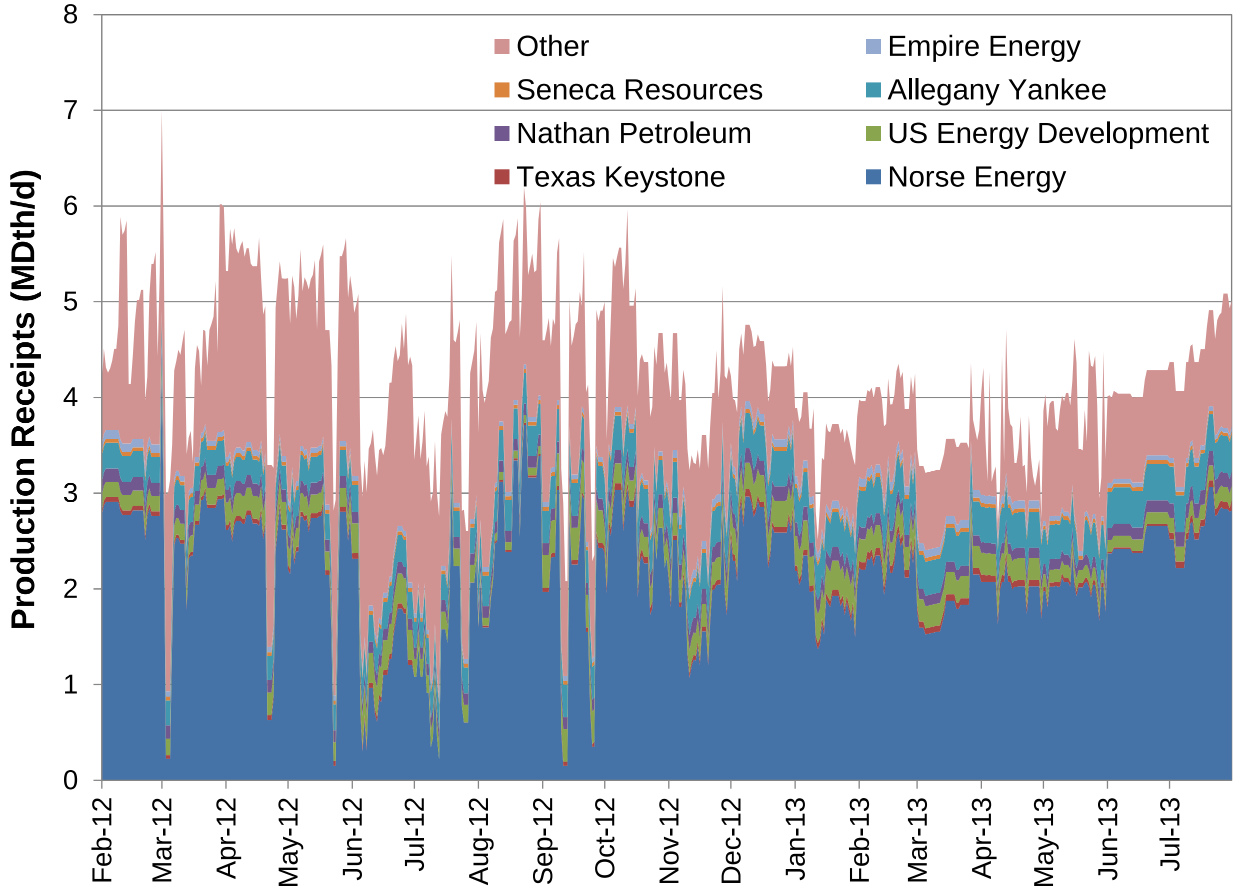
Figure 112. Millennium Production Receipts



3.3.1.3 <u>NFG</u>

Receipts from NFG's producer interconnections are shown in Figure 113. Summing the peak seasonal volumes from each producer yields a heating season total of 8 MDth/d and a cooling season total of 7 MDth/d.

Figure 113. NFG Production Receipts[81]

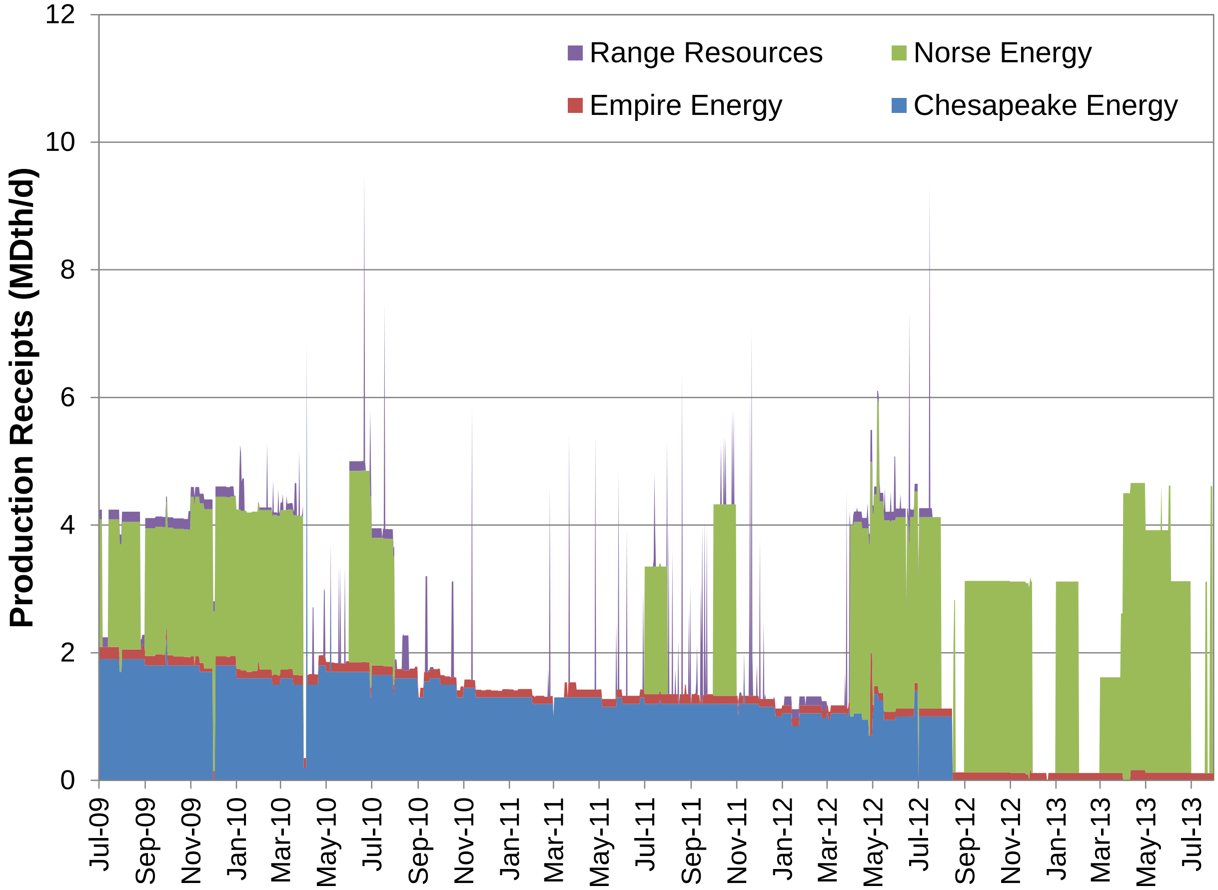


3.3.1.4 Tennessee

Tennessee receives locally produced gas at several meters in upstate New York. Daily receipts by producer are shown in Figure 114. The connections with Empire Energy, Norse Energy and Range Resources are located in Chautauqua County, and the Chesapeake Energy connection is in northern Steuben County. Tennessee has not received any gas from Range Resources and Chesapeake Energy since July and August 2012, respectively. Therefore we have not modeled any receipts at these points in future years. The peak heating and cooling season receipts from Empire Energy are 0.3 MDth/d. The peak heating and cooling season receipts from Norse Energy are 3 MDth/d and 4.5 MDth/d, respectively.

[81] The "Other" series includes production from Lenape Resources, Richardson Petroleum, Plants & Goodwin, and U.S. Energy Development that are grouped at a single NFG receipt meter.

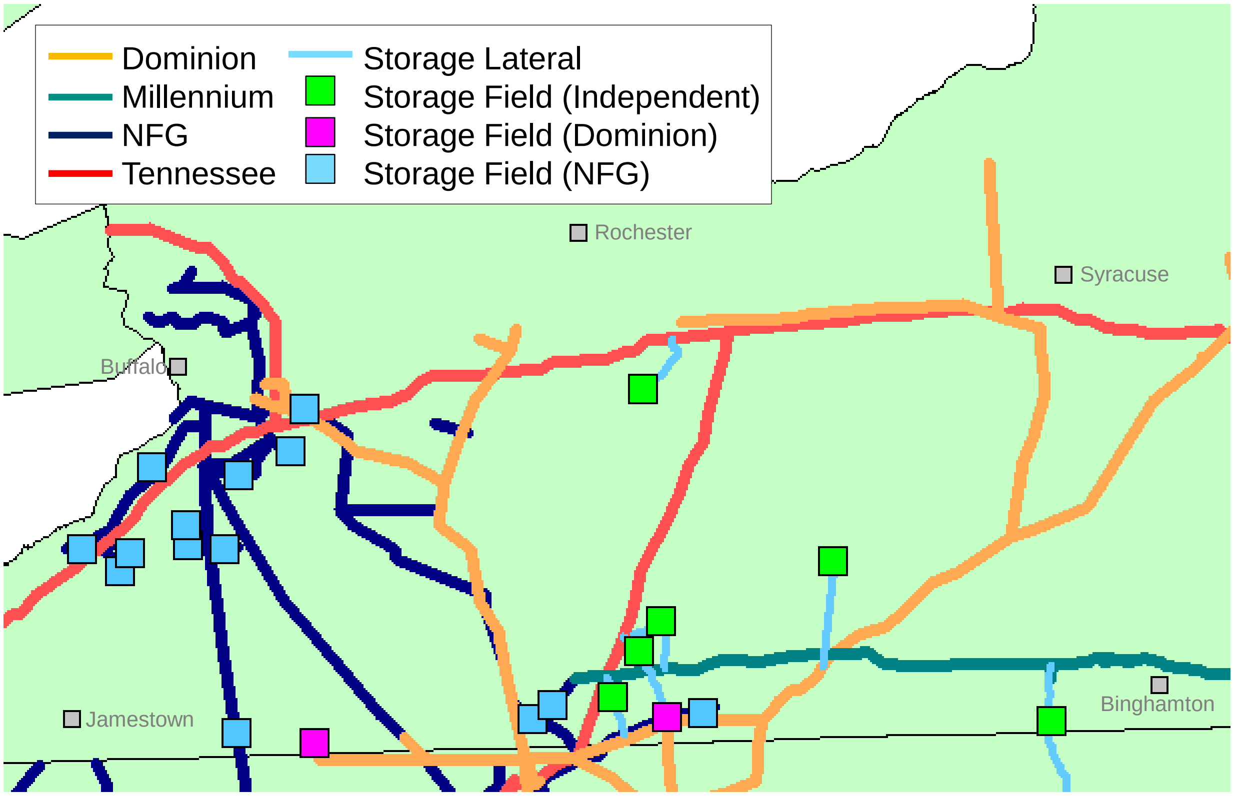
Figure 114. Tennessee Production Receipts



3.3.2 Storage Fields

The underground gas storage facilities in NYCA are shown in Figure 115. Storage fields are separated into facilities run by non-pipeline operators, Dominion facilities and NFG facilities. In order to develop storage inputs to the heating season flow balance model, we have based peak day withdrawal capability on the historical peak day withdrawal. Conversely, for the cooling season we have modeled injections as the historical peak injection volume. We believe this is a conservative assumption because pipelines can adjust storage injections in the short-term during the cooling season in order to maximize system efficiency and flexibility on a peak day.

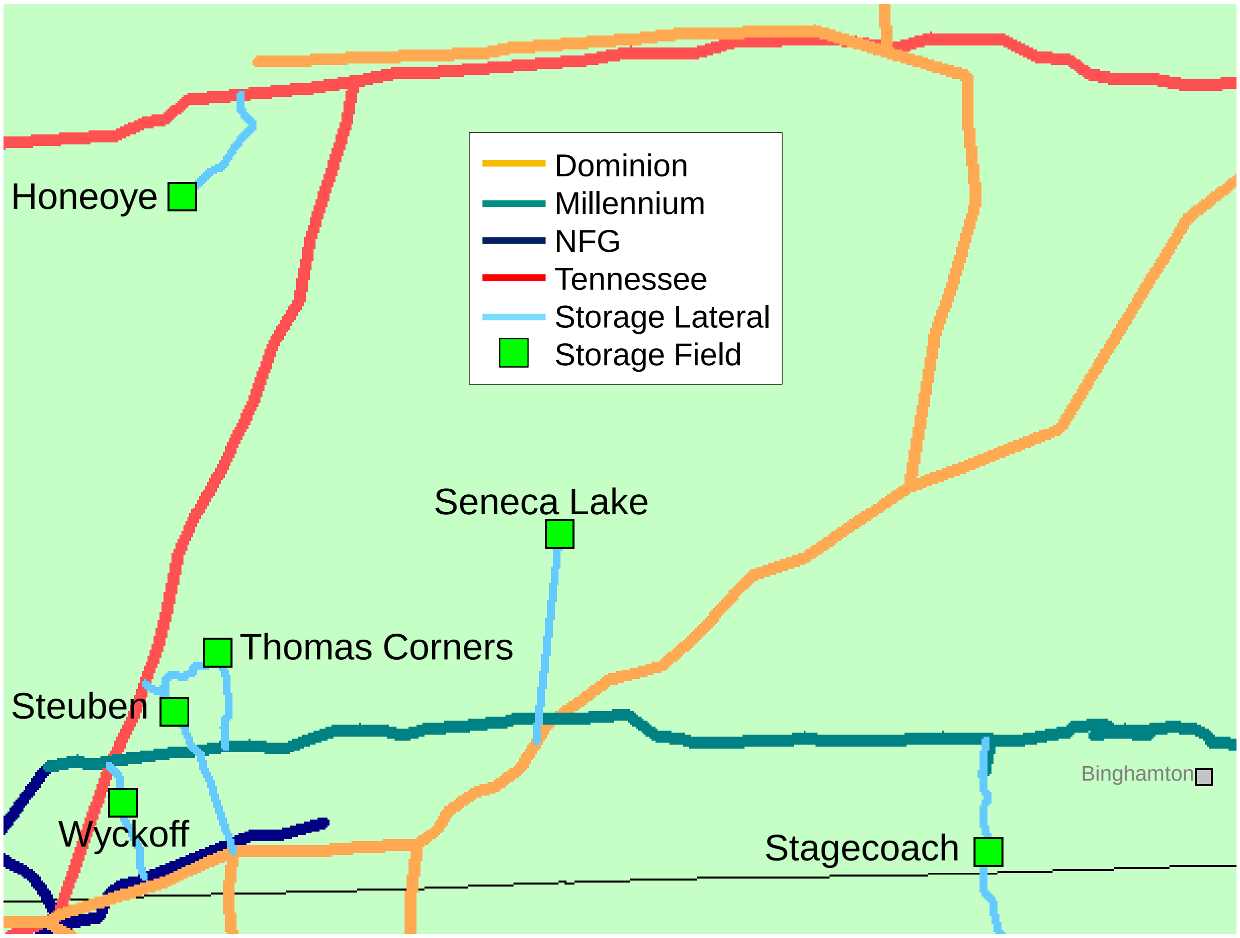
Figure 115. NYCA Underground Gas Storage



3.3.2.1 Non-Pipeline Storage Fields

There are six storage fields in NYCA run by non-pipeline operators: Honeoye, Seneca Lake, Stagecoach, Steuben, Thomas Corners and Wyckoff. The locations of these facilities and the laterals that connect each facility to one or more pipelines are shown in Figure 116.

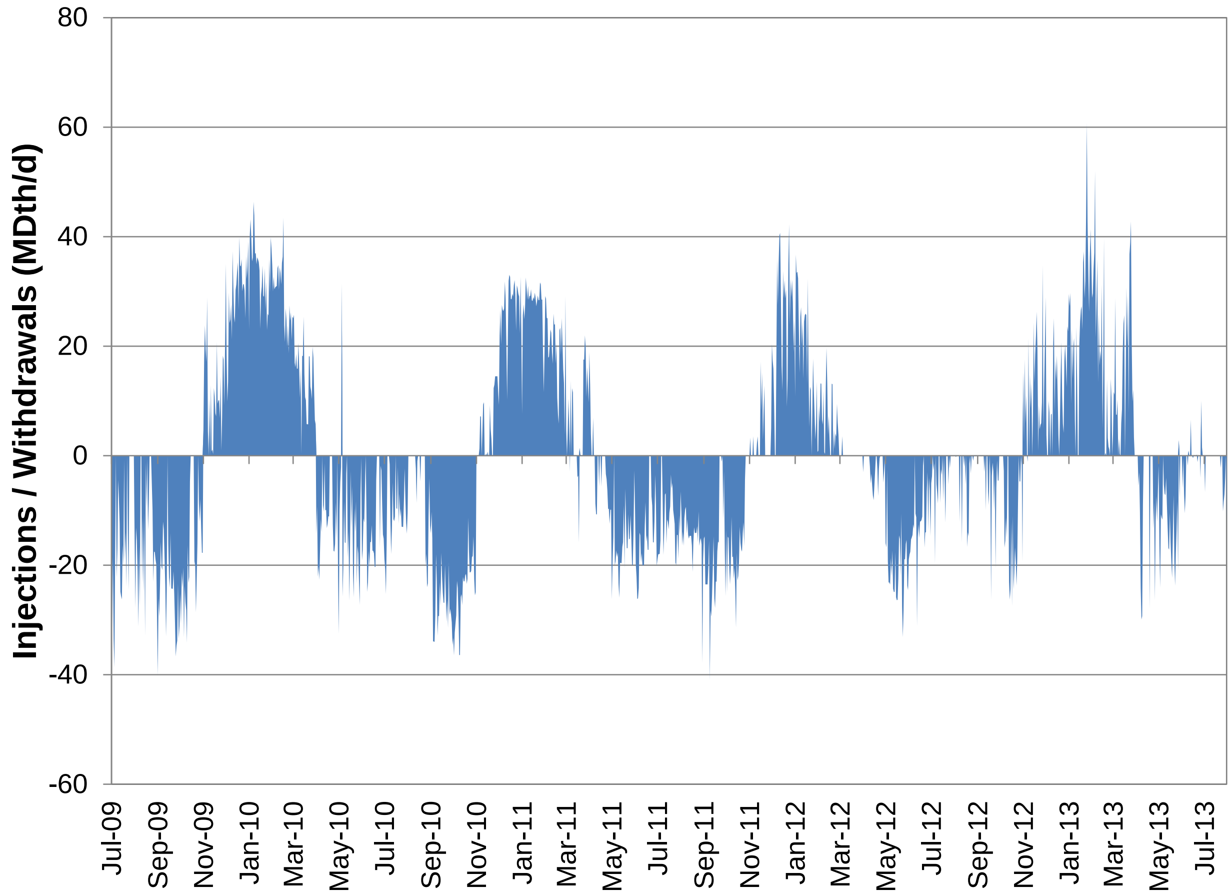
Figure 116. Non-Pipeline-Operated Storage Fields



The Honeoye storage facility is owned by Honeoye Storage Corporation. The facility has a working gas storage capacity of 6.5 Bcf, injection capability of 40 MDth/d and withdrawal capability of 56 MDth/d. A 10.5 mile lateral connects the storage field to Tennessee. Pipeline receipts from and deliveries to Honeoye are shown in Figure 117. This storage field exhibits a very typical injection / withdrawal profile. The peak heating season withdrawal is 61 MDth/d and the peak cooling season injection is 41 MDth/d, which closely approximate the capabilities of the storage facility.[82]

[82] The peak injection and withdrawal days are the only days that exceeded the design capability of the field.

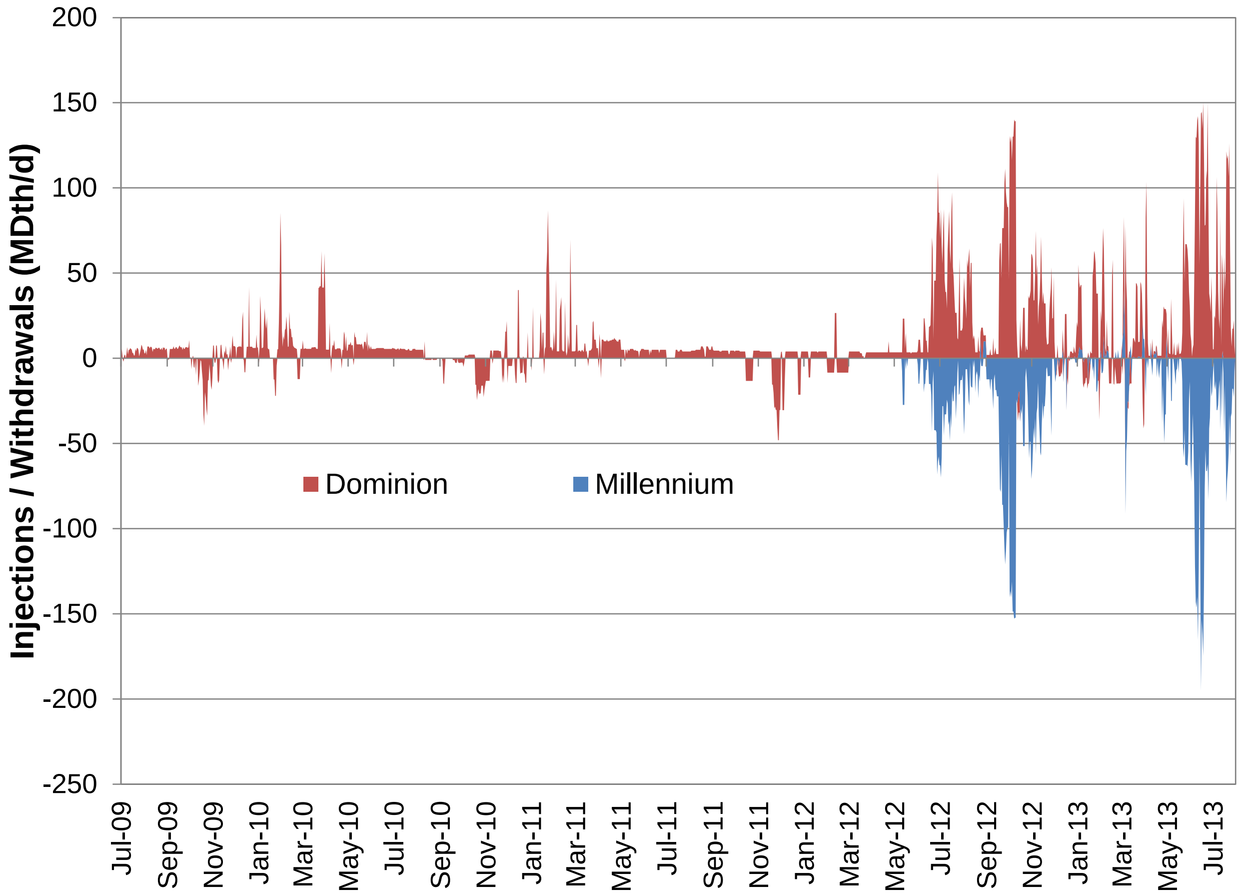
Figure 117. Honeoye Storage Operations



The Seneca Lake storage facility is owned and operated by Arlington Storage Company, a subsidiary of Inergy. The facility has 1.5 Bcf of working gas, with injection and withdrawal capabilities of 72.5 MDth/d and 145 MDth/day, respectively. A 20-mile lateral connects the field to Dominion and Millennium. Pipeline receipts from and deliveries to Seneca Lake are shown in Figure 118. The change in operations since Millennium activity started in May 2013 indicates that the Seneca Lake lateral is being used primarily to move gas between Dominion and Millennium. Since Millennium activity began, the peak net heating season withdrawal is 83 MDth/d and the peak net cooling season injection is 63 MDth/d. Although the withdrawal capabilities have not been fully utilized, there was sufficient working gas inventory at Seneca Lake at the end of the 2012-13 heating season to support the withdrawal of the full 145 MDth/d on a peak day.[83] The peak injection is approaching the injection capability. Therefore we have modeled the full injection volume for the cooling season.

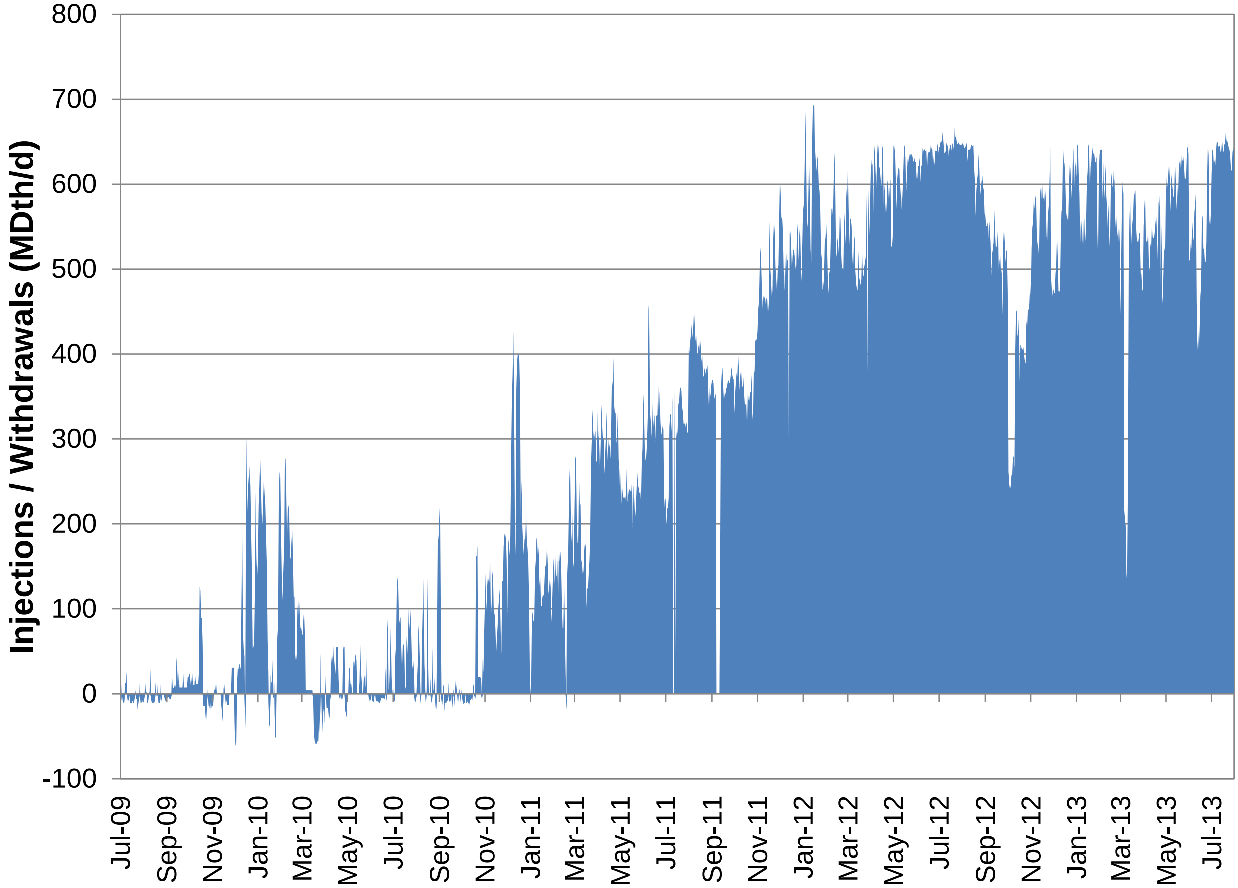
[83] The working gas balance on April 1, 2013 was 690 MDth.

Figure 118. Seneca Lake Storage Operations



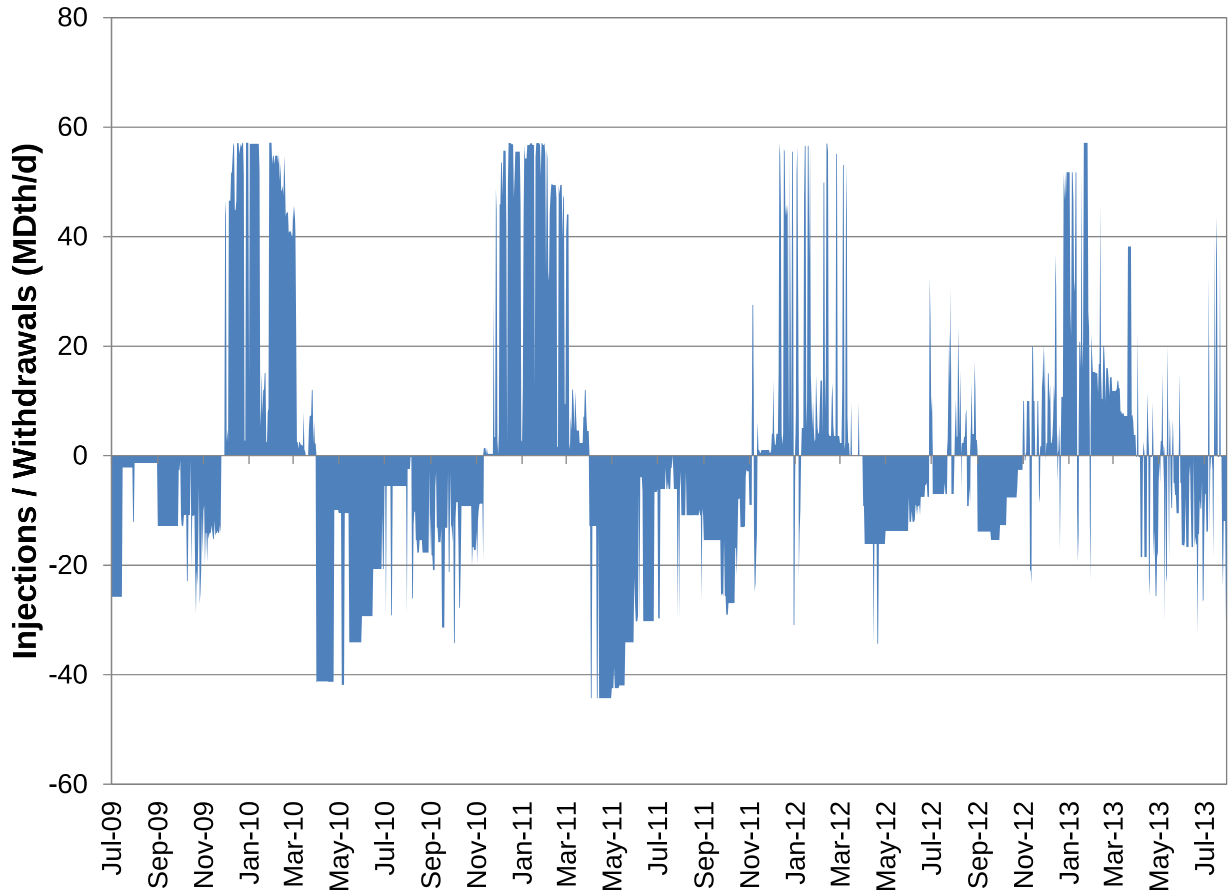
Originally an eCorp asset, the Stagecoach storage facility is now owned and operated by Inergy. The facility has 26.25 Bcf of working gas, with injection and withdrawal capabilities of 250 MDth/d and 500 MDth/d, respectively. Stagecoach is connected to Millennium in New York via a 10-mile lateral and to Tennessee and Transco in Pennsylvania via a 63-mile lateral. A high-deliverability storage field, Stagecoach has the operational flexibility to move gas between pipelines when market conditions warrant. Millennium's Stagecoach operations are shown in Figure 119. Because Millennium receives gas from other pipelines via Stagecoach's wheeling service, in addition to volumes withdrawn from storage, the flow patterns are atypical of a storage interconnection. Millennium's peak historical heating and cooling season receipts from Stagecoach are 693 MDth/d and 667 MDth/d, respectively, indicating that the 770 MDth/d design capacity of the lateral to Millennium is nearly fully utilized. Therefore we have modeled the full capacity as being available on a peak day in either season.

Figure 119. Stagecoach Storage Operations – Millennium



The Steuben storage facility is also owned and operated by Arlington Storage Company. The facility has 6.2 Bcf of working gas, with injection and withdrawal capabilities of 45 MDth/d and 60 MDth/d, respectively. A 12.5-mile lateral connects the field to Dominion. Pipeline receipts from and deliveries to Steuben are shown in Figure 120. Similarly to Honeoye, since Steuben is only connected to one pipeline it exhibits a traditional operating pattern. The peak heating season withdrawal is 57 MDth/d and the peak cooling season injection is 44 MDth/d, indicating that the field capabilities are being fully utilized.

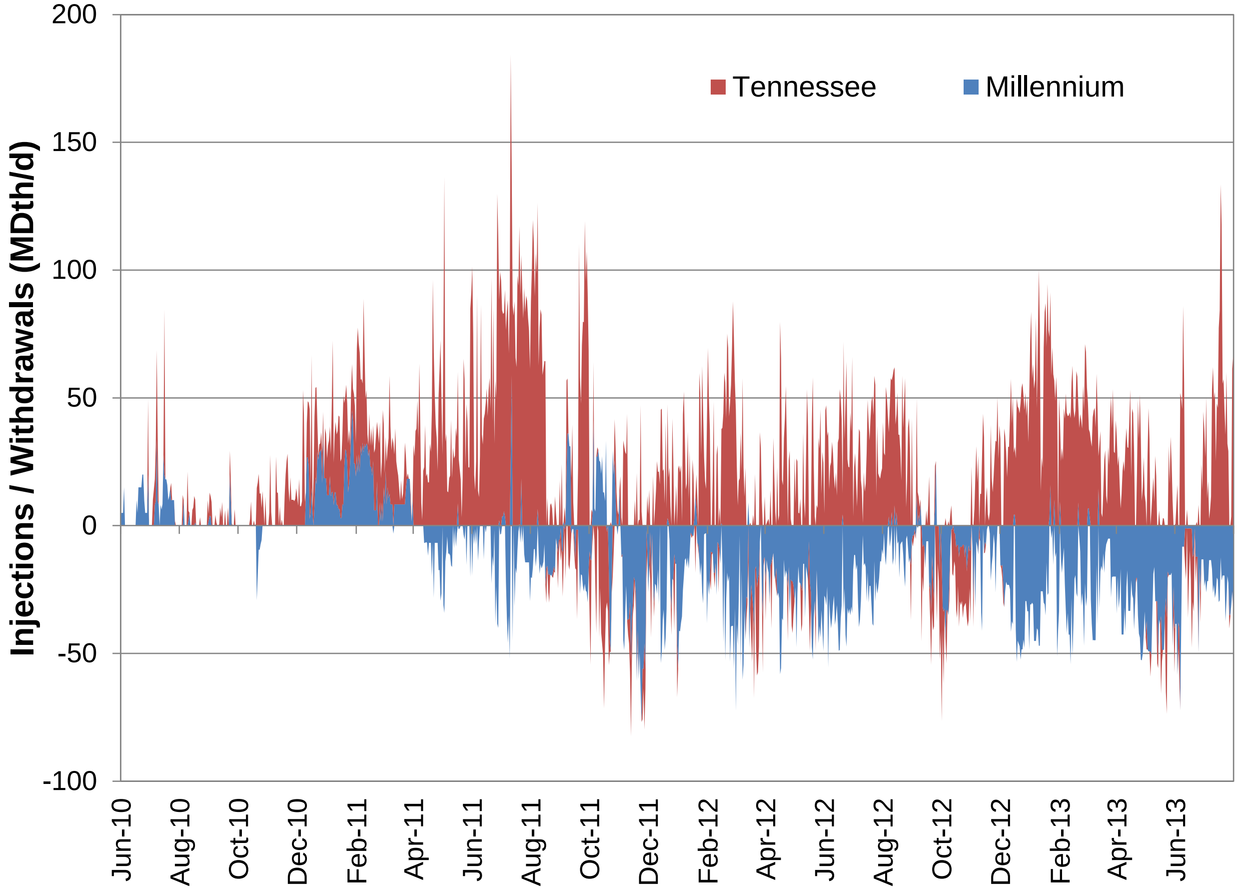
Figure 120. Steuben Storage Operations



The Thomas Corners storage facility is owned and operated by Arlington Gas Storage. It has a working gas capacity of 7 Bcf and injection and withdrawal capabilities of 70 MDth/d and 140 MDth/d, respectively. The facility is connected to Tennessee by an 8-mile lateral and to Millennium by a 7.5 mile lateral. Pipeline receipts from and deliveries to Thomas Corners are shown in Figure 121. The complementary injections by Millennium and withdrawals by Tennessee indicate that the storage laterals are being used to wheel gas from Millennium to Tennessee. The peak net heating season withdrawal is 91 MDth/d and the peak net cooling season injection is 74 MDth/d. Although the withdrawal capabilities have not been fully utilized, the was sufficient working gas in Thomas Corners' inventory at the end of the 2012-13 heating season to indicate that that the full 140 MDth/d could be withdrawn if needed on a peak day.[84] The peak injection is approaching the injection capability. Therefore we have modeled the full volume for the cooling season.

[84] The working gas balance on April 1, 2013 was 3,438 MDth.

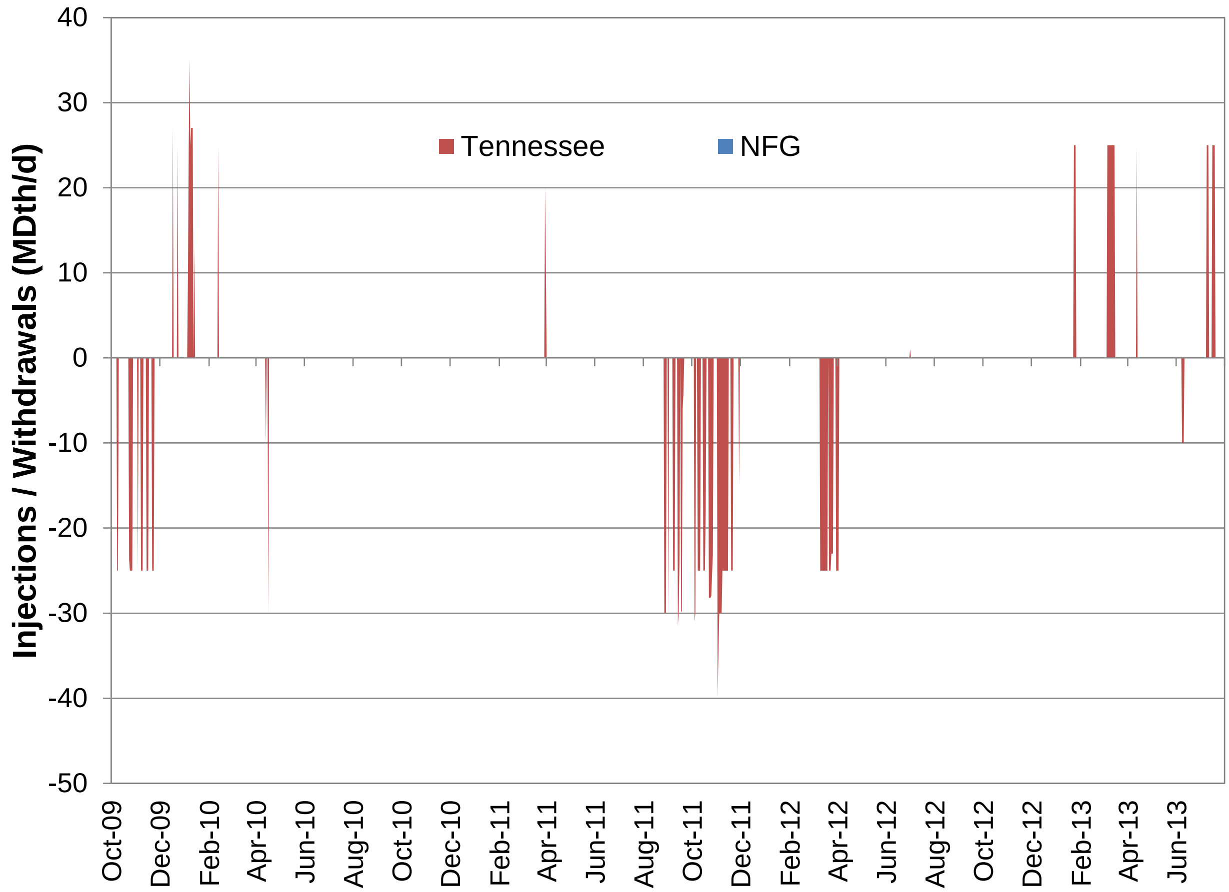
Figure 121. Thomas Corners Storage Operations



The Wyckoff storage facility is owned by Wyckoff Gas Storage, a subsidiary of Kaiser-Francis Oil Company. The facility has 6.1 Bcf of working gas capacity, with injection and withdrawal capabilities of 250 MDth/d and 400 MDth/d, respectively. The facility is connected to Tennessee by a 3.5-mile lateral, and to NFG by a 7-mile lateral. Pipeline receipts from and deliveries to Wyckoff are shown in Figure 122; NFG's EBB reports that no volumes have flowed to or from Wyckoff, therefore only the Tennessee dataset is seen. Tennessee's EBB data indicates that the Wyckoff has been used only intermittently and not at full capacity. Therefore we have modeled the peak historical injection and withdrawal volumes of 40 MDth/d and 35 MDth/d, respectively, rather than the field's capability.[85]

[85] Wyckoff's EBB does not appear to allow viewing of historical data, therefore usage data cannot be independently confirmed.

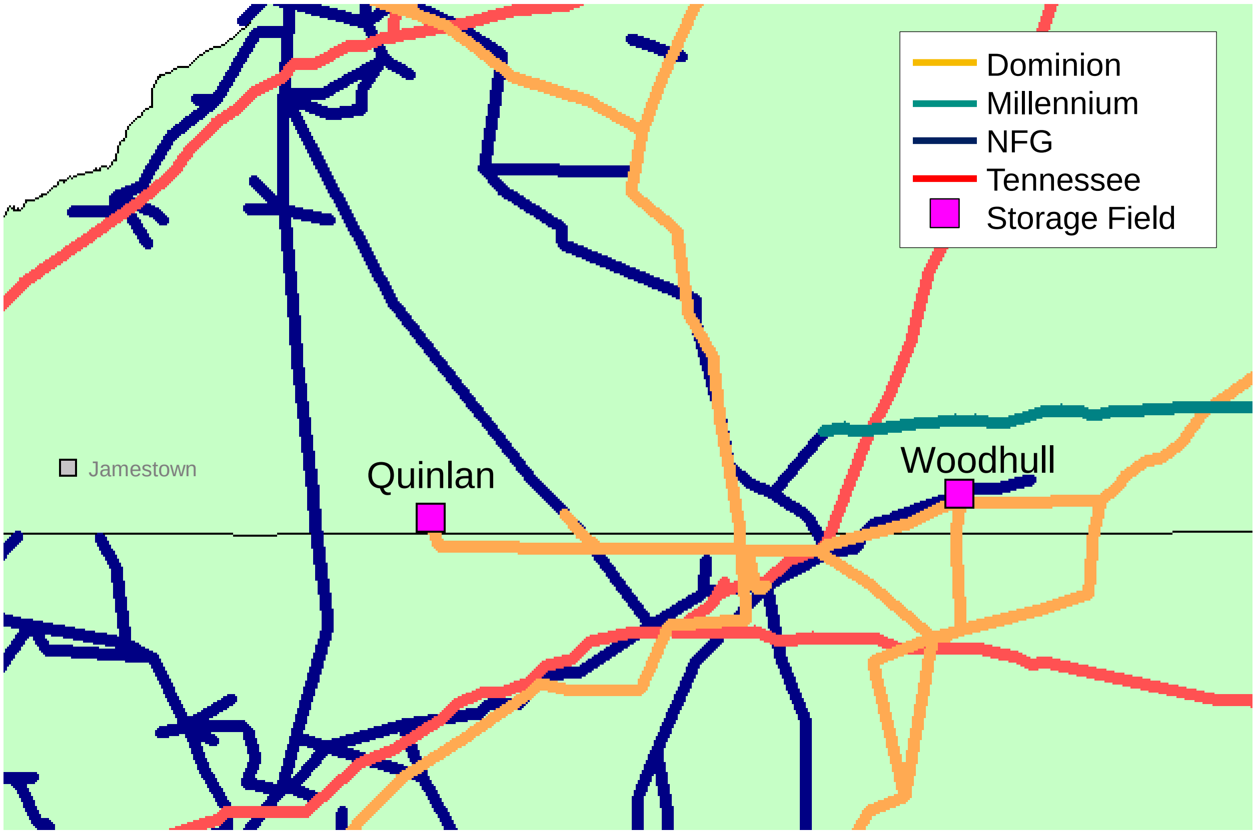
Figure 122. Wyckoff Storage Operations



3.3.2.2 Dominion Storage Fields

Dominion's two NYCA storage facilities are Quinlan and Woodhull, located as shown in Figure 124.

Figure 123. Dominion-Operated Storage Fields



The Quinlan storage pool has 4 Bcf of working gas capacity and a withdrawal capability of 300 MDth/d, respectively. The Woodhull storage pool has 20.6 Bcf of working gas capacity and a withdrawal capability of 357 MDth/d. EIA does not report daily injection capability. Therefore we have assumed that each storage facility has an injection capability equal to half of the maximum withdrawal quantity: 150 MDth/d into Quinlan and 178.5 MDth/d into Woodhull.[86] Dominion does not report injections and withdrawals from individual storage fields on its EBB, only net storage activity across the system. In order to be consistent with the modeling assumptions for the non-pipeline storage facilities described in the previous section, we have assumed that the full withdrawal and injection capabilities will be utilized on heating and cooling season peak days, respectively.

3.3.2.3 <u>NFG Storage Fields</u>

NFG's NYCA storage fields are shown in Figure 124 and listed in Table 45. As with Dominion, working gas capacity and withdrawal capability data were collected from EIA; injection capability data is not available, therefore we have assumed that each storage facility has an injection capability equal to half of the maximum withdrawal quantity.

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[86] Working gas capacity and maximum withdrawal quantities are reported in EIA Form 191 (Field Level Storage Data).

Figure 124. NFG-Operated Storage Fields

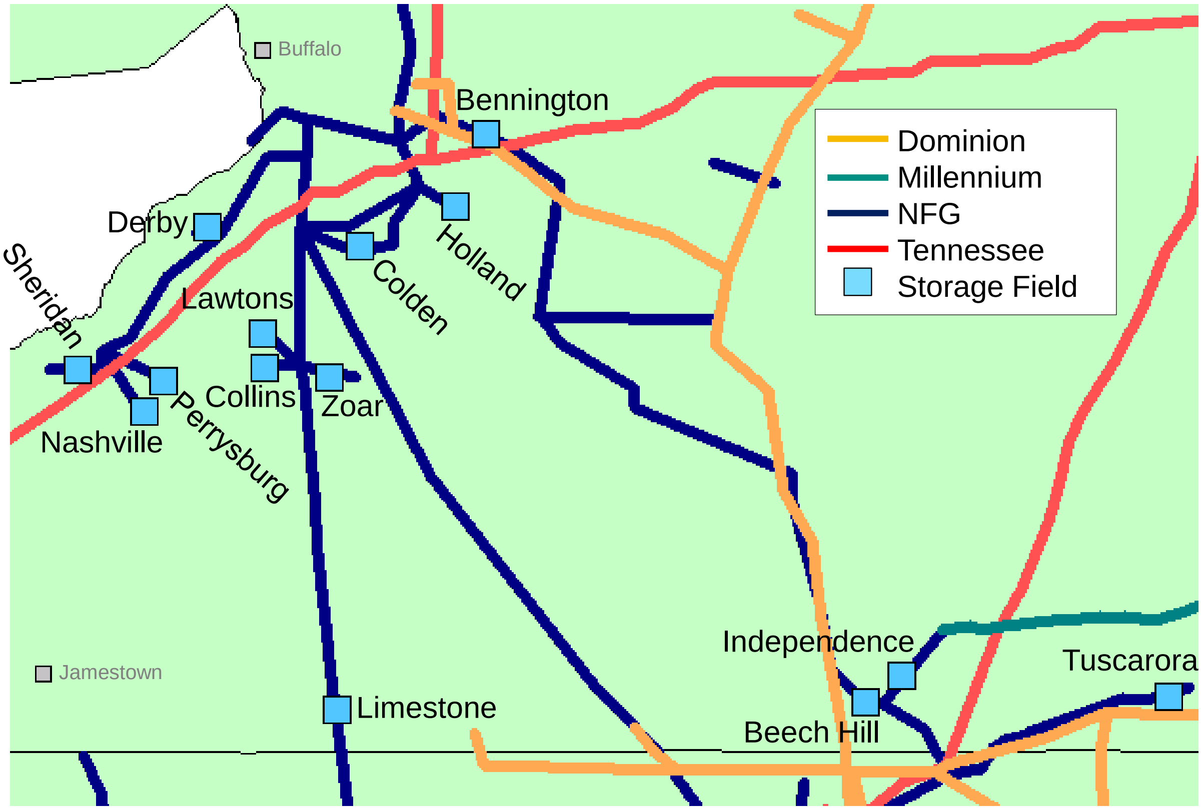


Table 45. NFG-Operated Storage Fields

Field	Working Gas Capacity (Bcf)	Withdrawal Capability (MDth/d)	Injection Capability (MDth/d)
Beech Hill	9.9	66	33
Bennington	1.8	75	37.5
Colden	7.55	120	60
Collins	2.85	50	25
Derby	0.25	5	2.5
Holland	9.5	91	45.5
Independence	1.1	35	17.5
Lawtons	0.97	33	16.5
Limestone	2	37	18.5
Nashville	3.93	110	55
Perrysburg	1.85	60	30
Sheridan	1.1	25	12.5
Tuscarora	3.8	58	29
Zoar	0.6	51	25.5

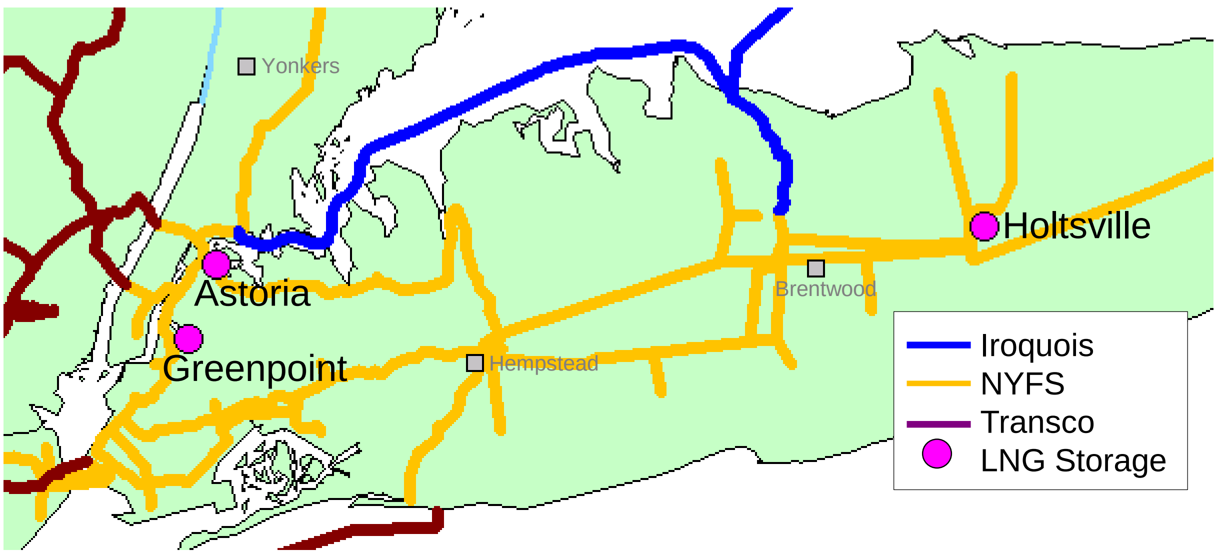
NFG also does not report storage activity for individual storage fields, therefore we have assumed full utilization of injection and withdrawal capability on the relevant seasonal peak days.

3.3.3 LDC Receipts

As part of the Winter Supply Review submissions to the NYPSC for the 2012-heating season, LDCs reported on-system receipts from sources other than pipelines. Central Hudson Gas & Electric (CHG&E), Niagara Mohawk and St. Lawrence reported that they did not have any additional on-system receipts. Corning, National Fuel Gas Distribution Corporation (NFGDC), NYSE&G, and Rochester Gas & Electric (RG&E) reported small amounts of local production.[87]

NGrid and Con Edison each reported significant LNG withdrawal capability during peak demand periods. The locations of the LNG facilities are shown in Figure 125. Con Edison can withdraw up to 166 MDth/d from its Astoria facility, while NGrid can withdraw up to 291 MDth/d from its Greenpoint facility in Brooklyn and up to 103 MDth/d from its Holtsville facility in Suffolk County on Long Island. These supplies are available only during the heating season, and are used sparingly by the LDCs to bolster pressure and flow during cold snaps.[88,89,90]

Figure 125. Downstate LNG Facilities



3.4 Core Demand

Core demand has been differentiated by season, as described in the following sections.

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[87] Corning estimates that it can call upon 11 MDth/d from local producers in time of need. NFGDC reports that total local production averaged approximately 19 MDth/d for the twelve months ending December 2011. NYSE&G reports an average of approximately 15 MDth/d of peak day local production over the 2011/12 and 2012/3 heating season, we have estimated 8 MDth/d during the cooling season. RG&E reports less than 1 MDth/d of peak day local production receipts.

[88] Facility specific withdrawal capabilities extracted from http://www.narucpartnerships.org/Documents/Thomas_Dvorsky_Natural_Gas_Contracts_in_New_York.pdf (page 6).

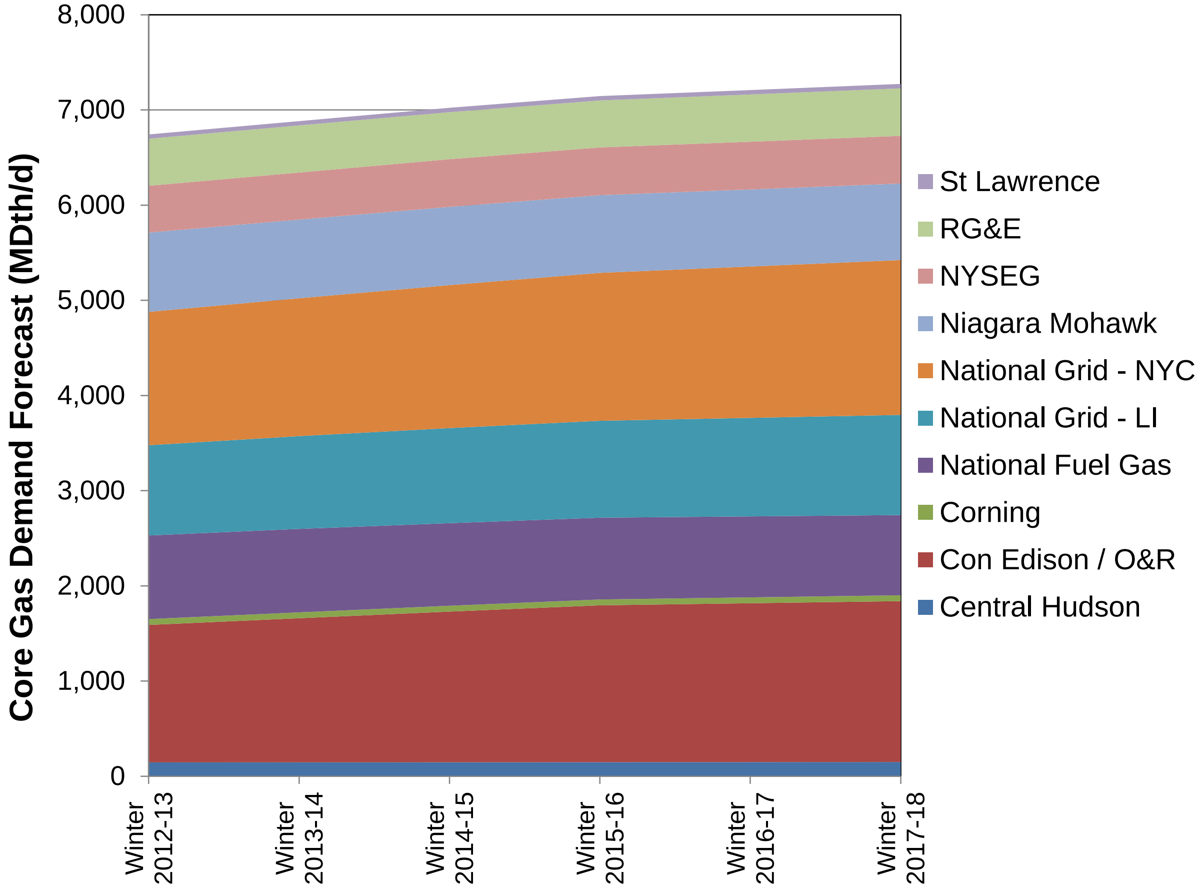
[89] National Grid also has a supply agreement with Fresh Kills Landfill for up to 6.5 MDth/d of landfill gas, and the Newtown Creek wastewater demonstration project will produce an average of 1.3 MDth/d beginning in early 2013.

[90] We have not accounted for liquefaction demand to refill the LNG storage facilities during the cooling season, because the relevant liquefaction rates are not in the public domain. For benchmarking purposes, assuming a typical liquefaction rate approximately 1/40th of the vaporization rate, the demand would be 14 MDth/d.

3.4.1 Heating Season

Heating season core demand is based on LDC filings with the NYPSC in Case No. 12-G-0206 – Winter Supply Review 2012-2013. The total design peak day demand for firm customers is shown in Figure 126.

Figure 126. Design Peak Day Firm Customer Demand by LDC (Heating Season)

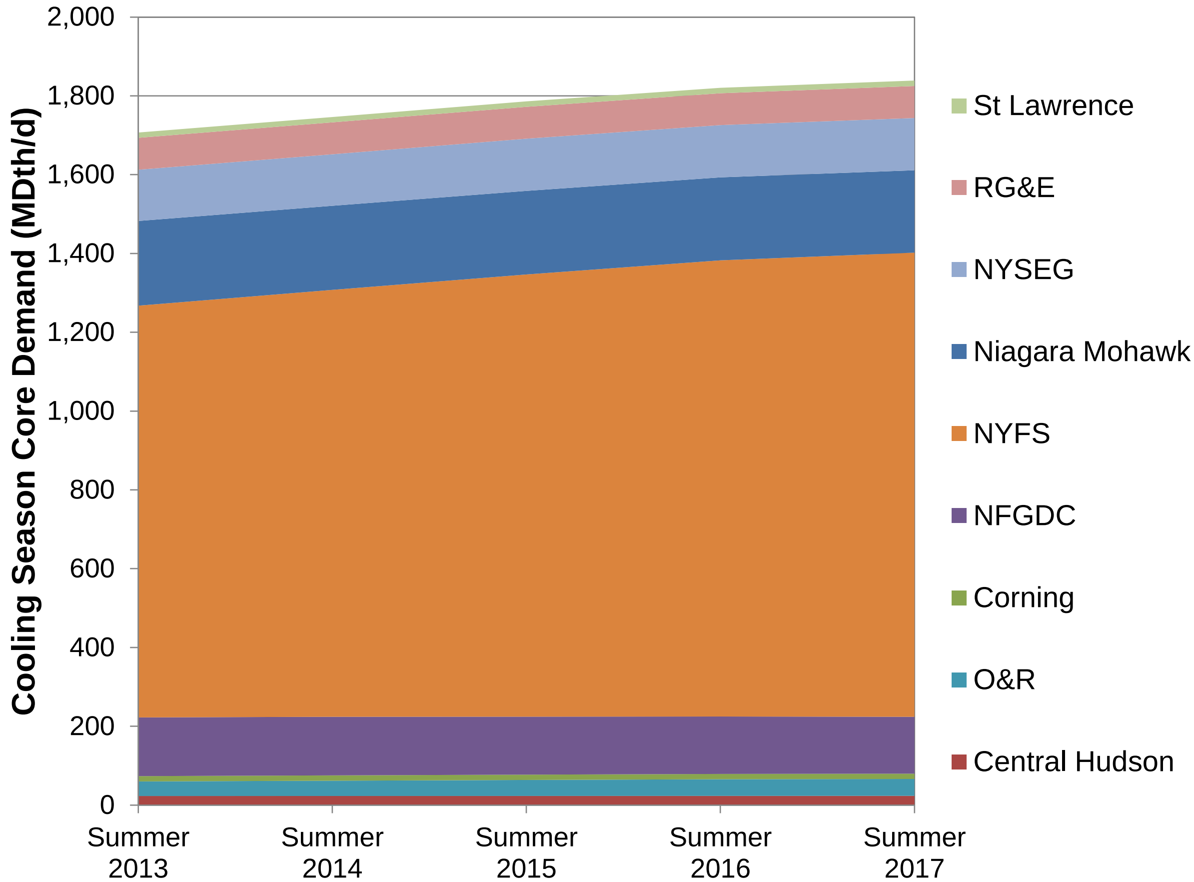


3.4.2 Cooling Season

The cooling season core demand forecast was developed based on pipeline EBB data and reported deliveries to LDC gate stations. Non-core demand behind the citygate was calculated using emissions data from the EPA's Clean Air Markets Program database and subtracted from the daily LDC deliveries. To the extent that there is additional non-core demand behind the citygate over and above those modeled by NYISO, such additional non-core demand remains commingled with core demand for purposes of the cooling season analysis.

A summary of the calculated cooling season core demands by LDC is shown in Figure 127. The summer 2013 values are calculated based on average daily demand over the 2010, 2011 and 2012 cooling seasons, subsequent data is escalated based on the year-over-year growth rates shown in the heating season demand forecasts.

Figure 127. Cooling Season Core Gas Demand[91]



<u>New York Facilities System</u>

Four pipelines deliver gas into the New York Facilities System as shown in Figure 128: Iroquois, Tennessee, Texas Eastern and Transco. The deliveries by pipeline are shown in Figure 129.

[91] Because of the way pipeline deliveries are reported, we have grouped Con Edison and National Grid together for purposes of estimating cooling season core gas demand in Zones J and K.

Figure 128. Pipelines Serving the New York Facilities System[92]

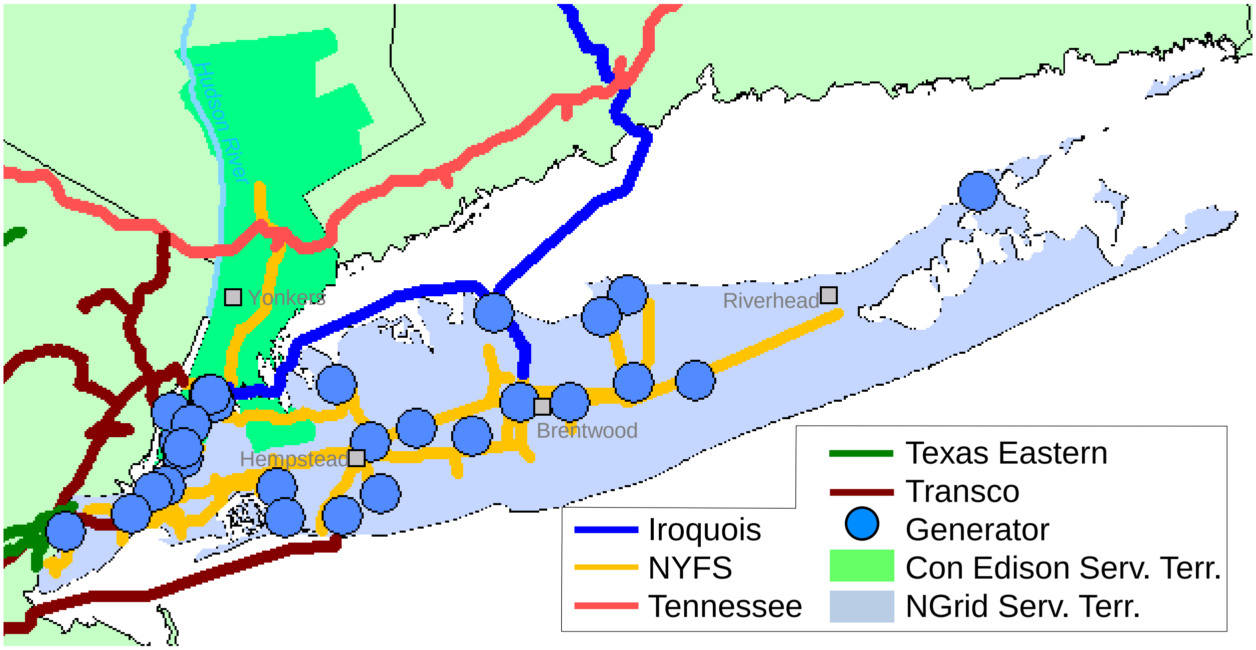
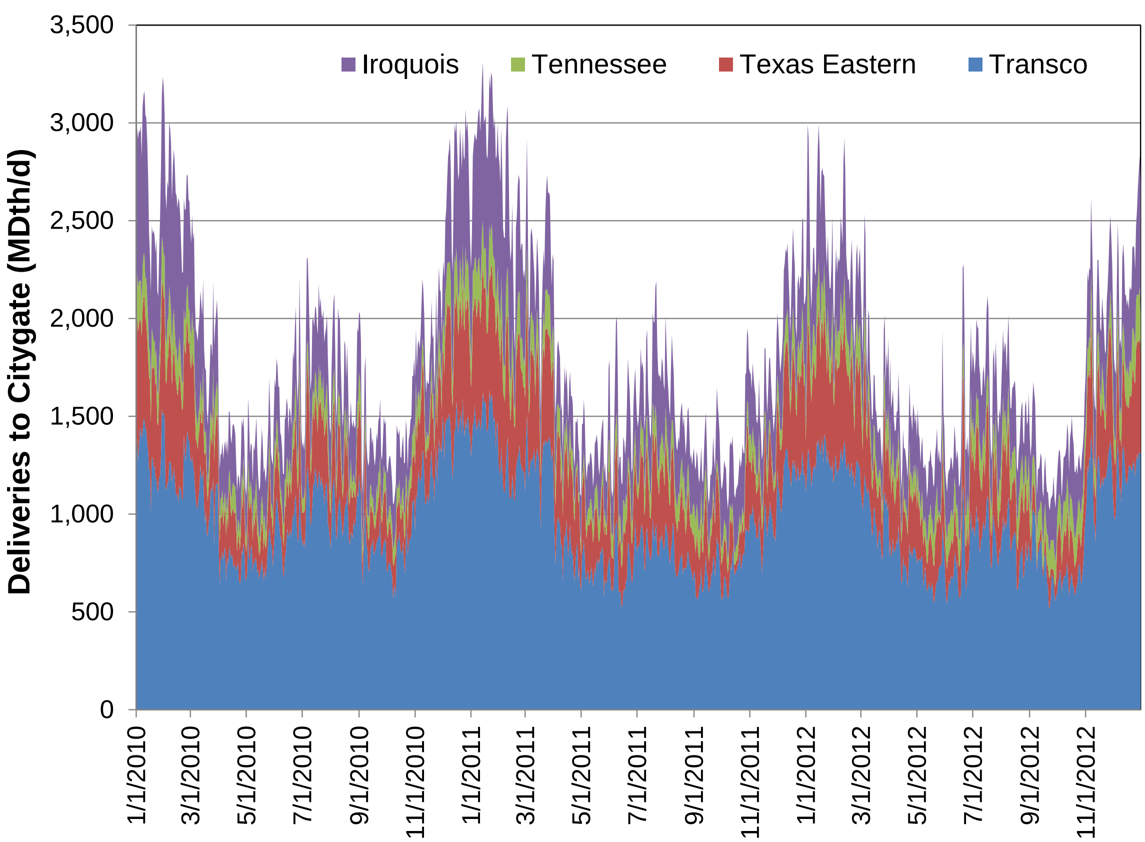


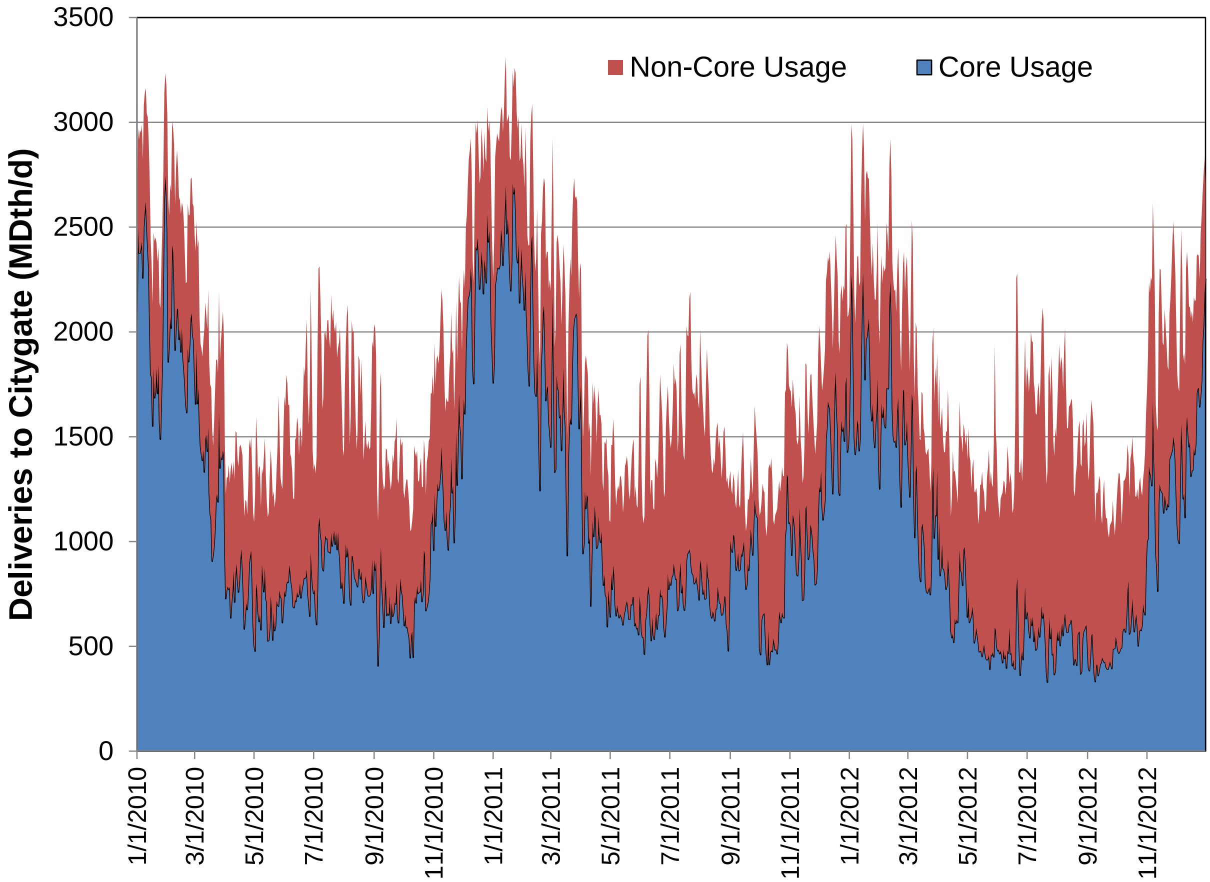
Figure 129. New York Facilities System Deliveries by Pipeline



[92] This map excludes the majority of laterals and reticulated pipe across the distribution system.

Of the plants modeled by NYISO, all the generation in NYC and Long Island is served by the New York Facilities System: Astoria East Energy, SCS Astoria, Brooklyn Navy Yard Cogen, East River, KIAC Cogen, NYPA Astoria (Poletti), Ravenswood, Arthur Kill, Astoria Generating, NRG Astoria, Gowanus, Harlem River, Hell Gate, Kent Avenue, Pouch Terminal, Narrows, and Vernon Boulevard in NYC and Bethpage, Caithness, Flynn, Pinelawn, Trigen-Nassau, Barrett, Northport, Port Jefferson, Brentwood, Far Rockaway, Freeport, Glenwood, Greenport, Pilgrim, and Stony Brook on Long Island, as shown in Figure 128 above.[93] The division between core and non-core demand is shown in Figure 130.

Figure 130. Core and Non-Core Usage on NYFS



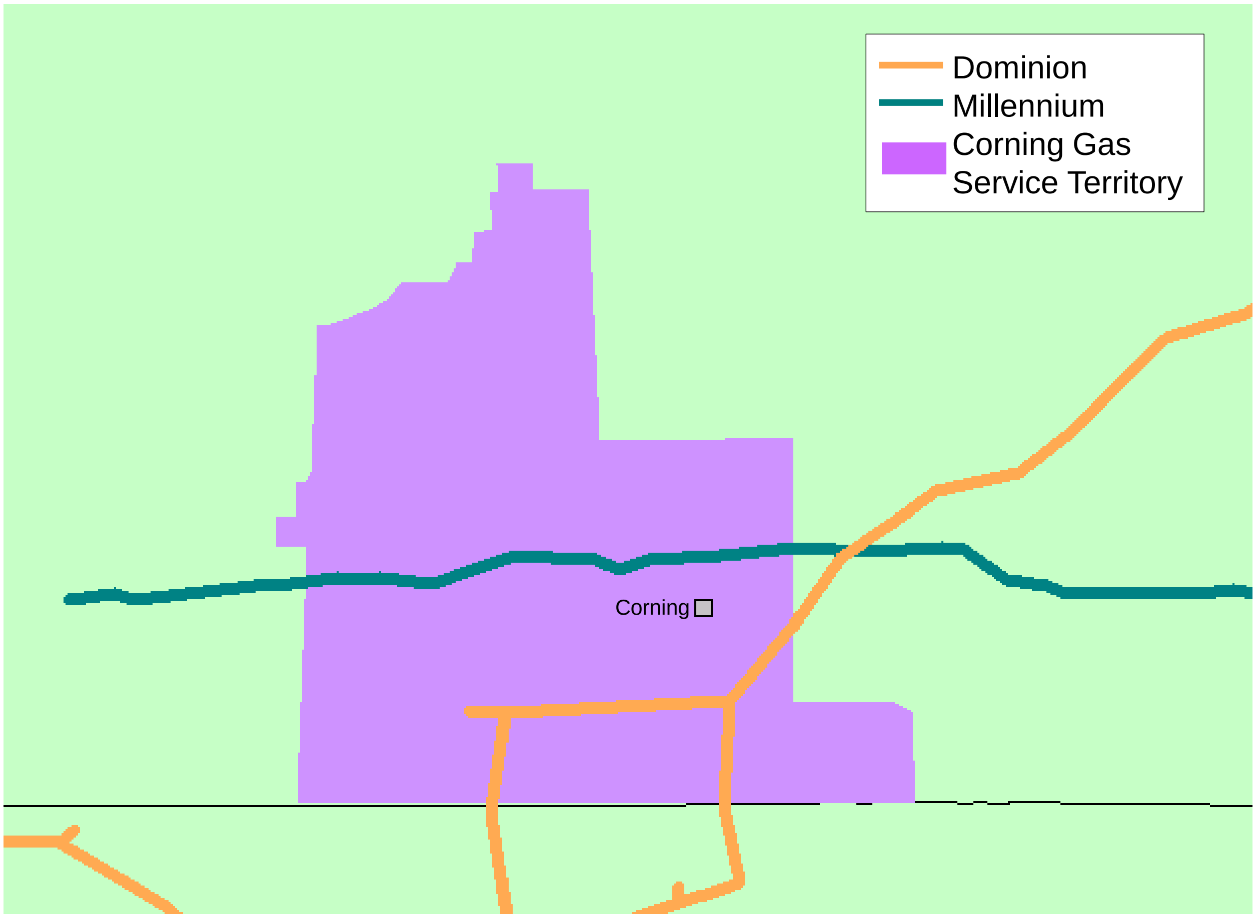
Corning Natural Gas

Corning Natural Gas receives gas from Dominion and Millennium, as shown in Figure 131. Dominion's daily EBB nomination postings do not include Corning Natural Gas delivery points, therefore the total daily consumption has not been calculated. Instead, summer demand has been estimated to be 13 MDth/d by multiplying the average ratio of summer to winter demand across

[93] NGrid's Barrett Station in Long Beach is located next to the Transco terminus. NGrid's Northport station is located next to the Iroquois mainline segment that runs from Northport to South Commack. Technically, both Barrett and Northport are situated behind the citygate on the New York Facilities System.

the other NYCA LDCs by Corning's heating season peak day demand.[94] Corning does not serve any of the power plants modeled by NYISO.

Figure 131. Pipelines Serving Corning Natural Gas



Central Hudson Gas & Electric

CHG&E receives gas from Algonquin, Columbia (via lease on Millennium), Iroquois, Millennium and Tennessee, as shown in Figure 132.[95] Figure 133 shows the deliveries by pipeline.

[94] Because the volumes served by Corning are relatively small, any error relative to the actual cooling season demand will not have a significant impact on the total cooling season core demand estimate.
[95] Service from Columbia is via Columbia's leased Millennium capacity.

Figure 132. Pipelines Serving CHG&E

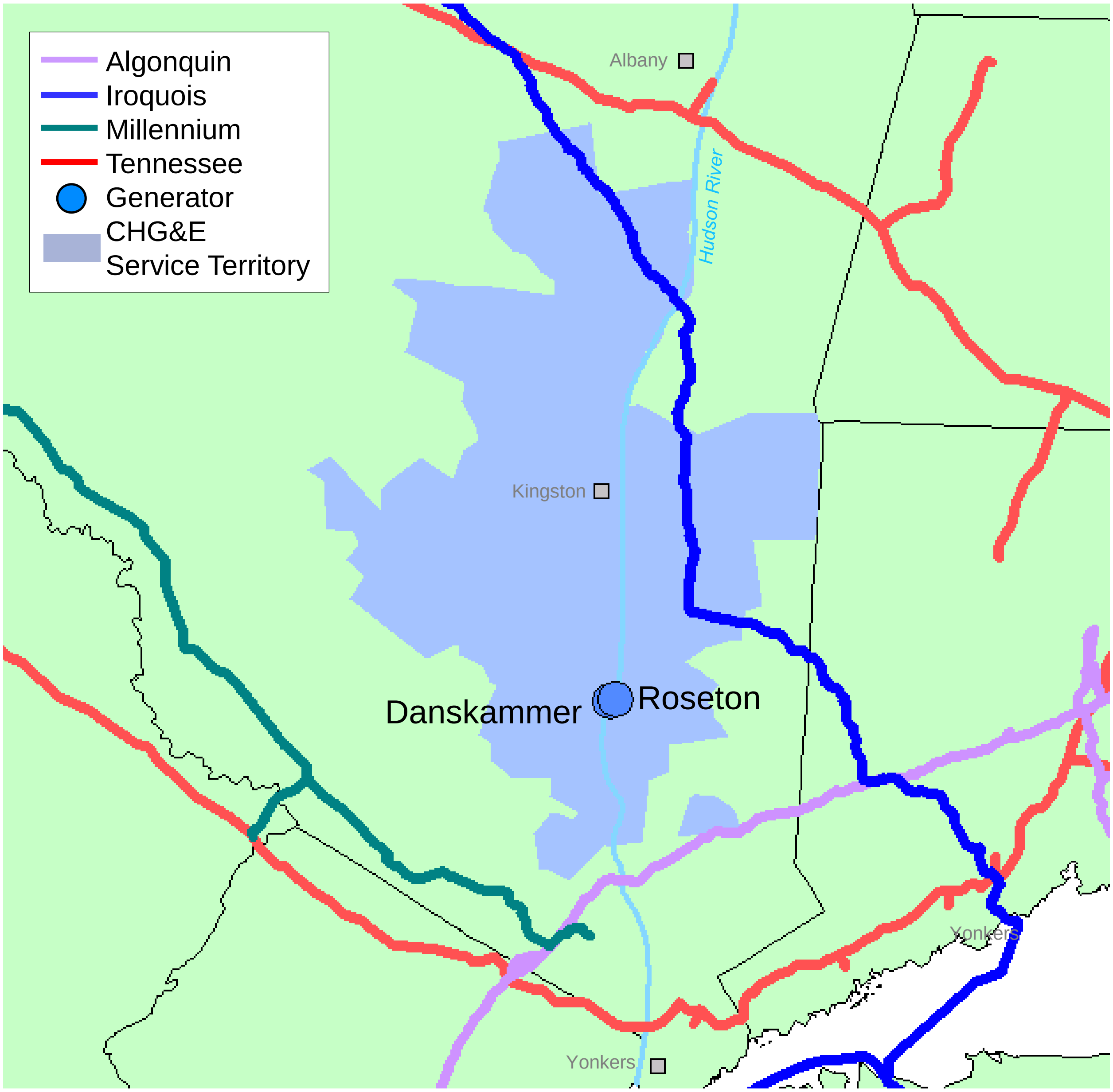
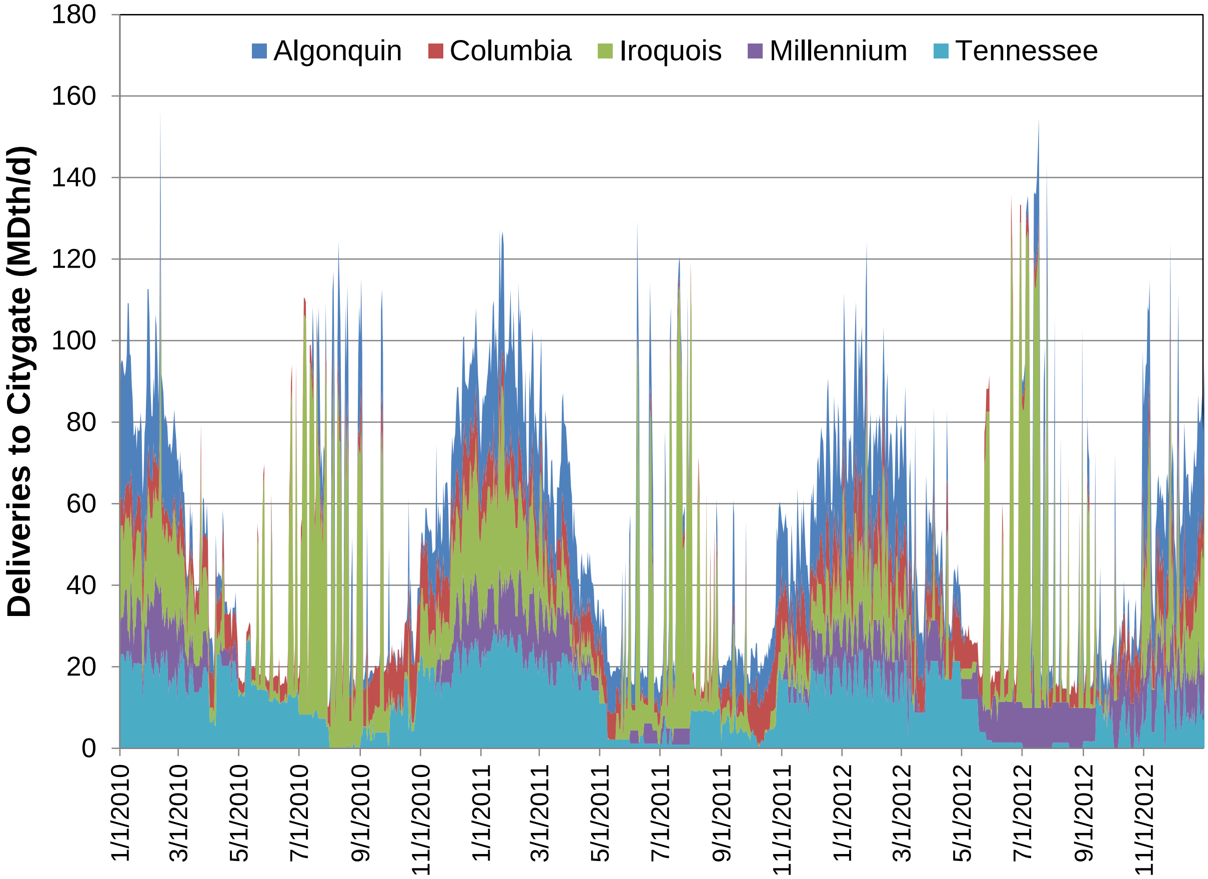
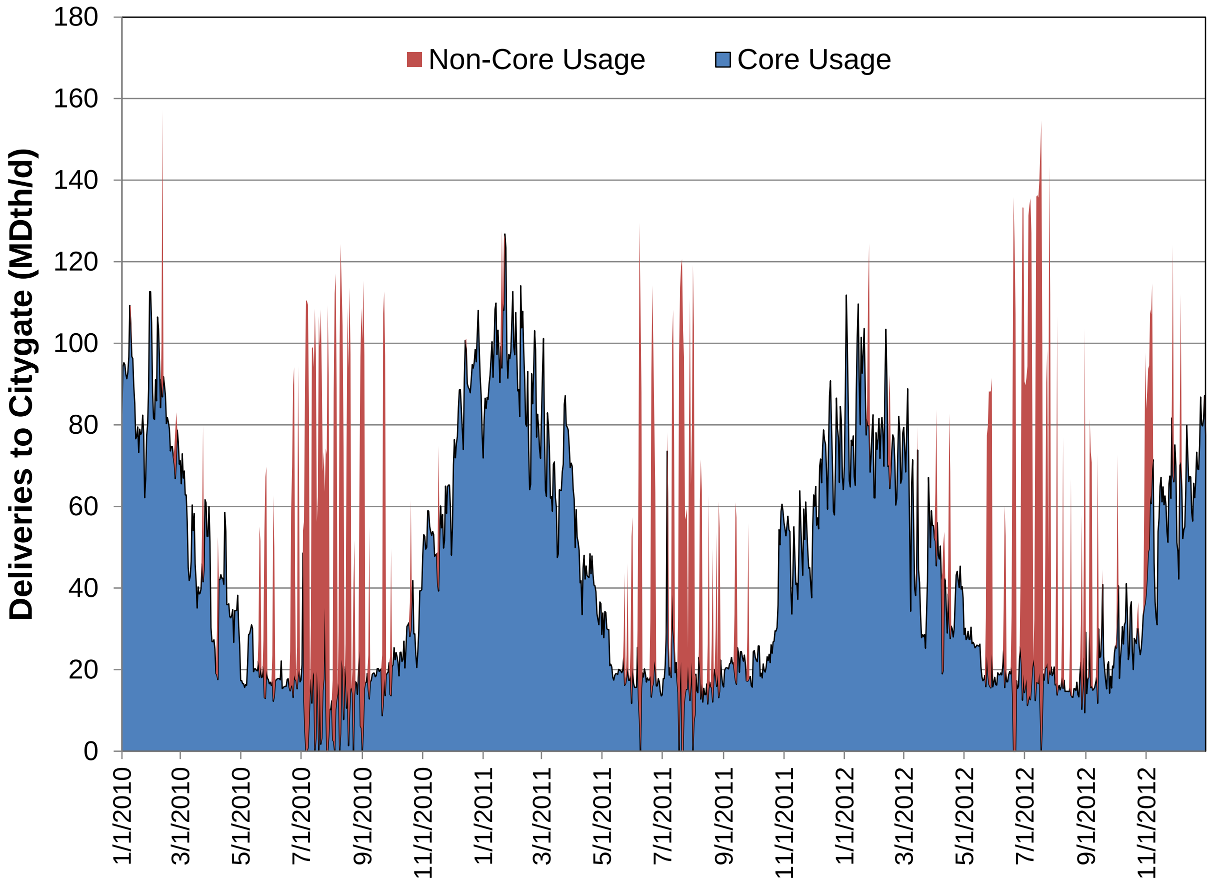


Figure 133. CHG&E Deliveries by Pipeline



Of the plants modeled by NYISO, two are served by CHG&E behind the citygate – Roseton and Danskammer. Separating deliveries to the CHG&E citygate by core and non-core usage yields the breakdown shown in Figure 134. The average core demand over the past three cooling seasons is 19 MDth/d.

Figure 134. Core and Non-Core Usage Behind CHG&E Citygate[96]



<u>NFGDC</u>

NFGDC receives gas from Dominion, NFG and Tennessee, as shown in Figure 135. Figure 136 shows deliveries by pipeline. The decrease in deliveries from Tennessee coincides with the reduction in receipts into Tennessee from TransCanada at Niagara.

[96] Comparing Figure 133 and Figure 134 indicates that the majority of the gas to serve non-core demand was delivered by Iroquois.

Figure 135. Pipelines Serving NFGDC

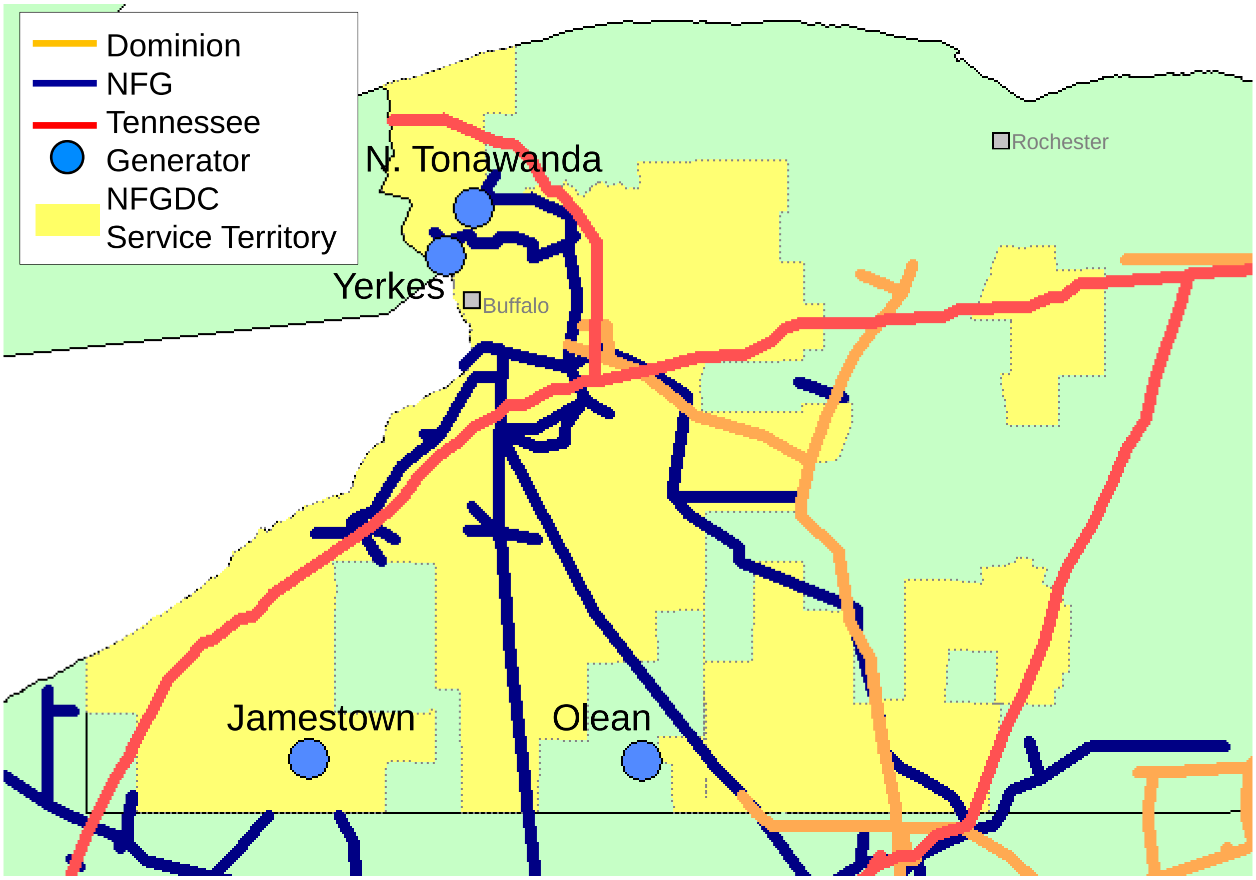
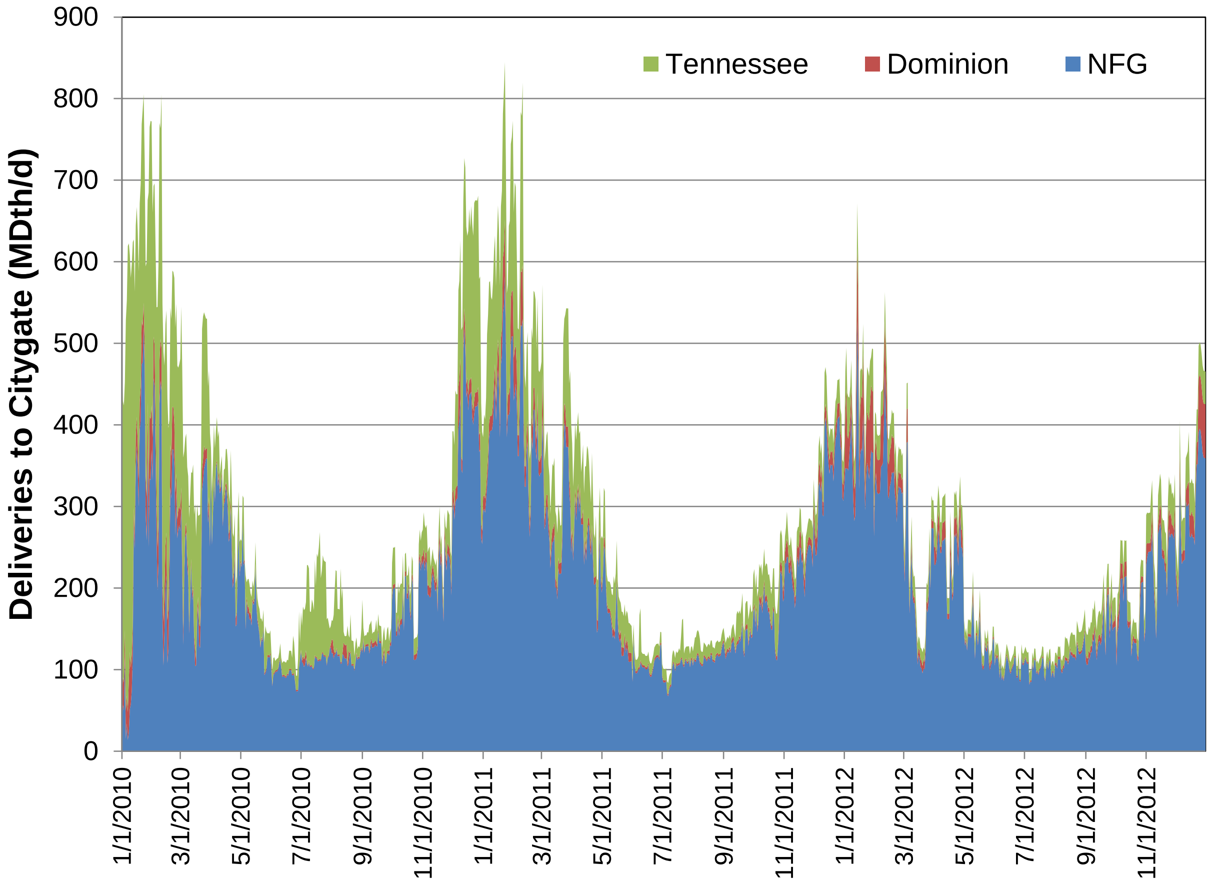
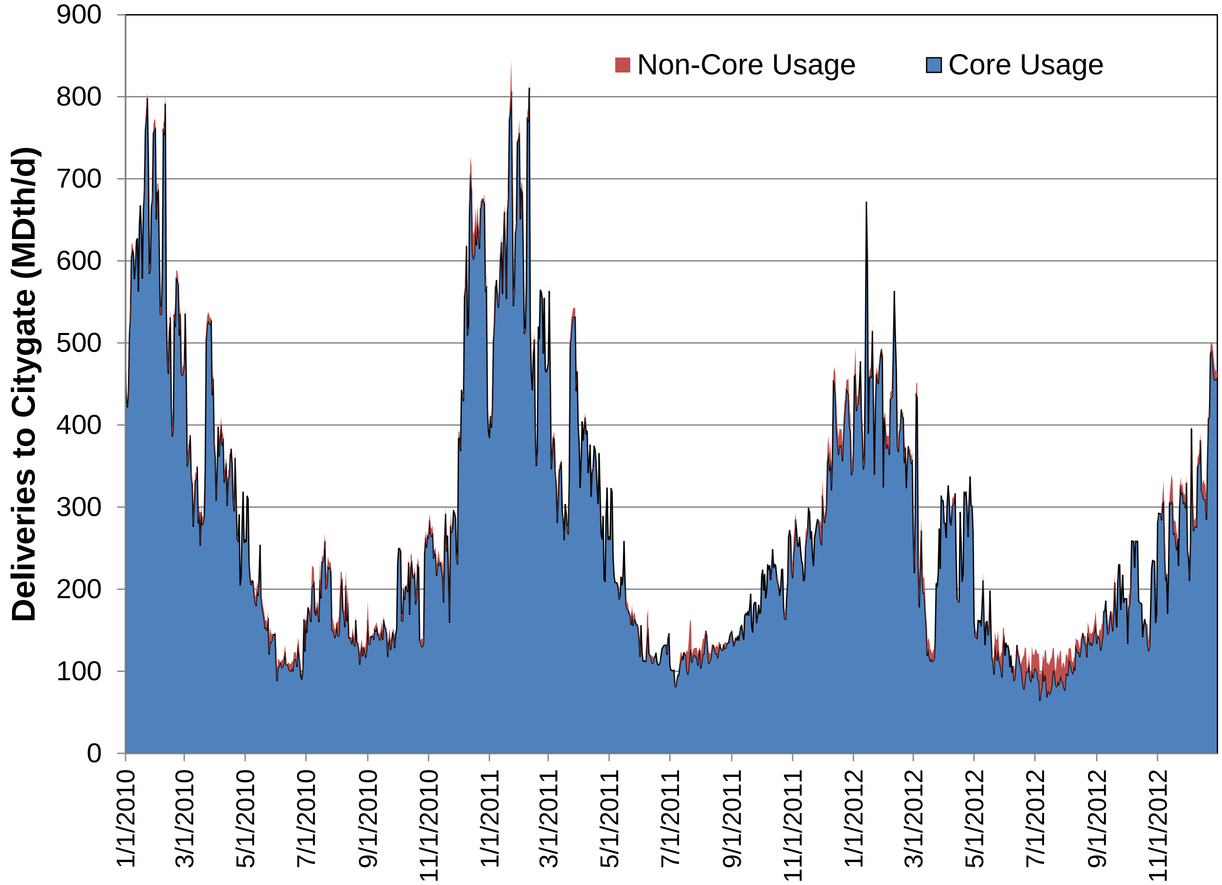


Figure 136. NFGDC Deliveries by Pipeline



Of the plants modeled by NYISO, four are served by NFGDC behind the citygate – Fortistar North Tonawanda, Indeck Yerkes, Indeck Olean, and Jamestown / Carlson. Separating deliveries to the NFGDC citygate by core and non-core usage yields the breakdown shown in Figure 134. The average core demand over the past three cooling seasons is 153 MDth/d.

Figure 137. Core and Non-Core Usage Behind NFGDC Citygate



New York State Electric & Gas

NYSE&G is served by Algonquin, Columbia, Dominion, Empire, Iroquois, North Country and Tennessee, as shown in Figure 138. The deliveries by pipeline are illustrated in Figure 139.

Figure 138. Pipelines Serving NYSE&G

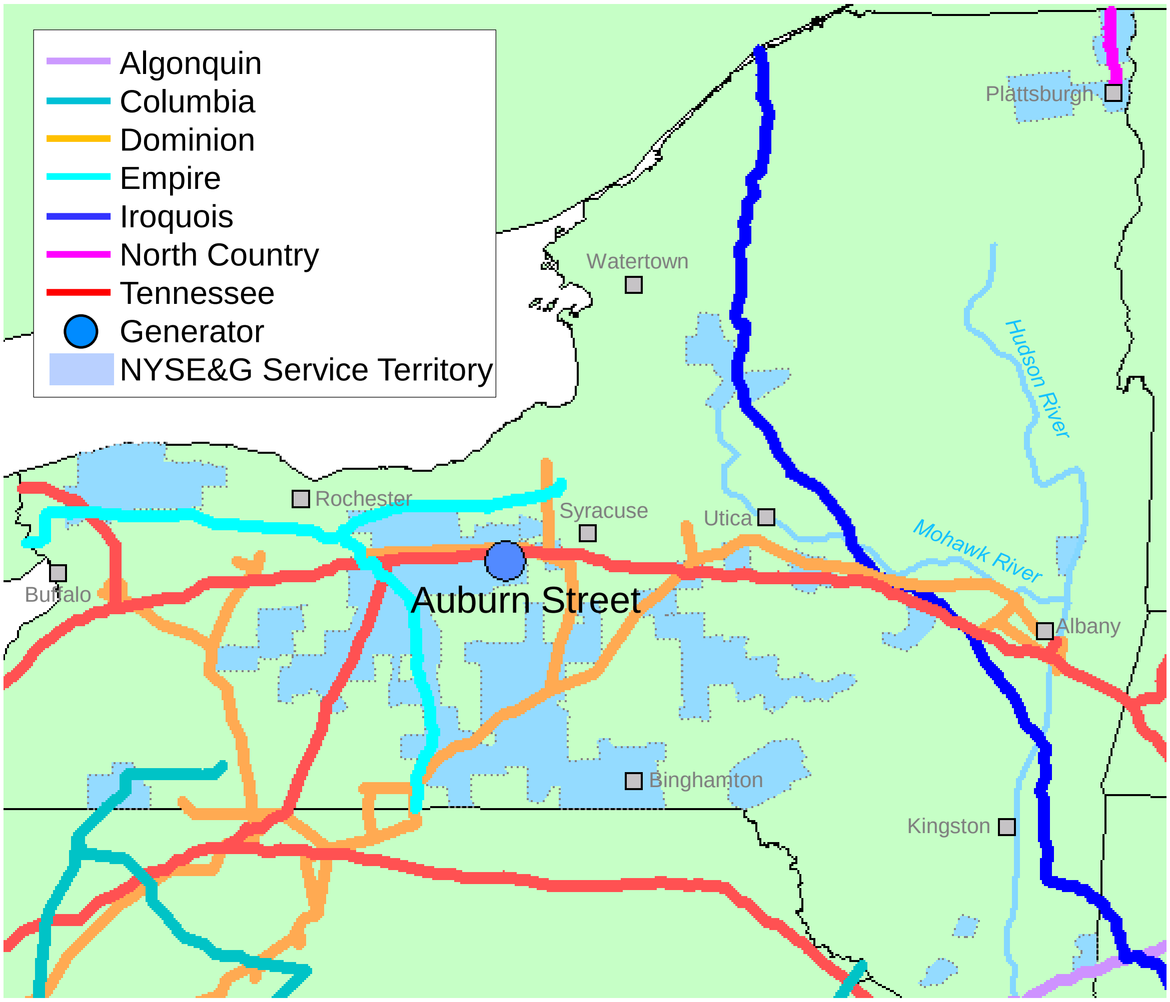
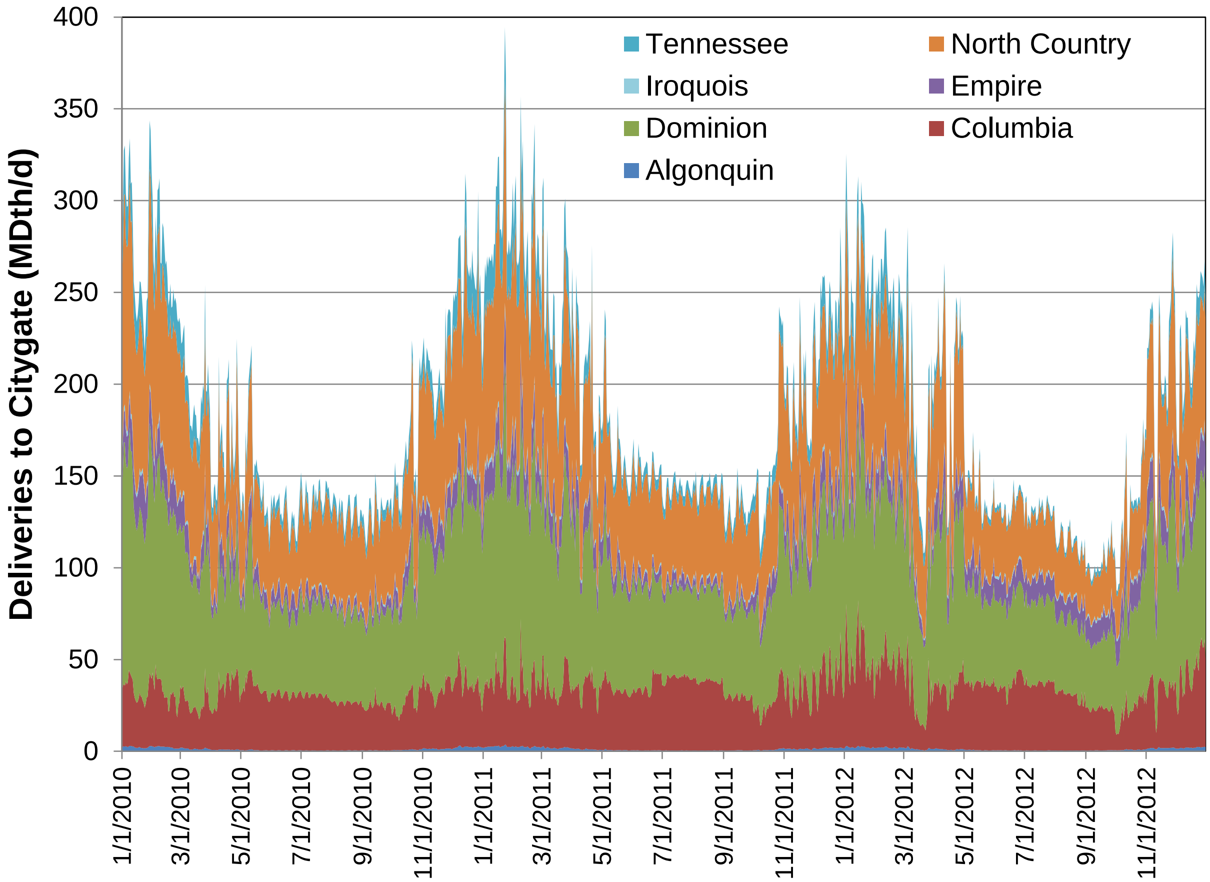
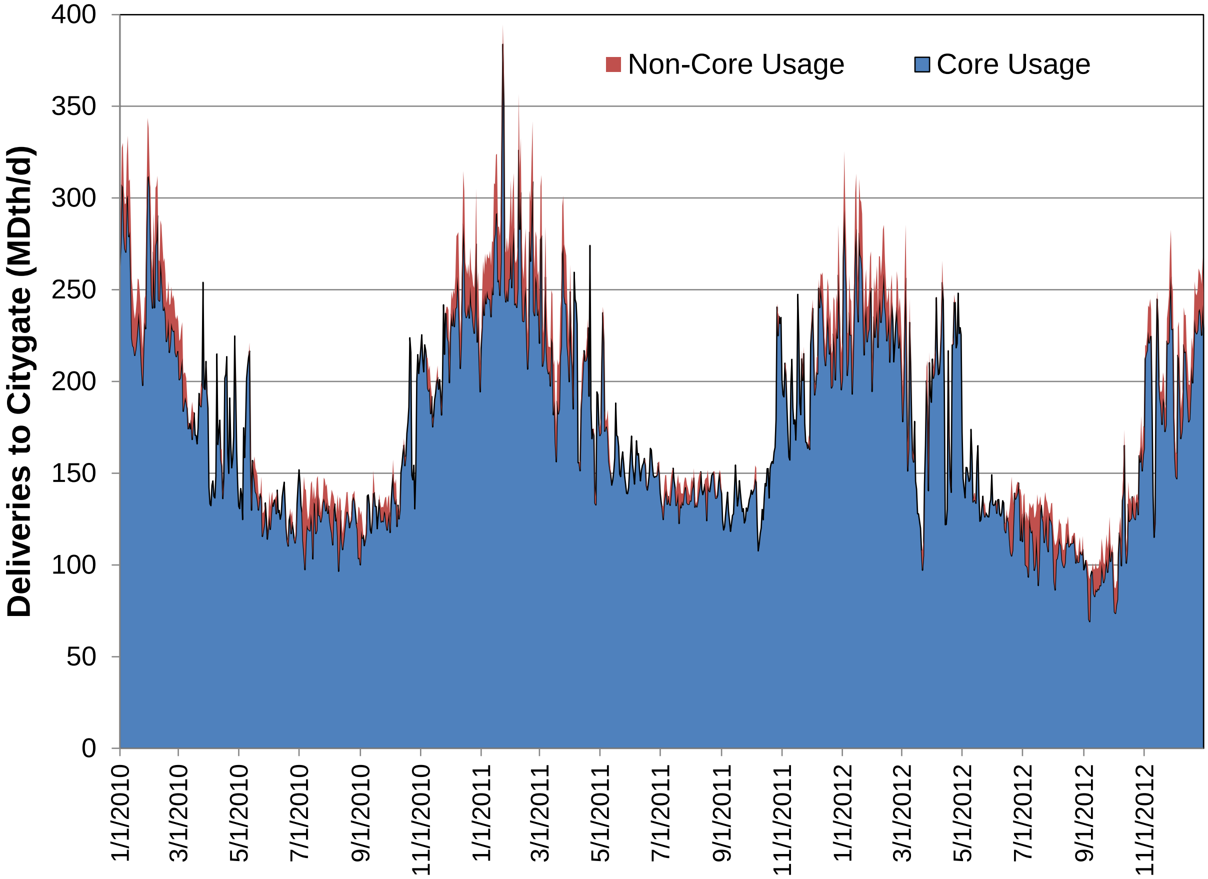


Figure 139. NYSE&G Deliveries by Pipeline



Of the plants modeled by NYISO, Auburn Street is served by NYSE&G. Deliveries by gate station are not available for the North Country pipeline, therefore the full daily throughput is included in Figure 139. The gas demand for the Saranac power plant is included in the generation gas demand when differentiating between core and non-core demand in Figure 140, although the Saranac plant is directly served by North Country. The average NYSE&G core demand over the previous three cooling seasons is 133 MDth/d.

Figure 140. Core and Non-Core Usage Behind NYSE&G Citygate



<u>Niagara Mohawk</u>

Niagara Mohawk receives gas from Dominion, Empire and Iroquois, as shown in Figure 141. The deliveries by pipeline are shown in Figure 142.

Figure 141. Pipelines Serving Niagara Mohawk

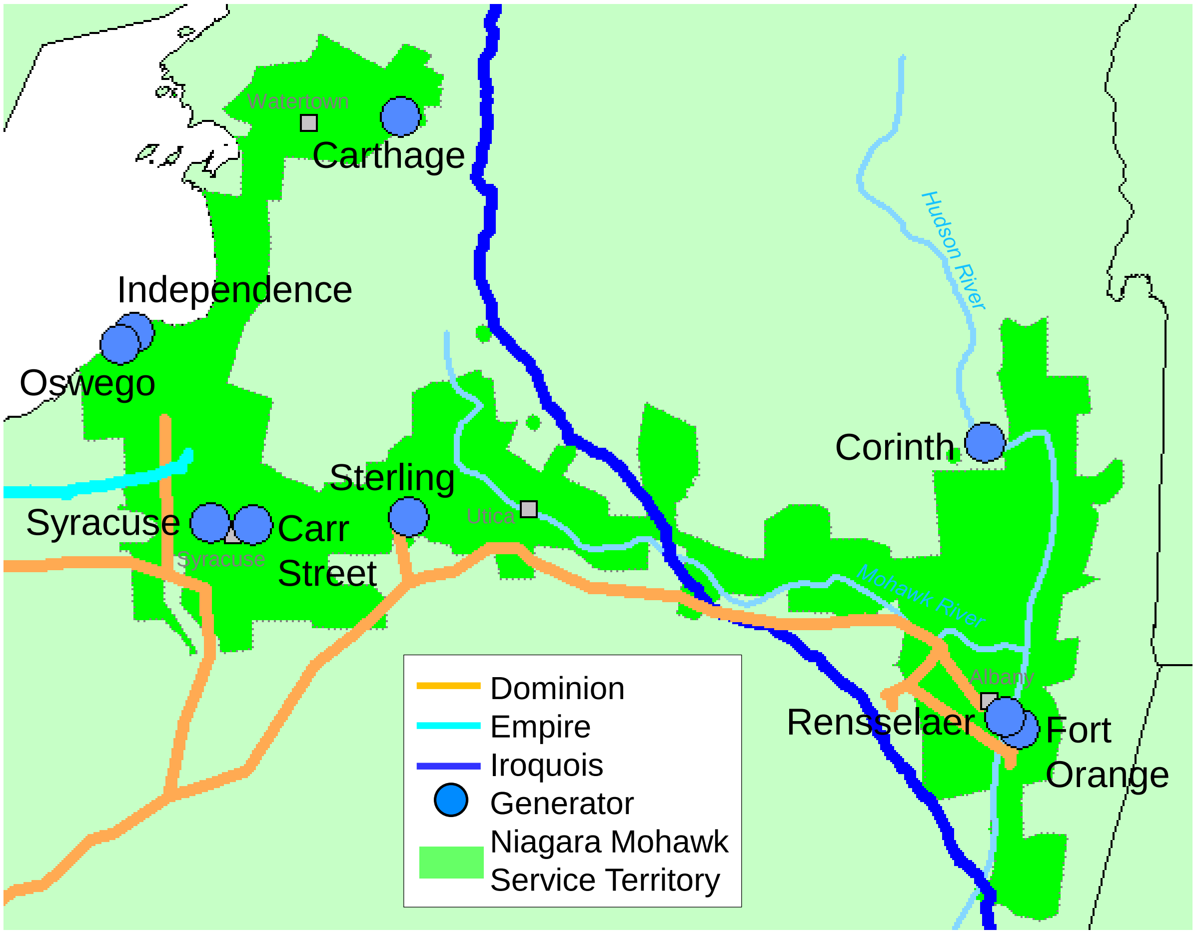
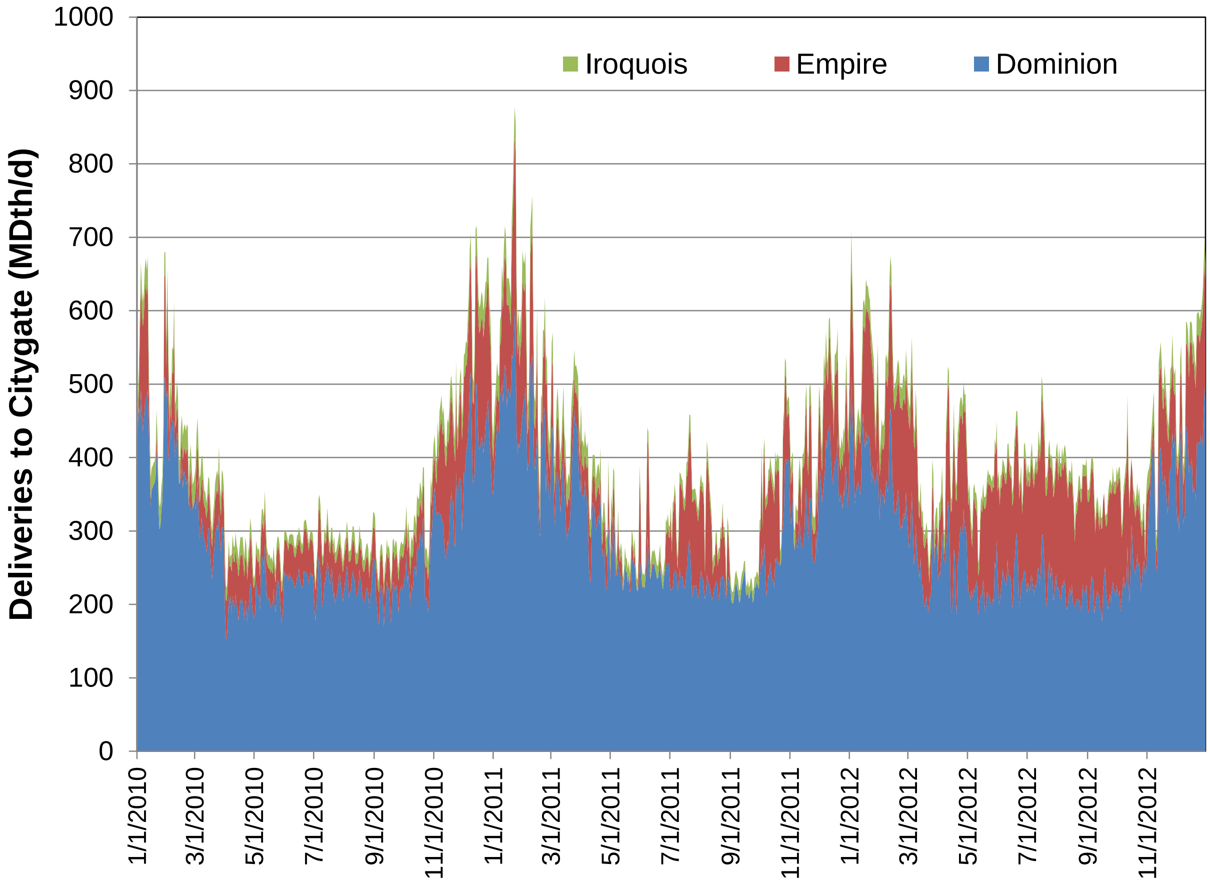


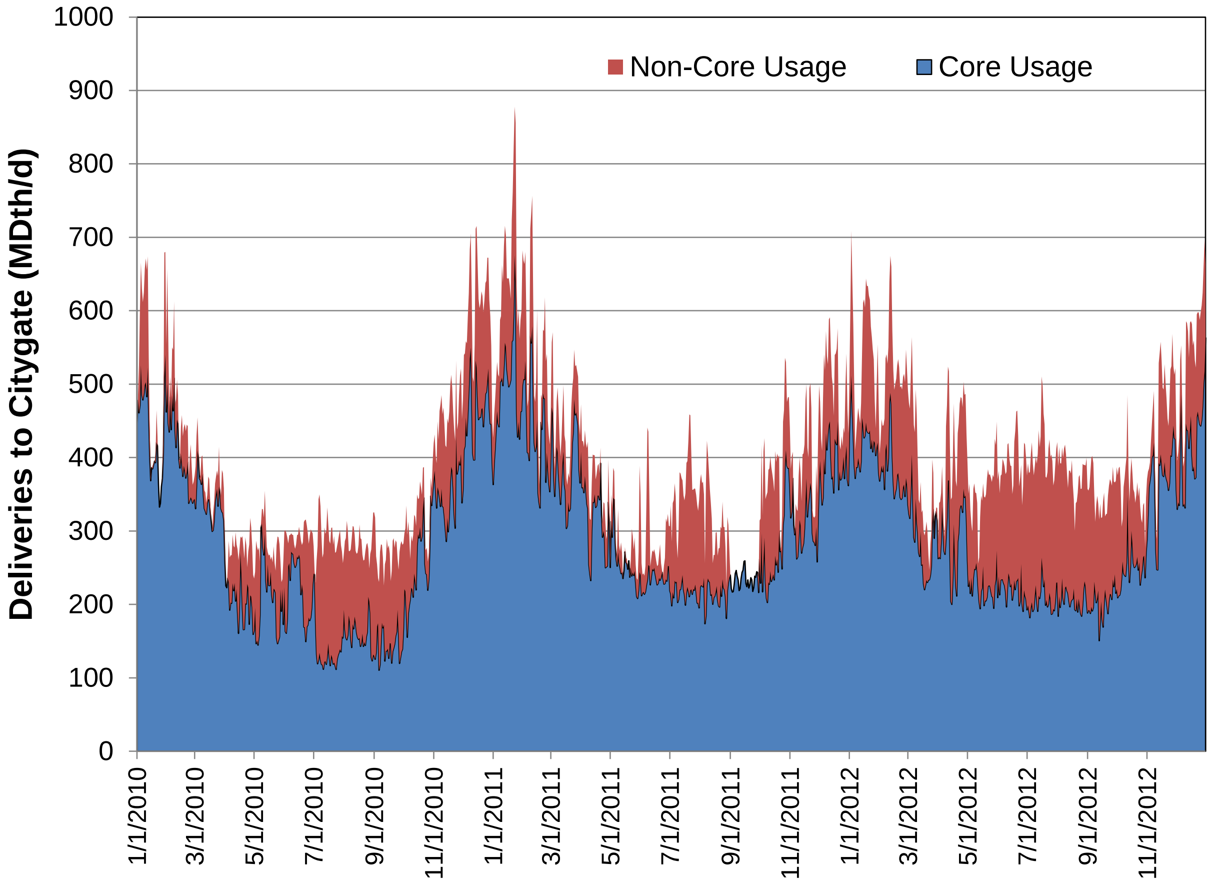
Figure 142. Niagara Mohawk Deliveries by Pipeline



Of the plants modeled by NYISO, nine are served by Niagara Mohawk behind the citygate – Carr Street, Indeck Corinth, Indeck Oswego, Sithe Independence, WPS Syracuse, Sterling Energy, Carthage Energy, Castleton Fort Orange, and Rensselaer Cogen.[97] Separating deliveries to the Niagara Mohawk citygate by core and non-core usage yields the breakdown shown in Figure 143. The average core demand over the last three cooling seasons is 215 MDth/d.

[97] Sithe Independence is served by Empire via a dedicated Niagara Mohawk lateral.

Figure 143. Core and Non-Core Usage Behind Niagara Mohawk Citygate



<u>Orange & Rockland</u>

Orange & Rockland (O&R) is served by Algonquin, Columbia, Millennium, Tennessee and Transco, as shown in Figure 144.[98] Because O&R is operated in conjunction with Con Edison and the service territories are adjacent, some of the gas delivered to O&R meters may be delivered to Con Edison customers and vice versa. The daily deliveries by pipeline are shown in Figure 145.

[98] Transco has not delivered any volumes to O&R for the last several years.

Figure 144. Pipelines Serving O&R

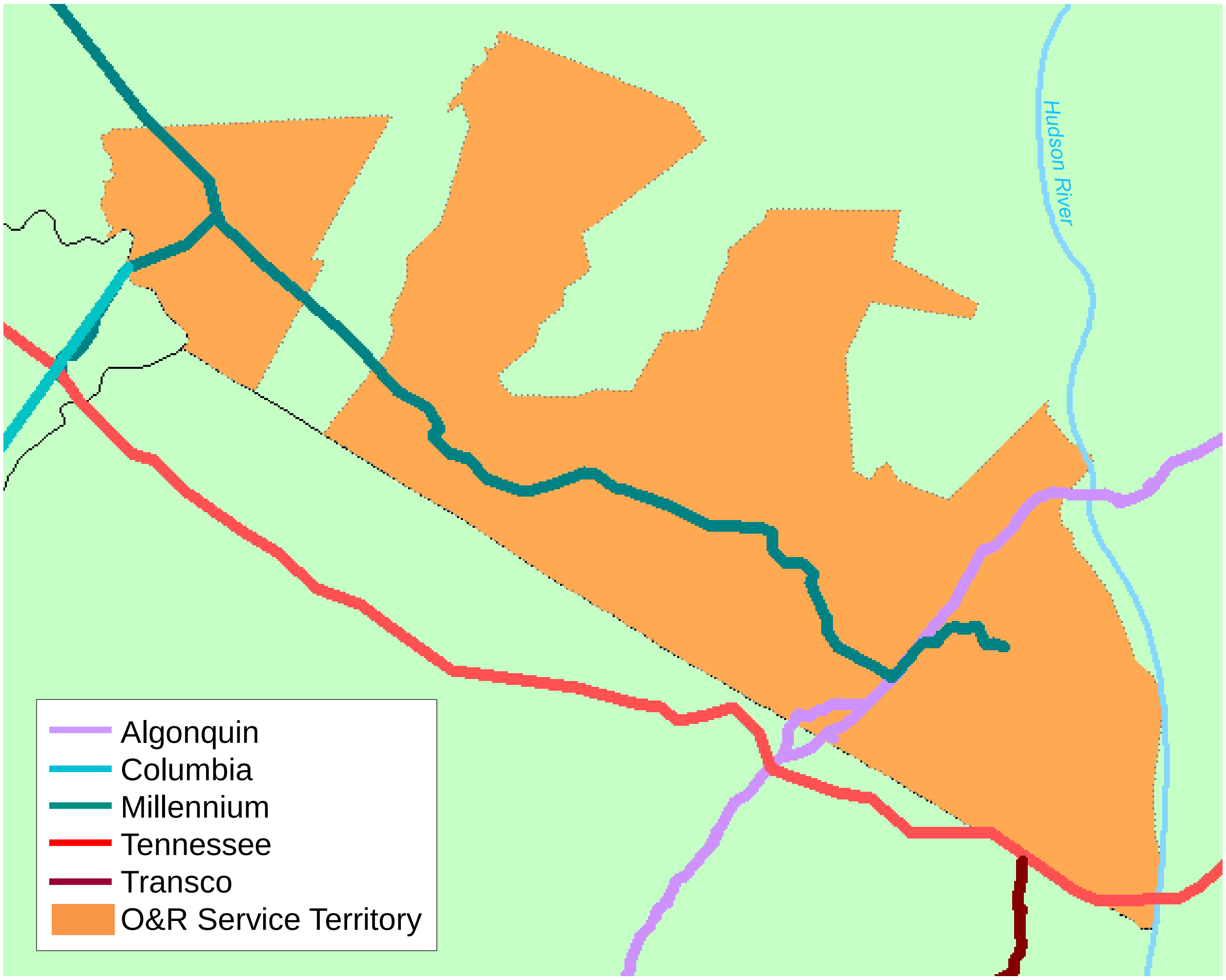
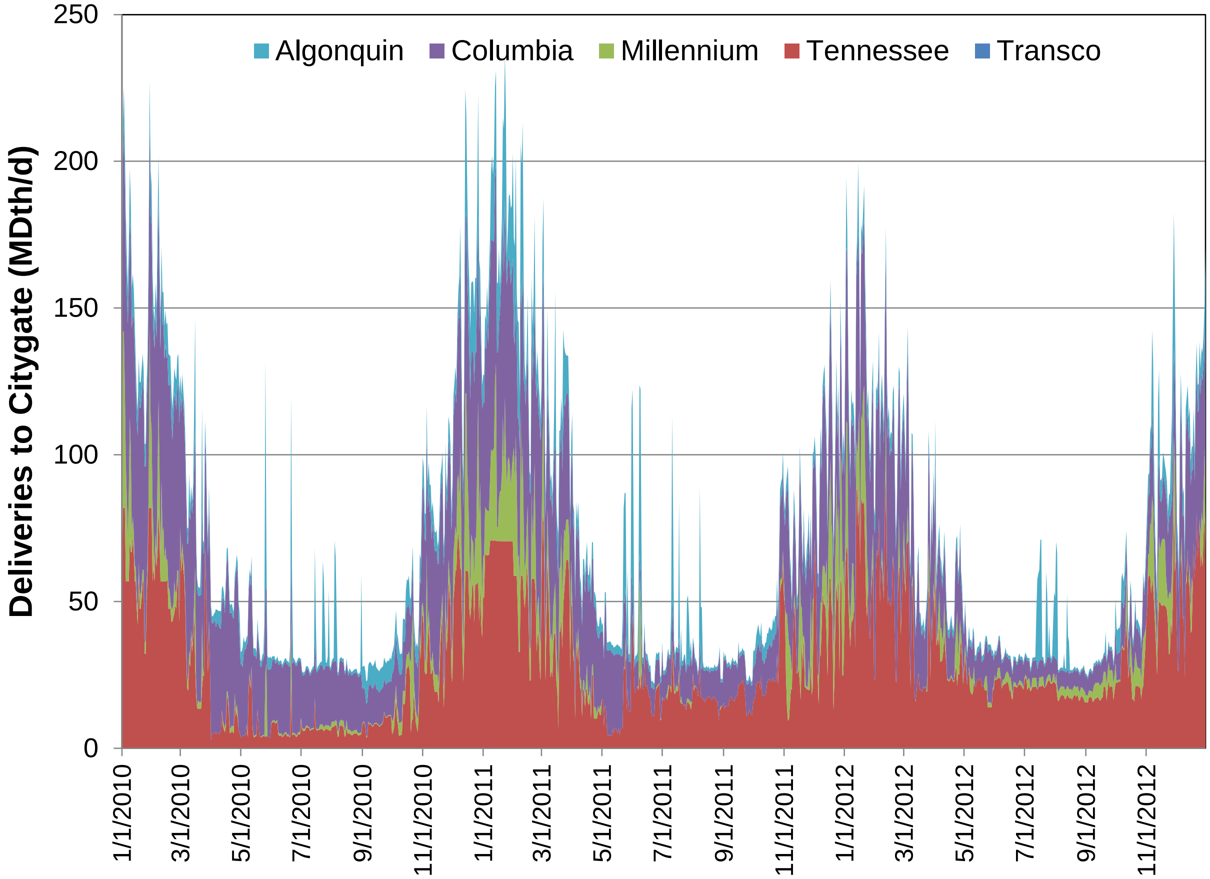


Figure 145. O&R Deliveries by Pipeline



None of the plants modeled by NYISO are located in O&R's service territory. Therefore the full volume delivered to the citygate is classified as core usage, with an average demand of 37 MDth/d over the last three cooling seasons.

Rochester Gas & Electric

RG&E is served by Dominion and Empire, as shown in Figure 146. Although Tennessee passes through the RG&E service territory, it does not operate any delivery meters to RG&E. The daily deliveries by pipeline are shown in Figure 147.

Figure 146. Pipelines Serving RG&E

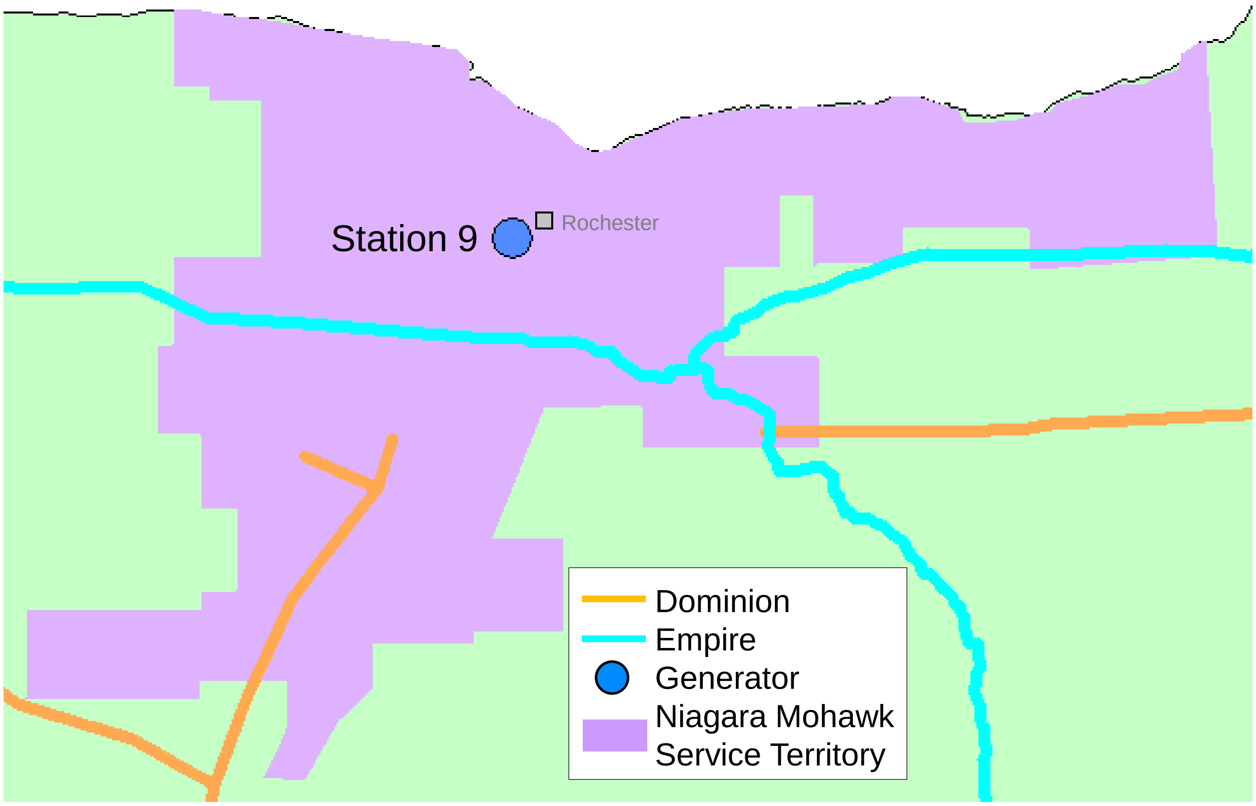
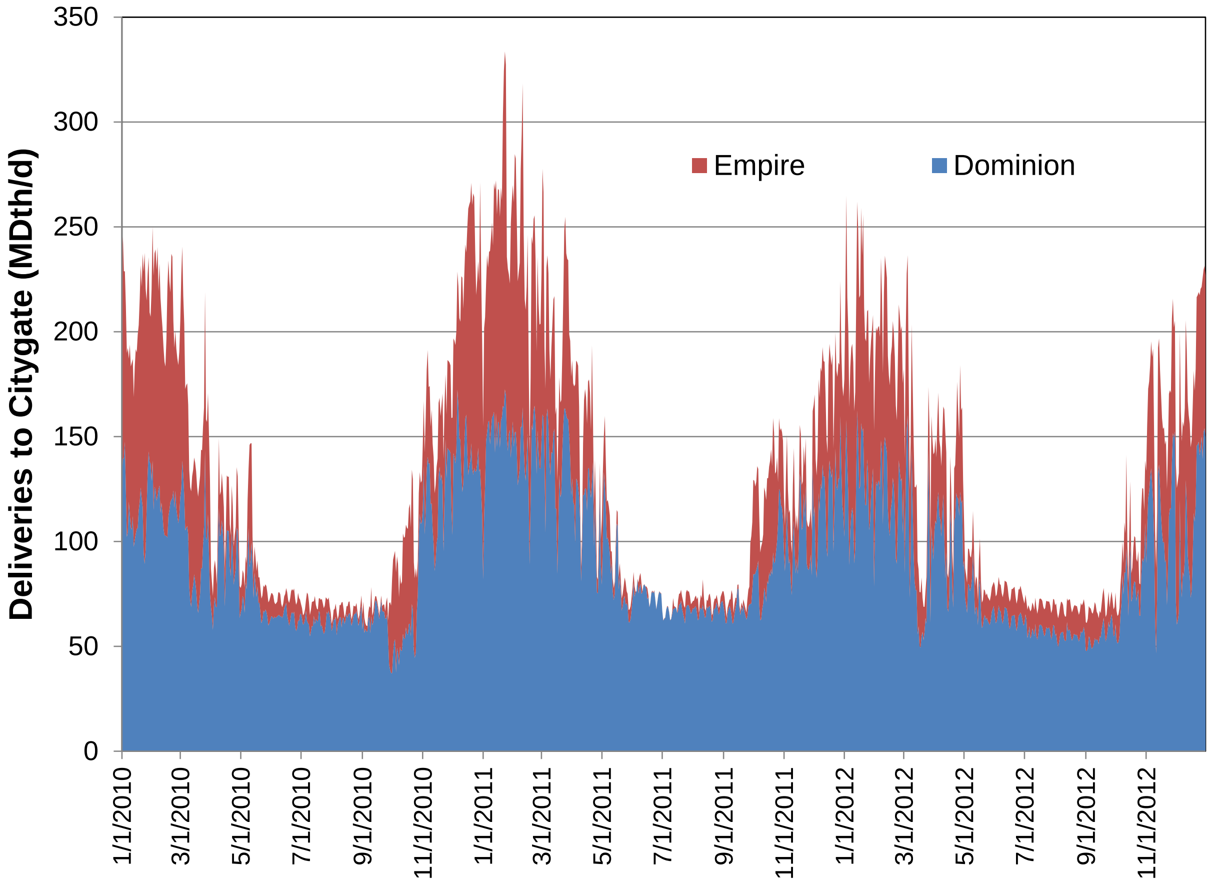


Figure 147. RG&E Deliveries by Pipeline



Of the plants modeled by NYISO, only RG&E Station 9 is located behind the RG&E citygate. EPA's emissions database does not have a listing for this generator, therefore any historical usage cannot be separated from core demand, but NYISO's forecasted plant usage is 0 MDth/d for all years in the Base Case, and less than 1 MDth/d when it is used in the +1,000-MW Case. Therefore we do not believe that this results in any double counting, especially as the cooling season periods in Figure 147 do not show any spikes attributable to non-core usage. The average core demand over the last three cooling seasons is 81 MDth/d.

St Lawrence Gas

As shown in Figure 150, St Lawrence Gas receives gas from Iroquois and from the Niagara Gas Pipeline, an Enbridge subsidiary.[99] Daily deliveries to St. Lawrence Gas are shown in Figure 151.[100]

[99] Daily flow data for Niagara Gas is based on deliveries into the pipeline from TransCanada, as described on page 128.

[100] Niagara Gas had a planned outage in late 2011 to replace/relocate a segment over a bridge (the St. Lawrence River Pipeline Crossing Replacement Project).

Figure 148. Pipelines Serving St. Lawrence Gas

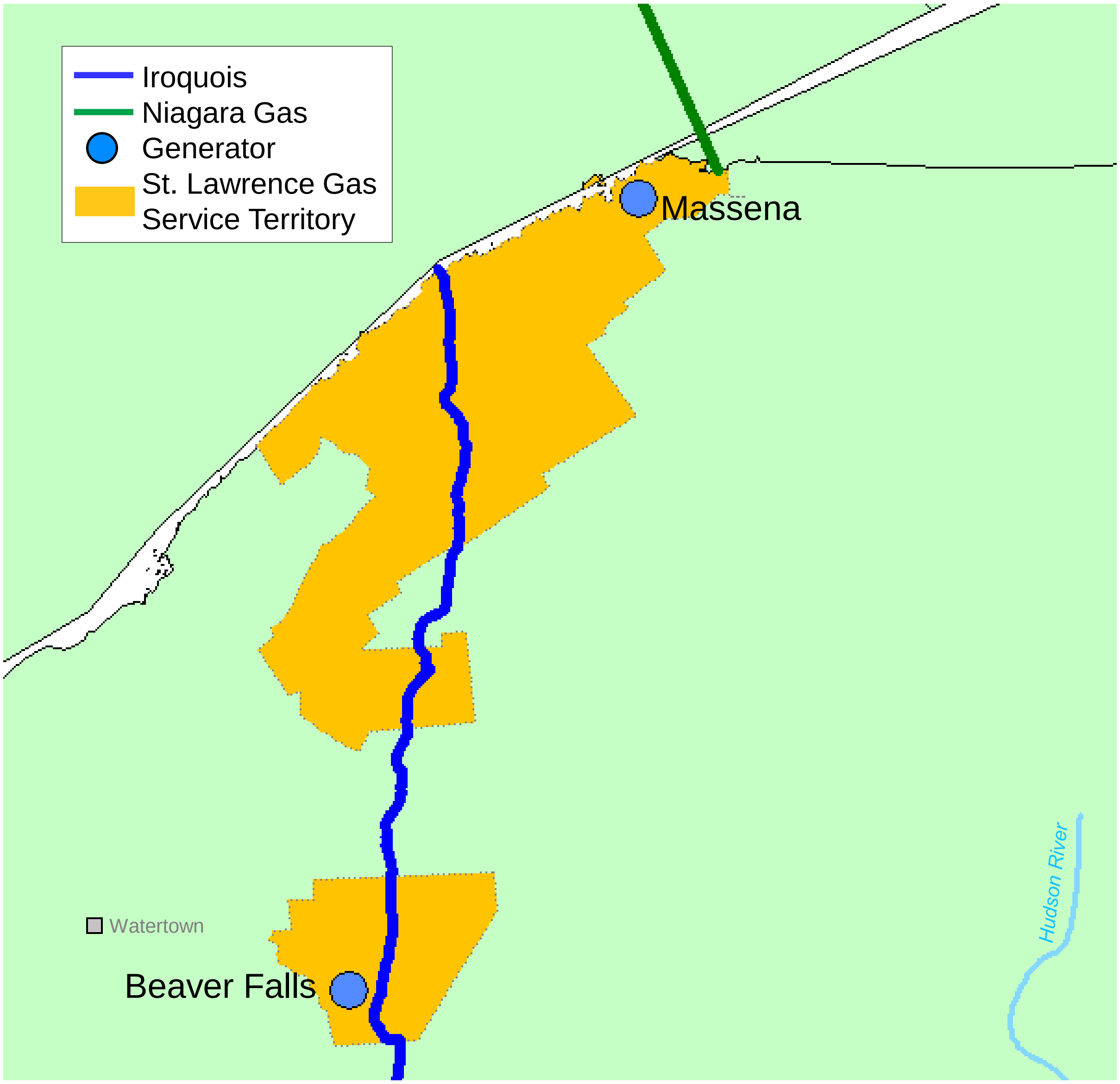
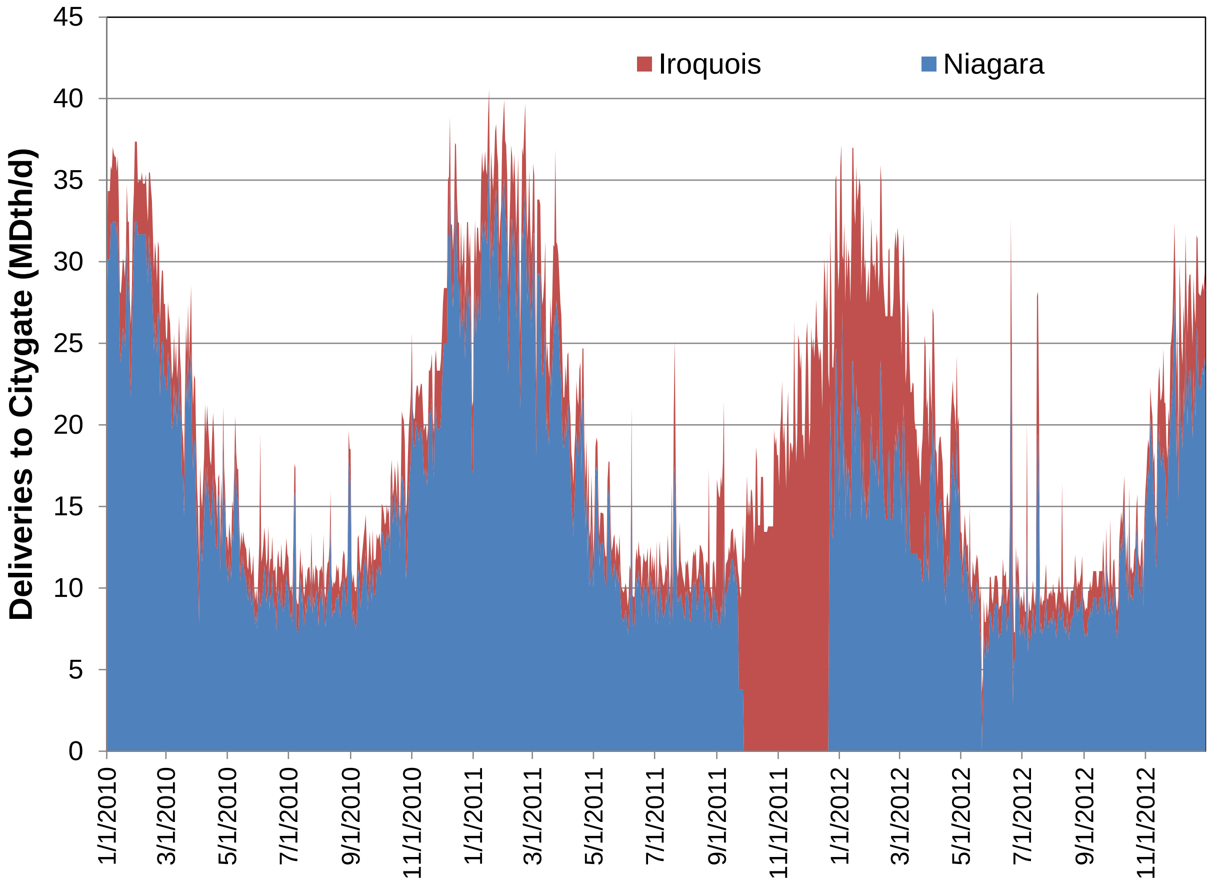


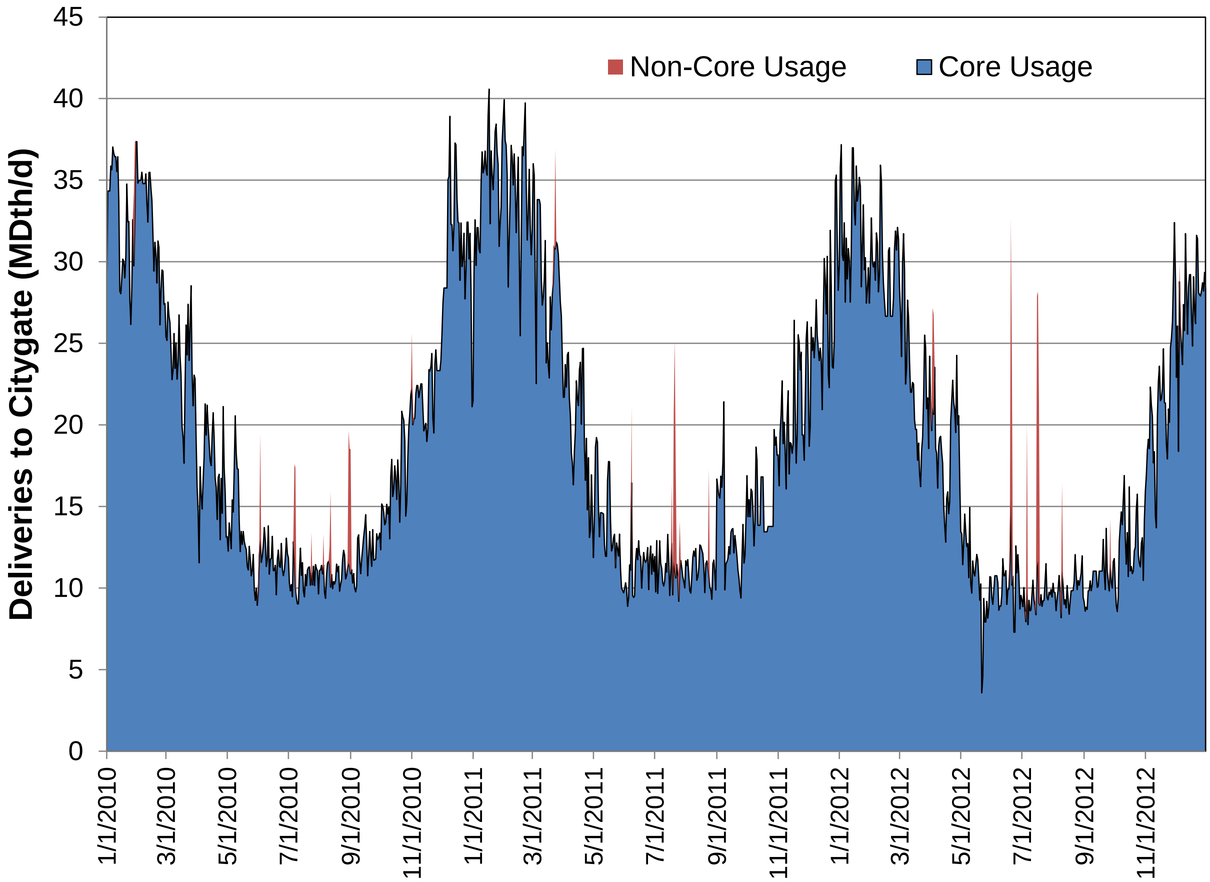
Figure 149. St. Lawrence Gas Deliveries by Pipeline



Of the plants modeled by NYISO, two are served by St. Lawrence Gas behind the citygate – Beaver Falls and Massena Energy.[101] Separating deliveries to the St. Lawrence Gas citygate by core and non-core usage yields the breakdown shown in Figure 150. The average core demand over the last three cooling seasons is 12 MDth/d.

[101] The original gas import authorization for Massena Energy (DOE Office of Fossil Energy Docket No. 90-33-NG) indicates that the supplies to serve the plant originate from Niagara Gas and are re-delivered via St. Lawrence Gas.

Figure 150. Core and Non-Core Usage Behind St. Lawrence Gas Citygate



3.5 Non-Core Demand

The non-core demand forecast was provided by NYISO for two cases – Base and +1,000-MW. NYISO modeled three years of generation demand for each case: 2013, 2016, and 2020. The Base Case includes incremental generation additions in Zones A (2013) and J (2020). The +1,000-MW Case includes a third incremental generator in the LHV (2016). LAI interpolated the intervening years which were not modeled, as shown in Figure 151. Because heating seasons bridge two years, the maximum demand between the start (in one calendar year) and end (in the next calendar year) of a given winter was determined to be the peak seasonal demand.

Figure 151. Interpolation of Non-Core Demand Data

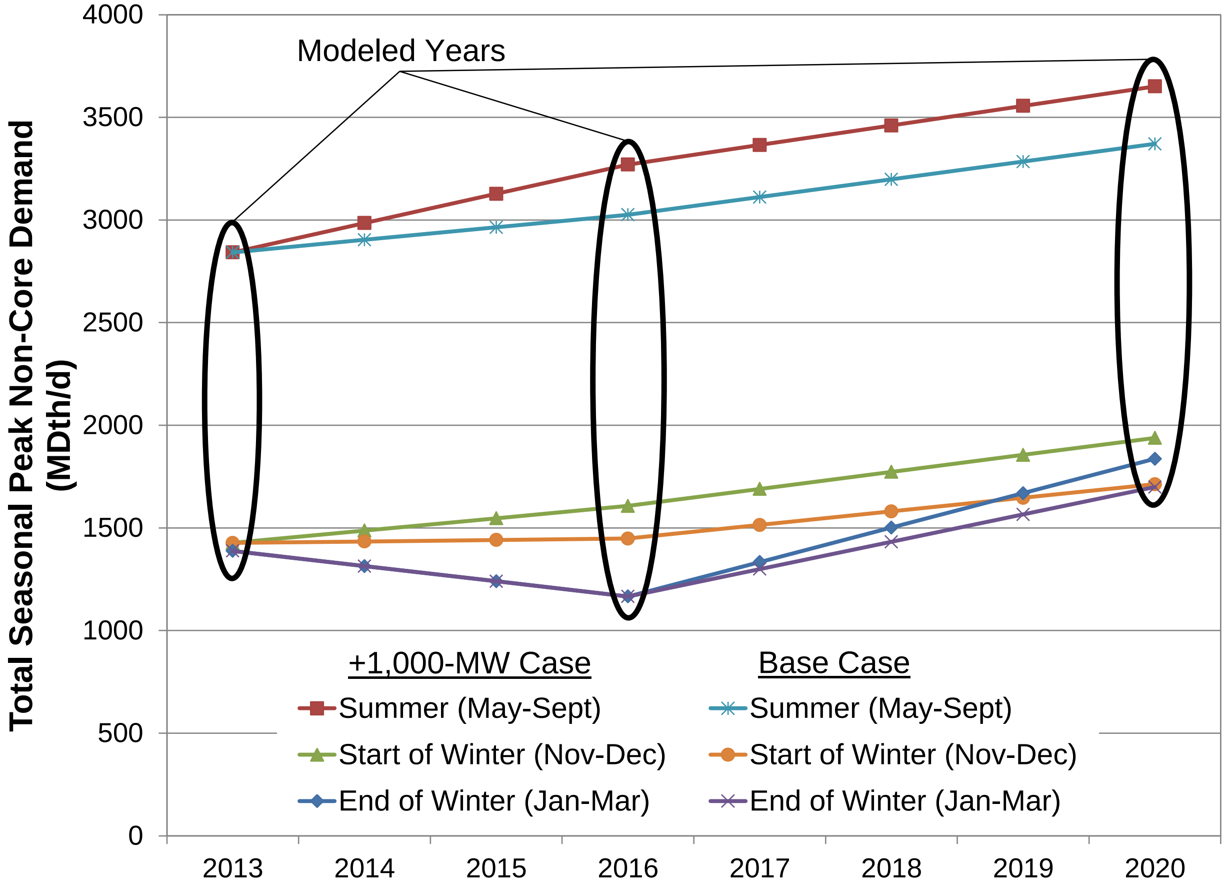
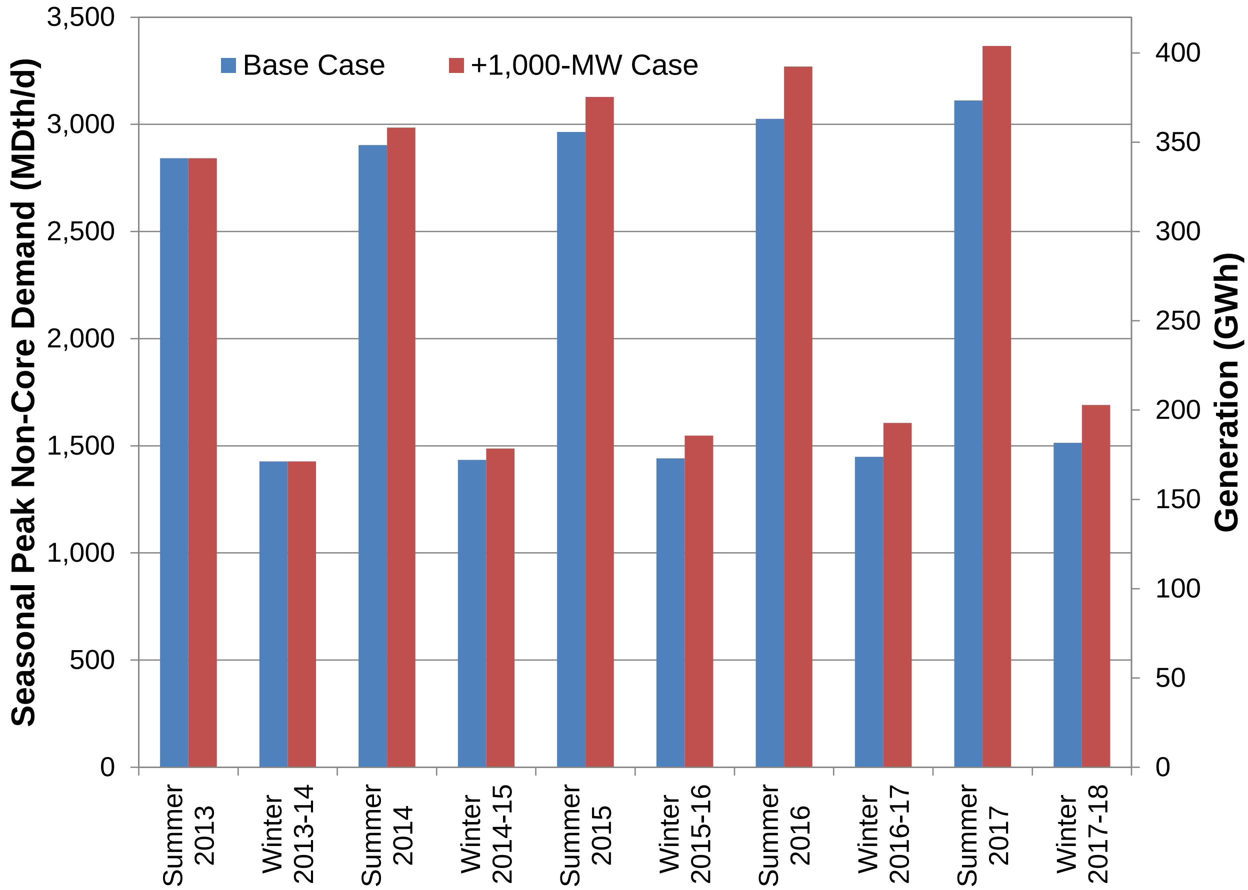


Table 46 summarizes the total non-core demand by season and Case. Figure 152 shows a comparison of the two evaluated demand cases.

Table 46. Non-Core Demand by Season and Case (MDth/d)

Heating Season	Winter 2012-13	Winter 2013-14	Winter 2014-15	Winter 2015-16	Winter 2016-17	Winter 2017-18
Base Case	1,388	1,427	1,434	1,441	1,448	1,514
+1,000-MW Case	1,388	1,427	1,487	1,547	1,607	1,690
Cooling Season	Summer 2013	Summer 2014	Summer 2015	Summer 2016	Summer 2017	
Base Case	2,842	2,903	2,964	3,025	3,112	
+1,000-MW Case	2,842	2,985	3,128	3,270	3,365	

Figure 152. Base v. +1,000-MW Case Non-Core Demand[102]



The two generators that are electrically connected to NYC but physically located in New Jersey, Bayonne Energy Center and Linden Cogen, are not included in the infrastructure adequacy results presented in the following section because they do not receive their gas via the New York Facilities System. The 512-MW Bayonne Energy Center is directly connected to Transco via the Bayonne Delivery Lateral, which went into service in April 2012 and has a capacity of 250 MDth/d.[103] The Bayonne Energy Center holds 125 MDth/d of lateral capacity, but does not have entitlements to mainline capacity. Whether or not Bayonne Energy Center has entered into a firm or secondary firm transportation with one or marketers is not known.[104] The location of the lateral and plant are shown in Figure 153, relative to the lateral off-take point downstream of Linden.[105] The Bayonne Energy Center has dual-fuel capability and can operate on oil in the event of an interruption in gas supply.

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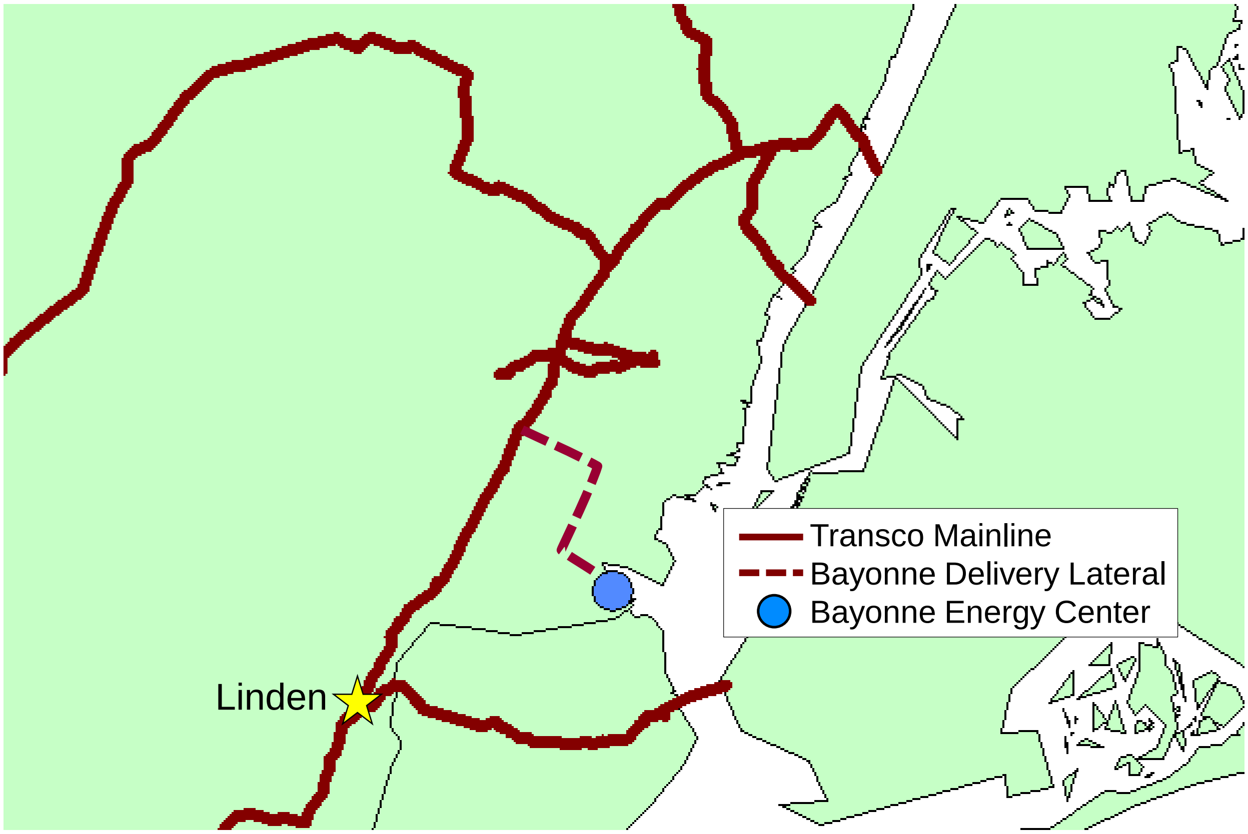
[102] The generation on the secondary axis is based on a heat rate of 8,334 Btu/kWh, calculated as the average system heat rate across the seasonal peak days in the years modeled by NYISO for the Base and +1,000-MW Cases.

[103] The Bayonne Energy Center serves NYC through a 6.75-mile 345-kV submarine cable which crosses New York Harbor to an interconnection with Consolidated Edison's Gowanus substation in Brooklyn.

[104] The remaining 125 MDth/d of lateral capacity is held by Hess.

[105] An analysis of historical mainline utilization at Linden is discussed in Section 2.8 on page 102.

Figure 153. Bayonne Delivery Lateral and Bayonne Energy Center



Linden Cogen's gas supply is served via two New Jersey LDCs: Public Service Electric & Gas (PSE&G) and Elizabethtown Gas. The gas sales agreements with the LDCs allow for supply to be interrupted on peak days when the temperature drops below 22°F. Linden Cogen holds 100,000 barrels of butane storage capacity at an adjacent refinery facility, but due to the high cost of butane and environmental considerations, among other factors, the primary backup to the LDC sales service is for Linden Cogen to arrange for natural gas to be delivered to the citygate and moved to the plant using the LDCs' transportation service.[106]

3.6 Infrastructure Adequacy Results

The following series of figures shows the progression of analyzing the flow balance inputs to determine the amount of supply and capacity available to serve the non-core demand. First, we will illustrate the heating season calculations over the study period.

Figure 154 shows the pipeline transportation balance, with upstream boundary flows shown as positive values and downstream boundary flows shown as negative values.

Figure 155 compounds the net boundary flow into NYCA from Figure 154 with in-state receipts to define the total available supply to serve in-state demand.

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[106] Linden Cogen maintains butane in storage as a backup fuel, and has investigated replacing butane with off-gas from the adjacent refinery.

Figure 154. Boundary Flows Into and Out of NYCA (Heating Season)

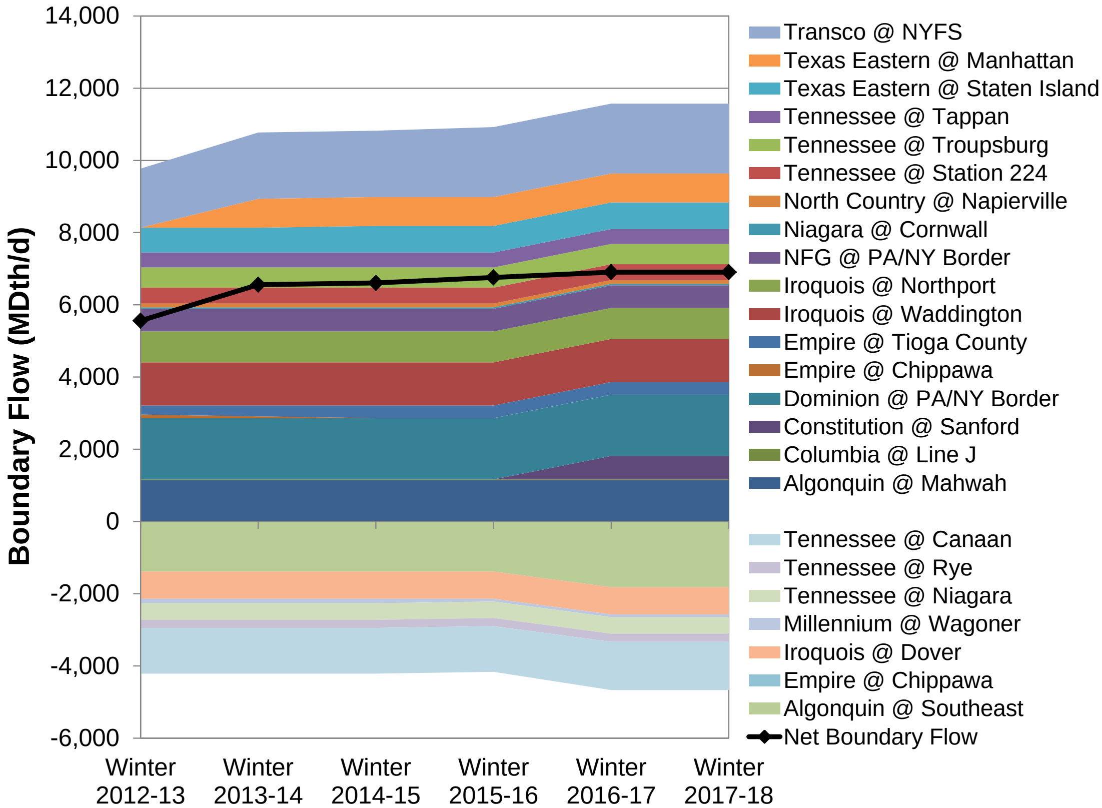


Figure 155. Total Supply Available to Serve Demand (Heating Season)

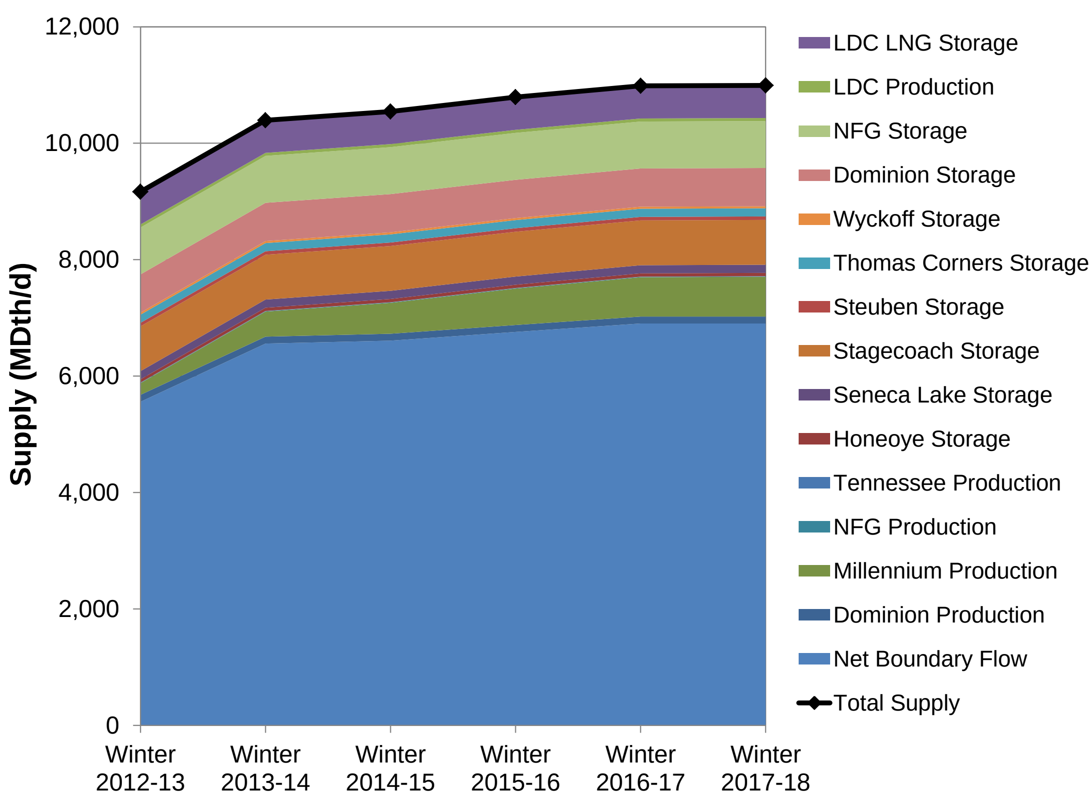


Figure 156 compares the total supply and transportation available to serve demand from Figure 155 against core demand to determine the residual deliverability to serve non-core demand.

Figure 156. Supply Relative to Core Demand (Heating Season)

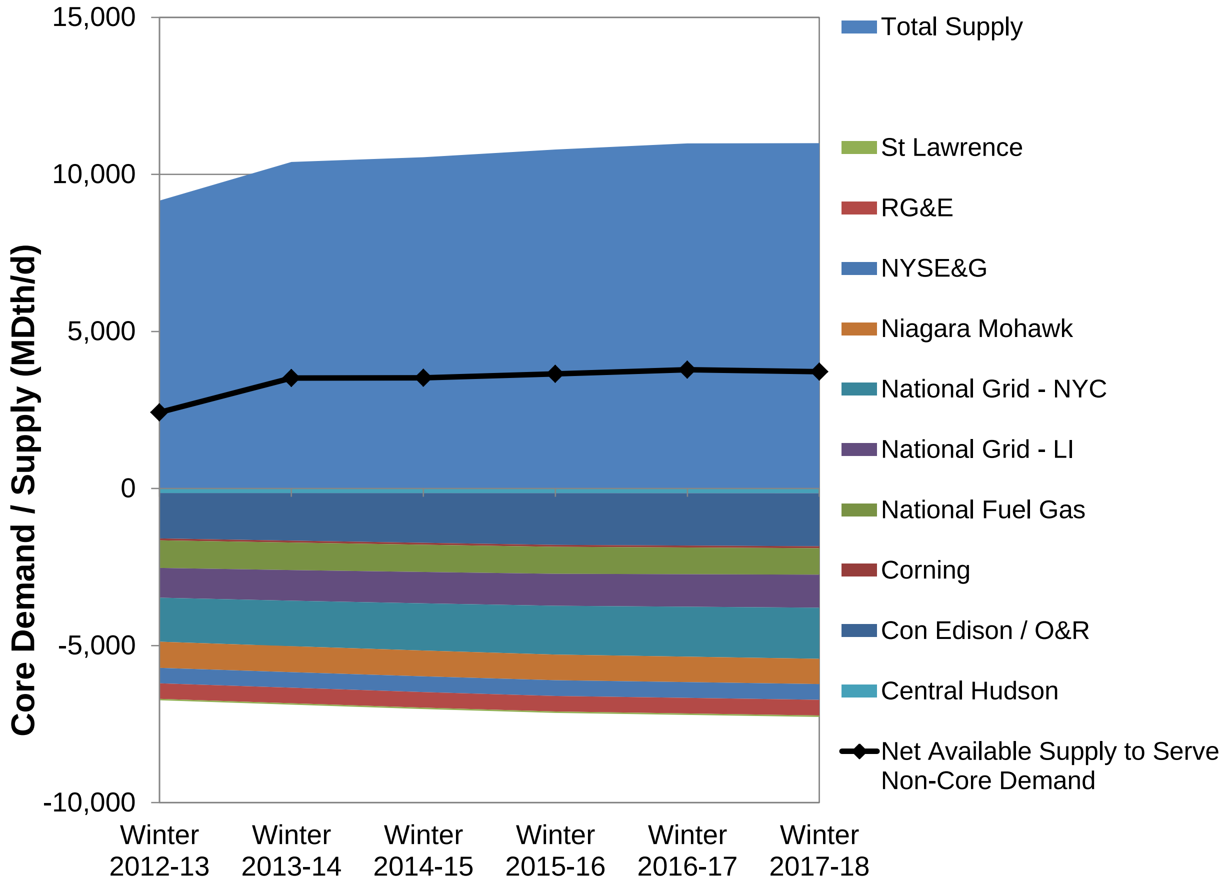


Figure 157 compares the available supply to serve non-core demand from Figure 156 against non-core demand over the study horizon for the Base Case. In the framework of this figure, positive values for residual available supply / unserved non-core demand, indicated by the heavy black line, indicate that throughout the study period, there is a surplus of supply and no unserved non-core demand on a state-wide basis. The +1,000-MW Case results, shown in Figure 157, are very similar, also showing no unserved non-core demand over the study horizon, on a state-wide basis.

Figure 157. Available Supply Relative to Non-Core Demand (Base Case, Heating Season)

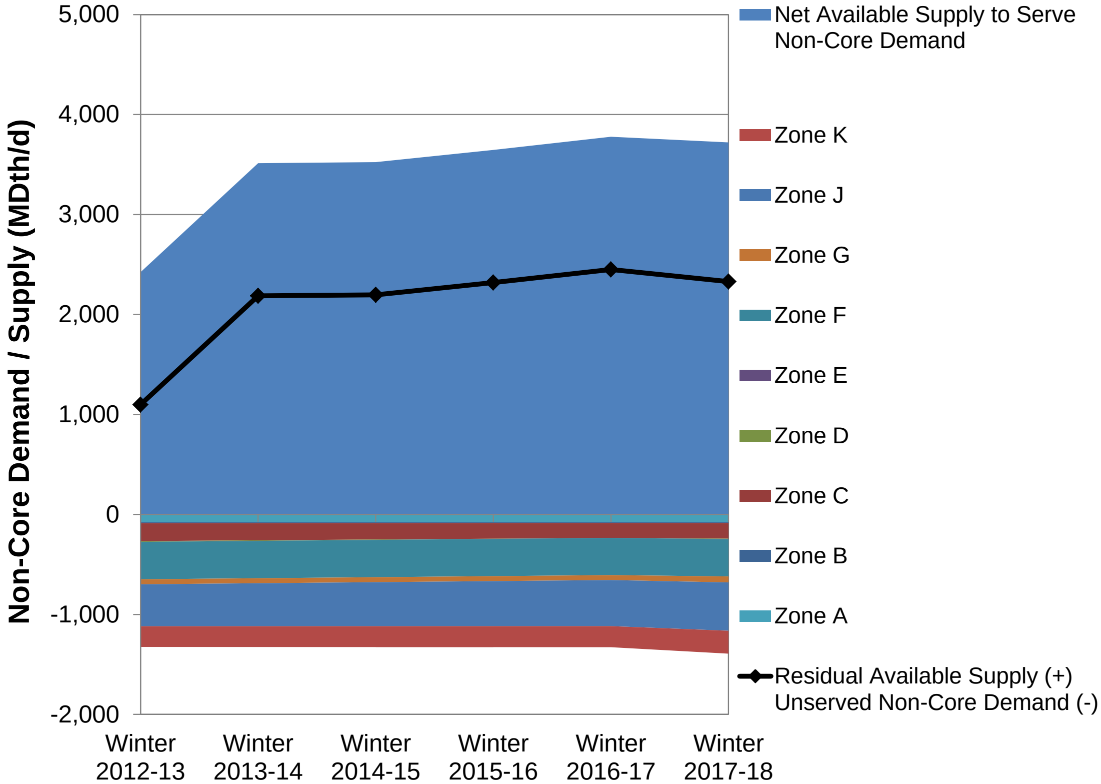


Figure 158. Available Supply Relative to Non-Core Demand (+1,000-MW Case, Heating Season)

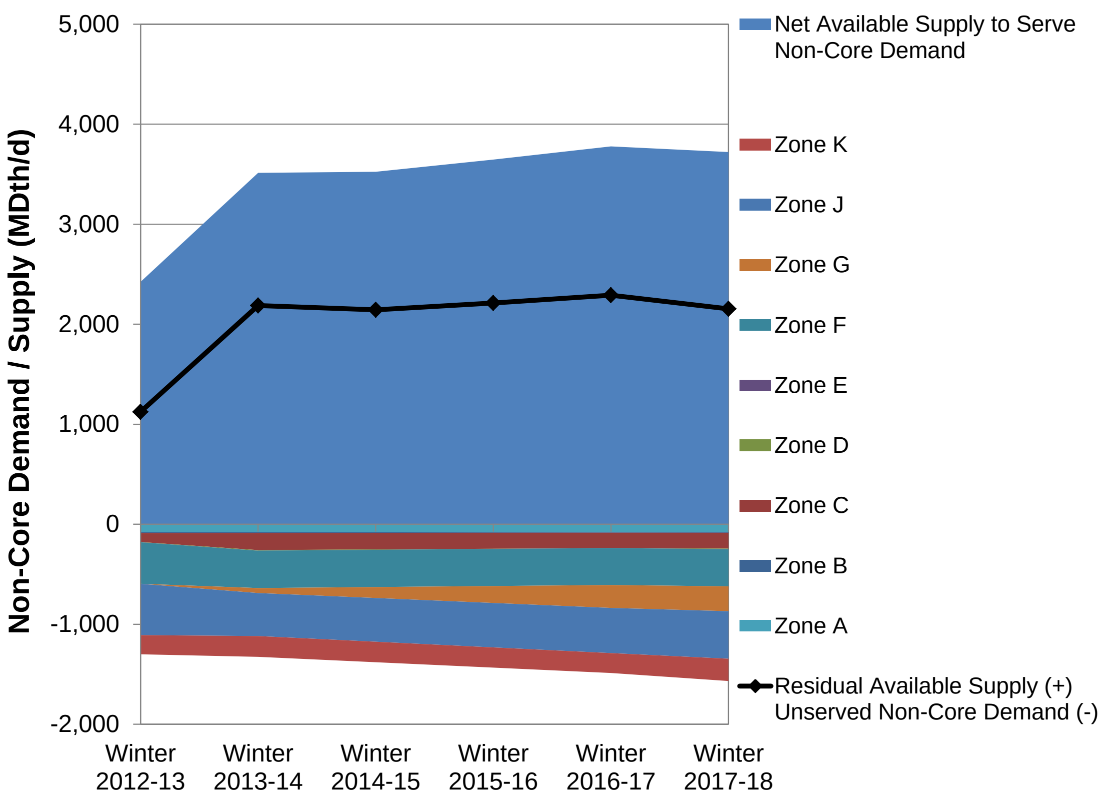


Figure 159 through Figure 162 show the same progression for the cooling seasons over the study horizon. Again, the Base Case and +1,000-MW Case have very similar results, with no unserved demand in either Case on a state-wide basis.

Figure 159. Boundary Flows Into and Out of NYCA (Cooling Season)

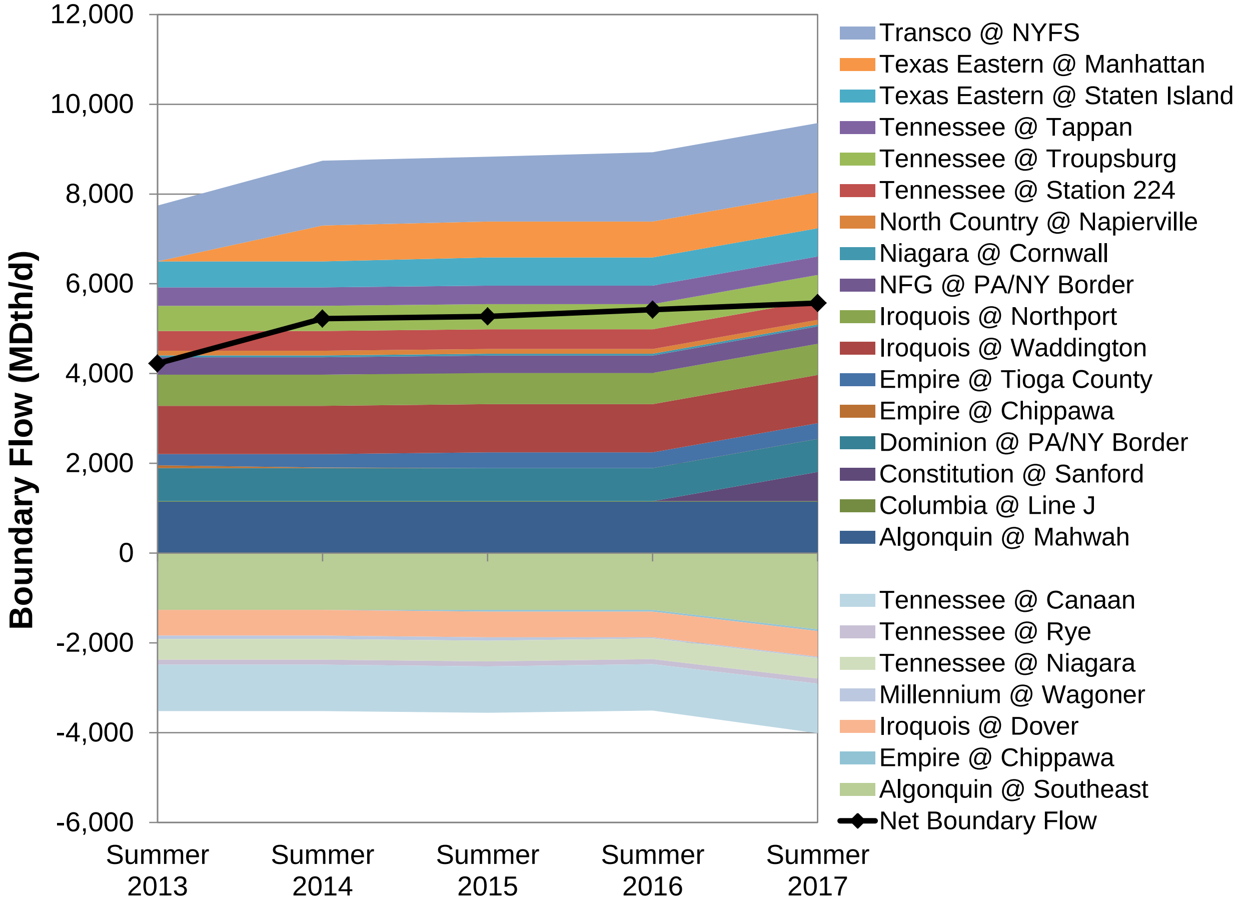


Figure 160. Total Supply Available to Serve Demand (Cooling Season)

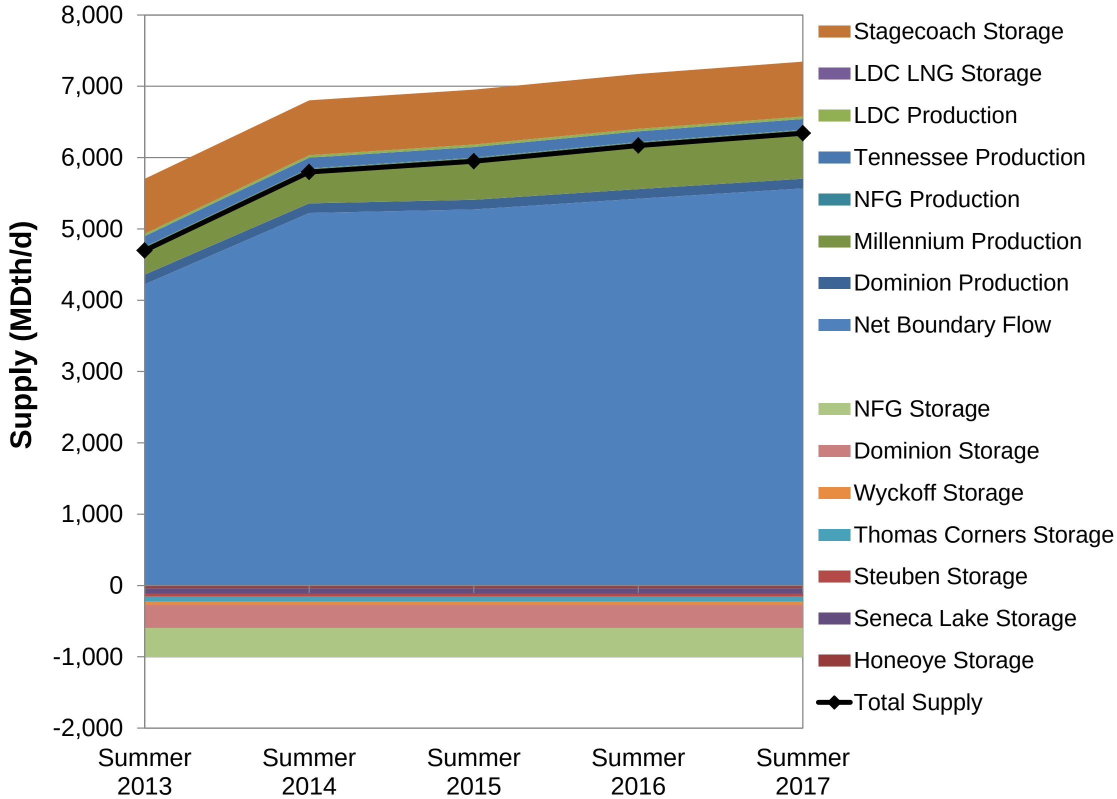


Figure 161. Supply Relative to Core Demand (Cooling Season)

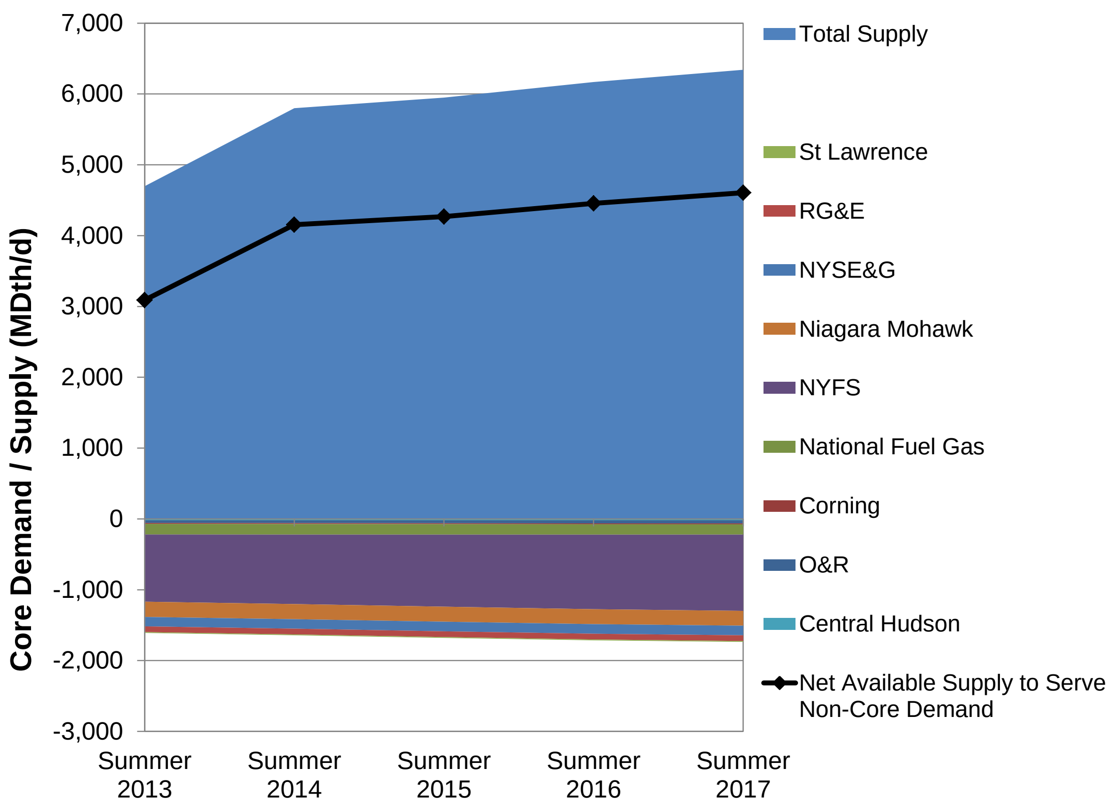


Figure 162. Available Supply Relative to Non-Core Demand (Base Case, Cooling Season)

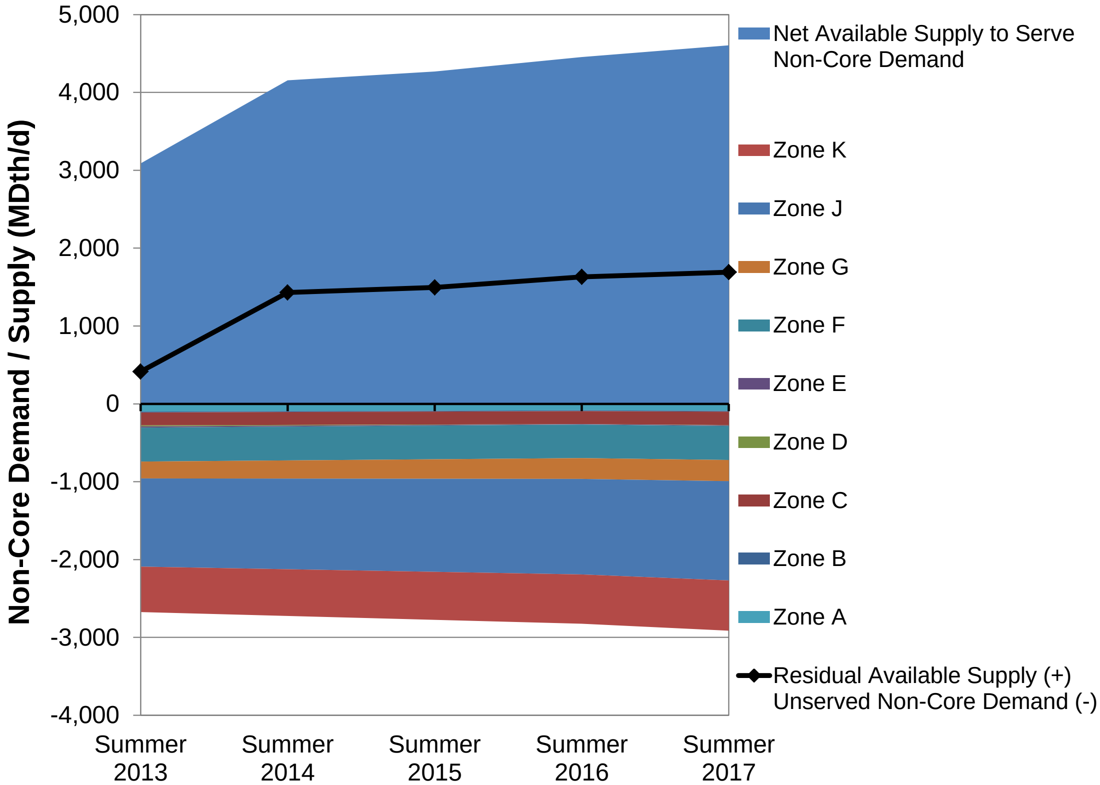
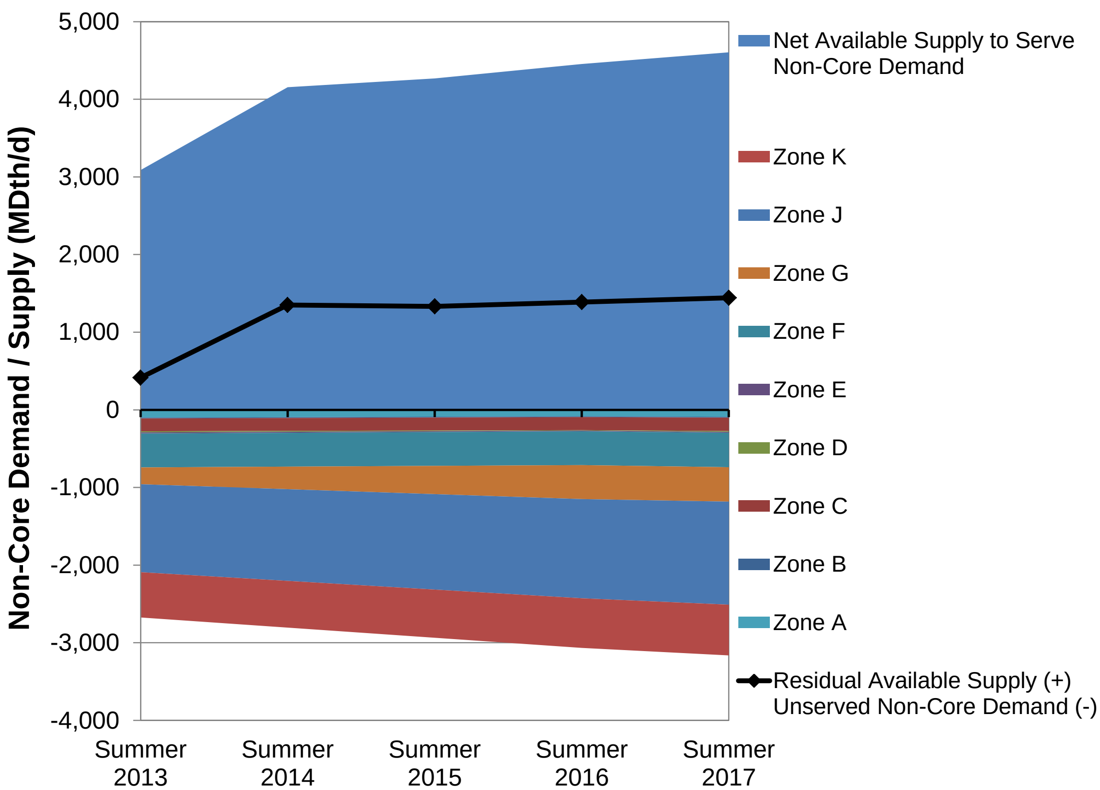


Figure 163. Available Supply Relative to Non-Core Demand (+1,000-MW Case, Cooling Season)



For both Cases in all future seasons, no unserved non-core demand is seen on a state-wide basis, due to the major infrastructure expansions that are due to be commercialized later this year, and the simplifying assumptions about new pipeline capacity additions over the remainder of the study period. The residual available supplies are summarized in Table 47.

Table 47. Residual Available Gas Supply by Season and Case

Heating Season	Winter 2012-13	Winter 2013-14	Winter 2014-15	Winter 2015-16	Winter 2016-17	Winter 2017-18
Base Case	1,098	2,187	2,197	2,318	2,449	2,328
+1,000-MW Case	1,098	2,187	2,144	2,212	2,290	2,153
Cooling Season	Summer 2013	Summer 2014	Summer 2015	Summer 2016	Summer 2017	
Base Case	414	1,431	1,494	1,630	1,691	
+1,000-MW Case	414	1,351	1,333	1,388	1,442	

Given the limitations of this modeling approach, we note that the derivation of the residual available gas supply should be construed as a reasonable upper limit insofar as scheduling constraints characteristic of the intra-day gas market when pipelines have posted OFOs are not captured therein.

Due to the concentration of non-core demand in NYC and on Long Island, we have also evaluated the flow balance of supply and demand around the New York Facilities System, shown for the heating season in Figure 164 and for the cooling season in Figure 165.[107] The +1,000-MW Case results are similar to those shown for the Base Case. While the 2012-13 heating season results indicate a shortage, downstate generation is not shown to be at risk over the five-year study horizon. The heating season residual supply margin is close to or less than the local LNG withdrawal capability. When pulling vapor from the satellite LNG tanks during cold snaps, Con Edison and NGrid will likely continue to curtail deliveries to non-firm customers.

[107] The net boundary flows for the New York Facilities System model slightly overestimate the capacity that is delivered into the New York Facilities System from Tennessee, because meters other than White Plains are served by the 300 Line.

Figure 164. NYFS Deliverability (Base Case, Heating Season)

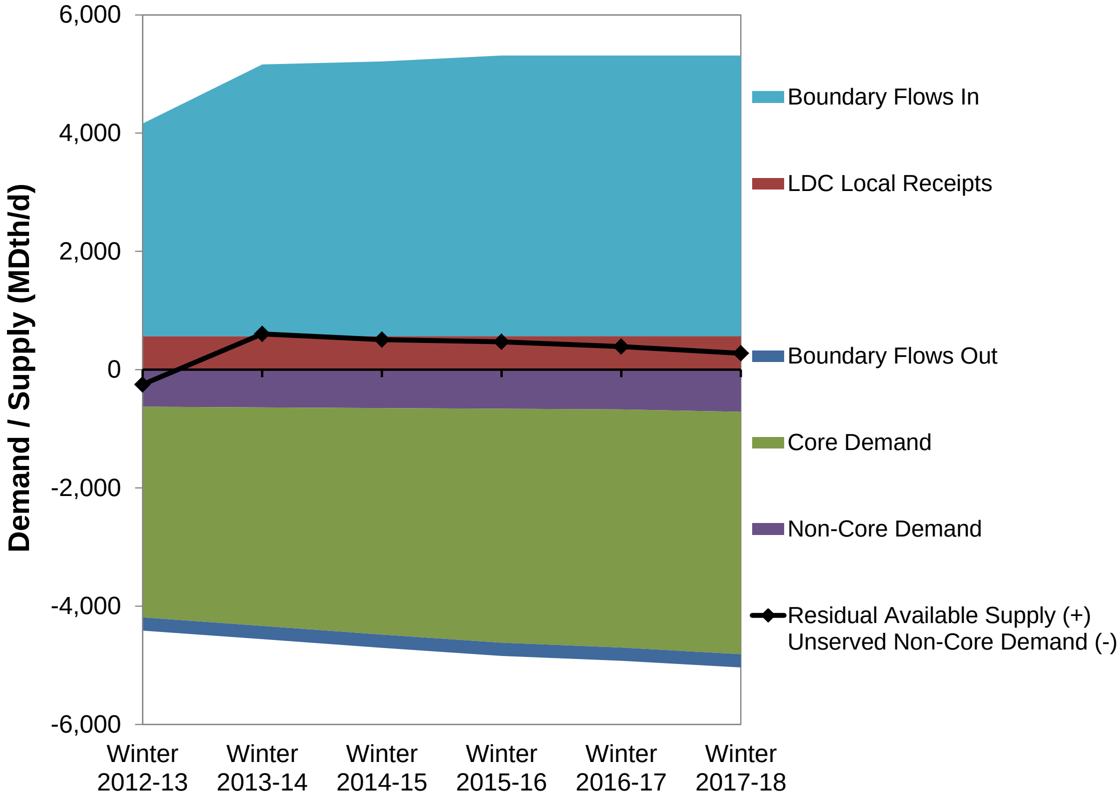
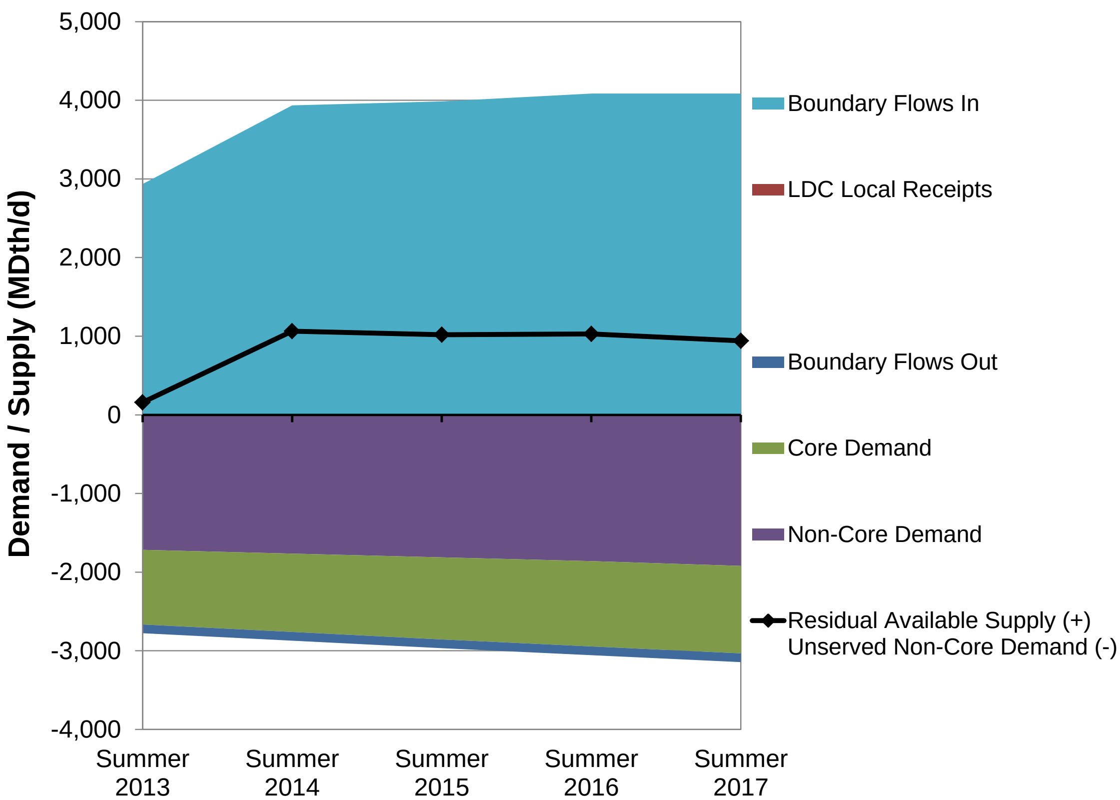


Figure 165. NYFS Deliverability (Base Case, Cooling Season)



3.7 Pipeline Capacity to Serve Generation on Peak Electric Days

In addition to the Base and +1,000-MW Cases, NYISO modeled a third generation gas demand scenario (the "+2,000-MW Case") with 1,000 MW of incremental generation in the LHV, in addition to the 1,000 MW of new LHV generation modeled in the +1,000-MW Case. In this section, we present the available pipeline capacity to serve non-core demand relative to the generator demand on the top ten peak electric days in the 2016-17 heating season and the 2016 cooling season.

Figure 166 shows the load duration curves for the Base, +1,000-MW and +2,000-MW Cases for November and December of 2016. These curves include the Bayonne and Linden Cogen plants located in New Jersey.

Figure 166. 2016-17 Heating Season Load Duration Curves[108]

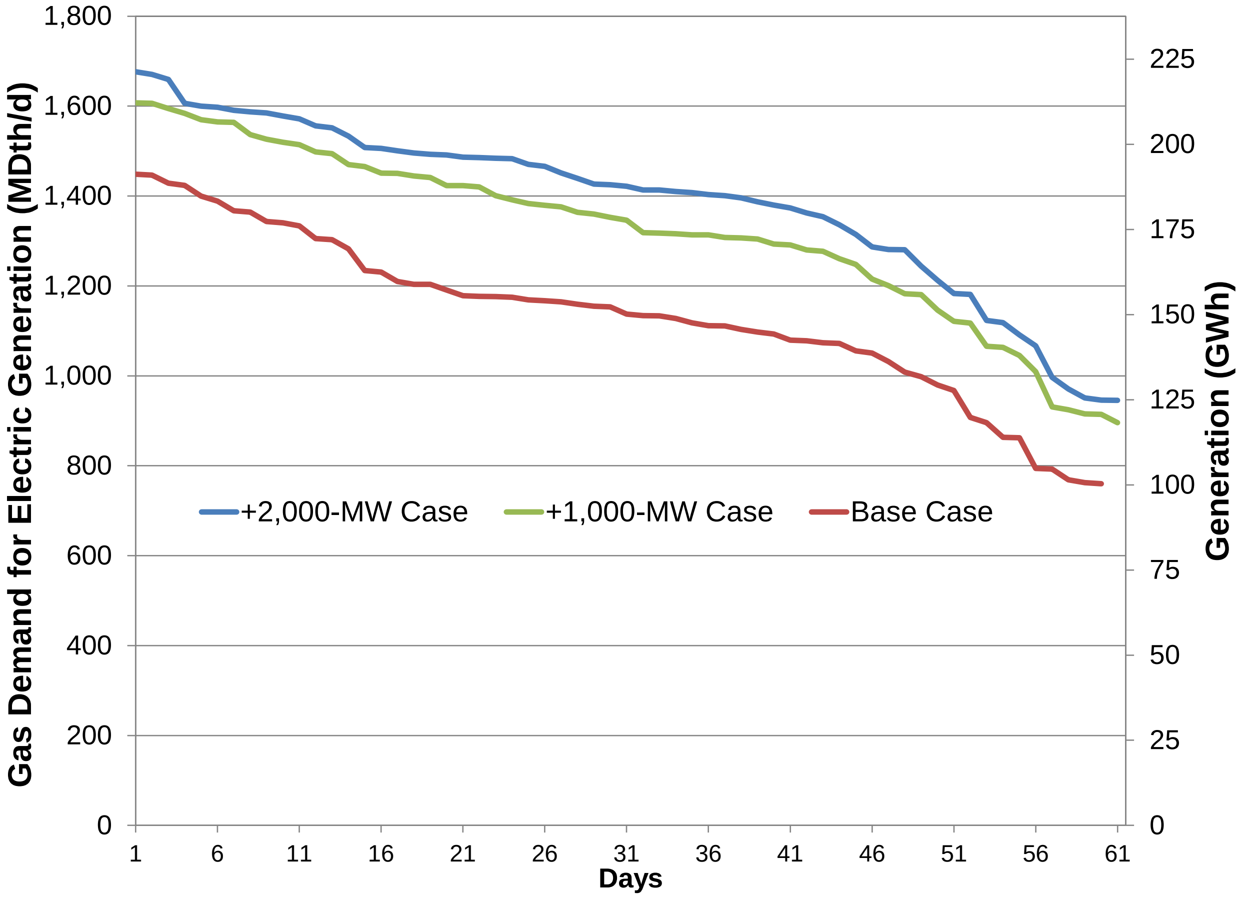


Figure 167 shows the non-core gas demand for the top ten heating season days in the Base and +2,000-MW Cases relative to the calculated Net Available Supply to Serve Non-Core Demand (derived in Figure 156). In order to present the supply and demand data on the same basis, gas demand for the Bayonne and Linden Cogen plants is not included here.

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108 The generation shown on the secondary axis is based on a system heat rate of 7,575 Btu/kWh, *i.e.*, the average system heat rate for all gas-fired plants across all three Cases for the peak days from November and December 2016.

Figure 167. Non-Core Demand on Top Ten Heating Season Days

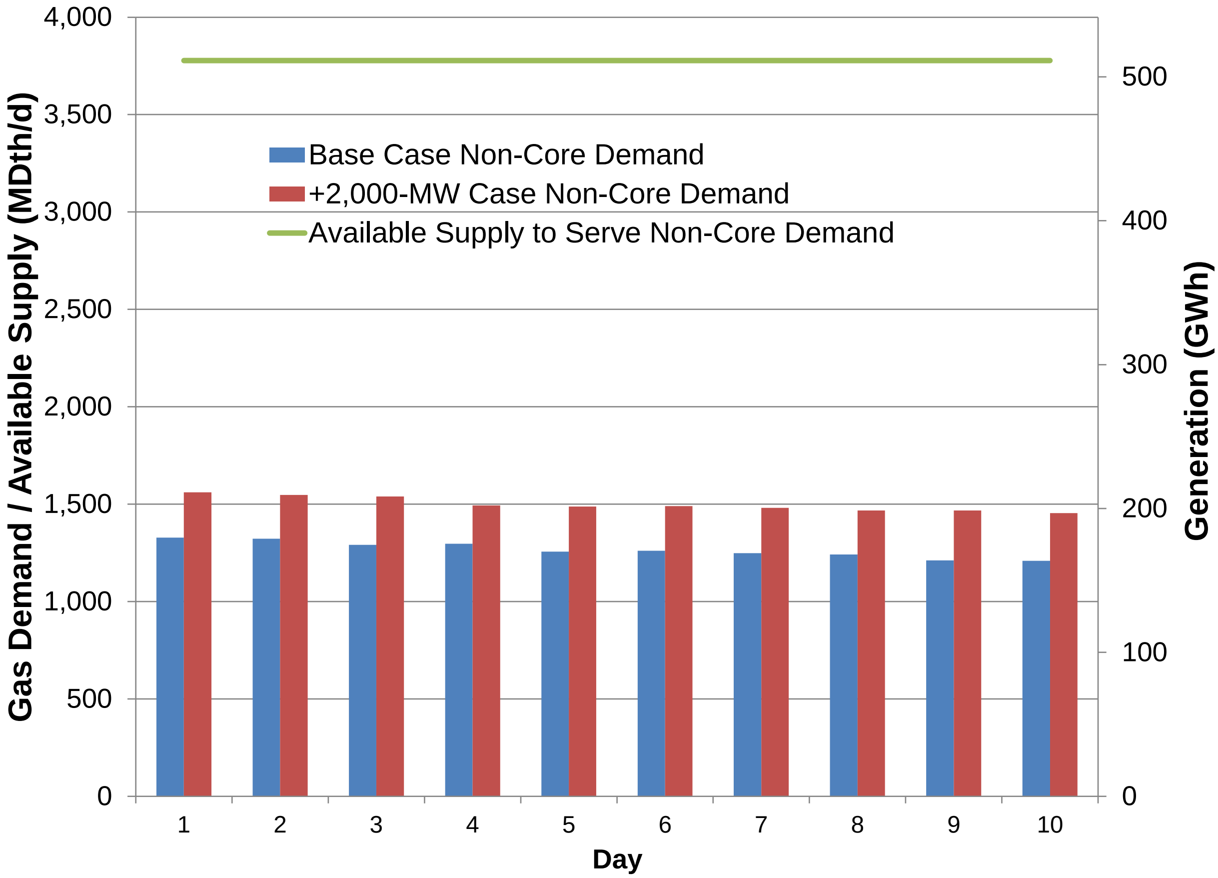


Figure 168 shows the load duration curves for the Base, +1,000-MW and +2,000-MW Cases for May through September 2016. These curves include the Bayonne and Linden Cogen plants located in New Jersey.

Figure 168. 2016 Cooling Season Load Duration Curves[109]

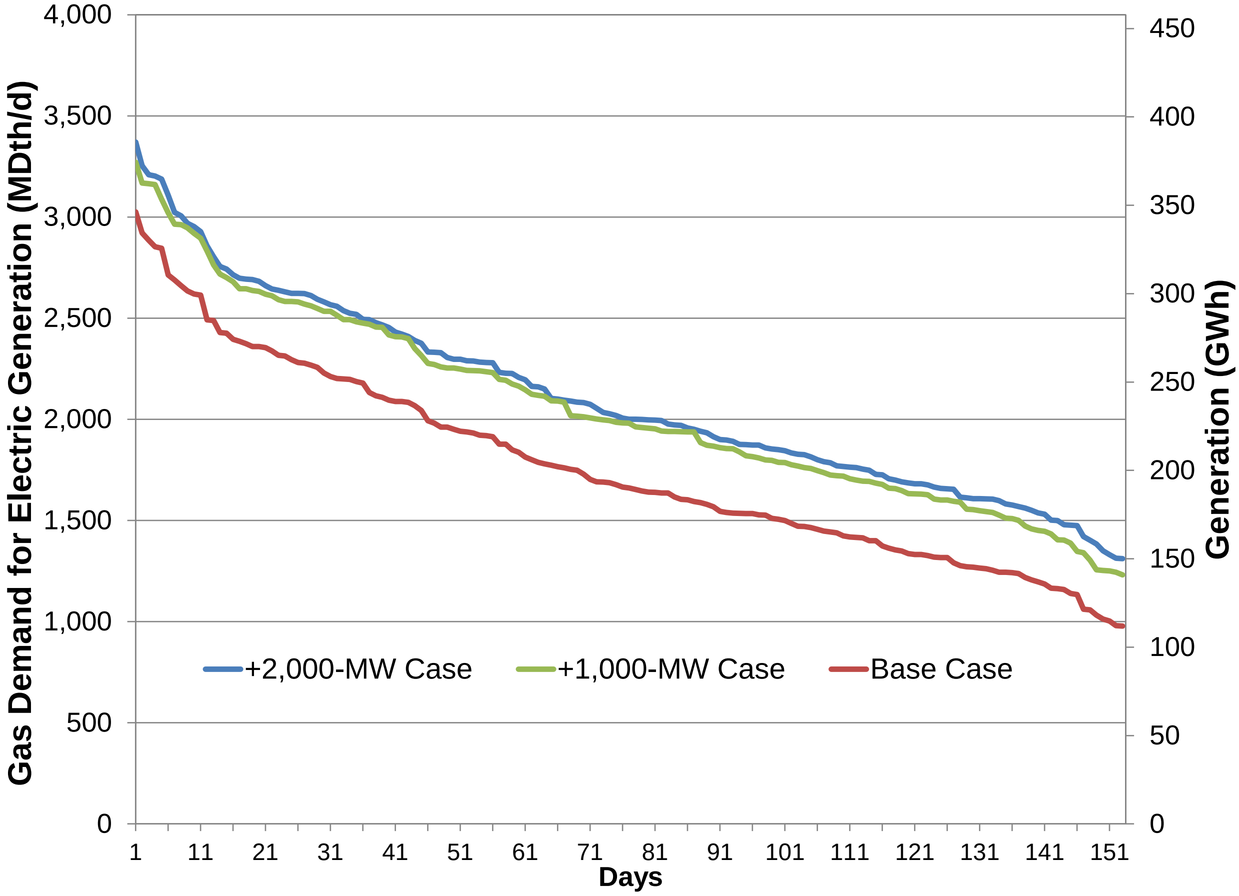
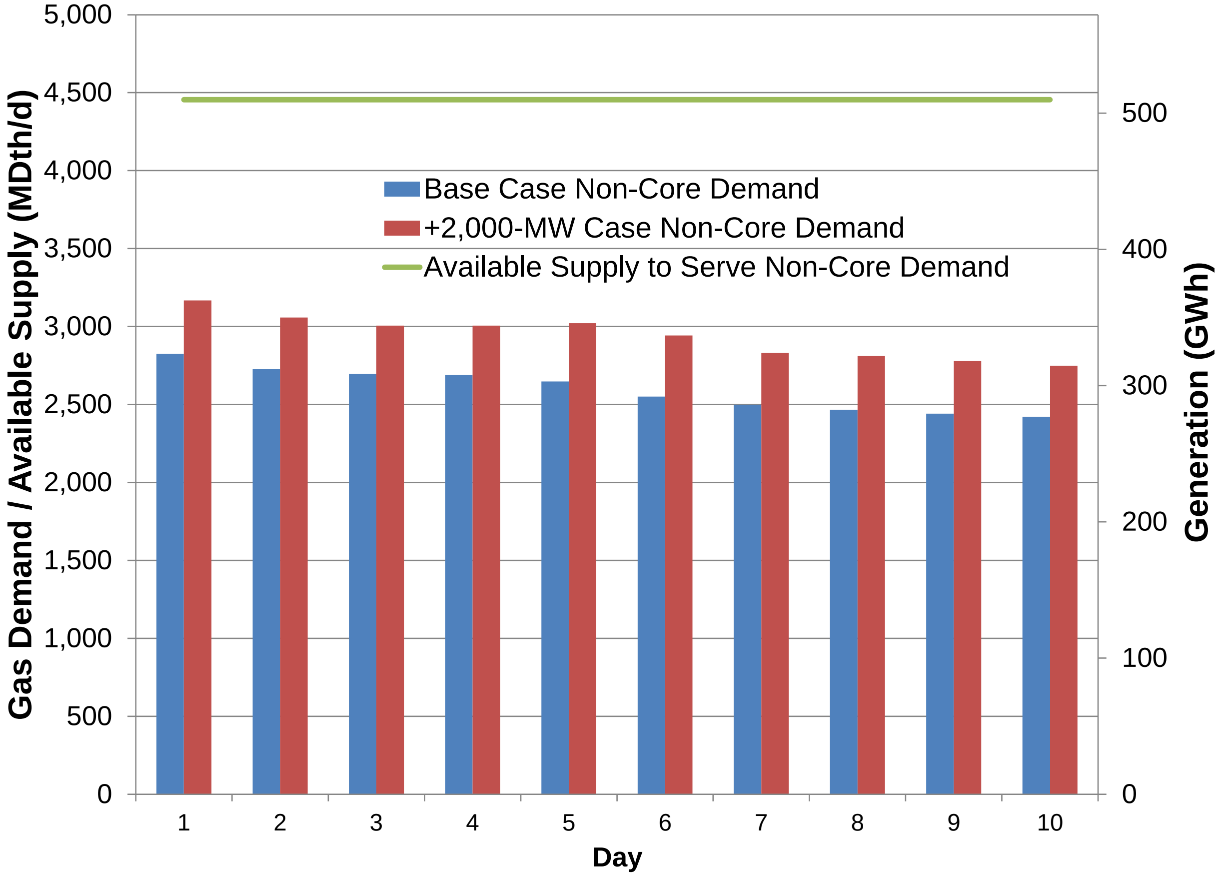


Figure 167 shows the non-core gas demand for the top ten cooling season days in the Base and +2,000-MW Cases relative to the calculated Net Available Supply to Serve Non-Core Demand (derived in Figure 156). In order to present the supply and demand data on the same basis, gas demand for the Bayonne and Linden Cogen plants has been excluded.

[109] The generation shown on the secondary axis is based on a system heat rate of 8,737 Btu/kWh, calculated as the average system heat rate for all gas-fired plants across all three Cases for the peak days from May through September 2016.

Figure 169. Non-Core Demand on Top Ten Cooling Season Days



The relationships between the modeled available supply to serve non-core demand and non-core demand on the top ten days in each season illustrate that deliverability on a NYCA-wide basis is sufficient to meet demand. During the heating season, the demand on the tenth-highest day is 91% of the peak day demand for the Base Case, and 93% for the +1,000-MW Case. During the cooling season, the demand on the tenth-highest day is 86% of the peak day demand for the Base Case, and 87% for the +1,000-MW Case. These percentages indicate a relatively steep drop-off in demand, more so during the summer. Hence, even if deliverability were to be tight on the peak day, the constraint would be short in duration.

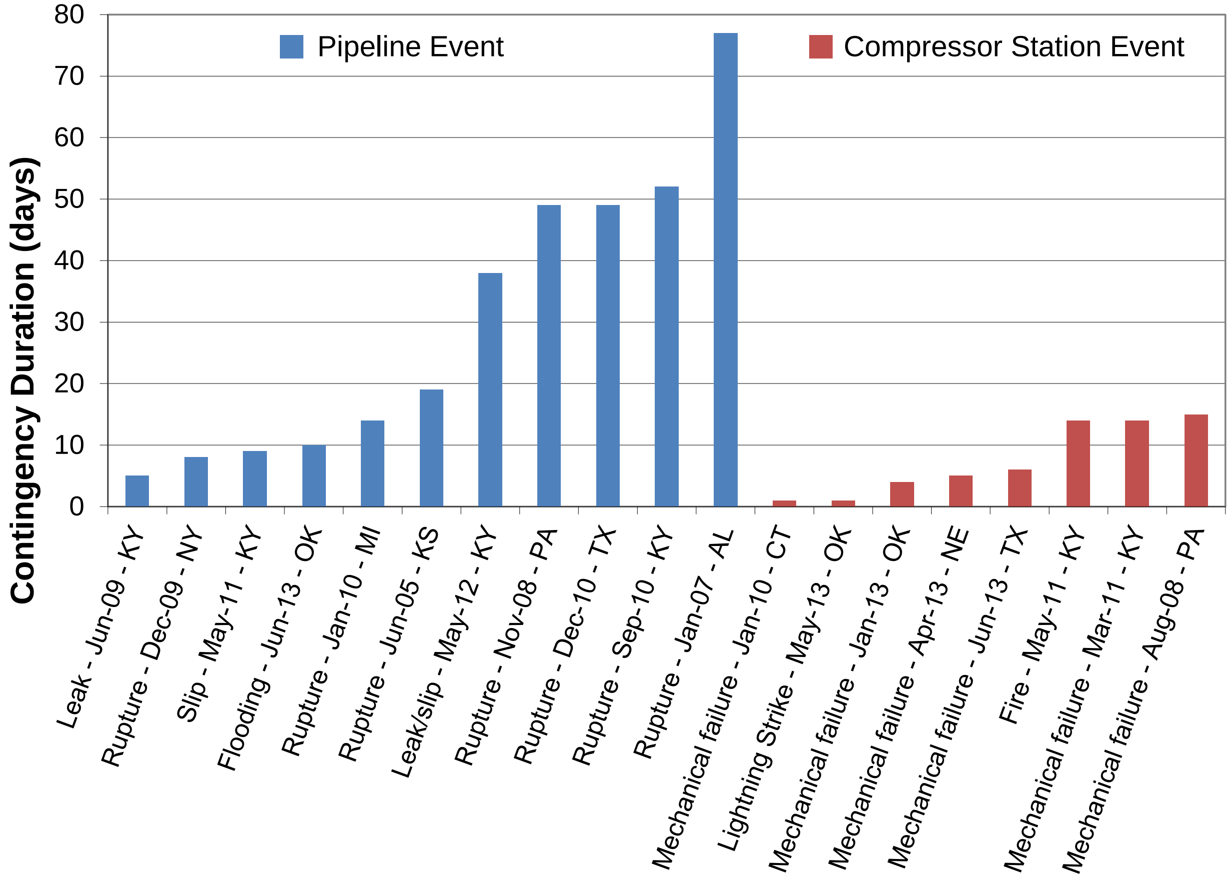
3.8 Contingency Assessment

When an operating contingency occurs, pipelines and LDCs work closely and aggressively with one another in order to implement emergency measures to protect deliverability to the maximum extent possible. The pipelines and LDCs doing business on the New York Facilities System undertake substantial planning activities on a regular basis to coordinate maintenance and to minimize scheduling disruptions. Also, annual operational drills are held to facilitate efficient responsiveness in the event of a contingency. While there are no hard standards regarding the sustainability of pipeline workarounds when gas side contingencies occur during the peak heating season, or, to a lesser extent, during the peak cooling season, the high degree of pipeline integration and resiliency among the NYCA pipelines compensate for a short duration loss of a pipeline segment or compressor station. LAI has found that flexibility is generally adequate such that most contingencies can be mitigated with limited impacts on customer deliveries, except during peak demand periods. The Pipeline and Hazardous Materials Safety Administration (PHMSA) mandates inspection cycles as frequently as every seven years, depending on the characteristics and location of the pipe segment. Pipelines schedule these inspections as part of their standard maintenance cycles during the lower-demand shoulder months. Therefore if anomalies are detected that require further inspection or repair, impacts on core and non-core customers alike are typically minimized.

LAI has conducted a review of national contingency events in order to gain a broader perspective on the potential duration of service impacts following adverse events at compressor stations or along pipeline segments. Findings are based on public information from pipeline EBBs and PHMSA incident reports. The pipeline incidents include leaks, slips, and ruptures of pipes ranging from fourteen to twenty-six inches in diameter, with repair times ranging from five days to eleven weeks. The reported causes of compressor station incidents include fire, mechanical failure, and lightning strike, with repair times ranging from one to fifteen days. These outage durations are summarized in Figure 170.[110] The events shown occurred across the country from June 2005 through June 2013. This is not intended to be an exhaustive list of national contingency events, due to data availability limitations. While events requiring unscheduled compressor maintenance occur much more frequently than pipeline ruptures, due to the nature of mechanical turbine operations, significantly disruptive events of either type are rare.

[110] The likelihood of occurrence for each event cause and duration is outside the scope of this inquiry.

Figure 170. Contingency Event Causes and Durations



One noteworthy trend consistent throughout the *force majeure* notices from the pipeline EBBs was an initial underestimation of the time required to complete system repairs following a contingency event. Of the eight EBB-sourced events that included an initial estimate of repair times, six underestimated the necessary repair time by a factor of two or more. This trend was consistent for both mainline and compressor station events.

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