Eastern Interconnection Planning Collaborative

Gas-Electric System Interface Study

Existing Natural Gas-Electric System Interfaces

DOE Award Project
DE-OE0000343

Final Draft

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LEVITAN & ASSOCIATES, INC.

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Glossary

AECO	Alberta gas pricing hub
AEK	Atmos Energy Kentucky
AMA	Asset Management Agreement
Bcf	Billion cubic feet
CBS	Customer balancing service
CCT	Central clock time
CDE	Contract demand energy
CHP	Combined heat and power
Con Edison	Consolidated Edison Co. of New York
DAM	Day-Ahead Market
Delmarva	Delmarva Power & Light
DOE	Department of Energy
DOT	Department of Transportation
Dth	Dekatherm
EA	Environmental Assessment
EBB	Electronic Bulletin Board
EIPC	Eastern Interconnection Planning Collaborative
EIS	Environmental Impact Statement
EISPC	Eastern Interconnection States Planning Council
Enbridge	Enbridge Gas Distribution
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FOA	Funding Opportunity Announcement
FT	Firm Transmission
FT-SN	Firm Transmission-Short Notice
GAO	Government Accountability Office
GJ	Gigajoule
Gulf	Gulf of Mexico
IESO	Independent Electricity System Operator of Ontario
INGAA	Interstate Natural Gas Association of America
ISO-NE	Independent System Operator--New England
IT	Interruptible Transportation
LAI	Levitan & Associates, Inc.
LDC	Local distribution company
LNG	Liquefied natural gas
MAOP	Maximum allowable operating pressure
Marcellus	Marcellus shale natural gas producing region
MDQ	Maximum daily quantity
MDth	Thousand dekatherms
MISO	Midcontinent Independent System Operator
MMBtu	Million British thermal units
MMcf	Million cubic feet
MW	Megawatt
MWh	Megawatt hour
NAESB	North American Energy Standards Board
NAPSR	National Association of Pipeline Safety Representatives
NEB	National Energy Board
NEPA	National Environmental Policy Act
NIPSCO	Northern Indiana Public Service Company
NYC	New York City

NYCA New York Control Area

NYISO New York Independent System Operator

NYPSC New York Public Service Commission

NYSRC New York State Reliability Council

OBA Operating Balance Agreement

OEB Ontario Energy Board

OFO Operational Flow Order

OPS Office of Pipeline Safety

Petajoule Petajoule

PGA Purchased gas adjustment

PHMSA Pipeline and Hazardous Materials Safety Administration

PJM PJM Interconnection

PPA Participating Planning Authority

PSE&G Public Service Electric & Gas Co.

RAM Risk Alleviation Mechanism

ROFR Right-of-first-refusal

ROW Right-of-way

RTM Real-Time Market

RTO Regional Transmission Organization

SNB Short Notice Balancing

STFT Short-Term Firm Transportation

ST-SN Short-term Short Notice

TAQ Total Authorized Quantity

Tcf Trillion cubic feet

TSA Transportation Security Administration

TSP Transmission service provider

TVA Tennessee Valley Authority

VAC Value added charge

WCSB Western Canadian Sedimentary Basin

WEQ Wholesale Electric Quadrant

WGL Washington Gas Light

WGQ Wholesale Gas Quadrant

List of Interstate Pipelines

Algonquin	Algonquin Gas Transmission LLC
Alliance	Alliance Pipeline LP
AM AlaTenn	American Midstream (AlaTenn) LLC
AM MidLa	American Midstream (MidLa) LLC
ANR	ANR Pipeline Company
Big Sandy	Big Sandy Pipeline LLC
Bison	Bison Pipeline LLC
CNYOG	Central New York Oil And Gas LLC
Columbia Gas	Columbia Gas Transmission LLC
Columbia Gulf	Columbia Gulf Transmission LLC
Crossroads	Crossroads Pipeline Company
Destin	Destin Pipeline Company LLC
Dominion	Dominion Transmission, Inc.
Dominion Cove Point	Dominion Cove Point LNG, LP
East Tennessee	East Tennessee Natural Gas LLC
Eastern Shore	Eastern Shore Natural Gas Company
Egan	Egan Hub Storage LLC
Empire	Empire Pipeline, Inc.
Enable	Enable Gas Transmission LLC
Equitrans	Equitrans, LP
Fayetteville Express	Fayetteville Express Pipeline LLC
Florida Gas	Florida Gas Transmission Company LLC
Granite State	Granite State Gas Transmission, Inc.
Great Lakes	Great Lakes Gas Transmission LP
Guardian	Guardian Pipeline LLC
Gulf Crossing	Gulf Crossing Pipeline Company LLC
Gulf South	Gulf South Pipeline Company, LP
Horizon	Horizon Pipeline Company LLC
Iroquois	Iroquois Gas Transmission System, LP
KM Illinois	Kinder Morgan Illinois Pipeline LLC
KM Louisiana	Kinder Morgan Louisiana Pipeline LLC

KO	KO Transmission Company
M&N	Maritimes & Northeast Pipeline LLC
Midcontinent Express	Midcontinent Express Pipeline LLC
Midwestern	Midwestern Gas Transmission Company
Millennium	Millennium Pipeline Company LLC
Mississippi River	Enable Mississippi River Transmission LLC
MoGas	MoGas Pipeline LLC
NFG	National Fuel Gas Supply Corporation
NGPL	Natural Gas Pipeline Company of America LLC
NGO	NGO Transmission, Inc.
Northern Border	Northern Border Pipeline Company
Northern Natural	Northern Natural Gas Company
Ozark	Ozark Gas Transmission LLC
Panhandle Eastern	Panhandle Eastern Pipe Line Company, LP
PNGTS	Portland Natural Gas Transmission System
Rockies Express	Rockies Express Pipeline LLC
Sabine	Sabine Pipe Line LLC
Southeast Supply Header	Southeast Supply Header LLC
Southern	Southern Natural Gas Company LLC
Southern Star Central	Southern Star Central Gas Pipeline, Inc.
Tennessee	Tennessee Gas Pipeline Company LLC
Texas Eastern	Texas Eastern Transmission, LP
Texas Gas	Texas Gas Transmission LLC
Tiger	ETC Tiger Pipeline LLC
TransCanada	TransCanada PipeLines Ltd.
Transco	Transcontinental Gas Pipe Line Company LLC
Trans-Union	Trans-Union Interstate Pipeline, L.P.
Trunkline	Trunkline Gas Company LLC
Union Gas	Union Gas Ltd.
USG	USG Pipeline Company LLC
Vector	Vector Pipeline LP
Viking	Viking Gas Transmission Company
WBI Energy	WBI Energy Transmission, Inc.

Note on Conversion Factors:

Natural gas is measured by volume or heating value. The standard measure of heating value in the English system of units is millions of British thermal units or "MMBtu." Dekatherms (Dth) are also a standard unit of measurement. One MMBtu equals one Dth. The standard measure of heating value in the metric system is gigajoule (GJ); one GJ is slightly smaller than one MMBtu (1 GJ = .948 MMBtu).

The standard measure of gas volume in the English system of units is standard cubic feet or "scf." The "s" for standard is typically omitted in expressing gas volume in cubic feet. Therefore "scf" is typically short formed to "cf." Because the heating value of natural gas is not uniform across production areas, there is no one fixed conversion rate between gas volume and heating value. Pipeline gas in North America usually has a heating value reasonably close to 1,000 Btu/cf. Therefore, for discussion purposes, one thousand cubic feet (Mcf) is roughly equivalent to one million Btu (MMBtu).

The standard measure of gas volume in the metric system is cubic meters (m^3). The straightforward conversion between metric and English volumes is 1 m^3 = 35.31 cf. There are a number of different volumetric conventions used in Canada and the U.S.

$$\mathbf{1\ Mcf \approx 1\ MMBtu = 1\ Dth \approx 1\ GJ}$$

$$\mathbf{1\ Bcf = 1{,}000\ MMcf \approx 10^6\ MMBtu = 10^6\ Dth \approx 10^6\ GJ = 1\ PJ}$$

ACKNOWLEDGEMENT

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DISCLAIMER

FOREWORD

In mid-2009, the Department of Energy (DOE) issued a funding opportunity announcement (FOA), "Resource Assessment and Interconnection-level Transmission Analysis and Planning," DE-FOA-0000068, funded by the American Recovery and Reinvestment Act of 2009. PJM Interconnection, LLC (PJM) was selected as the recipient of the Topic A portion of this FOA for the Eastern Interconnection and subsequently entered into a cooperative agreement with DOE's National Energy Technology Laboratory. The Eastern Interconnection Planning Collaborative (EIPC) was formed in 2009 by 25 of the major eastern electric utilities to conduct the work of PJM's award under this funding opportunity, DE-OE0000343. PJM's award under DOE's funding opportunity was divided into two phases – Phase 1 and Phase 2. Phase 1 focused on the formation of a diverse stakeholder group (the Stakeholder Steering Committee) and its work to model public policy "futures" through the use of macroeconomic models. This first work effort examined eight futures chosen by the stakeholder group. The final undertaking in Phase 1 was for the stakeholder group to choose three futures scenarios to pass onto Phase 2 of the project. Phase 2 of this project focused on conducting the transmission studies and production cost analyses on the three scenarios chosen by the stakeholders at the end of Phase 1. This work included developing transmission options, performing a number of studies regarding grid reliability and production costs resulting from the transmission options, and developing generation and transmission cost estimates for each of the three scenarios.

Subsequent to issuing the draft Phase 2 report, the DOE noted the rapid changes in the natural gas market since the beginning of the study. In particular, the discovery and development of new natural gas resources and the increasing reliance on natural gas for power generation raised a question about the sufficiency of the natural gas infrastructure to support the anticipated need for natural gas-fired power production. As a result, the DOE provided the EIPC Planning Authorities with an extension to perform additional technical analyses to evaluate the interaction between the natural gas and electric systems. The EIPC Planning Authorities identified four Targets for analysis under the DOE extension. This report has been prepared by Levitan & Associates, Inc. (LAI) on behalf of six members of the EIPC who contracted as the Participating Planning Authorities (PPAs) for this project. The Study Region is comprised of PJM, MISO, NYISO, ISO-NE, TVA and IESO, *i.e.*, the six PPAs. This report addresses only the first Target: Baseline the Existing Natural Gas-Electric System Interfaces.

INTRODUCTION AND BACKGROUND

The growing reliance on natural gas as a fuel for electricity generation throughout North America has brought the interaction between the natural gas and power grids into sharp focus. Across the Eastern Interconnection, each of the PPAs depends on natural gas-fired generation to varying degrees – certain PPAs are heavily dependent, others are not. The PPAs derived varying percentages of their total 2012 electrical energy from natural gas – in descending order: ISO-NE (50%), NYISO (45%), PJM (19%), IESO (14.6%), TVA (12%), and MISO North/Central (9%). In 2010, MISO South generated approximately 52% of its energy from natural gas.

The U.S. Energy Information Administration (EIA) forecast in the Annual Energy Outlook 2014 Preliminary Release shows that natural gas is expected to increase its share of total U.S. generation from 27% in 2013 to 29% in 2020 and 35% in 2040. Along with the benefits associated with the use of a relatively clean and cost-competitive fuel, increased reliance on natural gas has exposed the increasing potential impact on bulk power system reliability from events that can reduce or interrupt gas supplies and deliveries. Extreme cold weather often results in pipeline congestion when the pipeline is transporting at or near maximum capability, which can impact natural gas deliverability to generators relying on non-firm transportation arrangements throughout the Study Region. Moreover, extreme cold can cause freeze-offs in gas producing basins, reducing the amount of natural gas available to end-users, including generation companies, throughout the Study Region.

The growth in gas-fired generation is driven by abundant natural gas supplies and U.S. environmental regulations that are expected to cause generation retirements in five of the six PPAs. Traditionally, gas was transported through long-haul interstate pipelines that originated in the conventional gas fields in the Gulf Coast, Western Canada, the Mid-continent, and the Rocky Mountains. Over the last decade, shale gas has become an integral part of the commodity balance across North America. In 2005, shale gas production, sourced primarily from the Barnett shale in Texas, amounted to 1.6 billion cubic feet per day (Bcf/d), about 3% of total U.S. production. In 2013, nation-wide shale gas production averaged around 32.9 Bcf/d, representing 45% of total U.S. gas production, nearly a twenty-fold increase. Of this amount, 9.5 Bcf/d was produced from the Marcellus shale formation. Even as more gas is emanating from shale formations than ever before, the increase in gas demand for electric generation coupled with the lack of infrastructure expansions to serve this demand in certain PPAs raises concerns over pipeline and storage companies' ability to meet the coincident requirements of gas utilities and generators on peak demand days. Even under more temperate weather conditions, many pipelines still run full or near full, or otherwise experience temporary capacity reductions due to seasonal maintenance, typically during off-peak periods.

These concerns have been borne out by the weather events that occurred in January 2014. Abnormally cold weather – the "Polar Vortex" – occurred from January 3rd through January 7th. The design or near design day conditions experienced throughout the Study Region stressed pipeline, storage, and local distribution company (LDC) systems throughout the Study Region, as well as the bulk power systems operated in the Midwest and Northeast. Gas demand reached record levels as spot prices spiked to record or near record levels at many key pricing points. Consequently, wholesale electricity prices reached, in some cases, record winter highs in PJM, New York, ISO-NE and MISO. Following the Polar Vortex, an additional blast of severe cold hit the Midwest and Northeast on January 21st. Frigid conditions occurred again on January 27th and 28th. Delivered gas prices across a large portion of the Study Region skyrocketed – the weighted average index price for gas delivered to the Transco Zone 6 Non-New York and New York pricing points reached $123/Dth. Record storage withdrawals resulted in regional working gas storage levels well below recent levels for a comparable point in the winter. The EIA storage report for the week ending January 17th – *before* the impact of the two cold spells that followed the Polar Vortex – showed storage levels almost 20% lower than the prior year and 13% lower than the rolling five-year average. Half-way through winter 2013/14, these developments underscore the importance of assessing natural gas infrastructure adequacy to supply generator fuel requirements on a peak day.

Six PPAs in the Eastern Interconnection have commissioned a four-part inquiry into gas-electric interfaces that affect infrastructure adequacy across the Study Region. In this Target 1 study, Levitan & Associates, Inc. has performed an assessment of the natural gas infrastructure and electric interfaces affecting the PPAs' ability to rely on gas-fired generation. The primary goals of the Target 1 research are fourfold:

- First, to develop a baseline assessment that includes descriptions of the natural gas-electric system interfaces and how pipeline, storage and LDC infrastructure impact each other;

- Second, to identify the specific drivers of the pipeline / LDC planning processes affecting the availability and operational risks borne by gas-fired generators across the Study Region;

- Third, to evaluate the current level of operational and planning interaction between the bulk electric and natural gas systems; and,

- Fourth, to assess the regulatory, commercial, and operational attributes of the gas infrastructure – electric interfaces affecting the performance of gas-fired generation.

In addition to the comprehensive mapping of electric generation, gas pipeline, storage, and LDC infrastructure across the Study Region, emphasis has been placed on the delineation of pipeline and LDC tariff provisions that limit power plant scheduling flexibility, provide for imposition of penalties, and influence generation company contracting norms.

Target 2, 3 and 4 research objectives will provide LAI's assessment of the magnitude, frequency and location of the gas-electric interfaces that represent significant risk factors for bulk power reliability during both the peak heating season and the peak cooling season. Based on the baseline assessment presented in this report, LAI will work in consultation with the PPAs and stakeholders at large, to define potential scenarios and sensitivities across the Study Region. Technical analysis will be performed to calibrate the resiliency of the new and improved natural gas infrastructure to meet the needs of residential, commercial, industrial and electric generation customers over a ten-year study period through 2023.

EXECUTIVE SUMMARY

A substantial shift in natural gas production across the Study Region over the last five years has resulted in the construction of new gas pipeline facilities to accommodate supplies from the Marcellus and other unconventional shale sources. The displacement of conventional gas production from the Gulf of Mexico and western Canada has changed the flow of gas from major production and storage facilities to market centers across the Study Region. New pipeline and gathering infrastructure projects located in shale gas production areas are being commercialized to link suppliers with the existing consolidated network of natural gas infrastructure serving LDC and gas-fired generators alike. The majority of the entitlement holders of the new pipeline capacity from shale formations to market are gas producers, LDCs, and marketers, not generators. In less than five years, shale gas production has materially changed continental gas flow patterns, in some instances causing economic obsolescence across upstream segments from traditional production basins. The increasing reliance on gas-fired generators to serve electric loads, in conjunction with the limited firm transportation contracts held by these generators, creates the potential for generators relying upon interruptible, secondary firm, or recallable released capacity to not be scheduled during peak demand conditions, such as those seen during the Polar Vortex and subsequent frigid weather events across the Study Region, causing a greater reliance on back-up fuel sources where available, including oil and kerosene, which are dependent on truck or rail deliveries. Secondary firm refers to transportation utilizing secondary receipt and/or delivery points, not specifically within the shipper's contract. Pipeline service priorities are discussed in more detail in Section 2.1.3.

Highlights of Target 1 research follow, including key findings and observations.

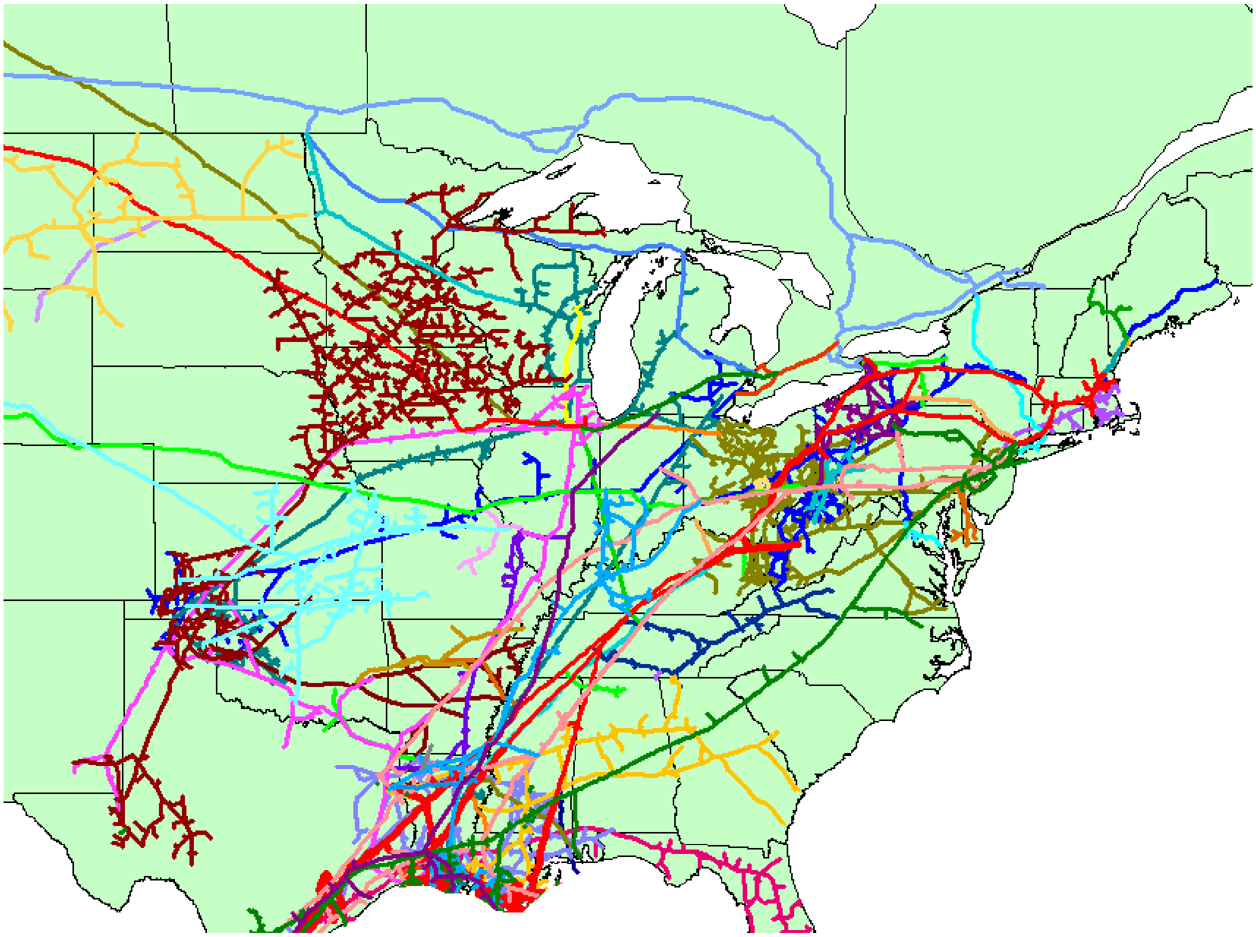
BASELINE ASSESSMENT OF THE NATURAL GAS INFRASTRUCTURE – ELECTRIC INTERFACES

Summary statistics regarding generating capacity and connectivity to pipelines and LDCs are presented in Table 1. If a generator has both an interstate/interprovincial connection and an intrastate/LDC connection, it is counted in the interstate/interprovincial total. Figure 1 shows the network complexity of the interstate pipelines operating in the Study Region.

Table 1. Generator Statistics by PPA

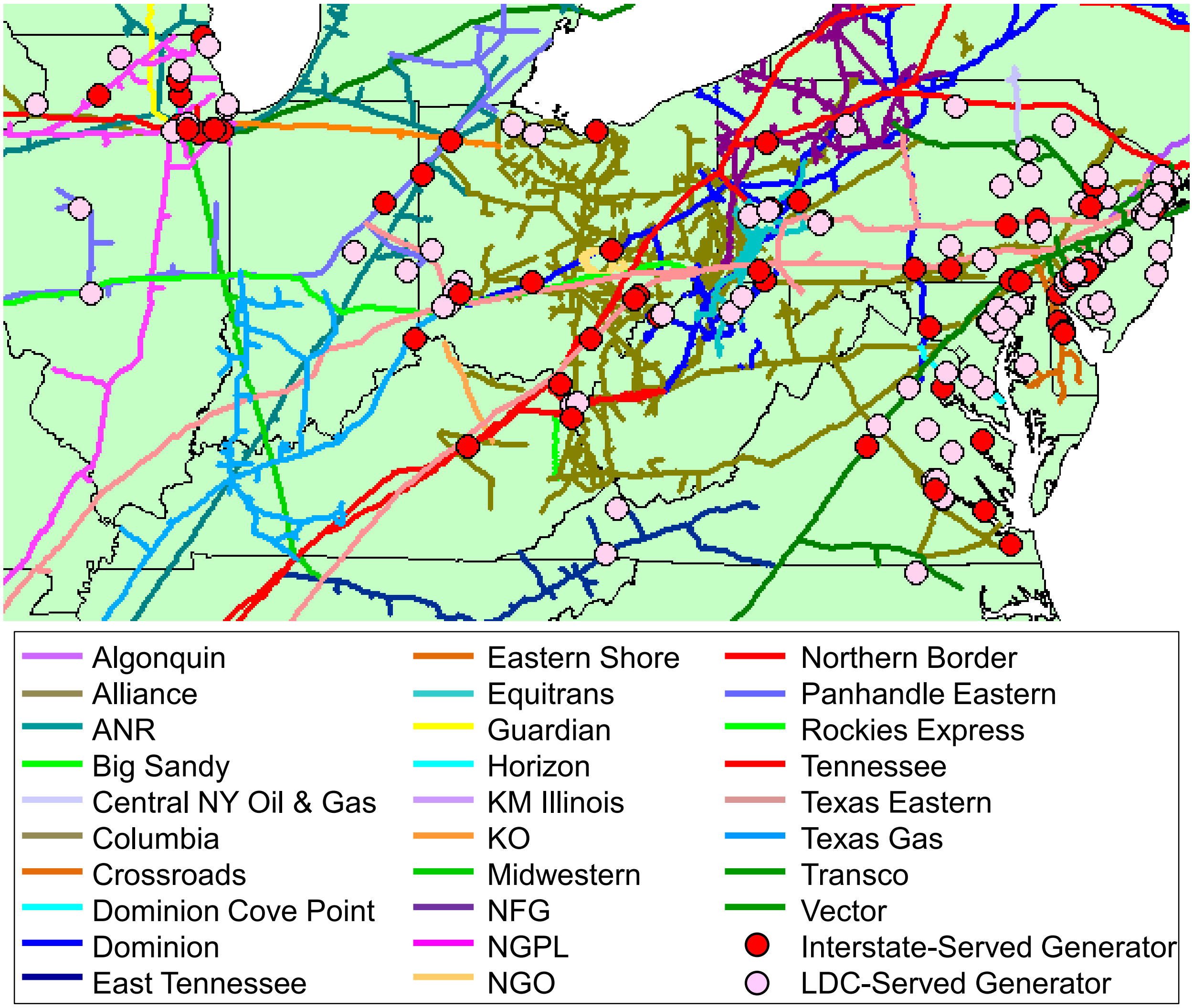
PPA	Total Capacity (GW)	Gas-Capable Capacity (GW)	% of Total	Interstate/Interprovincial-Served Capacity (GW)	Intrastate/LDC-Served Capacity (GW)
PJM	185	80.0	43%	40.3	38.7
MISO	177	69.0	39%	44.6	24.4
NYISO	38	21.0	55%	4.3	16.7
ISO-NE	35	18.6	54%	14.3	4.3
TVA	34	12.2	36%	9.9	2.3
IESO	33	9.9	28%	1.2	8.7
Total	502	210.7	42%	114.6	95.1

Figure 1. Interstate Pipelines Operating in the Study Region



There are 28 interstate pipelines operating in PJM, as shown in Figure 2. Also shown in this figure are the PJM gas-capable power plants that are larger than 15 MW. These units amount to 80 GW, about 43% of PJM's total installed capacity of 185 GW. About 38.7 GW of the gas-capable generation is located behind LDC citygates, the points at which interstate or intrastate pipelines transfer gas to the local delivery system.

Figure 2. Interstate Pipelines and Gas-Fired Generators in PJM



There are 39 interstate pipelines operating in MISO's service area, illustrated in Figure 3 and Figure 4, for MISO North/Central and MISO South, respectively, along with the existing gas-capable power plants that are larger than 15 MW. The total capacity of these plants is approximately 69 GW, or 39% of MISO's total installed generation of 176.5 GW. About 24 GW of the 69 GW are located behind LDC citygates.

Figure 3. Interstate Pipelines and Gas-Fired Generators in MISO North/Central

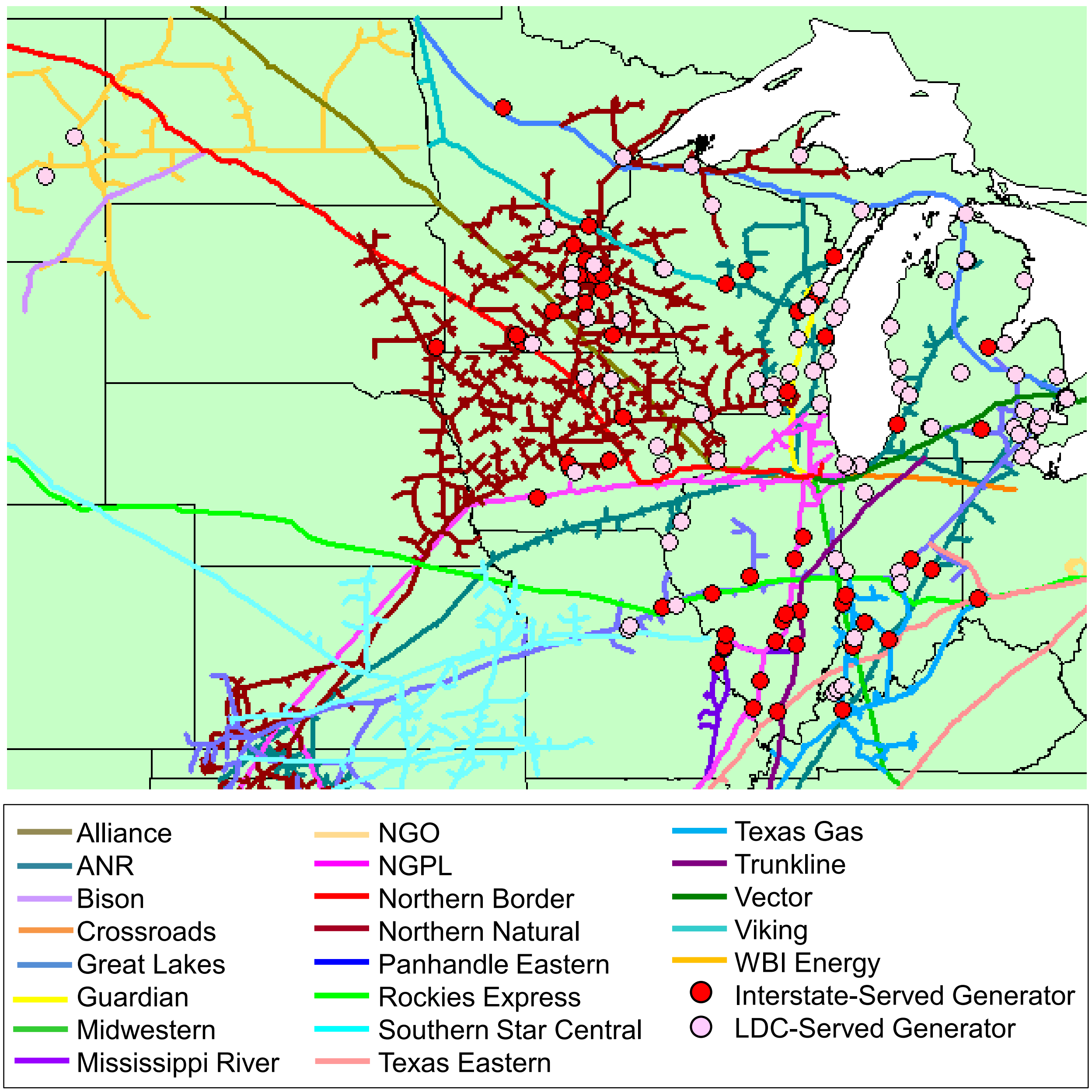
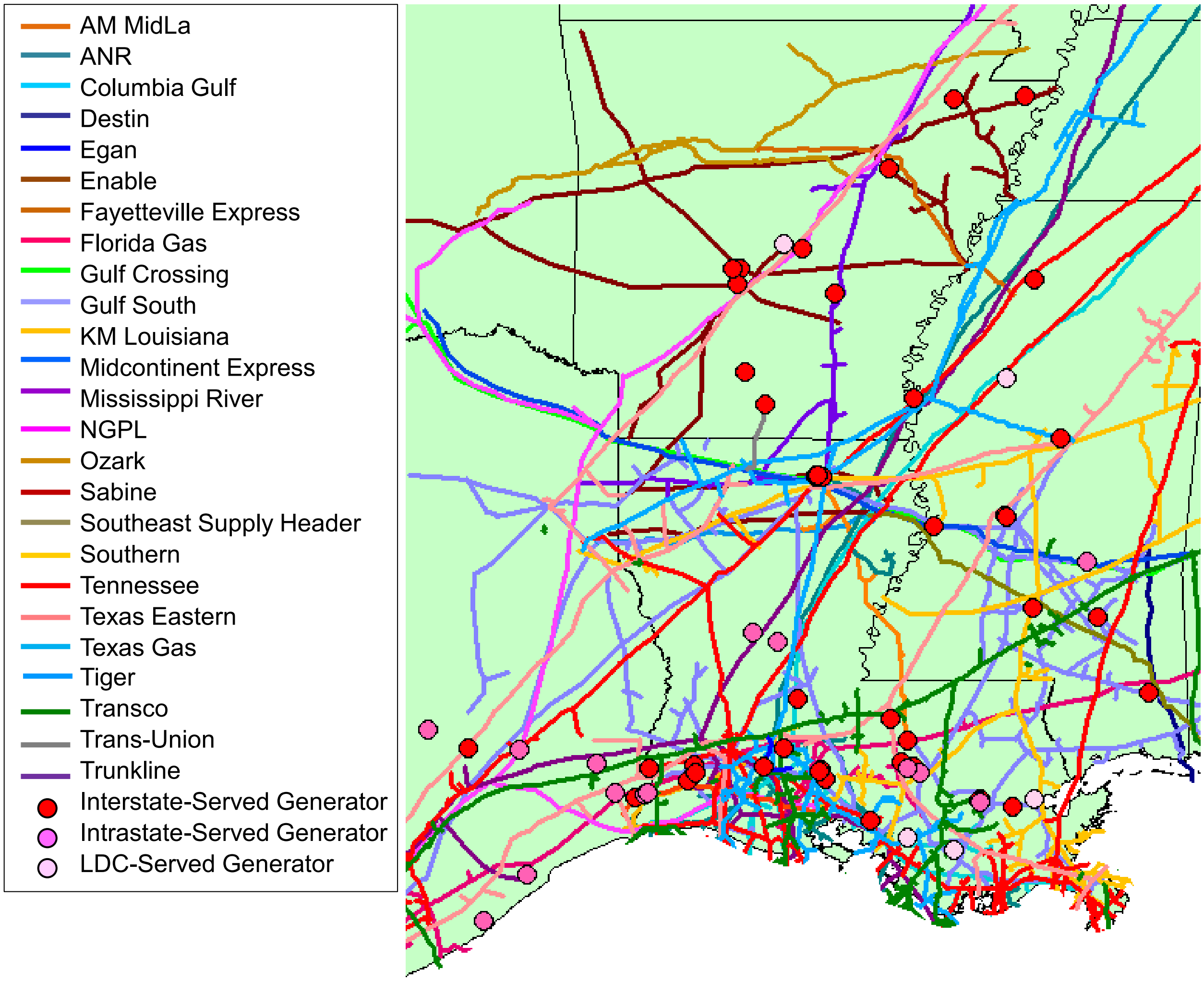
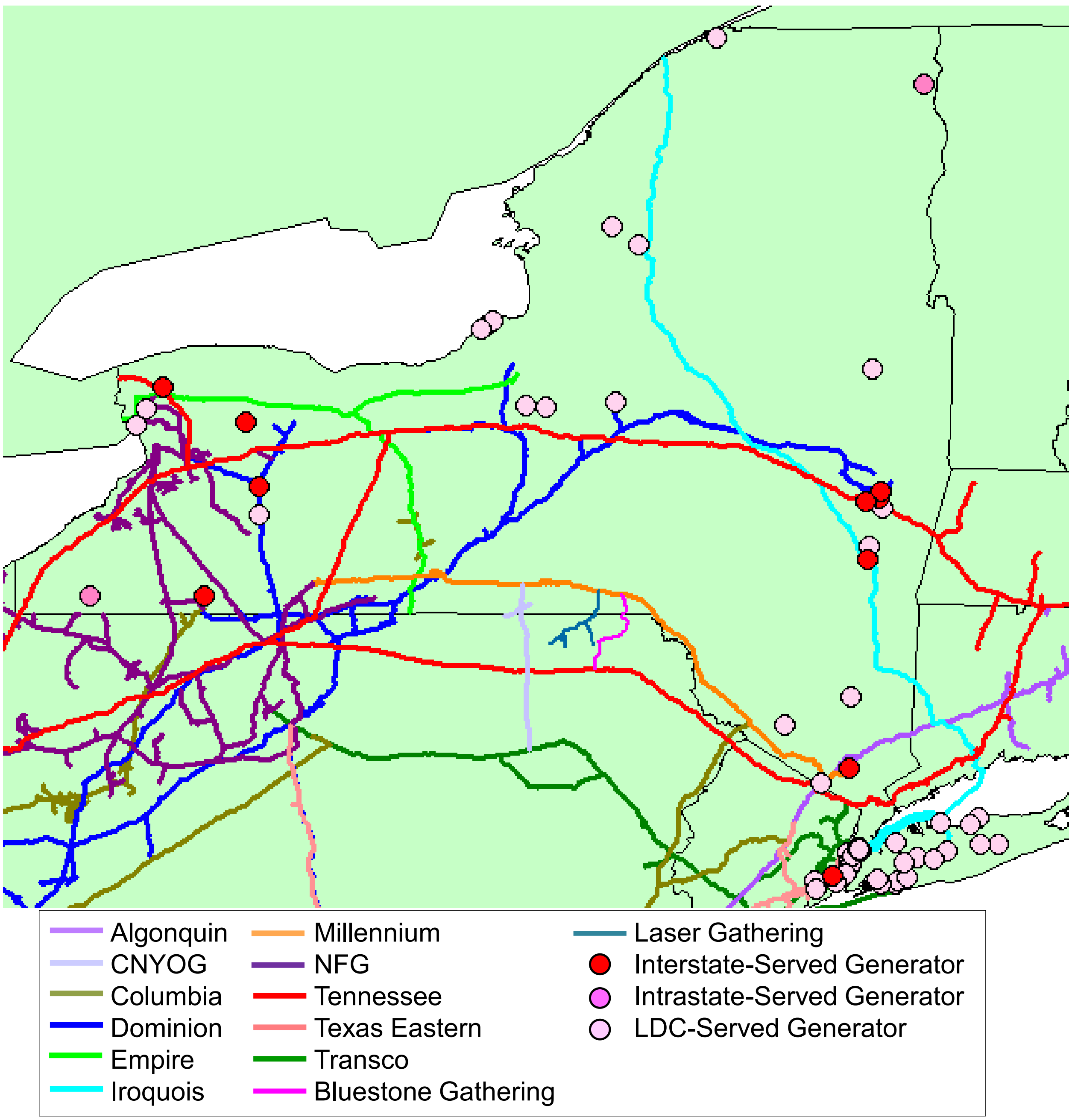


Figure 4. Interstate Pipelines and Gas-Fired Generators in MISO South



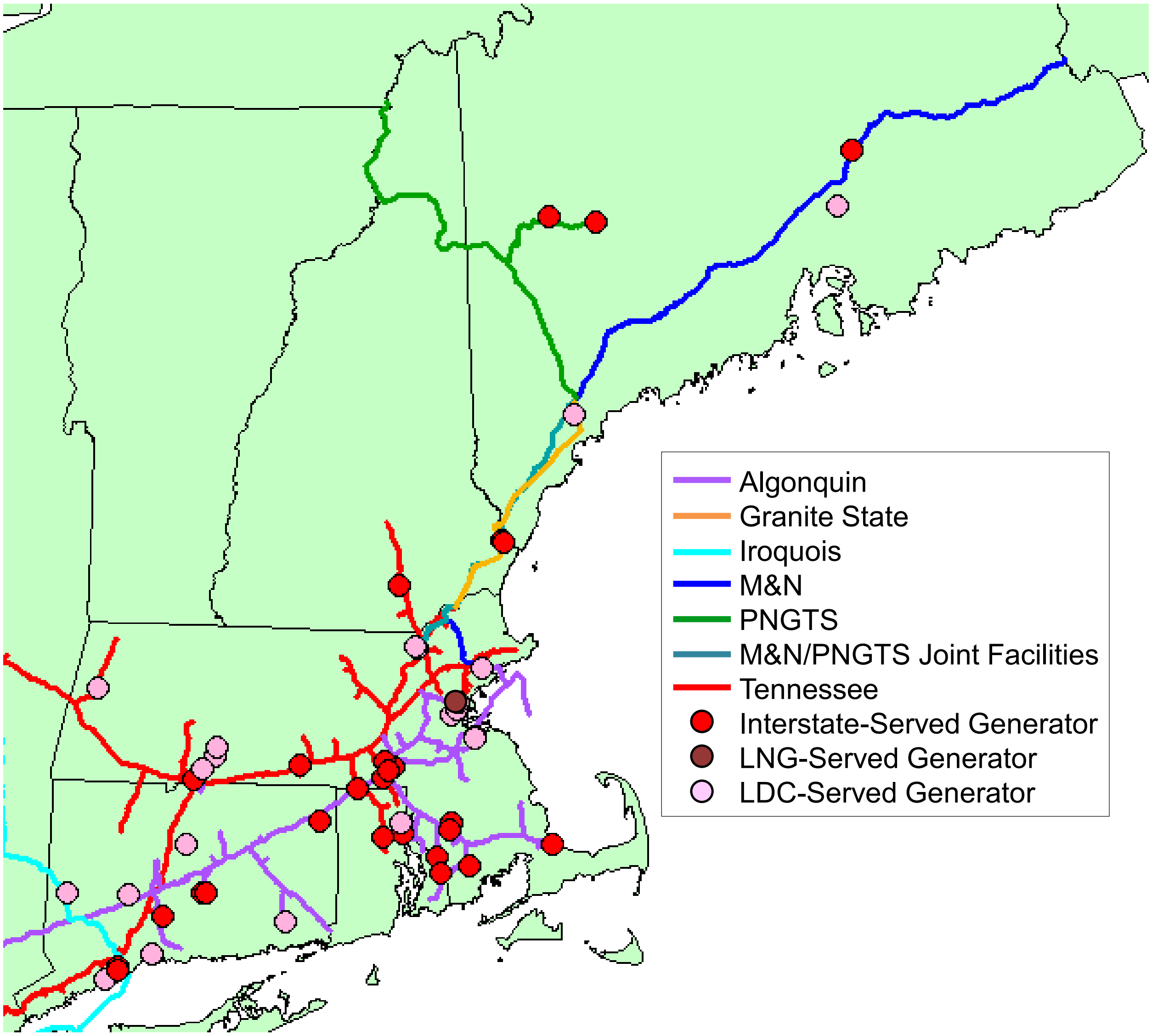
There are 11 interstate pipelines operating in the New York Control Area, as shown in Figure 5. NYISO has identified 68 existing power plants that are 15 MW or larger and capable of burning gas with a total capacity of 25.1 GW, about 66% of NYISO's total installed capability of about 38 GW. About 19.6 GW of the 25.1 GW are served by LDCs. The majority of this local gas-fired generation is served by the New York Facilities System in New York City and Long Island. Also shown in Figure 5 are the Laser and Bluestone gathering systems, which are not FERC-jurisdictional.

Figure 5. Interstate Pipelines and Gas-Fired Generators Operating in New York



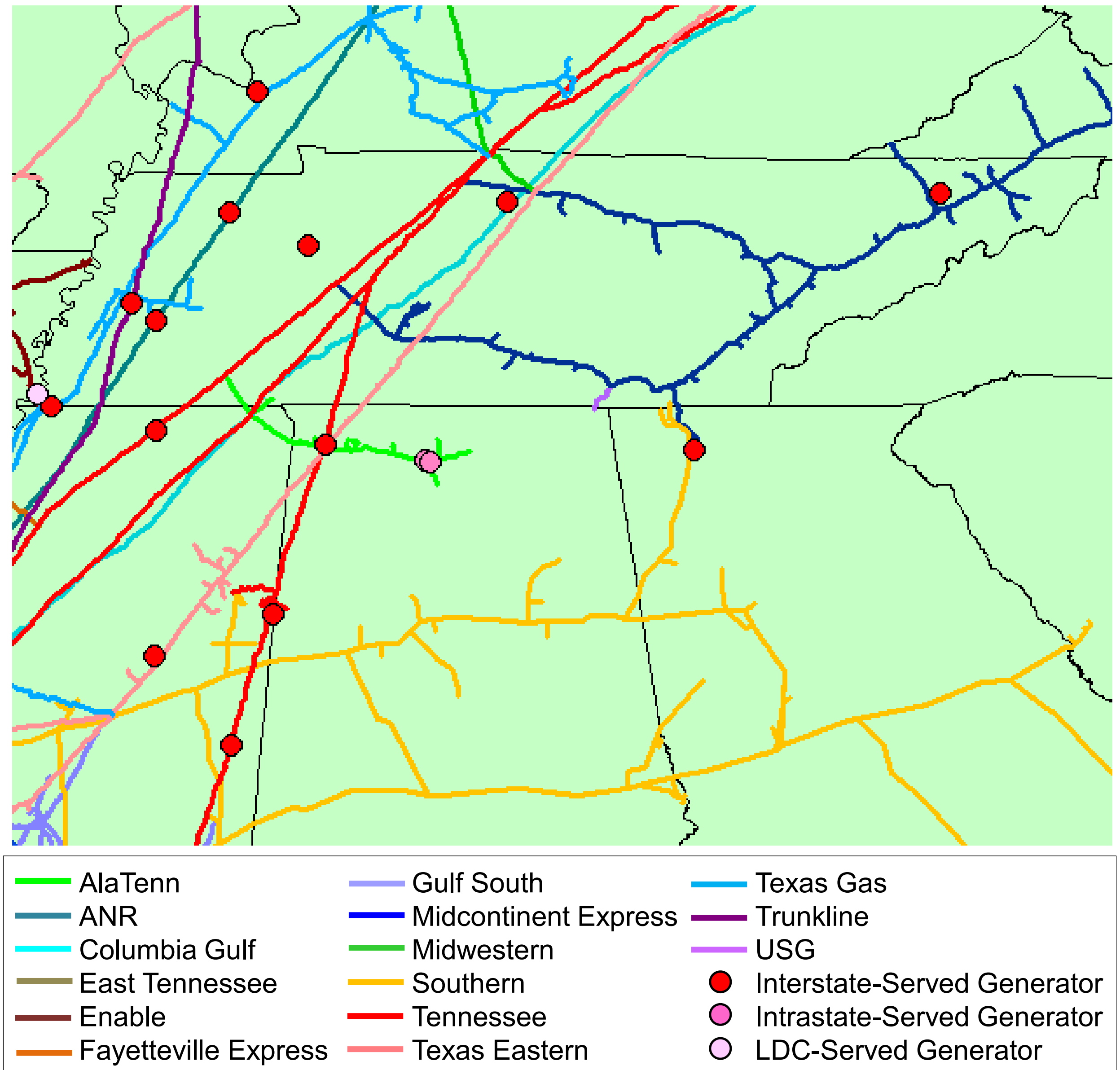
There are six interstate natural gas pipelines operating in New England, as shown in Figure 6. ISO-NE has identified 18.6 GW of existing gas-fired power plants that are larger than 15 MW, 54% of ISO-NE's total generation capacity of 35 GW. About 4.3 GW out of the 19 GW are located behind the citygate.

Figure 6. Interstate Pipelines and Gas-Fired Generators in New England



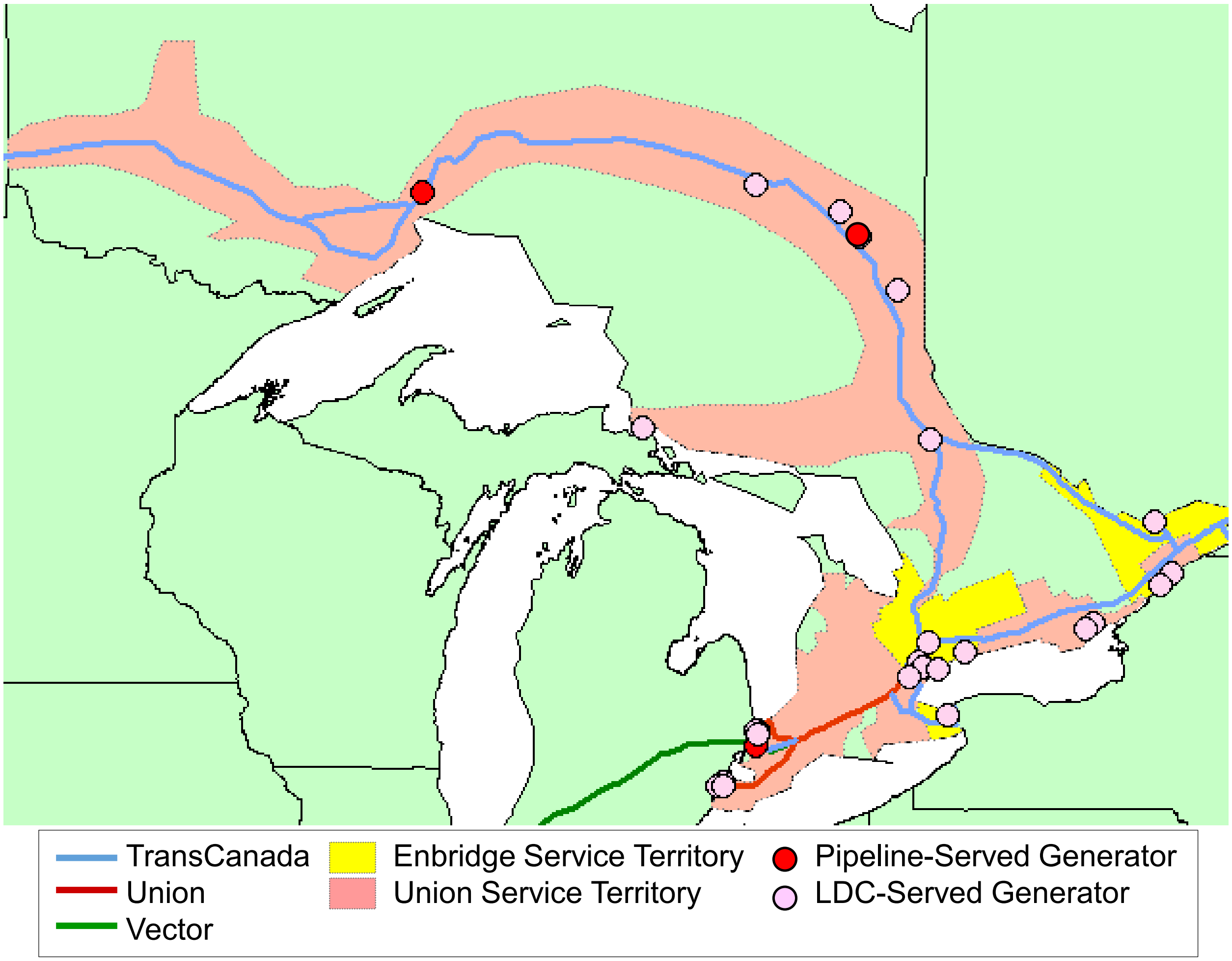
There are 15 interstate pipelines operating in TVA's service area, as shown in Figure 7. TVA owns 14 existing gas-fired power plants with a total capacity of 10.6 GW, or 31% of TVA's total generation nameplate of about 34 GW, with an additional four plants totaling 3.6 GW under contract or available for power purchases.

Figure 7. Interstate Pipelines and Gas-Fired Generators in TVA



The natural gas transmission and distribution infrastructure in Ontario is shown in Figure 8. IESO has identified 29 existing gas-fired power plants operating in Ontario. The installed capacity of these units is about 9.9 GW. About 1.2 GW are directly connected to either TransCanada or Vector, 6 GW are connected to the Union system, and 2.7 GW are connected to the Enbridge system.

Figure 8. Natural Gas Infrastructure in Ontario



Conventional underground storage fields are concentrated in MISO and PJM, are shown in Figure 9. There is also major storage deliverability in Ontario. While NYISO and TVA have significant conventional storage capability, ISO-NE lacks underground storage infrastructure. New England's LDCs and other stakeholders have physical and financial access to conventional storage facilities located in PJM and Ontario, in particular. Based on data from EIA and Ontario storage operators, working gas capacity and withdrawal capability are summarized by PPA in Table 2.

Figure 9. Underground Storage Facilities in the Study Region

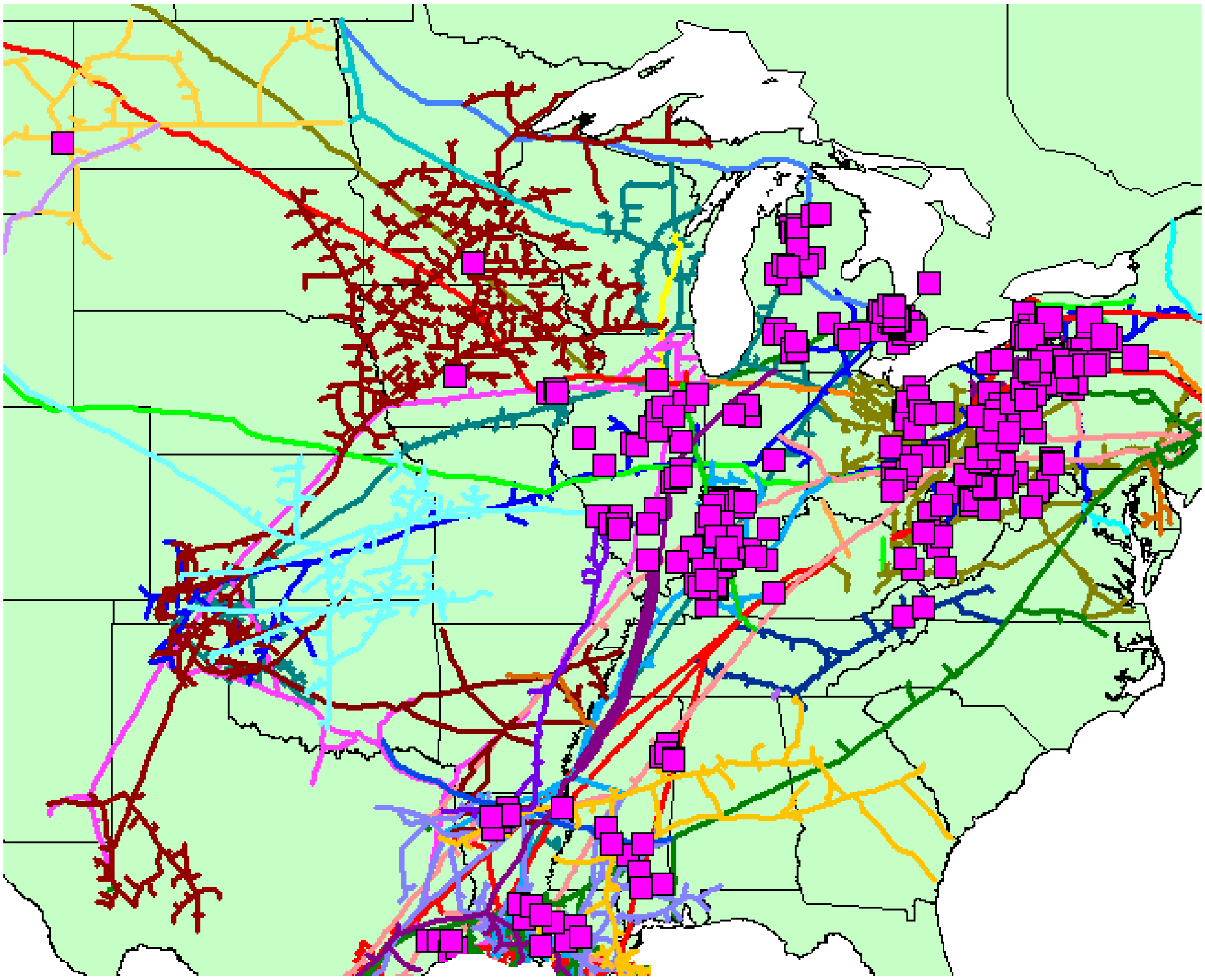
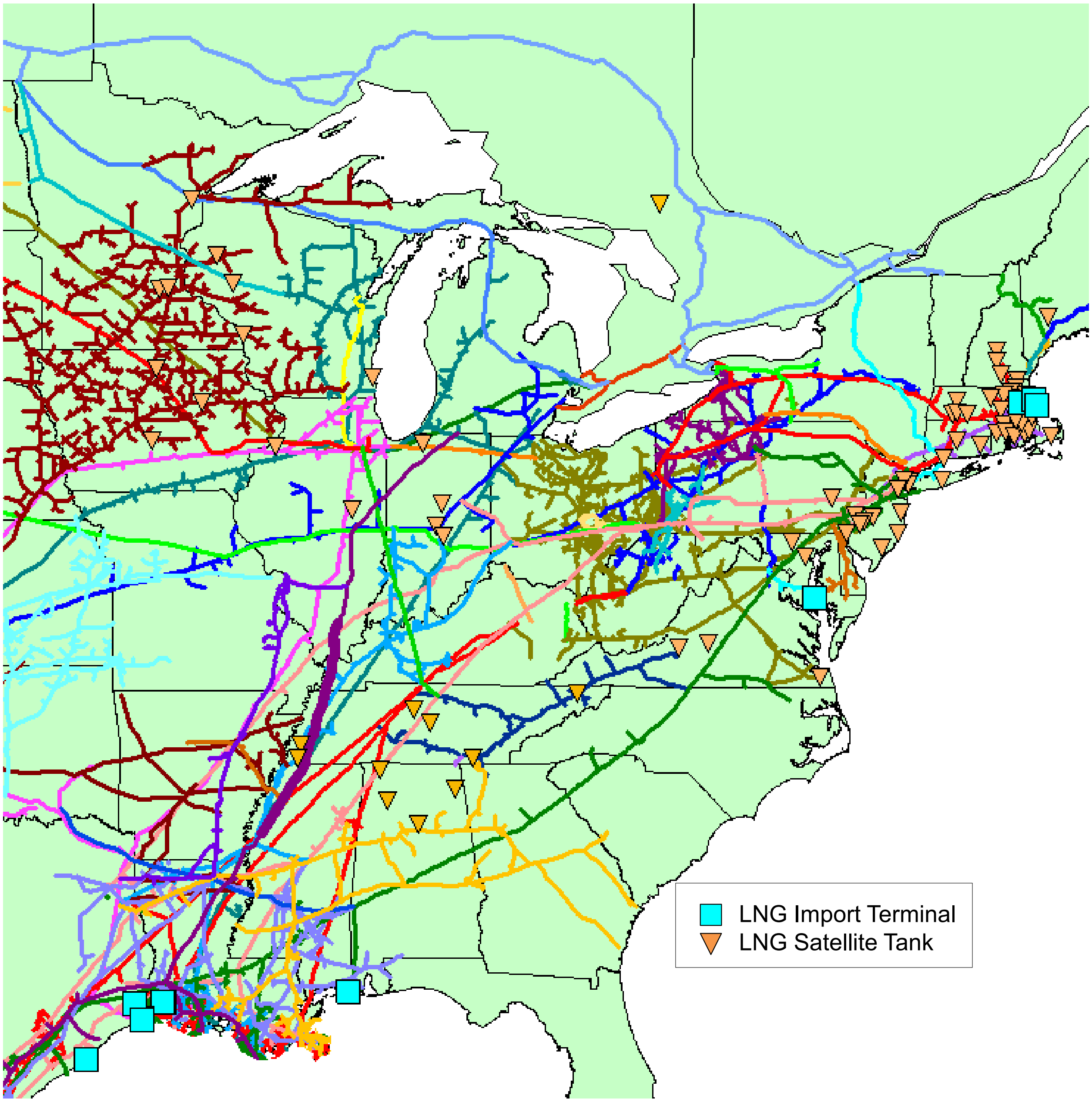


Table 2. Underground Storage Capacity by PPA

PPA	# of Fields	Working Gas Capacity (Bcf)	Maximum Withdrawal Capability (MMcf/d)
PJM	108	1,044	23,558
MISO	139	1,746	51,155
NYISO	26	129	2,856
ISO-NE	0	--	--
TVA	13	147	3,400
IESO	35	268	5,438
Total	321	3,334	86,407

The absence of conventional underground storage facilities in New England has resulted in the region's reliance on large LNG import terminals located near Boston and also in New Brunswick, as well as 45 satellite LNG storage tanks connected to LDC systems. The LNG import terminals and satellite LNG storage tanks located in the Study Region are shown in Figure 10.

Figure 10. LNG Facilities in the Study Region



PIPELINE, STORAGE AND LDC SERVICES AVAILABLE TO THE ELECTRIC SECTOR

Interstate pipeline and storage companies offer two basic services: firm transportation and/or storage, and interruptible transportation and/or storage. When built, pipeline and storage infrastructure capacity is sized to meet the contractual demand of firm customers, with little or no reserve capacity. Natural gas transportation customers are also referred to as "shippers," these terms are used interchangeably in this report. The firm shippers are those entitlement holders who pay the FERC-authorized cost of service rate to ensure guaranteed deliverability under all circumstances, except *force majeure*. By contrast, interruptible transportation shippers contract for a lower priority service that depends on the availability of capacity and either may not be scheduled or may be interrupted. Historically, *force majeure* events are rare, and include only the most severe or unusual operating conditions that cannot be foreseen when mainline segments or compressor stations are not available, thereby reducing a pipeline's physical delivery capability. These events are particularly disruptive because gas pipeline and storage infrastructure typically is not designed with redundant capacity during peak conditions, only the amount of capacity contracted by firm pipeline transportation shippers, and, in some instances, a small additional amount. This is in contrast to the bulk electric system design basis to ensure grid reliability by including a reserve margin to mitigate the impact of low-probability contingency events. Because the pipelines are sized to accommodate the needs of firm shippers, many pipelines are fully subscribed. Hence, for a generator to contract for firm transportation in its own name, the pipeline would need to expand its delivery capability to accommodate the incremental demand.

Within the broad categories of firm and interruptible transportation service, there is a range of service options offered by the different pipelines doing business in the Study Region. For example, a service may be seasonal, provide enhanced hourly flexibility, or be available on a no-notice basis to serve the firm transportation and peaking requirements of LDCs, small municipal and cooperative utilities that have historically leaned on the pipeline for deliverability assurance. Shippers that do not hold pipeline contracts in their own name can obtain firm transportation through arrangements with gas marketers or asset managers that hold pipeline contracts, or through the secondary market via capacity release.

In some cases, LDCs do not offer firm service to generators operating behind the citygate. In other cases, firm service is available from the LDC, but has a lower priority than firm service to other customer classes, and is therefore effectively interruptible during periods of peak demand. Hence, the majority of gas-fired generation located behind LDC citygates is supplied on a non-firm basis, exposing the generators to the risk of not being scheduled or being interrupted or otherwise curtailed during cold snaps or outage contingencies. In these instances, gas-fired generators with dual-fuel capability can rely on alternative fuels such as oil or kerosene, although these fuels carry with them their own deliverability and price issues. These issues will be addressed as part of the Target 4 analysis conducted later this year. Local generation in Ontario is predominantly served by LDCs under firm transportation arrangements. LDC service priorities are discussed in more detail in Section 2.4.

Daily Scheduling Protocols

To ensure the systematic flow of natural gas from various producing basins and storage facilities to market centers across North America, pipelines and LDCs utilize the North American Energy Standards Board's (NAESB) Wholesale Gas Quadrant (WGQ) nomination, confirmation and scheduling process. NAESB scheduling protocols are the product of stakeholder review and periodic modification. Since the mid-1980s when the pace of pipeline deregulation accelerated in response to FERC decisions and rulemakings, various scheduling modifications have been implemented in response to stakeholder feedback and technology progress. The gas industry has a national gas day running from 9:00 am to 9:00 am (Central). Across the Study Region, pipelines must utilize at least four standard NAESB WGQ daily nomination cycles, with the first nominations for the gas day due at 11:30 am the day before gas flows (referred to as the Timely nomination cycle), a second nomination opportunity at 6:00 pm the day before gas flows, and two intra-day cycles during the gas day, with nominations at 10:00 am and 5:00 pm. The National Energy Board of Canada does not require Canadian pipelines to follow the NAESB WGQ Standards; however, TransCanada's Canadian pipelines generally follow the standards due to its numerous interconnects with U.S. pipelines who are required to follow the standards. By contrast, the electric operating day runs from midnight to midnight, generally according to each time zone. In addition, the schedule for independent system operators (ISOs) and regional transmission organizations (RTOs) to post generators' day-ahead dispatch schedules varies by PPA. This timing results in an operational and planning gap between the gas and electric days, with Timely gas nominations generally due before the day-ahead electric market schedules are available.

Pipelines are open for business 24/7, with the same gas nomination procedures used on weekdays and weekends, subject to each pipeline's specific scheduling protocols. Many pipelines in the region have made significant investments in software and automation to facilitate a streamlined nomination and scheduling process; however, the scheduling process remains complex and can sometimes be unwieldy, due in part to the mismatch between the gas and electric days and scheduling timelines. In light of heightened pressure on gas-fired generators to obtain natural gas on a timely basis in accord with the PPAs' scheduling requirements in the Day-Ahead and Real-Time Markets, some pipelines in the Study Region have implemented greater scheduling flexibility in the form of specific additional nomination cycles or hourly scheduling flexibility. Whether gas marketing firms maintain similar around-the-clock operations and scheduling flexibility is uncertain, and, in any event, is not transparent.

Scheduling Priorities

The terms and conditions governing the scheduling priorities of nominated quantities are complex, multi-faceted, and vary significantly among pipelines in the Study Region, as well as within individual PPAs. Universally, the pipelines schedule firm nominations first. After confirmation of all primary firm nominations, the pipeline will schedule all secondary firm services. Primary and secondary firm may include transportation entitlements obtained via capacity release from the primary entitlement holder. After all primary and secondary firm transportation volumes have been scheduled, leftover pipeline capacity is made available to accommodate IT nominations. The pipelines' detailed scheduling priorities may further differentiate among various services offered within the broader categories of firm and interruptible service. In contrast, LDCs have broad discretion regarding how best to effectuate curtailments or interruptions to maintain gas system integrity. Usually, LDCs inform interruptible shippers of likely delivery constraints the day before action is taken, but much shorter notifications within the gas day can sometimes occur.

FERC has implemented policies to require non-discriminatory open access and to grant shippers the ability to substitute receipt and delivery points and the right to segment capacity. One of the purposes of these policies has been to facilitate liquidity in the secondary market for pipeline capacity. In establishing scheduling priorities, some pipelines make a distinction between the capacity available at a point of receipt or delivery, and the capacity available on the connecting pipeline segment. In such cases, receipt point capacity is typically allocated first to firm customers utilizing primary receipt points, then to firm customers utilizing secondary receipt points, and finally to interruptible services according to the highest rate paid. Allocation of delivery point capacity is similar. Similarly, when allocating segment capacity, preference is generally given for firm service nominated in-the-path using either primary or secondary receipt and delivery points over firm service out-of-the-path. An in-the-path nomination uses either primary receipt and delivery points, or secondary receipt and delivery points that are between the primary receipt and delivery points. An out-of-the-path nomination includes segments that are either upstream of the primary receipt point or downstream of the primary delivery point.

Other pipelines have similar, but by no means identical, scheduling priorities. There are many noteworthy differences among scheduling priorities affecting gas-fired generation across the Study Region. Some pipelines establish zoned rate structures where there is no ostensible distinction drawn by the pipeline between flows in-the-path and out-of-the-path.

With regard to capacity release transactions, the replacement shipper, or "assignee," steps into the shoes of the releasing shipper, or "assignor," in that the replacement shipper has the same primary firm service priority as the releasing shipper if it delivers gas to the receipt or delivery point(s) identified in the primary releasing shipper's contract. Pipelines, however, give capacity release transactions secondary point priority when the assignee seeks to schedule natural gas at points that would be secondary receipt and delivery points under the assignor's contract..

Some pipelines have received FERC authorization to provide a scheduling priority for in-the-path secondary receipt to primary delivery points, thereby motivating long-haul shippers to retain their long-haul contracts rather than move their primary receipt point rights to new shale supply regions. Major trunklines serving PJM, MISO, NYISO and, to a lesser extent, ISO-NE, give higher priority to in-the-path versus out-of-the-path secondary firm nominations, and in allowing assignees to request a re-designation of the shipper's primary receipt and delivery points. This trend promotes flexibility, thus providing buyers and sellers of secondary capacity rights with improved access to pipeline capacity.

Shipper Balancing Opportunities and Operational Balancing Agreements

While pipeline and LDC firm and interruptible transportation tariffs typically require shippers, including generators, to schedule and take gas ratably, that is, approximately 1/24th of the daily quantity each hour, generator hourly gas demand profiles often call for non-ratable gas deliveries to meet early morning and late afternoon ramping requirements. A pipeline or LDC may allow a gas-fired generator to exceed these limits if it does not interfere with providing service to other firm customers. In LAI's experience, generators typically enjoy this operational flexibility during the non-heating season, when slack pipeline deliverability conditions are more likely to occur. However, per their tariffs, most pipelines retain the right to require customers to adhere strictly to uniform hourly flows when required by peak demand conditions or operating contingencies.

Imbalances are variances that occur at receipt or delivery points and are resolved based on applicable tariff provisions. There are many ways imbalances can be resolved. One primary mechanism is a cash-out provision when an imbalance exceeds a specified tolerance range. Cash-outs are usually tied to a percentage of a specified gas price index that is modified as the imbalance exceeds the tolerance. Pipeline companies and LDCs often have imbalance resolution provisions in their tariffs that provide shippers with innovative reconciliation methods, in particular, "netting" or trading gas volumes with third parties. When an imbalance reflects a greater take than the daily scheduled quantity, the cash out price paid to the pipeline or LDC increases in general accord with the magnitude of the unauthorized overpull. When the imbalance reflects a volume less than the daily scheduled quantity, the cash out price paid to the shipper decreases against the daily index price in general accord with the magnitude of the unauthorized underpull. Either way, the cash out provisions normally incorporated in the pipeline tariff or an Operational Balancing Agreement (OBA) deter the creation of imbalances on the system, thereby giving the pipeline company and/or the LDC the ability to maintain scheduling discipline on their respective systems.

A second mechanism to resolve imbalances is an OBA. An OBA is a balancing mechanism to address imbalances created when the actual physical flow differs from scheduled nominations, thus resulting in a debit or credit to the point operator 's balancing account. An OBA does not create the right for a shipper to take additional gas that is not scheduled by the pipeline, but rather allows the pipeline and the point operator to address imbalances (overpulls and underpulls) at the point that may occur at the end of the day, or within the day, in order to get the point into balance on the system. Gas-fired generator availability and performance in the Study Region can be impacted by a pipeline company's and/or LDC's OBA with the generator, where one exists.

In Order No. 587-G, FERC required interstate pipelines to enter into OBAs with the point operators at all interstate and intrastate pipeline interconnects. FERC also encouraged pipelines to negotiate OBAs with point operators at other interconnections. Not all pipelines have OBAs with generators. Pipeline and LDC OBAs with gas-fired generators are based on the character of service of each generator's contract(s). While the provisions set forth in the OBA are generally the same based on NAESB's recommended standards, a pipeline company has broad discretion in regard to its ability to negotiate the specific imbalance resolution provisions in each OBA. Importantly, shipper-specific OBAs are not in the public domain, and were therefore not available for review in preparing this report.

Pipeline tariffs permit a pipeline to assess a shipper or OBA party a penalty for remaining out of balance on the system, if the imbalance is causing or has the potential to cause operational harm to the pipeline. Most pipelines, under non-critical operating conditions, allow shippers flexibility to get back into balance within a certain period without assessing a penalty. While imbalance penalties assessed during such normal operating conditions are small, the financial penalties assessed for imbalances when Operational Flow Orders (OFOs) are in effect much greater and punitive because they are intended to deter shipper misconduct that could harm a pipeline's operational integrity, thereby impairing the pipeline's ability to meet its firm service obligations. The OFO may require customers to remain in contractual balance and adhere to ratable takes. OFOs are issued in extreme operating conditions. Pipelines typically issue OFOs after issuing other levels of critical notices advising customers of operational conditions and the need for receipts to equal deliveries. If a pipeline assesses a penalty to an offending shipper or point operator, FERC policy requires the pipeline to distribute the revenue from the penalty to non-offending shippers. The pipeline remains revenue neutral.

For example, during the Polar Vortex event, Tennessee issued an OFO notifying shippers that under-deliveries into the system or over-takes out of the system greater than 2% of scheduled quantities or 500 Dth would incur a penalty of $5.00/Dth plus the applicable gas price. Transco also issued an OFO, with under-deliveries or over-takes greater than 5% or 1,000 Dth subject to a penalty of $50.00/Dth. Columbia Gas issued an OFO declaring that any customer overrunning its entitlements would be subject to a penalty ten times the penalty that would otherwise be applicable – the standard overrun penalty on Columbia Gas is equal to three times the mid-point of the Columbia Gas-Appalachia price.

Regarding services available to the electric sector:

- Some pipelines across the Study Region offer tariff transportation services designed for generators that permit non-ratable takes or allow the shipper to consume gas during an eight to 12-hour period rather than a 24-hour period to coincide with electric usage. Exhibit 2 includes a list of all the rate schedules offered by pipelines in the Study Region.
- Some LDCs across the Study Region offer tariff rates and services specifically for electric generators. LDC services are discussed in Section 2.4.
- Pipeline transportation rates for interruptible service may be discounted or negotiated by the pipeline with individual shippers. LDC transportation rates may be negotiated by the LDC based on value associated with the desired character of service.
- During normal operating conditions, pipelines typically are flexible in allowing shippers the ability to resolve any imbalances on the pipeline during a certain period without assessing penalties, which may or may not necessarily require reconciliation by the end of the day. Any gas-fired generator engaged in unauthorized overpulls relative to scheduled quantities during an OFO, which is instituted only during extreme operating conditions to maintain the integrity of the pipeline system, can be heavily penalized by the pipeline and/or LDC. The OFO notifies shippers to remain in contractual daily balance during the critical period. Multipliers applied to the daily gas or electric index price or the imposition of a large adder are standard operating practice.
- Some LDCs, particularly in PJM and MISO, allow shippers to use their systems for "banking" – delivering / depositing gas to the LDC one day and receiving / withdrawing it on a later day. Transaction fees apply to this service.
- Pipeline tariffs include provisions allowing for the interruption or "bumping" of shippers relying on interruptible transportation if a firm shipper wishes to deliver gas to that point. Pipeline companies have established scheduling priorities that safeguard firm entitlement holders, thereby subordinating non-firm services consistent with FERC rules.
- LDC tariffs generally include provisions allowing for the interruption or curtailment of gas-fired generators on short notice.
- Selected LDCs in the Study Region have strict dual fuel requirements in their non-firm transportation tariffs that apply to gas-fired generators, particularly in eastern PJM, NYISO and ISO-NE.

GAS-FIRED GENERATION CONTRACTING TRENDS

Except in Ontario and, to a lesser extent, TVA, one noteworthy trend common across the Study Region is the limited direct participation of gas-fired generators in the primary or secondary market for pipeline capacity entitlements. As discussed in Section 2.4, most gas-fired generators in the Study Region do not have firm transportation rights from a liquid sourcing point to the plant gate in their own name. In some cases, generators hold firm transportation rights that are limited to laterals, which means that the contract does not provide the generator with firm transportation rights on the mainline upstream of the lateral nor does it provide a firm path back to a liquid supply point. In other cases, as noted below, generators secure transportation through marketers who bundle both commodity and transportation services.

In PJM, twelve generators hold firm mainline transportation contracts in their own names. In MISO, 27 generators holding firm mainline transportation contracts have been identified, divided roughly evenly between MISO North/Central and MISO South. In MISO North/Central, ten of the contracts are on Northern Natural, and seven of these are held by Xcel Energy to fuel utility-owned generation. In MISO South, Entergy holds eight of the firm transportation portfolios, typically with volumes sufficient to support full plant output.

In NYISO, eleven generators hold firm mainline transportation contracts. Four of these contracts are for volumes sufficient to fuel the full plant capacity, the others range from approximately one-third to three-fourths of plant capacity. Seven of the contracts are held by generators which are ultimately served by LDCs, the character service of the last leg of the transportation path is not known. In NGrid's Long Island service territory, for example, generators can negotiate a limited-curtailment or "quasi-firm" character of service. Such arrangements typically have a temperature trigger or a specified number of days of curtailment rights, thereby assuring the generation company of firm service during the remainder of the year.

In ISO-NE, six generators hold firm mainline transportation contracts, only one of which is a long-term contract to a liquid pricing point with a volume sufficient to fuel the entire plant output. Another generator is uniquely dependent on LNG for its gas supply and has, in effect, a firm fuel supply throughout the year. In TVA, transportation contracts are in place for nine generators, including all TVA-owned combined-cycle units. In Ontario, while the Ontario Power Authority (OPA) has no mandatory requirement for contracted resources to have firm gas, generators cannot invoke *force majeure* due to gas deliverability constraints; therefore, most gas-fired generators have firm transportation rights in order to manage contractual risks with OPA.

The limited number of merchant generators holding primary firm transportation contracts reflects the absence of a PPA requirement for generators to hold firm transportation in MISO, PJM, NYISO, and ISO-NE. The competition inherent in electric markets, in which generators must clear based on price, may discourage the inclusion of incremental costs associated with firm transportation in bid structures, even where such costs could be recoverable under market rules. In evaluating gas/electric interfaces across the Study Region, LAI has not assessed the PPAs' respective penalty structure(s) for failure to perform due to pipeline deliverability constraints or the impact on gas-fired generators' contracting practices.

Rather than acquiring firm primary or secondary firm transportation capacity through pipeline contracts and released capacity, generators generally transact with gas marketers and other third-party suppliers for fuel supplies, or utilize dual fuel capability to bridge the fuel supply gap. Gas marketers offer short- and long-term supply arrangements at the citygate or plant meter, on either a firm or non-firm basis. Often, a marketer or gas supplier will enter into an Asset Management

Agreement (AMA) with a generation company to meet all or a portion of the generator's gas requirements in the Day-Ahead Market (DAM) or Real-Time Market (RTM). An AMA often covers a portfolio of generation assets rather than one individual plant. The pricing of bundled gas supply services under either a third-party marketer agreement or an AMA reflects market prices, *i.e.*, the value of natural gas delivered to the consuming region as well as an allowance for daily swing and imbalance resolution, among other things.

Regarding contracting trends, key findings or observations are as follows:

- Gas-fired generation owners generally do not hold significant primary entitlements from liquid sourcing points or storage centers to their respective delivery points in their own name, instead relying on marketers for gas supply and transportation. There are a number of reasons for this market dynamic, including credit constraints and the reduced energy margins due to lower regional gas prices.
- Gas-fired generators can also contract for firm supply and transportation through third-party arrangements with marketers and asset managers who have firm pipeline entitlements.
- From a character of service standpoint, many gas-fired generators rely on non-firm service or released capacity, including new combined-cycle plants and recent vintage peakers in New York City and Long Island that operate under long term contracts with Con Edison, the New York Power Authority, and the Long Island Power Authority.
- Many generators rely on oil storage capacity to provide fuel assurance when natural gas cannot be delivered. In many cases, this is a consequence of choices made by the generator or its fuel supplier about the quality of the natural gas pipeline or LDC service they have subscribed..

THE SECONDARY MARKET FOR RELEASED CAPACITY

Over the last two decades, FERC has promulgated regulatory incentives that have fostered transparency and a vibrant secondary market for the release of primary entitlement holders' rights. Released capacity rights are typically actively pursued by assignees: annual, monthly and weekly transactions typically clear around the price offered by the assignee, in most, cases, subject-to-recall by the assignor. Gas-fired generators generally opt to conduct business with gas marketers or gas suppliers under short- or long-term fueling arrangements or AMAs. On a short-term basis, the commodity supply can typically be bundled just-in-time to meet a generator's scheduling requirements in the DAM or RTM. On a long-term basis, generators can contract for firm supply using bundled marketer transportation rights.

The following are primary observations regarding the secondary market:

- LDCs are by far the most active assignors across all PPAs. Unregulated gas marketers are the most active assignees of released capacity. Gas marketers have achieved high market share by aggregating secondary capacity entitlements, both in-the-path and out-of-the-path, with other contract entitlements to serve gas-fired generation across the Study Region.

- Pipeline transportation rates for released capacity rights are negotiable by the assignor and the assignee. There is no price cap for capacity released by the assignor for releases of one year or less.

- Gas-fired generation owners are not among the most active direct assignees of released capacity. Generators instead arrange for gas supplies through marketers that transact for released capacity. Some merchant generators across the Study Region do actively participate directly on their own behalf in the secondary market for a portion of their daily fuel requirements, but this is much more the exception than the rule.

- Nearly all capacity released in the secondary market is released on a subject-to-recall basis. Primary entitlement holders' recall rights provide valuable option benefits, in particular, when unanticipated weather conditions result in higher-than-expected demand or when operating conditions, for example, a producer *force majeure* event, require the use of upstream primary receipt points to lessen curtailment exposure.

- Released capacity generally provides secondary entitlement holders with access to traditional and shale gas supplies as a result of FERC's regulatory innovations, *e.g.*, segmentation and flexible receipt and delivery points.

- Release transactions are predominantly short-term in nature, that is, one month or less. Some release transactions are for multiple months up to one year, and a few multi-year releases have occurred in TVA. Quantitative information by PPA is provided on the term structure of capacity release transactions in Section 2.4.

QUALITATIVE ASSESSMENT OF GAS-ELECTRIC INTERFACE CAPABILITY

The comprehensive nature of the research conducted by LAI in Target 1 invites a qualitative summary of the gas-electric interface capability by PPA. In the narrow context of bulk power reliability objectives and resource adequacy from the standpoint of gas-fired generators, LAI has defined a number of evaluation criteria that encompasses gas supply diversity, access to pipeline and storage infrastructure, character of service, pipeline and LDC tariff provisions, penalty structure, and the liquidity level in the secondary market.

Table 3 summarizes this assessment in a color-coded matrix. The color coding is relational, based on the gas-electric interface attributes observed in the six PPAs. Green represents favorable gas-electric interface conditions relative to the other PPAs, that is, the absence of pressing concerns regarding the operational and commercial infrastructure available to generation companies. Yellow represents neutral conditions, that is, conditions not clearly favorable or unfavorable to generation companies. Red represents comparatively unfavorable conditions.

Table 3. Qualitative Assessment of Gas – Electric Interface Attributes

	Criterion	PJM	MISO	NYISO	ISO-NE	TVA	IESO
Natural Gas Supply	Gas Supply Portfolio Diversity						
	Pipeline Connectivity Level						
	Conventional Storage Deliverability						
	LNG Storage Capability						
Electric-Gas Interface	Firm Transportation Entitlements						
	Direct Pipeline Connectivity						
Electric/Gas Tariff	Pipeline or LDC Penalties						
	LDC Provision of Flexible Service						
	Active Secondary Market						

In terms of portfolio diversity and pipeline connectivity, PJM, MISO and NYISO are benefited by improved access to new sources of gas supply, while substantial existing pipeline and storage infrastructure supports flow from conventional producing basins in the Gulf of Mexico, Rocky Mountains, and western Canada. A building boom from Marcellus to downstate New York has improved gas supply diversity into PJM and NYISO. New England, with access to supply sources in eastern Canada, western Canada, LNG imports, Marcellus gas, and the Gulf Coast ostensibly has adequate supply portfolio diversity. However, declining production from eastern Canada, the cost disadvantages associated with long-haul transportation from western Canada, and high prices for LNG in global markets limit the level of portfolio diversity in New England relative to the other PPAs. As the region experiences a material decline in both Canadian supply and LNG imports, reliance on west-to-east and south-to-north flows on pipelines linking Marcellus and the Gulf of Mexico into the region will increase even though current pipeline connectivity is less than adequate to keep pace with demand. Pipeline expansions on the drawing boards are expected to improve pipeline connectivity, but heighten reliance on supplies from Marcellus.

Flow reversals on the major pipelines serving TVA will increase supply diversity by moving more Marcellus gas north-to-south to TVA. Supply diversity into Ontario has improved with the onset of new transportation services on TransCanada and the reversal-of-flow on pipelines in New York, thereby providing much improved access to Marcellus. MISO has favorable access to a range of both conventional and shale gas supply sources, thus displacing gas from the

Midcontinent, Rocky Mountains, and western Canada. MISO also benefits from the well-developed pipeline and storage infrastructure that provides access to diverse supply sources across North America.

Regarding storage deliverability, there are significant conventional and, to a lesser extent, high deliverability storage resources in PJM and MISO. In contrast to conventional storage resources, high deliverability facilities are capable of multiple injection and withdrawal cycles each year. Ontario's storage infrastructure is also favorable to LDC and gas-fired generator operations with large storage facilities and access around the Dawn storage hub in southern Ontario. Storage connectivity levels for TVA are also favorable with good access to the storage facilities along the Gulf Coast. Absent conventional storage resources in New England, there is significant LNG import terminal capacity around Boston and New Brunswick, as well as satellite storage capacity earmarked exclusively for LDC use. While the use of import terminal capacity has declined in recent years due to price differentials in Europe and Asia relative to New England, a significant amount of LNG is available year-round on a reliable basis to supply gas-fired generation around Boston.

Regarding the gas-electric interface pertaining to contract provisions and trends, gas-fired generators predominantly rely on non-firm transportation arrangements, except in TVA and Ontario. The red notation in ISO-NE relates to the increased frequency of interruptible service not being available on Algonquin and Tennessee, the primary pathways into New England, due to congestion patterns emanating from Marcellus. Out-of-the-path secondary releases appear to be constrained during the heating season, and also at other times of the year when pipeline maintenance is scheduled or throughput is maximized during the peak cooling season. While primary and secondary firm pipeline services are available to generators in PJM, NYISO MISO and ISO-NE, the cost associated with this service coupled with the availability of firm and non-firm services from gas marketers at the citygate or plant gate has resulted in generation companies' general reliance on gas marketers for an aggregated local delivery service. Surrounded by pipeline connectivity and the reversal of flow from Marcellus, TVA appears favorably positioned to obtain firm transportation service when appropriate.

Regarding direct pipeline connectivity, the majority of new combined-cycle plants and peakers are directly connected to interstate pipelines, thereby exploiting higher delivery pressures to supplement heat rate efficiency, while avoiding local transportation costs. Again, Ontario is the exception where the majority of new generation facilities are located behind citygates throughout the province. New generation on the New York Facilities System depends on local service from either Con Edison or NGrid. While the provision of such service is non-firm, LDC tariffs and New York State Reliability Council (NYSRC) Reliability Rules require generators on the New York Facilities System to have backup fuel capability throughout the year. The use of such fuels is subject to air permit limitations.

Regarding penalty charges for unauthorized overpulls, both pipelines and LDCs have provisions memorialized in their respective tariffs to safeguard against scheduling conduct that degrades service to firm customers. Under normal operating conditions, pipelines typically do not require shippers to keep strictly to scheduled quantity levels or to uniform hourly flows, so long as any daily imbalance is resolved within a time frame agreeable to the pipeline, and any non-uniform hourly flows within the gas day are manageable by the pipeline. Further, pipelines typically do not assess penalties to shippers that take gas within a certain tolerance level above their scheduled quantities. Both LDCs and pipelines, however, have the ability to assess significant and punitive penalties during extreme operating conditions, when OFOs are in effect, and a shipper's non-ratable takes or unauthorized overpulls, which diverge from the scheduling requirements set forth in the tariffs, threaten to harm pipeline operational integrity. A broad array of tariff provisions oriented around generation service are offered by LDCs in PJM and NYISO. Because generation companies in Ontario have firm transportation rights, operational issues pertaining to daily imbalances and non-ratable takes are not typically problematic. Moreover, LDC tariff provisions in Ontario afford generation companies substantially similar rights and privileges as other firm customers.

Regarding the secondary market, FERC policy has enabled an active, transparent, and efficient secondary market for released capacity rights throughout most of the Study Region. The secondary market in Ontario appears moribund in relation to trading activity elsewhere in the Study Region, largely a result of the recent National Energy Board (NEB) decision regarding TransCanada's rates and TransCanada's renewed ability to offer new transportation services on a short term basis.

In the Target 1 Report that follows, LAI addresses the gas-electric interface capability in each PPA. While emphasis has been placed on the compilation of pipeline, storage, LDC and generation resources across the Study Region, to streamline the content of the report, readers will find the baseline description of gas-electric infrastructure in the Appendix. Subsequent Target research to be conducted this year and next will incorporate the baseline description of resources presented herein, culminating in the engineering, economic and market based insights, as well as the modeling capability, required by the PPAs in order to calibrate the operational risks and available mitigation measures associated with increased reliance on gas-fired generation.

1 NATURAL GAS FACILITIES AND OPERATIONS

Energizing North America with natural gas involves a complex and multi-faceted supply chain from the wellhead to the burner-tip. The supply chain includes production, midstream, transmission, storage, and distribution facilities. Natural gas is produced from wells located primarily in sedimentary basins throughout North America. Traditionally, gas was produced from conventional reservoirs where vertical wells were drilled from the surface on land or from offshore platforms into porous bedrock structures that contained trapped natural gas or natural gas and crude oil. Major commercial gas production from conventional reservoirs experienced rapid growth starting in the 1940s, when the first long-haul interstate pipelines were built to transport natural gas from the Gulf Coast to major markets in the Midwest and Northeast. Conventional gas production continued to grow throughout the 1950s and 1960s, reaching a peak in the 1970s. By the mid-1970s the conventional wisdom held that gas production in the U.S. would continue to decline for the foreseeable future, rendering natural gas consumers increasingly dependent on expensive imported gas from Canada as well as imported LNG. In the early 1970s, relatively small amounts of gas were produced from unconventional gas reservoirs, namely, coalbeds, tight sandstones and, to a lesser extent, gas-bearing shales. The technology needed to enable large scale economic production from unconventional reservoirs, namely, horizontal drilling, hydraulic fracturing, and three-dimensional seismic imaging, would require another 20 years of development.

Until the middle of the last decade, the majority of U.S. gas flows originated from traditional producing basins in Texas, the Gulf Coast, New Mexico, California, the Midcontinent region, the Rocky Mountains, and western Canada. Comparatively small amounts of natural gas were produced from other, mostly conventional basins throughout the U.S., and then in the late 1990s from Atlantic Canada. Over the last several years, the emergence and growth of shale gas has radically changed natural gas production and transportation dynamics throughout North America. In 2005, total annual shale gas production in the U.S. amounted to about 600 Bcf. The majority of this early shale gas production originated in the Barnett shale in Texas. By 2012, total annual U.S. shale gas production amounted to more than 9.9 Tcf, predominantly from the Marcellus, Haynesville, Barnett, Eagle Ford, Fayetteville, and the Woodford formations. The emergence of shale gas has upended conventional gas flows across North America.

Figure 11 depicts changing gas flows across the Study Region attributable to prolific shale gas production. Gas flows out of Western Canada to the east have decreased substantially, while gas flowing from the Rocky Mountains and Gulf Coast producing regions has been largely displaced across the Study Region by gas emanating from Marcellus. A recent energy market assessment by Canada's NEB indicates that Marcellus production is displacing Canadian natural gas in the U.S. Northeast and in some parts of Ontario.[1] This report also concluded that further displacement of Canadian gas could occur as a result of continued development of the Utica shale.[2] Shale gas production has also displaced LNG imports as the supply of natural gas has

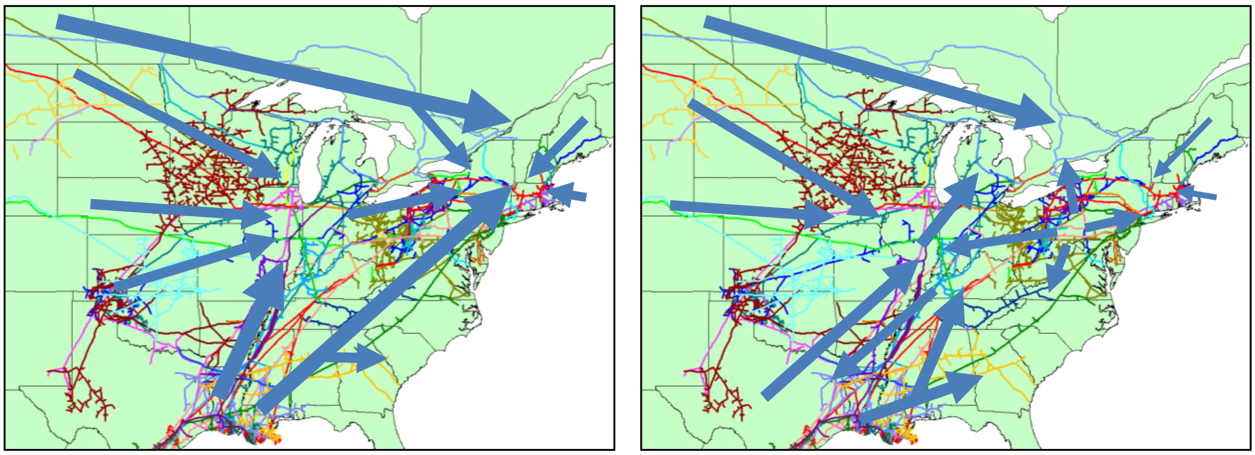
[1] National Energy Board, "Short-Term Canadian Natural Gas Deliverability 2013-2015," May 2013.

[2] The Utica shale, currently being developed in Ohio, is 2,000 feet deeper than the Marcellus shale, but with a similar distribution.

reduced commodity prices, thereby motivating LNG importers to move destination flexible cargoes to premium markets in Europe and Asia.

Figure 11. Pre-Shale and Post- Shale Gas Flow Patterns

Pre-Shale Flow Patterns   Post-Shale Flow Patterns



Abundant shale gas production has materially affected the entire gas supply chain from production field to end user. In order to get gas to market from the new wells being drilled throughout the shale gas producing fields, extensive gathering facilities are needed to take gas from the well site to processing plants. Such facilities remove impurities and natural gas liquids in order to make the gas compatible with interstate pipeline quality requirements. After processing, the gas is delivered to pipelines for transportation to direct-connected gas-fired generation, industrial customers, and storage facilities, as well as to LDCs.

The term "supply push" has been used to describe the recent supply-driven changes that are being imposed on the North American gas infrastructure.[3] These supply-driven infrastructure changes are having the greatest impact on gas markets in PJM, MISO, NYISO and Ontario, with lesser but still significant impacts on the gas markets in New England and TVA. For TVA, the abundant supply of natural gas coupled with increasingly stringent emission requirements have resulted in increased consideration of gas-fired generation as part of the resource planning process currently underway.[4] Several recent studies have concluded that pipeline capacity constraints are the primary impediments to New England's ability to access increased Marcellus gas supplies.[5] A recent study conducted by LAI on behalf of NYISO showed that the capacity

[3] EnVision Energy Solutions, Bentek Energy, "Phase III: Natural Gas-Fired Electric Power Generation Infrastructure Analysis, An Analysis of Pipeline Capacity Availability," Prepared for The Midcontinent Independent Transmission System Operator, December 1, 2013.

[4] TVA, "2015 Integrated Resource Plan, Public Scoping Meeting," October 24, 2013.

[5] ICF International, "Gas-Fired Power Generation in Eastern New York and its Impact on New England's Gas Supplies," Submitted to: ISO New England, November 18, 2013.

ICF International, "Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Power Generation Needs, Phase II," presentation to ISO-New England Planning Advisory Committee Meeting, December 18, 2013.

serving the New York Facilities System and, to a lesser extent, the New York Control Area (NYCA) has experienced frequent congestion during the heating season. However, new and planned pipeline expansions will enable additional Marcellus gas to flow into the NYCA.[6]

Interstate pipelines have established gas quality criteria to ensure that pipeline and end-user equipment and products will not be damaged by chemical impurities within the gas stream. Pipeline gas quality criteria typically include ranges limiting the water content, the amount of heavier hydrocarbons (*e.g.*, ethane, propane, butane and pentanes), non-combustible gases including carbon dioxide and nitrogen, and other contaminants such as particulates, hydrogen sulfide and sulfur. Pipelines also set the range for the acceptable heating value of the gas to be transported. The economics of gas processing are impacted by the relative cost of natural gas liquids and crude oil: the heavier hydrocarbons, or natural gas liquids, have premium uses that are priced in relation to crude oil. Typically, some ethane can be left in the gas stream without violating a pipeline's gas quality requirements. However, when oil prices are substantially higher than gas prices on a Btu-equivalent basis, more ethane will be removed from the gas stream at the processing plant. Often, ethane is more valuable as a petrochemical feedstock in competition with oil-based feedstocks.

With new sources of gas production accounting for a larger portion of gas moved by the pipelines serving the Study Region, another pipeline consideration involves the compatibility and interchangeability of gas from different sources. Interchangeability refers to the ability of gas from different sources to be utilized in the same manner with the same performance in end-use applications. When taking gas from different sources, the pipeline operators must ensure that the resultant gas mixture is nearly identical in terms of combustion characteristics and burner-tip flame properties, referred to as co-mingling. The most widely used methodology for predicting gas interchangeability is the Wobbe Index, which provides a standardized comparative measure of the heating characteristics for natural gas from different sources. All pipelines doing business across the Study Region enforce gas interchangeability requirements to ensure safety and efficiency across the supply chain.[7,8,9]

Black & Veatch, "Natural Gas Infrastructure and Electric Generation: Proposed Solutions for New England," prepared for The New England States Committee on Electricity, August 26, 2013.

NESCOE letter to ISO-NE regarding a "Request for ISO-NE technical support and assistance with tariff filings related to electric and natural gas infrastructure in New England," January 21, 2014, http://www.nescoe.com/uploads/ISO_assistance_Trans___Gas_1_21_14_final.pdf.

Competitive Energy Services, "Assessing Natural Gas Supply Options for New England and their Impacts on Natural Gas and Electricity Prices," February 2014.

[6] Levitan & Associates, Inc., "NYCA Pipeline Congestion and Infrastructure Adequacy Assessment," New York Independent System Operator, August 2013.

[7] If it can do so on a non-discriminatory basis, a pipeline can commingle natural gas that does not meet tariff specifications with other natural gas that exceeds the specifications in order to produce a blended gas stream that complies with the gas quality specification in its tariff.

[8] Pipelines generally accept gas that falls within a range of Btu contents with higher Btu gas blended with lower Btu gas to conform to these limits. Under unusual circumstances, generally prior to the construction of sufficient gas processing capabilities in new producing areas, some gas flowing in the pipeline may be permitted to exceed these limits. Texas Eastern currently accepts gas that exceeds the tariff gas quality specifications on a section of its

1.1 INTERSTATE PIPELINES

1.1.1 FERC Regulatory Jurisdiction and Regulatory Highlights

In the U.S., FERC has jurisdiction over the regulation of interstate pipelines, including the rates and services offered. FERC is also responsible for certifying and permitting new pipeline construction.[10,11] FERC decisions encompass both company-specific and industry-wide topics. Company-specific issues can include applications for changes to rates, tariffs or contract terms and conditions, and complaints filed against FERC-regulated entities. Industry-wide decisions and rules that promulgate structural changes to pipeline operations are also the regulatory responsibility of FERC.

Since the natural gas industry was restructured in the mid-1980s, there have been a number of landmark FERC orders and policy statements affecting market dynamics across the U.S., including how gas-fired generators obtain natural gas directly from the pipeline or storage company, as well as from LDCs. In this section, we review landmark FERC Orders and Policy Statements dating back to 1992. Brief review of these landmark FERC orders and policy statements provides insight into the chronology of regulatory events that has culminated in the open access and highly competitive pipeline industry serving core and non-core shippers[12] across North America, in general, and the six PPAs, in particular.[13]

<u>Order No. 636</u>

FERC Order No. 636 was issued on April 8, 1992. After decades of efforts by Congress and FERC to decrease regulation and increase competition in the natural gas commodity markets, Order No. 636 represented a critical juncture in the evolution to open access and a competitive national gas commodity market. Open access on interstate pipelines facilitated direct transactions between natural gas buyers and sellers throughout the U.S.

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pipeline in eastern Ohio and western Pennsylvania that serves the "wet" gas producing areas in the Marcellus and Utica shales, but only to the extent that the higher Btu volumes do not result in gas quality that exceeds the limits outside of this pipeline section.

9 On June 13 2013, Texas Eastern issued an Action Alert due to gas quality issues associated with the high levels of ethanes and heavier hydrocarbons present in gas received in western Pennsylvania and eastern Ohio. Texas Eastern took proactive steps to ensure that generators received their required gas quality without negatively affecting deliverability.

10 FERC obtains its regulatory authority from federal enabling legislation, including the Natural Gas Act (http://www.law.cornell.edu/uscode/usc_sup_01_15_10_15B.html), the Natural Gas Policy Act of 1978 (http://www.law.cornell.edu/uscode/html/uscode15/usc_sup_01_15_10_60.html), the Natural Gas Wellhead Decontrol Act of 1989 (http://ferc.gov/legal/fed-sta/natural-gas-wellhead-decontrol-1989.pdf) and the Outer Continental Shelf Lands Act (http://www.law.cornell.edu/uscode/usc_sup_01_43_10_29_20_III.html).

11 The FERC-regulated expansion planning process is addressed in more detail in the following section of this report.

12 Throughout this report, references to "core" load are synonymous with residential, commercial and industrial (RCI) demand. References to "non-core" load are synonymous with gas-fired generator demand.

13 Other landmark FERC orders and policy statements prior to 1992 also occurred that paved the way for deregulation of the gas industry, in particular the Natural Gas Policy Act of 1978 and FERC Order No. 436 in 1985.

In Order No. 636, FERC sought to improve the competitive structure of the natural gas industry and at the same time maintain an adequate and reliable service. FERC also sought to achieve this goal in a way that continued to ensure consumer access to an adequate supply of gas at reasonable prices.[14] Order No. 636 required interstate pipelines to unbundle their transportation, storage, and sales services. Open access rules, which began with Order No. 436, ensured that pipeline transportation could not be provided on more favorable terms to the pipeline's own merchant service to the detriment of competing sellers.[15] Order No. 636 sought to ensure that all shippers have meaningful access to the pipeline transportation grid so that willing buyers and sellers can meet in a competitive, national market to transact the most efficient deals possible.[16] FERC mandated the separation of transportation and sales, thereby allowing customers to purchase gas from suppliers at competitive, deregulated prices while purchasing transportation from the pipelines under traditional cost of service principles. FERC also issued blanket sales certificates to interstate pipelines allowing them to offer firm and interruptible sales at market-based rates. Order No. 636 also introduced a new, unbundled no-notice firm transportation service and improve the quality of interruptible transportation service, and unbundled storage services. This landmark order established structural changes to the secondary (capacity release) market, where owners of firm transportation rights could release unwanted capacity subject to the as-billed rate cap, thereby recouping part or all of their reservation charges from replacement shippers. To encourage market transparency and efficiency, FERC required pipelines to create Electronic Bulletin Boards (EBBs) with standardized informational postings about pipeline capacity availability in order to facilitate equal and timely access to information regarding service availability on interstate pipelines. FERC also required pipelines to manage the capacity released program through their EBBs on behalf of their customers.

FERC ordered interstate suppliers to redesign their rates using Straight Fixed Variable rate design to maximize the benefits of wellhead decontrol by increasing competition for a national commodity market.[17] Under this rate design, all fixed costs, including the rate of return component are recovered in the reservation charge that a pipeline assesses a shipper regardless of that shipper's actual throughput. Variable costs are recovered in the usage rate, which does vary based on a shipper's actual throughput. Pipelines design interruptible transportation rates based on a daily derivative of the firm transportation rate. Interruptible rates are recovered through volumetric rates applied to gas actually transported.[18] Regarding this new rate structure, the United States General Accounting Office noted:

> "Under the new rate design, customers that require 'firm,' or uninterrupted, service will pay more of the pipeline companies' fixed costs; these customers are

[14] FERC Order No. 636, pages 7-8.

[15] FERC Order No. 636 at 2. "This rule will therefore reflect and finally complete the evolution to competition in the natural gas industry initiated by those changes [FN omitted] so that all natural gas suppliers, including the pipeline as merchant, will compete for gas purchasers on an equal footing."

[16] FERC Order No. 636, page 7.

[17] FERC Order No. 636, page 128.

[18] EIA, "FERC Order 636: The Restructuring Rule" http://www.eia.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/ferc636.html.

> mainly local distribution companies that serve residential or commercial end-users. Customers that can tolerate "interruptible" service could pay a smaller percentage of these costs; these customers are mainly industrial customers, such as manufacturers of fertilizer, glass, and other consumer products, linked directly to the pipeline companies or distribution companies that serve industrial end-users."[19]

Like prior landmark FERC orders, particularly Order No. 436, Order No. 636 caused pipeline companies to incur significant transition costs that were deemed recoverable by FERC, including buy-out or continuation of legacy contracts, stranded cost liabilities associated with the provision of gas sales service, and the cost of new equipment, in particular, metering devices and EBB technology. Finally, Order No. 636 provided interstate pipelines with pre-granted abandonment authority under certain conditions.

PL94-4

On May 31, 1995, FERC issued a Policy Statement on Pricing Policy for New and Existing Facilities Constructed by Interstate Natural Gas Pipelines (PL94-4). This statement was spurred by a proceeding discussing the need for FERC to establish pricing policies for new construction projects under the new open access regime. Comments were split on the equity and allocative efficiency benefits attributable to rolled-in versus incremental pricing of pipeline facility additions. Under rolled-in pricing, a pipeline would in essence "socialize" the cost of facility additions among existing ratepayers and any new users associated with the project. In contrast, under incremental pricing the economic burden falls solely on the users of the new project. Both incremental and rolled-in pricing are determined in the FERC certificate when FERC establishes initial rates. A pipeline may move from incremental rate design to rolled-in rate design in a rate case proceeding, but the pipeline must carry the burden of proof to do so. Proponents of both pricing regimes conveyed sound arguments regarding the merit of rolled-in pricing and incremental pricing: rolled-in pricing had merit when significant system-wide benefits could be attributed to the project, while incremental pricing had merit when the project's benefits were self-contained or localized.

FERC elected to select the best pricing policy based on determining the appropriate rate design in pipelines' certification proceedings. FERC noted, "[W]hen the pipeline seeks rolled-in pricing, the Commission will base its pricing decision on an evaluation of the system-wide benefits of the project and the rate impact on existing customers. To reduce uncertainty, in those cases, the Commission will establish a presumption for rolled-in rates when the rate effect on existing customers is not substantial."[20] In PL94-4, FERC established the pipeline's responsibility to identify and value the benefits ascribable to the project. Operational benefits include reliability, access to new supplies or markets, and flexibility through increased storage access. Financial benefits include enabling the pipeline to serve new demand, reducing customer

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[19] United States General Accounting Office, "Natural Gas: Costs, Benefits, and Concerns Related to FERC's Order 636", November 1993. http://www.ferc.gov/legal/maj-ord-reg/land-docs/gao-636study-1993.pdf.

[20] FERC Policy Statement PL94-4, page 4.

costs, or producing economies of scale. FERC noted that "financial or cost-related benefits should be quantified, to the maximum extent possible."[21]

FERC required pipeline companies to make an affirmative case regarding operational benefits, in particular, whether the expansion project will increase system or operational reliability, such as a resolving a capacity constraint, and whether a project can provide system benefits by increasing shippers' access to new supplies or markets.[22] FERC elected to favor rolled-in rates if the rate impact is 5% or less and the pipeline adequately demonstrates benefits. In the Policy Statement, FERC noted that customers opposing rolled-in rates in these cases have the burden of proof to demonstrate the rate increase is not justified. FERC found that this provision protected existing customers from rate shocks while providing some rate certainty to pipelines and shippers. If a pipeline's project is deemed "at-risk," meaning the pipeline does not adequately demonstrate demand for the project during the certificate proceedings, the 5% threshold does not apply. In this case, no pricing regime will be favored, although the pipeline may still achieve rolled-in pricing with benefits proportional to the project costs. Projects that meet low cost and other limitations may acquire blanket/automatic certification. When system-wide benefits are shown, FERC indicated that rolled-in pricing would be presumed.

In PL94-4, FERC expressed its support for incremental pricing of downstream laterals. FERC's support for incremental pricing of downstream laterals hinged on the absence of system-wide customer benefits. In contrast, upstream laterals could qualify for rolled-in pricing by facilitating connections with new gas supply sources, or pipeline interconnects. FERC set forth the standard that projects with rolled-in rates greater than the 5% threshold will need to demonstrate that the project is properly sized by performing open seasons and soliciting permanent capacity release offers. The pipeline should also propose rate mitigation measures, particularly negotiated solutions. Solutions include expansion shippers making Contributions-in-Aid-of-Construction, rolling in costs over a multi-year period, or innovative rate design, e.*g*., seasonal rates. FERC allowed for pricing determinations for new facilities to be set through the certification process, and then applied in the first rate case after the facilities go into operation.

PL99-3

On September 15, 1999, FERC issued a Policy Statement on the Certification of New Interstate Natural Gas Pipeline Facilities (PL99-3). Recognizing the growth in gas demand throughout the U.S., in particular the Northeast, FERC noted that an effective certificate policy is "designed to foster competitive markets, protect captive customers, and avoid unnecessary environmental and community impacts while serving increasing demands for natural gas…It should also provide appropriate incentives for the optimal level of construction and efficient customer choices."[23] Upon review of the then existing certification policy, in particular, the policy's drawbacks, FERC laid out a new certification policy.

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[21] FERC Policy Statement PL94-4, page 6.

[22] Operational benefits due to major expansions must be shown to accrue to most customers on the system rather than a select group.

[23] FERC Policy Statement 99-3, page 13.

First, FERC sought to determine whether a pipeline project can proceed without subsidies from existing customers. Next, FERC sought to determine whether the project will have any adverse effects on "existing customers of the pipeline proposing the project, existing pipelines in the market and their captive customers, or landowners and communities affected by the route of the new pipeline."[24] If no adverse effects are found, FERC set forth in the Policy Statement the process of issuing preliminary determination or final order. If adverse impacts are found, FERC recognized the need for mitigation as well as the delineation of further conditions for certification. If FERC determines the benefits outweigh the adverse effects, FERC may issue a preliminary determination or final order, depending on whether the Environmental Assessment (EA) or Environmental Impact Statement (EIS) has been completed in accordance with FERC's authority under the National Environmental Policy Act (NEPA).

PL99-3 established the no-subsidies requirement. FERC sought to change the then-current pricing policy which had "a presumption in favor of rolled-in pricing."[25] FERC asserted that pipelines must assume the risk of a project or share the risk with new customers rather than socialize costs.[26] FERC argued that charging incremental rates to expansion customers sent better pricing signals to the market to determine the true value of capacity. FERC also considered having the right-of-first-refusal (ROFR) customers match increased incremental or rolled-up rates if incremental capacity is fully subscribed. The no-subsidy threshold set forth in the Policy Statement ensures that existing customers are not subsidizing expansions or forcing other pipeline owners to compete with subsidized projects. Moreover, it assures landowners that the project is needed. PL99-3 also ensures that affiliate expansions do not receive subsidies from existing customers. In PL99-3, FERC decided to no longer require precedent agreements to demonstrate the need for a project, but such contracts would be viewed favorably by the Commission as "significant evidence."[27] However, "a project built on speculation… will usually require more justification than a project built for a specific new market when balanced against the impact on the affected interests."[28] Still, as a practical matter, FERC has not demonstrated a willingness to certificate a proposed pipeline where the applicant's demonstration of need is based on pure speculation or unsupported assertions of market demand. This is particularly true if there is evidence that the project will cause adverse effects.

FERC acknowledged the difficulty of determining a "bright line" test for balancing the benefits and adverse effect of the project. FERC noted that several factors may greatly increase the prospect of certification, however. If the right-of-way is fully or substantially purchased through negotiations with landowners, and eminent domain is largely avoided, the demonstrated benefits may be less than for projects requiring land-taking through eminent domain. If captive customers of a competing pipeline face greater rates due to less subscribed capacity, the pipeline will be required to show commensurate benefits.

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[24] FERC Policy Statement PL99-3, page 18.

[25] FERC Policy Statement PL99-3, page 20.

[26] If a project is designed for the benefit of existing customers, increasing existing customers' rates in subsequent section 4 rate processing to support the project is not considered a subsidy.

[27] FERC Policy Statement PL99-3, page 25.

[28] FERC Policy Statement PL99-3, page 25.

Order No. 637

Order No. 637 was issued on February 9, 2000. FERC made regulatory changes to "to improve the efficiency of the market and provide captive customers with the opportunity to reduce their cost of holding long-term pipeline capacity while continuing to protect against the exercise of market power."[29] In Order No. 637, FERC initiated a two-year trial in which it waived the price caps for capacity releases of less than one year.[30] The waiver of the as-billed price cap for released capacity allowed assignors and assignees to transact capacity release based on the true value of the capacity entitlement. In furtherance of allocative efficiency principles, FERC sought to provide economic motivation to assignors to find the most efficient use of any capacity deemed surplus to the entitlement holder's needs.

FERC found that pipeline capacity was not efficiently allocated, particularly during peak periods. FERC noted that "the use of the pipeline's maximum rate as the cap for capacity release transactions can reduce the amount of release capacity available during peak periods precisely when capacity is needed most" and therefore potentially more valuable than the as-billed rate cap for short term releases. Order No. 637 therefore paved the way for assignors and assignees to exchange capacity at market-based prices even if such market prices exceeded the cost of service.[31] Order No. 637 also incorporated a policy that permits pipelines to establish cost-based seasonal, peak/off peak and term-differentiated rates for firm transportation service.

Order No. 637 implemented scheduling changes to facilitate transparency and liquidity in the daily market. In order to make capacity release more competitive with primary entitlements sold by interstate pipelines under cost of service principles, FERC ordered that released capacity holders be able to submit scheduling nominations as soon as possible in accord with NAESB nomination cycles rather than wait until the next day. Extending its reasoning in Order No. 636 to further promote open access, FERC formalized its recommendation that pipelines allow segmentation as well as flexible receipt and delivery point rights. Segmentation allows firm transportation holders to divide their primary receipt to primary delivery point entitlement into separate segments, thereby allowing the sale to assignees of discrete route segments.

FERC provided an example of this practice, noting "that a shipper holding firm capacity from a primary receipt point in the Gulf of Mexico to primary delivery points in New York could release that capacity to a replacement shipper moving gas from the Gulf to Atlanta while the New York releasing shipper could inject gas downstream of Atlanta and use the remainder of the capacity to deliver the gas to New York."[32] To effectuate this transaction structure, FERC authorized capacity segmentation rights as well as the flexible point rights to change both delivery and receipt points. FERC observed that some pipeline companies were not permitting or were otherwise limiting segmentation and flexibility. Order No. 637 explicitly set forth these requirements.

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[29] FERC Order No. 637, page 1.

[30] The price cap had been the maximum reservation charge collected by the pipeline in the primary market.

[31] FERC Order No. 637, page 67.

[32] FERC Order No. 637, page 126.

FERC noted that pipeline penalties and balancing systems may be creating arbitrage opportunities for shippers. In a policy shift, FERC called for pipelines to issue penalties only when needed to protect pipeline system integrity. In order to limit imbalances, FERC required pipelines to provide imbalance management services, such as park and loan service, expansion of trading provisions, and other measures to give shippers better access to information about their imbalance status as well as improved economic incentives to stay in balance.[33] FERC also narrowed ROFR provisions to remove economic biases by limiting ROFR rights to long-term shippers contracted at maximum rates, and made changes to pipeline EBB reporting requirements, including format changes, transaction data about capacity release, and timing requirements for informational postings.

PL05-8

On June 16, 2005, FERC issued a Policy Statement on Creditworthiness for Interstate Natural Gas Pipelines in lieu of a formal rulemaking (PL05-8). FERC noted that issues with creditworthiness had declined after the Notice of Proposed Rulemaking was issued. FERC concluded that NAESB business practices were sufficient to address general standards, and that most issues could be addressed on a case-by-case basis.

Nevertheless, FERC issued certain guidelines, as follows:

- Standards establishing a uniform set of documents that shippers would have to produce to pipelines, including business and financial information;
- Objective criteria for pipelines to determine shipper creditworthiness, and prompt responses with reasons for determination if a shipper is not deemed creditworthy;
- Objective, non-discriminatory collateral requirements, but potentially larger requirements for construction projects, in particular, pipeline laterals;
- Reasonable, non-discriminatory acceptance of security;
- Opportunity for shippers to earn interest on collateral;
- 30 days for shippers to provide security prior to termination of service;
- Identical creditworthiness requirements for releasing and replacement shippers;
- Permission for tariff changes permitting releasing shippers to establish lesser collateral requirements;
- Opportunity for replacement shippers to pick up released capacity from terminated releasing shippers at same or higher rate (but segmentation not honored); and
- Reversion of suspended replacement shipper capacity back to the releasing shipper.

Since Order Nos. 436 and 636, and confirmed in the Commission's Policy Statement, the Commission's general policy has been to permit pipelines to require shippers that fail to meet the pipeline's creditworthiness requirements to put up collateral equal to three months of reservation charges. The Commission stated that it would continue its policy of permitting larger collateral requirements for construction projects. For new construction, a pipeline needs sufficient collateral from non-creditworthy shippers to ensure, prior to committing significant resources to

[33] Park and loan service is discussed in more detail in Section 2.3.5.

a project, that it can protect its investment. For mainline projects, the pipeline's collateral requirement must reasonably reflect the risk of the project, particularly the risk to the pipeline of remarketing the capacity should the initial shipper default. Because these risks may vary depending on the specific project, no predetermined collateral amount would be appropriate for all projects. The collateral, however, may not exceed the shipper's proportionate share of the project's cost.[34]

FERC's Policy Statement on Creditworthiness made it more difficult for shippers with limited balance sheets or weak credit to satisfy FERC's standards for subscribing for interstate pipeline service.

<u>Order No. 698</u>

FERC issued Order 698, titled "Standards for Business Practices for Interstate Natural Gas Pipelines; Standards for Business Practices for Public Utilities", on June 25, 2007. The order incorporated NAESB standards into FERC rulemaking "to improve coordination between the gas and electric industries in order to improve communications about scheduling of gas-fired generators."[35] Standards from the WGQ and Wholesale Electric Quadrant (WEQ) of the NAESB were considered. Several standards were adopted, including:

- WEQ Standard 011-1.2/WGQ Standard 0.3.12: This standard "directs the power plant operator and the transportation service provider directly connected to the power plant operator's facility(ies) to establish procedures to communicate material changes in circumstances that may impact hourly flow rates, and the power plant operator to provide projected hourly flow rates accordingly."[36]
- WEQ Standard 011-1.3/WGQ Standard 0.3.13: This standard mandates that power plant operators operate with an approved scheduled quantity pursuant to the NAESB WGQ standard nomination timeline and scheduling processes or as permitted by the transportation service provider's tariff, general terms and conditions, and/or contract provisions. If the power plant operator requests scheduling changes which the transmission service provider can support, changes to nominations may be made through the communication procedures set forth above.[37]
- WEQ Standard 011-1.4 and WGQ Standard 0.3.14: These standards require the sharing of OFOs and other critical notices between transportation service providers and RTOs, ISOs, independent transmission operators and/or power plant operators.[38]
- WEQ Standard 011-1.5: Notes that "upon request, a power plant operator must provide to the appropriate independent balancing authority and/or reliability coordinator pertinent

[34] FERC Policy Statement on Creditworthiness for Interstate Natural Gas Pipelines and Order Withdrawing Rulemaking Proceeding, Proposed Rule; Withdrawal; Policy Statement; 111 FERC ¶ 61,412 (2005).

[35] FERC Order No. 698, page 1.

[36] FERC Order No. 698, page 12.

[37] FERC Order No. 698, page 14.

[38] FERC Order No. 698, page 17.

information concerning the level of gas transportation service (firm or interruptible) and its natural gas supply (firm, fixed or variable quantity, or interruptible)"[39]

- WEQ Standard 011-1.6/WGQ Standard 0.3.15: "This standard requires RTOs, ISOs, independent transmission operators, independent balancing authorities and/or regional reliability coordinators to establish operational communication procedures with the appropriate transportation service provider and/or power plant operator."[40]

Other issues were also raised by NAESB during the rulemaking process. FERC clarified that shippers can use gas indices to price capacity release transactions, deferred to NAESB regarding in-the-path scheduling changes, and noted that the NAESB nomination timeline is in fact a minimum standard. Pipelines may add more intraday nomination cycles if they would benefit shippers. FERC believed the rulemaking would improve communications, coordination, and reliability for the gas and electric industries.[41]

Order No. 712

FERC Order No. 712 was issued on June 19, 2008. Order No. 712 permanently waived the price cap for short-term capacity releases of one year or less that was temporarily lifted in Order No. 637. However, the price ceiling for long-term pipeline transportation transactions was not removed.

FERC also relaxed capacity release policies to provide greater flexibility for shippers to enter into AMAs. FERC defined an AMA as:

> "any pre-arranged release that contains a condition that the releasing shipper may, on any day during a minimum period of five months out of each twelve-month period of the release, call upon the replacement shipper to deliver to the releasing shipper a volume of gas up to one-hundred percent of the daily contract demand of the released transportation capacity. If the capacity release is for a period of less than one year, the asset manager's delivery obligation described in the previous sentence must apply for the lesser of five months or the term of the release. If the capacity release is a release of storage capacity, the asset manager's delivery obligation need only be one-hundred percent of the daily contract demand under the release for storage withdrawals."[42]

AMAs are now standard commercial arrangements between third party gas marketers and both LDCs or gas-fired generation companies in the Study Region. An AMA is a contractual relationship where a party agrees to manage gas supply and delivery arrangements, including transportation and storage capacity, for another party. Typically, a shipper holding primary or secondary firm transportation and/or storage capacity on a pipeline or multiple pipelines

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[39] FERC Order No. 698, page 18-19.

[40] FERC Order No. 698, page 21.

[41] FERC Order No. 698, page 36.

[42] FERC Order No. 712, page 98.

temporarily releases all or a portion of that capacity along with associated gas production and gas purchase agreements to an asset manager. The asset manager assembles a portfolio of gas supply, transportation and storage service entitlements to serve the needs of the counterparty. These counterparties can include direct connected generation plants to interstate pipelines as well as gas-fired generators served by LDCs.

Order No. 712 set forth significant changes in FERC guidelines affecting the secondary market in order to provide asset managers with increased flexibility. These changes included: permitting the tying of capacity rights to gas supply, the provision of exemptions for bidding capacity releases to asset managers, changes to the formal AMA definition to relax supply obligations, clarifying that uncapped AMA capacity releases of one-year or less may be rolled over without competitive bidding, recognition of profit sharing arrangements included in an AMA not being in violation of the applicable price cap, and, finally, exemption of some AMAs from buy/sell prohibitions.

Order No. 787

Order No. 787 was issued on November 15, 2013. Order No. 787 grants explicit authority to "interstate natural gas pipelines and public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce to share non-public, operational information with each other for the purpose of promoting reliable service or operational planning on either the public utility's or pipeline's system."[43] FERC defined the scope of permissible communications and provided examples of such communications. Yet, FERC did not provide a finite list of permissible communications, noting that transmission system operators should be allowed to determine what information would be helpful to share in order to maintain system reliability or promote operational planning.

FERC did not extend this authorization to LDCs, intrastate pipelines, or gatherers, over which it lacks jurisdiction.[44] FERC also instituted a No-Conduit Rule to ensure that non-public information remains confidential:

> "The No-Conduit Rule prohibits all public utilities and interstate natural gas pipelines, as well as their employees, contractors, consultants, or agents, from disclosing, or using anyone as a conduit for the disclosure of, non-public, operational information they receive under this rule to a third party or to its marketing function employees."[45]

FERC noted that transmission operators are under no obligation to share non-public information; however:

[43] FERC Order 787, page 1.

[44] Intrastate pipelines, gathering systems, LDCs and municipal gas companies operate are under state and/or local jurisdiction, discussed in more detail in Section 1.3.

[45] FERC Order 787, page 50.

> "[P]roviding explicit authority to transmission operators – who have the most insight and knowledge of their systems – to share non-public, operational information with each other will promote reliable service or operational planning on both the public utility's and pipeline's system."[46]

FERC's intent is to give transmission operators the flexibility to share information with one another for the purpose of promoting system reliability and operational planning, subject to the No Conduit rule. FERC may revisit the voluntary nature of this order if the approach proves "inadequate to promote reliable service or operational planning."[47] The Order does not supersede any current tariff-based restrictions on information sharing. FERC stated that utilities that needed to amend their codes of conduct tariff provisions to facilitate sharing of electric system operating data with pipelines in non-emergencies should file appropriate tariff amendments.

1.1.2 Department of Transportation Jurisdiction

The U.S. Department of Transportation's (DOT's) Pipeline and Hazardous Materials Safety Administration (PHMSA) Office of Pipeline Safety (OPS) is the federal authority for ensuring the safe operations of the pipeline network. While the natural gas industry's safety performance generally has been outstanding over the last half century, catastrophic events in recent years, including pipeline and local distribution system failures in San Bruno, CA, Allentown, PA, and New York City, have placed the issue of safety in the national spotlight and compelled PHMSA to examine the need for more stringent safety rules. In April 2011, DOT Secretary Ray LaHood issued a Call to Action to all pipeline stakeholders, urging pipelines to repair and rehabilitate their aging infrastructure. Secretary LaHood announced PHMSA's renewed effort to ensure the safety of the natural gas pipeline system.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act (the "Pipeline Safety Act") set forth a number of upgraded pipeline safety measures, new pipeline safety studies, and new regulations. The new law doubled the maximum civil penalty for pipeline violations from $100,000 per day and $1 million for violations related to a series to $200,000 per day and $2 million for violations related to a series, and called on PHMSA to create new regulations targeting specific areas of pipeline safety concern, including the use of automatic or remotely controlled shut-off valves on new or replaced transmission pipelines, tests to confirm material strength of previously untested gas transmission pipelines in high consequence areas, and confirmation of appropriate records of maximum allowable operating pressures (MAOP) on gas transmission pipelines in densely populated or high consequence areas.

The Pipeline Safety Act also puts pressure on gas utilities doing business in the Study Region to replace cast iron distribution lines. Cast iron main is characteristic of old distribution systems and can pose a safety threat. As of 2011, most of the remaining cast iron distribution main in the U.S. was located in New Jersey, New York, Massachusetts, Pennsylvania, and Michigan. Gas

[46] FERC Order 787, page 87.

[47] FERC Order 787, page 86.

utilities normally replace cast iron distribution system laterals as part of system maintenance, but there is no compulsory federal or state requirement that such replacements be done at once. In October 2013, PHMSA posted an advisory bulletin regarding the risks of cast-iron pipelines and encouraged LDCs to expedite the replacement process while managing the safe operation of cast iron distribution systems more aggressively through inspection techniques and other safety measures. The impact of these improvements on gas-fired generators appears to be very limited or minimal because most existing cast iron pipe is used for smaller-diameter route segments that serve residential and commercial customers, not for large industrial or electric generation facilities.

In “The State of the National Pipeline Infrastructure” report issued in 2011, DOT commented:

> “In managing the pipeline infrastructure it is necessary to begin with what we have and to determine how to improve safety from that starting point. The practical problems associated with major infrastructure change are enormous. It's not possible, or even prudent, to simply dictate that all pipelines of a certain type or age be replaced by a certain date. Even if we ignore the cost of such an effort, there is the problem of supply disruption. Replacing, rehabilitating, repairing, or requalifying current pipelines requires that the existing system be at least partially shut down. This would require a carefully thought out plan and schedule that does not result in unacceptable or widespread disruptions of energy supply.”

The tasks assigned to PHMSA in the Pipeline Safety Act of 2011 are tracked on PHMSA's website, including the assigned task deadline and the status of PHMSA's progress on the task. Regulations relevant to the natural gas industry that have not yet been promulgated but are required by the Pipeline Safety Act, include:[48]

- Regulations requiring the use of automatic or remote-controlled shut-off valves on new or replaced transmission pipelines,
- Regulations expanding the Integrity Management Program and/or replacing class locations,
- Revised regulations regarding accident and incident notification timelines, and
- Regulations requiring the use of excess flow valves on new or replaced distribution facilities.

The Surface Division Pipeline Security Branch within the Transportation Security Administration’s (TSA’s) Office of Security Policy and Industry Engagement is responsible for enhancing the security preparedness of the nation's natural gas pipeline system. Current initiatives include:

[48] http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=3bf33dd3892fb310VgnVCM1000001ecb7898RCRD&vgnextchannel=8fd9f08df5f3f010VgnVCM1000008355a8c0RCRD&vgnextfmt=print

- The Pipeline Corporate Security Review Program involves on-site security reviews with pipeline companies to establish working relations with key personnel and promote understanding of security planning and implementation;
- The Critical Facility Security Review Program involves on-site visits to critical pipeline facilities to collect site-specific information regarding security policies, procedures and physical security measures;
- The International Pipeline Security Forum is an ongoing initiative conducted jointly with National Resources Canada that holds annual conferences discussing major pipeline security issues; and
- Monthly pipeline security stakeholder conference calls allow the TSA to discuss pipeline security items of interest with industry officials and government representatives.

1.1.3 Certificate Application Process

Under Section 7(c) of the Natural Gas Act, interstate pipelines must obtain from FERC a certificate of "public convenience and necessity" in order to construct new or expand existing pipeline facilities, including laterals, new mainline facilities, or compressor stations. The Energy Policy Act of 2005 designated FERC as the lead agency for coordinating the environmental review of pipeline certificate applications under NEPA. To add pipeline facilities, the applicant must demonstrate that the new or expanded pipeline facility will serve the public interest, that it is economically feasible, and that it does not have significant environmental impacts that cannot be mitigated. Once a pipeline company identifies a market need, the pipeline must conduct an open season to alert shippers to the availability of new capacity, to allow shippers to bid for that capacity, and to support the applicant pipeline's ability to meet the evidentiary burden under the Natural Gas Act. The same certification process is used whether the shippers contracting for the capacity are producers, in the case of a "supply push" project, marketers and/or end-users, in the case of a "demand pull" project, or a combination of the two.

To facilitate the certification process, a pipeline may initiate a voluntary pre-filing process in coordination with FERC. The pre-filing process is designed to disseminate as much useful information to the public as possible in order to identify environmental concerns as well as to provide stakeholders with ample opportunity to share with pipeline applicants their concerns over route segments. Stakeholders may include landowners, tribal governments, state and local governments, public interest groups, and other community groups. Once a pipeline has proposed a specific route, landowner easement negotiations begin. FERC holds public scoping meetings to create a forum for landowners, stakeholders, state or federal agencies, or any member of the public to raise concerns and ask questions. Necessary surveys and natural and cultural resource reports are begun during this time.

After the Section 7(c) application is filed, FERC prepares an Environmental Assessment (EA), or if FERC determines that impacts are significant, a detailed EIS.[49] During the NEPA review process, FERC consults with various federal agencies, as applicable, including the

[49] Projects which meet certain *de minimis* requirements may fall under the "categorical exclusion" and meet the conditions for a blanket certificate.

Environmental Protection Agency (EPA), the Fish and Wildlife Service, National Marine Fisheries Service, Advisory Council on Historic Preservation, Bureau of Indian Affairs, Bureau of Land Management, Army Corps of Engineers, U.S. Forest Service, and state agencies with delegated authority. FERC coordinates with these agencies to ensure that all necessary federal approvals are obtained, and that the certificate, if issued, mandates appropriate measures to mitigate potential impacts during construction or operation of the project. For example, projects crossing a wetland or waterway, or discharging fill or dredged material into U.S. waters are required to obtain a permit from the Army Corps of Engineers under Section 404 of the Clean Water Act. EPA, or states with federally delegated authority under Section 402 of the Clean Water Act, issue National Pollutant Discharge Elimination Permits for water discharges. Other potentially applicable federal laws include the Endangered Species Act, National Historic Preservation Act, Rivers and Harbors Act, Coastal Zone Management Act, Clean Air Act, and Resource Conservation and Recovery Act. Congress intended FERC (and its predecessor the Federal Power Commission) to "occupy the field" to the exclusion of state law by establishing through the NGA a "comprehensive scheme of federal regulation of all wholesales of natural gas in interstate commerce." Therefore, federal law preempts any state or local law that obstructs federal law, such as local siting or zoning rules.

Upon completion of the environmental analysis and agency consultations, FERC staff issues a Draft EIS which includes staff's initial findings about the significance of the proposed route's environmental impact and recommendations for mitigation. Issuance of the draft EIS also initiates a public comment period of at least 45 days, during which public hearings are held. Following the public comment period, FERC revises the Draft EIS as necessary, and issues the Final EIS with environmental recommendations. A final FERC Order granting or denying the certificate cannot be issued until at least 30 days after FERC publishes notice of availability of the Final EIS.

A FERC certificate confers eminent domain authority on the pipeline project developer, although in practice, pipeline developers typically negotiate easements with landowners and rarely resort to land takings. An intervener who objects to the FERC Order may file a request a rehearing within 30 days of issuance of the Order. Under the NGA, a party to the proceeding that objects to a FERC order may seek rehearing within 30 days of issuance of the order. If FERC does not act on a petition for rehearing within 30 days of the petition having been filed, the rehearing is deemed to have been denied and the aggrieved party is free to seek judicial review of the FERC Order in a federal appellate court. As a practical matter, FERC can preclude a matter from becoming ripe for judicial review by issuing a tolling order that grants rehearing for purposes of further consideration. The net effect of this procedural order is to provide FERC with an unspecified time within which to consider the merits of the rehearing petition. If a pipeline certificate is approved after rehearing, the pipeline project may proceed even if additional challenges have been filed in federal court.

The time frame to obtain a FERC certificate varies depending the project size and environmental impact. The U.S. Government Accountability Office (GAO) conducted an analysis of pipeline projects certificated between Jan 1, 2010 and October 24, 2012 and determined that the time from initiation of the pre-filing process to project certification ranged from 370 to 886 days, and averaged 558 days.[50] Projects that began with the 7(c) filing ranged from 63 to 455 days and averaged 225 days, but nearly all of these were compression-only projects.

1.1.4 Pipeline Maintenance Practices

Interstate pipelines typically undertake major planned maintenance activities during the spring shoulder season, when firm transportation customers are not utilizing their full contractual entitlements. Pipelines select dates for planned maintenance that minimize disruption to firm transportation customers; typically, planned maintenance has little or no effect on a pipeline's ability to serve its firm transportation customers. Of course, maintenance is conducted throughout the year as needed. Pipeline companies do not normally schedule maintenance during the heating season, November through March. Pipelines, however, are always quick to mobilize the requisite maintenance to expedite service restoration when outage contingencies occur. Pipelines post their planned maintenance schedules on their EBBs and announce them during customer meetings. Hence, shippers are aware of upcoming planned maintenance events that result in capacity reductions and can plan accordingly. Large gas customers often work with pipelines to coordinate maintenance schedules in order to avoid simultaneous capacity reductions to the maximum practical extent. Frequent communication among pipeline companies, LDCs, state regulatory commissions, and generation companies reasonably assures stakeholder awareness of anticipated pipeline maintenance schedules, in particular, significant maintenance projects that have the potential to cause capacity reductions for several weeks, or months.

PHMSA requires each pipeline to develop and implement a formal Integrity Management Program that includes a set of safety management, analytical, operations and maintenance processes to provide protection to High Consequence Areas.[51]

1.1.5 Systems Operating in the Study Region

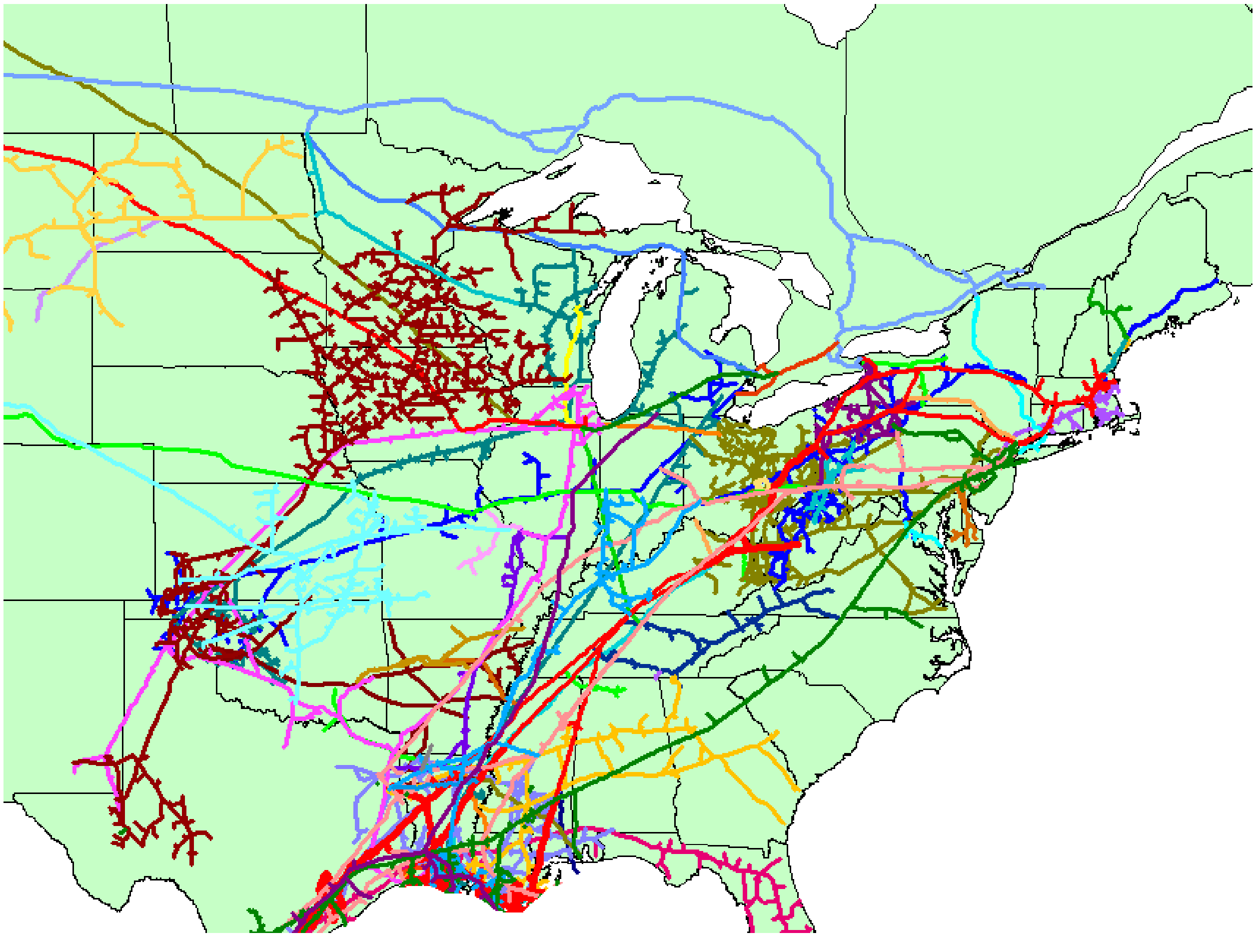
The 61 interstate pipelines operating in the Study Region are shown in Figure 12.[52] The systems operating in each PPA are summarized in the following sections, and described in detail in appendices to this report.

[50] U.S. GAO, "Pipeline Permitting: Interstate and Intrastate Natural Gas Permitting Processes Include Multiple Steps, and Time Frames Vary," February 2013, http://www.gao.gov/products/GAO-13-221.

[51] High Consequence Areas include urban areas and other populated places as designated by the U.S. Census Bureau, commercially navigable waterways, and drinking water and ecological resources that are unusually sensitive to a pipeline failure.

[52] This figure does not include storage facility and LNG header pipelines.

Figure 12. Interstate Pipelines Operating in the Study Region



PJM Region

There are 28 interstate pipelines operating in PJM's service area, as illustrated in Figure 13. A change is occurring in the distribution of unit types within PJM as coal units retire and new gas units are built. In Eastern MAAC and Southwestern MAAC, the capacity mix is shifting to more gas-fired generation while elsewhere in PJM continued reliance will be on mainly coal units, even taking into consideration the continued retirements of coal capacity in PJM.[53] The generators that are directly served by these pipelines are included in the map and listed in Table 4. Plant nameplate capacity values throughout this report represent the gas-capable generating capacity, not necessarily the full plant capacity in the case of multi-fuel units. Detailed maps of each pipeline system are shown in Appendix 1.

[53] Monitoring Analytics, Inc., 2013 Quarterly State of the Market Report for PJM: January through September.

Figure 13. Interstate Pipelines Operating in PJM

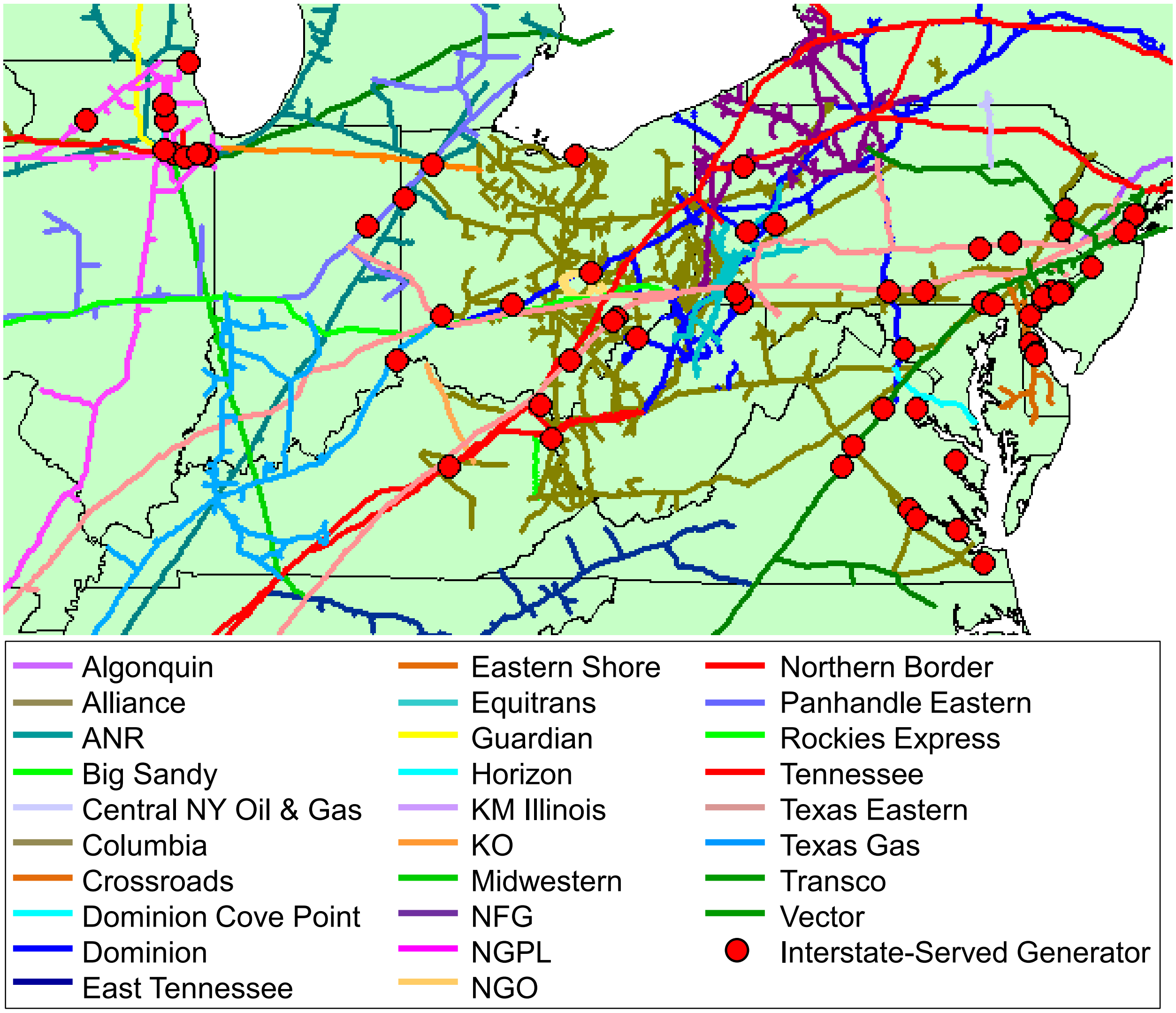


Table 4. Interstate-Served Generators in PJM[54]

Pipeline	Generator(s)
ANR	Crete (356 MW),[55] Mone (582 MW), University Park North (540 MW), University Park South (342 MW)
Columbia Gas	Chesterfield (447 MW),[56] Darby (564 MW), Elizabeth River (389 MW), Gans (88 MW), Gilbert (606 MW), Gravel Neck (408 MW), Hopewell (399 MW), Louisa (509 MW),[57] Pedricktown (120 MW), Rock Springs (780 MW), Warren County (1,329 MW),[58] West Deptford (738 MW),[59] West Lorain (556 MW), Yankee (126 MW)
Dominion	Dickerson (326 MW), Dresden (678 MW), Oak Grove (344 MW), South Bend (688 MW), Springdale (88 MW), Springdale CC (556 MW)
Dominion Cove Point	Possum Point (966 MW)
Eastern Shore	Delaware City (196 MW), Beasley/DEMEC (50 MW), Dover/Kent (100 MW), McKee Run (151 MW), Van Sant (37 MW)
Horizon	Elgin (540 MW)
NFG	Handsome Lake (285 MW)
NGPL	Aurora (1,275 MW), Kendall (1,256 MW), Lee County (814 MW), Zion (597 MW)
Northern Border	Elwood (1,728 MW), Lincoln (692 MW)
Panhandle Eastern	Montpelier (236 MW), Richland (450 MW)
Tennessee	Hanging Rock (1,288 MW),[60] JK Smith (1,055 MW),[61] Zelda (1,150 MW)
Texas Eastern	Chambersburg Guilford (88 MW), Flatlick (800 MW), Hanging Rock (1,288 MW),[60] Hunterstown (869 MW),[62] Ironwood (704 MW), JK Smith (1,055 MW),[61] Liberty (521 MW), Martins Creek (1,701 MW),[63] Ontelaunee (557 MW), Ronco/Fayette (675 MW), Washington (600 MW), Waterford (913 MW)
Texas Gas	Lawrenceburg (1,232 MW)
Transco	Bear Garden (559 MW), Delta/York (560 MW), Eagle Point (223 MW), Fluvanna (946 MW), Ford Mill (1,078 MW), Hudson (1,115 MW), Kearny (311 MW), Louisa (509 MW),[57] Lower Mount Bethel (582 MW), Marsh Run (513 MW), Martins Creek (1,701 MW),[63] Phillips Island (836 MW), Sewaren (431 MW), Sunoil (51 MW), West Deptford (738 MW)[59]
Vector	Crete (356 MW)[55]

[54] Source for PJM nameplate capacity values: 2012 EIA Form 860.

[55] Crete is directly connected to ANR and Vector.

[56] Chesterfield also has a connection to the City of Richmond municipal gas utility.

[57] Louisa is directly connected to Columbia Gas and Transco.

[58] Warren County is currently under construction. The expected in-service date is late 2014 or early 2015.

[59] West Deptford is currently under construction. The expected in-service date is June 2014. It will be connected to both Columbia Gas and Transco.

[60] Hanging Rock is directly connected to Tennessee and Texas Eastern.

[61] JK Smith is directly connected to Tennessee and Texas Eastern.

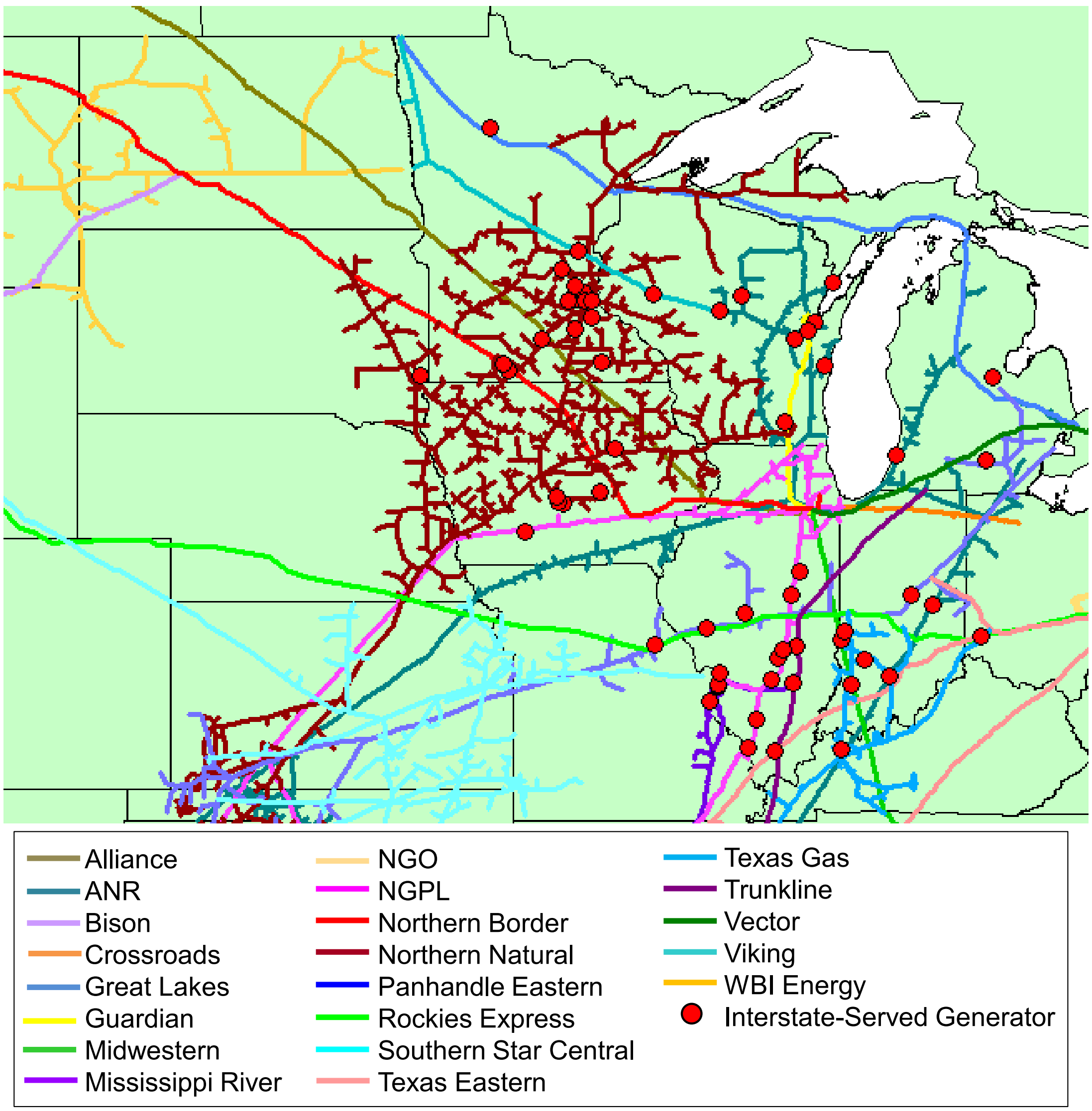
[62] Hunterstown is also served by the Columbia Gas of Pennsylvania LDC.

[63] Martins Creek is directly connected to Texas Eastern and Transco.

MISO Region

There are 39 interstate pipelines operating in MISO's service area, as illustrated in Figure 14 (MISO North/Central) and Figure 15 (MISO South).[64][65] The generators that are directly served by these pipelines are included in the map and listed in Table 5. Detailed maps of each pipeline system are presented in Appendix 2.

Figure 14. Interstate Pipelines Operating in MISO North/Central



[64] MISO North/Central refers to the part of MISO's territory north of Arkansas. MISO South refers to the southern part of MISO's territory, including parts of Mississippi, Louisiana, Arkansas, and Texas.

[65] Additional information regarding pipeline flow patterns in MISO (North/Central and South) can be found in "Phase III: Natural Gas-Fired Electric Power Generation Infrastructure Analysis, An Analysis of Pipeline Capacity Availability," https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Phase%20III%20Gas-Electric%20Infrastructure%20Report.pdf

Figure 15. Interstate Pipelines Operating in MISO South

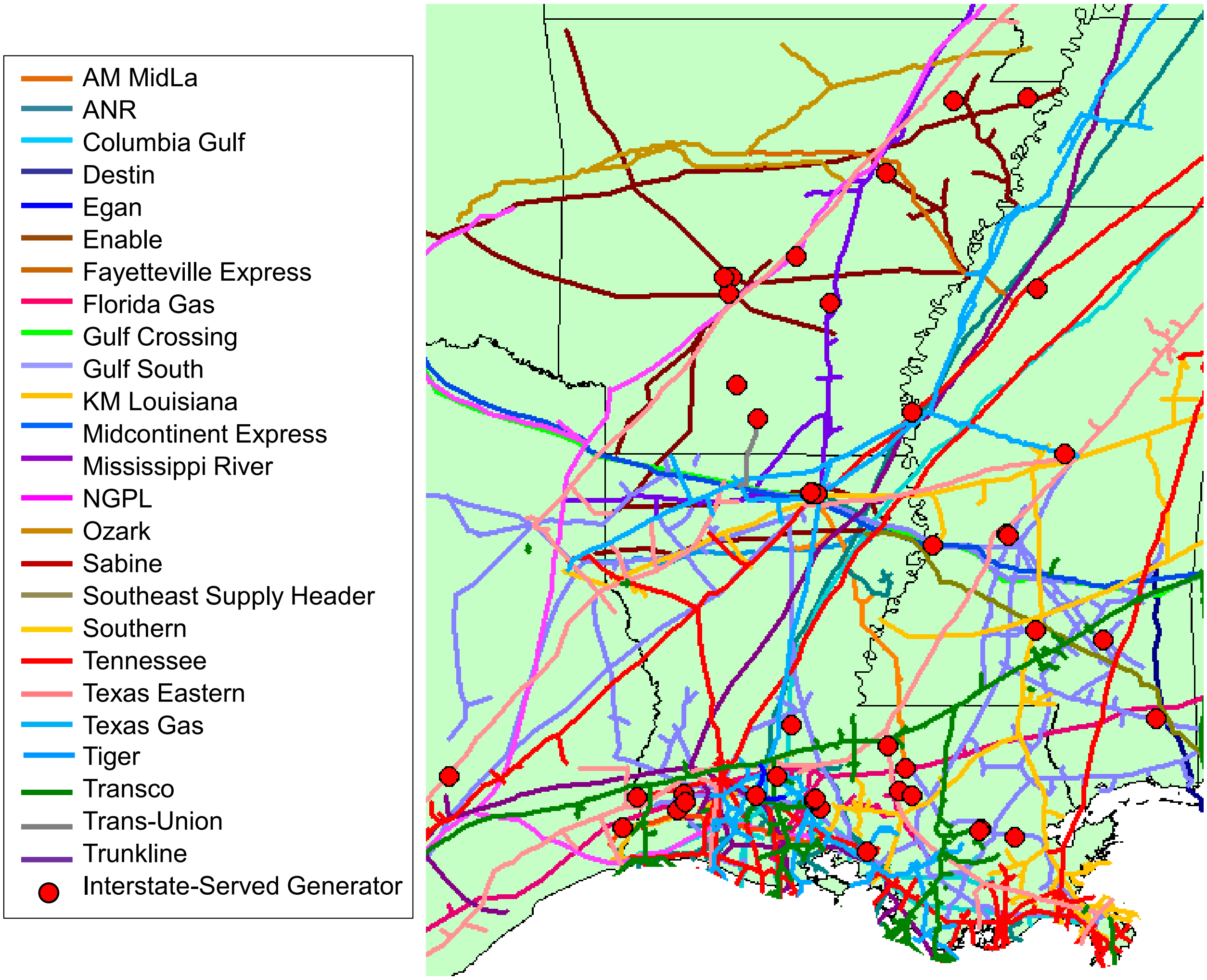


Table 5. Interstate-Served MISO Generators

Pipeline	Generators
AM MidLa	Louisiana 1 (150 MW), Ouachita (770 MW), Perryville (691 MW)[66]
ANR	Acadia (1,107 MW),[67] Batesville (837 MW),[68] De Pere (196 MW), Fox (520 MW), Henry County (129 MW), Lawrence County (261 MW), Marshfield (60 MW), Neenah (317 MW), New Covert (1,080 MW), Sheboygan Falls (300 MW), West Marinette-MGE (88 MW), West Marinette-WPS (200 MW), Weston (82 MW)
Columbia Gulf	Baxter Wilson (1,167 MW),[69] Bonin (171 MW),[70] Evangeline (730 MW), Teche (350 MW)
Egan	Bayou Cove (320 MW)
Enable	Carl Bailey (122 MW), Dell (679 MW), Hot Spring (620 MW),[71] Lake Catherine (520 MW), Magnet Cove (660 MW), McClellan (134 MW), Pine Bluff (232 MW)
Florida Gas	Acadia (1,107)[67], Sabine[72]
Great Lakes	Midland Cogen (1,710 MW), Solway (50 MW)
Gulf South	Baxter Wilson (1,167 MW),[69] Benndale (16 MW), Calcasieu (310 MW),[73] Hargis-Hebert (96 MW), Little Gypsy (1,168 MW),[74] Moselle (509 MW), Nine Mile Point (1,564 MW),[74] NRG Sterlington (130 MW), Rex Brown (233 MW), RS Cogen (235 MW), RS Nelson (420 MW), Sterlington (177 MW), TJ Labbe (96 MW), Waterford (822 MW),[74] Willow Glen (650 MW)[74]
Midwestern	Sugar Creek (578 MW), Wabash River (282 MW), Wheatland (488 MW)
Mississippi River	Meramec (50 MW), Raccoon Creek (386 MW),[75] Trigen St. Louis (28 MW), Venice (605 MW), Wood River (446 MW)
NGPL	Freedom (47 MW), Gibson City (270 MW), Goose Creek (552 MW), Grand Tower (506 MW), Harry L Oswald (548 MW), Holland Energy (710 MW), Kinmundy (260 MW), Pinckneyville (368 MW), Summit Lake (82 MW)
Northern Border	Lakefield Junction (594 MW)

[66] Perryville is directly connected to AM MidLa, Texas Gas and Tennessee.

[67] Acadia is directly connected to ANR and Florida Gas.

[68] Batesville is directly connected to ANR, Tennessee and Trunkline.

[69] Baxter Wilson is directly connected to Columbia Gulf and Gulf South.

[70] Bonin is also served by the Crosstex LIG intrastate system.

[71] Hot Spring is directly connected to Enable and Texas Eastern.

[72] Sabine is connected to the Florida Gas and Texas Eastern interstate pipelines, and to the KM Tejas and KM Texas intrastate pipelines.

[73] Calcasieu is directly connected to Gulf South and Sabine.

[74] Little Gypsy, Nine Mile Point, Waterford and Willow Glen are also served by the Acadian intrastate pipeline system.

[75] Raccoon Creek is directly connected to Mississippi River and Trunkline.

Pipeline	Generators
Northern Natural	Angus Anson (432 MW), Black Dog (305 MW), Blue Lake (343 MW), Cambridge (190 MW), Cannon Falls (356 MW), Cottage Grove (273 MW), Electrifarm (243 MW), Elk River (220 MW), Faribault (255 MW), Fox Lake (88 MW), Greater Des Moines (570 MW), Grinnell (50 MW), High Bridge (540 MW), Inver Hills (428 MW), Mankato (367 MW), Pleasant Valley (493 MW), River Hills (150 MW), Riverside (624 MW), Sycamore (190 MW), Whitewater Cogen (257 MW)
Panhandle Eastern	Alsey (120 MW), Audrain (736 MW), Interstate (134 MW), Noblesville (310 MW)
Southern	Silver Creek (249 MW)
Tennessee	Batesville (837 MW),[68] Gerald Andrus (640 MW),[76] Perryville (691 MW)[66]
Texas Eastern	Attala (455 MW),[77] Big Cajun (486 MW), Jonesboro (169 MW), Cottonwood (1,327 MW), Hinds (449 MW), Hot Spring (620 MW),[71] Lewis Creek (460 MW),[78] Madison (704 MW), Marion (176 MW), Plaquemine (38 MW), Sabine (1,809)[72]
Texas Gas	Attala (455 MW),[77] Gerald Andrus (640 MW),[76] Perryville (691 MW),[66] RA Reid (60 MW), Worthington (172 MW)
Trans-Union	Union Power Partners (1,365 MW)
Trunkline	Batesville (837 MW),[68] Raccoon Creek (368 MW),[75] Shelby (360 MW)
Vector	Jackson (560 MW)
Viking	Elk Mound (70 MW)

New York

There are eleven interstate pipelines operating in New York, as shown in Figure 16.[79] The generators directly served by these pipelines are shown on the map and listed in Table 6. Also shown in Figure 16 are the two non-FERC-jurisdictional gathering systems that deliver gas into Millennium, Bluestone and Laser. Detailed maps of each interstate pipeline system are presented in Appendix 3.

[76] Gerald Andrus is directly connected to Tennessee and Texas Gas.

[77] Attala is directly connected to Texas Eastern and Texas Gas.

[78] Lewis Creek is also connected to the KM Tejas and TM Texas intrastate systems.

[79] Additional information regarding the gas infrastructure and flows in New York can be found in NYISO's "NYCA Pipeline Congestion and Infrastructure Adequacy Assessment," September 2013, http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_egcwg/meeting_materials/2013-10-23/Levitan%20Pipeline%20Congestion%20and%20Adequacy%20Report%20Sep13%20-%20Final%20CEII%20Redacted.pdf.

Figure 16. Interstate Pipelines Operating in New York

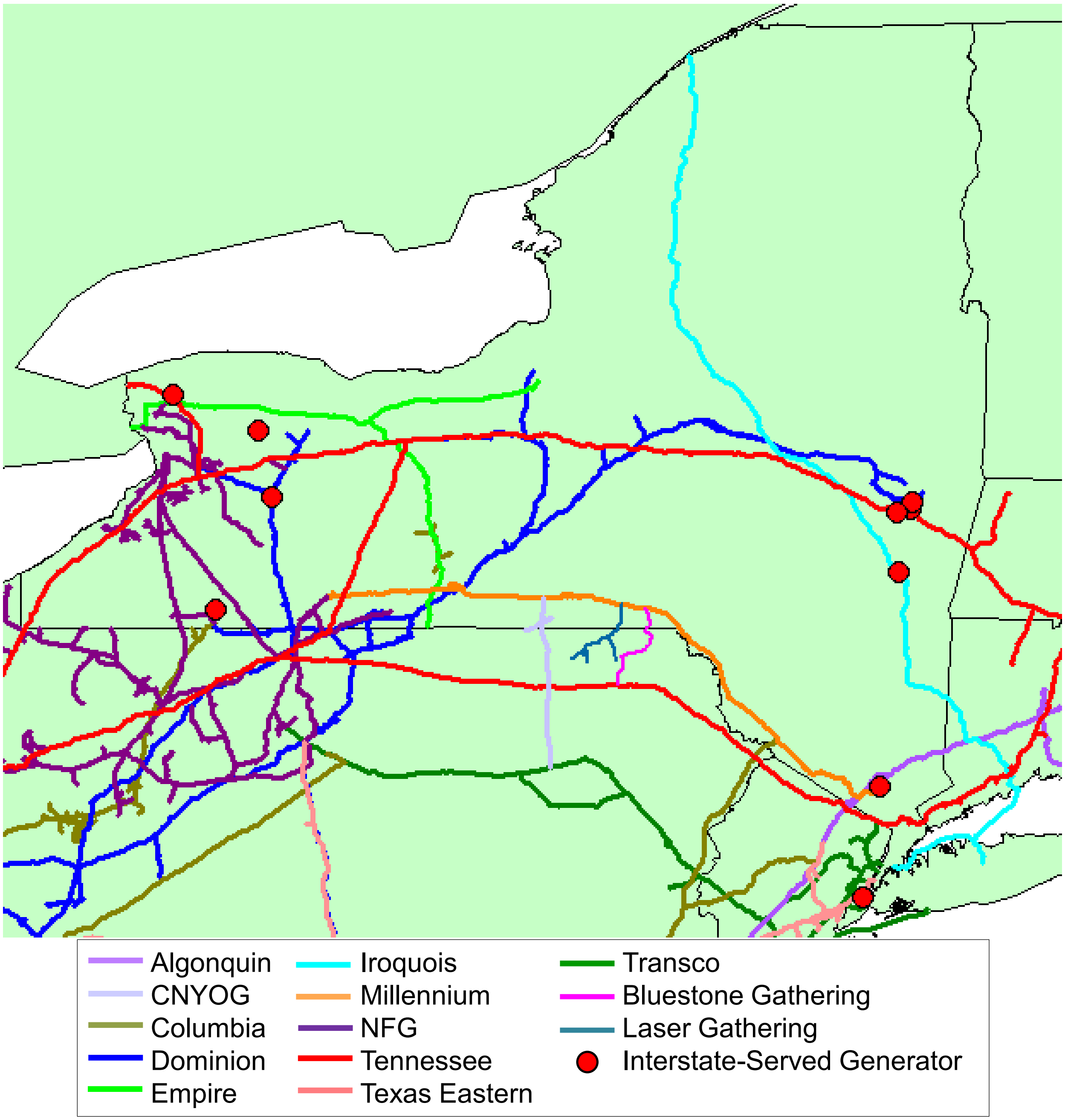


Table 6. Interstate-Served NYISO Generators[80]

Pipeline	Generators
Dominion	Batavia (67 MW), Bethlehem (893 MW),[81] Indeck Silver Springs (57 MW)
Iroquois	Athens (1,323 MW)
Millennium	Bowline (1,242 MW)[82]
NFG	Indeck Olean (91 MW)
Tennessee	Bethlehem (893 MW),[81] Empire (670 MW), Lockport (221 MW), Selkirk (446 MW)
Transco	Bayonne Energy Center (512 MW)[83]

[80] Capacity values represent nameplate capacity as listed in NYISO's 2013 Load and Capacity Data "Gold Book."
[81] Bethlehem is directly connected to Dominion and Tennessee.
[82] Bowline is also connected to the Orange & Rockland LDC.
[83] Bayonne Energy Center is also connected to the PSE&G LDC.

New England

There are six interstate natural gas pipelines operating in New England, as shown in Figure 17. The generators directly served by these pipelines are shown on the map and listed in Table 7. Detailed maps of each pipeline system are presented in Appendix 4.

Figure 17. Interstate Pipelines Operating in New England

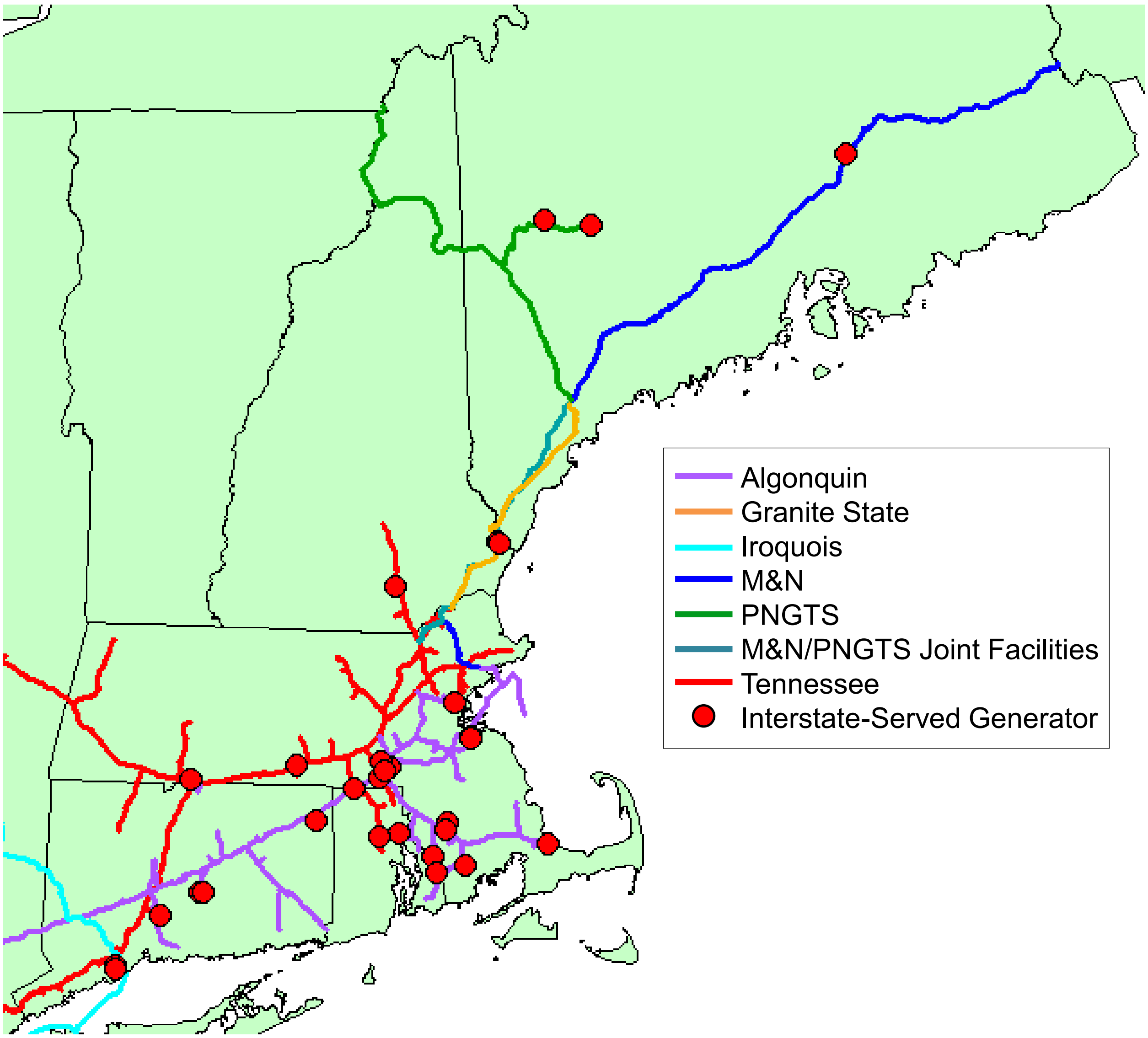


Table 7. Interstate-Served ISO-NE Generators

Pipeline	Generators
Algonquin	ANP Bellingham (532 MW), Brayton Point (446 MW), Canal (547 MW), Cleary (110 MW), Dartmouth Power (90 MW), Dighton (185 MW), Fore River (843 MW), GenConn Middletown (197 MW), Kleen Energy (620 MW), Lake Road (857 MW), Manchester Street (510 MW),[84] Milford Power (MA, 171 MW), NEA Bellingham (337 MW), NRG Middletown (364 MW), Ocean State Power (635 MW),[85] Pierce (95 MW), Thomas A Watson (115 MW), Tiverton (279 MW), Wallingford (244 MW)
Iroquois	GenConn Devon (197 MW), Milford Power (CT, 569 MW), NRG Devon (157 MW)
M&N	EP Newington Energy (561 MW),[86] Maine Independence (538 MW), PSNH Newington (400 MW)[86]
PNGTS	EP Newington Energy (561 MW),[86] PSNH Newington (400 MW),[86] Rumford Power (269 MW), Verso Cogen (167 MW)
Tennessee	ANP Blackstone (515 MW), Berkshire Power (246 MW), Granite Ridge (770 MW), Millennium (384 MW), Ocean State Power (635 MW),[85] RISEP (617 MW)

[84] National Grid / Narragansett Electric owns, operates and maintains the pipeline between the Algonquin meter and the Manchester Street plant.

[85] Ocean State Power is directly connected to Algonquin and Tennessee.

[86] EP Newington Energy and PSNH Newington are served by the M&N/PNGTS Joint Facilities System.

TVA

There are 15 interstate pipelines operating in TVA's service area, as illustrated in Figure 18. These pipelines directly serve 14 TVA generators, listed in Table 8. Detailed maps of each pipeline system are shown in Appendix 5.

Figure 18. Interstate Pipelines Operating in TVA

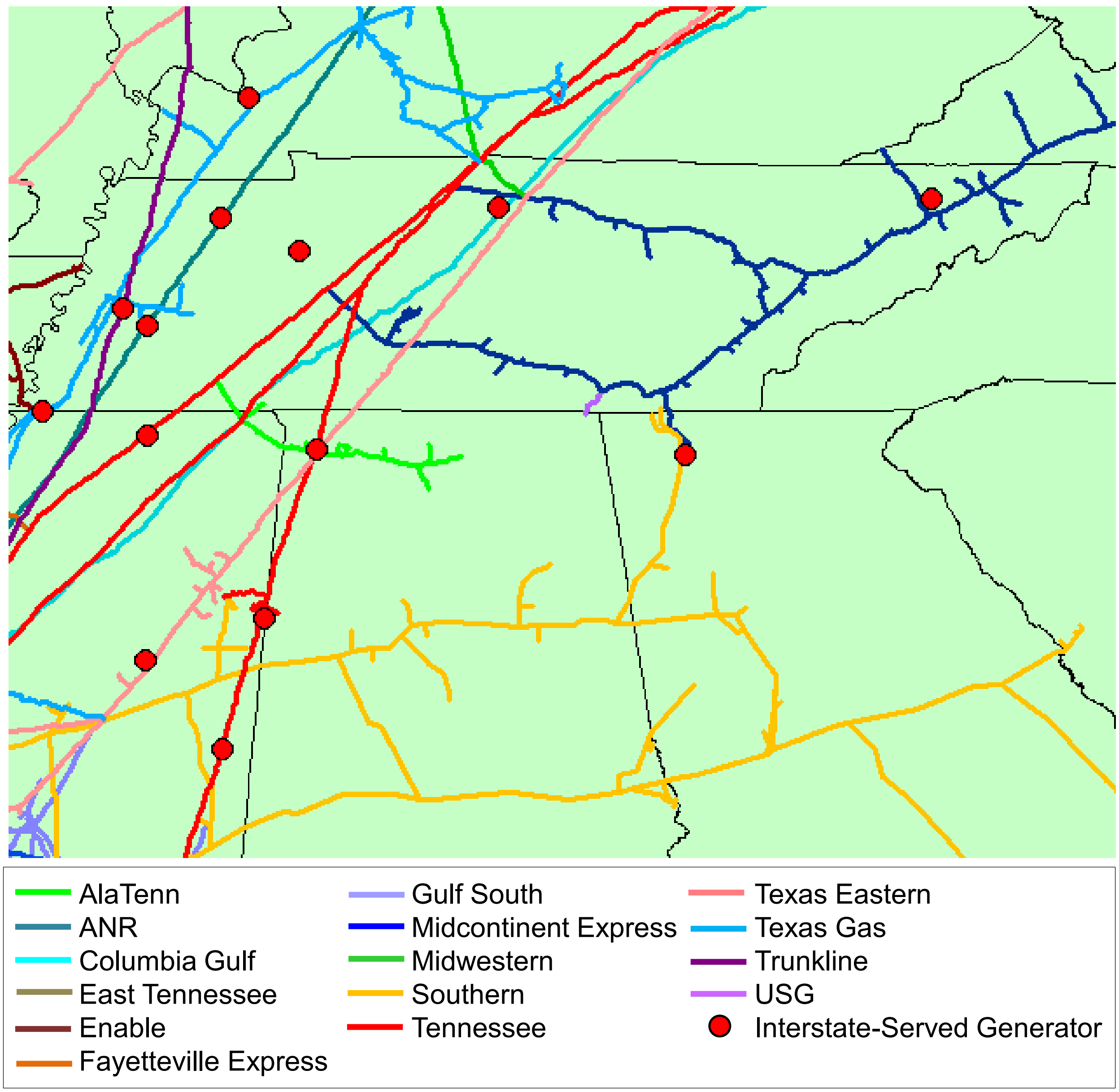


Table 8. Interstate-Served TVA Generators[87]

Pipeline	Generator(s)
AlaTenn	Colbert (464 MW)
ANR	Brownsville (496 MW), Gleason (360 MW)
Columbia Gulf	Gallatin (752 MW)
East Tennessee	John Sevier (955 MW), Oglethorpe Smith (1,250 MW)[88]
Southern	Oglethorpe Smith (1,250 MW)[88]
Tennessee	Caledonia (816 MW), Johnsonville (4261440 MW), Kemper County (384 MW), Magnolia (999 MW)
Texas Eastern	Quantum Choctaw (760 MW)
Texas Gas	Lagoon Creek (1,160 MW),[89] Lagoon Creek CC (622 MW),[90] Marshall County (768 MW), Southaven (852 MW)
Trunkline	Lagoon Creek (1,160 MW),[89] Lagoon Creek CC (622 MW)[90]

1.2 STORAGE FACILITIES

The majority of U.S. and Canadian natural gas storage is held in underground facilities which are located either near producing basins or close to major market centers. Conventional underground storage is an integral part of the supply chain across the Study Region. Natural gas storage facilitates the ability to meet core customers' needs throughout the heating season. Storage services are also available to generation companies, marketers, and gas producers who manage the injection and withdrawal of natural gas to supplement pipeline entitlements, manage pipeline imbalances, as well as daily or seasonal gas price volatility. As of the end of January 2014, following the Polar Vortex and subsequent cold weather events, EIA reported that 920 Bcf of working gas was held in underground storage facilities in the East region, notably less than both the five-year average level of 1,232 Bcf and the five-year *minimum* level of 1,071 Bcf.[91] Across the lower 48 states, January 2014 experienced a record four-week drawdown of 894 Bcf.

Natural gas is typically injected into storage during the summer season when there is slack pipeline delivery capacity and beneficial commodity prices relative to the heating season, and withdrawn from storage during the heating season, in particular, the peak winter months of December through early March. FERC considers interstate natural gas storage to be the equivalent of interstate natural gas transportation for purposes of exercising its jurisdiction under the NGA. Consequently, interstate natural gas storage is subject to the same open access requirements that apply to interstate natural gas pipeline transportation. Further, this is the case even if the storage is operated by an entity that is not an interstate natural gas pipeline. Many storage facilities are regulated by state regulatory commissions. In Ontario, storage is regulated by the provincial regulatory commission rather than the NEB.

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[87] Capacity values represent winter capabilities.

[88] Oglethorpe Smith is directly connected to East Tennessee and Southern.

[89] Lagoon Creek is directly connected to Texas Gas and Trunkline, the primary connection is to Texas Gas.

[90] Lagoon Creek CC is directly connected to Texas Gas and Trunkline, the primary connection is to Trunkline.

[91] EIA Weekly Natural Gas Storage Report, http://ir.eia.gov/ngs/ngs.html.

In addition to conventional underground storage facilities, natural gas can be stored above ground in liquefied form. There are ten LNG import terminals in or near the Study Region, including two offshore submersible buoy systems near Boston that have the potential to accommodate destination flexible cargoes.[92] LDCs throughout New England, New York and, to a lesser extent, New Jersey, also have LNG storage tanks located behind the citygate to supplement pressure and flow during the peak heating season. There are also satellite storage tanks located behind the citygates in other PPAs, including MISO and Ontario. While regasification of LNG from import terminals is used by gas-fired generators in addition to, or in lieu of, pipeline-rendered supply, the regasification of LNG from satellite tanks is primarily used to serve core LDC customers under extreme weather conditions or outage contingencies.

Most storage capacity involves underground storage in depleted oil/gas reservoirs, aquifers or salt caverns. Gas held in storage consists of working gas and base or cushion gas. Working gas is the gas that can be injected and withdrawn to meet market needs. Cushion gas represents the underlying inventory that remains in the storage reservoir to provide the requisite pressure for working gas to be withdrawn.

The majority of the gas storage facilities in the U.S. are depleted reservoirs. The list of FERC jurisdictional storage fields as of May 23, 2013 indicates that 77% of the total working gas capacity in the U.S. portion of the Study Region is held in depleted oil/gas reservoirs, with the remaining 22% split between aquifer facilities and storage caverns.[93] Depleted reservoirs are the most common underground storage facility because they exploit existing oil or gas infrastructure, and have proven gas containment capabilities. Base gas requirements for a depleted reservoir storage facility can be up to one-half of the facility's total storage capacity. Aquifer storage facilities are defined by water-bearing formations in which water in the formation is displaced by injected gas. Aquifer storage facilities generally require a higher volume of base gas ranging from 50% to 80% of the total gas storage capacity. Most of the aquifer storage facilities in the U.S. are located in the Midwest. Salt cavern storage facilities provide high withdrawal and injection rates relative to their working gas capacity. Unlike depleted reservoirs and aquifer storage facilities, salt cavern storage capacity typically has very low base gas requirements, usually 20% to 30% of total storage capacity. The working gas in high deliverability storage facilities, generally storage caverns, can be cycled up to 10 or more times each year. In contrast, gas in depleted reservoirs and aquifers is generally cycled seasonally, injected during the non-heating season and withdrawn during the heating season.

Actual injection and withdrawal rates for storage facilities may be materially lower than the reported maximum daily deliverability for various reasons, including tariff provisions that safeguard the amount of working gas inventory in the event of extreme cold toward the end of the heating season. The actual day-to-day deliverability and injection capacity depend on the current volume of gas in storage, operating pressure, and other factors. Withdrawal rates vary directly with the total amount of gas in storage. Withdrawal rates are lowest when working gas

[92] Repsol's Canaport LNG import terminal is located in New Brunswick, but when operated it sends natural gas to New England as well as the Maritimes.

[93] Source: Jurisdictional Storage Fields in the United States by Owner (Updated May 23, 2013), http://www.ferc.gov/industries/gas/indus-act/storage/fields-by-owner.pdf

volume is low, and *vice versa*. Injection rates vary inversely with the total amount of gas in storage, with the slowest rates occurring when the inventory is close to full. In order to maintain sufficient pressure in the reservoir to meet deliverability requirements throughout seasonal cycles, storage contracts often contain ratchets which limit the injection and withdrawal rates as a function of the storage facility's working gas inventory level. At higher inventory levels the ratchets limit the amount of gas that can be injected into the reservoir while at low inventory levels the ratchets limit the amount of gas that can be withdrawn.

Interstate storage facilities, whether connected to interstate pipelines or not, are regulated by FERC. In 2006, FERC issued Order No. 678, which amended its regulations to establish criteria for obtaining market-based rates for storage services using a two-prong approach.[94] First, the market power analysis methodology was modified to include consideration of close substitutes to gas storage in defining the relevant market. Second, following the Energy Policy Act of 2005, which amended the NGA to add section 7(f), FERC developed regulations to permit the authorization of storage providers to charge market-based rates for new capacity in the absence of a demonstration of market power. The purpose of these changes was to reduce natural gas price volatility and improve supply adequacy during peak demand conditions by encouraging market participants to construct new storage capacity.

The underground storage capacity in the U.S. portion of the Study Region is summarized in Table 9, and the locations of the fields in each of the U.S. PPAs are shown in the following five figures.[95] Field-level operational details are presented in Exhibit 1. For purposes of these statistics and figures, storage facilities are grouped by PPA based on their physical location. Storage facilities can and do provide service to generators and other shippers that are located in other PPAs.

Table 9. Underground Storage Capacity by PPA

PPA	# of Fields	Working Gas Capacity (Bcf)	Maximum Withdrawal Capability (MMcf/d)
PJM	108	1,044	23,558
MISO	139	1,746	51,155
NYISO	26	129	2,856
ISO-NE	0	--	--
TVA	13	147	3,400
IESO	35	268	5,438
Total	321	3,334	86,407

[94] http://www.ferc.gov/whats-new/comm-meet/061506/C-2.pdf

[95] There are no underground storage fields in New England, and Ontario's storage facilities are included in the Ontario infrastructure discussion that begins on page 60.

Figure 19. Underground Storage Facilities in PJM

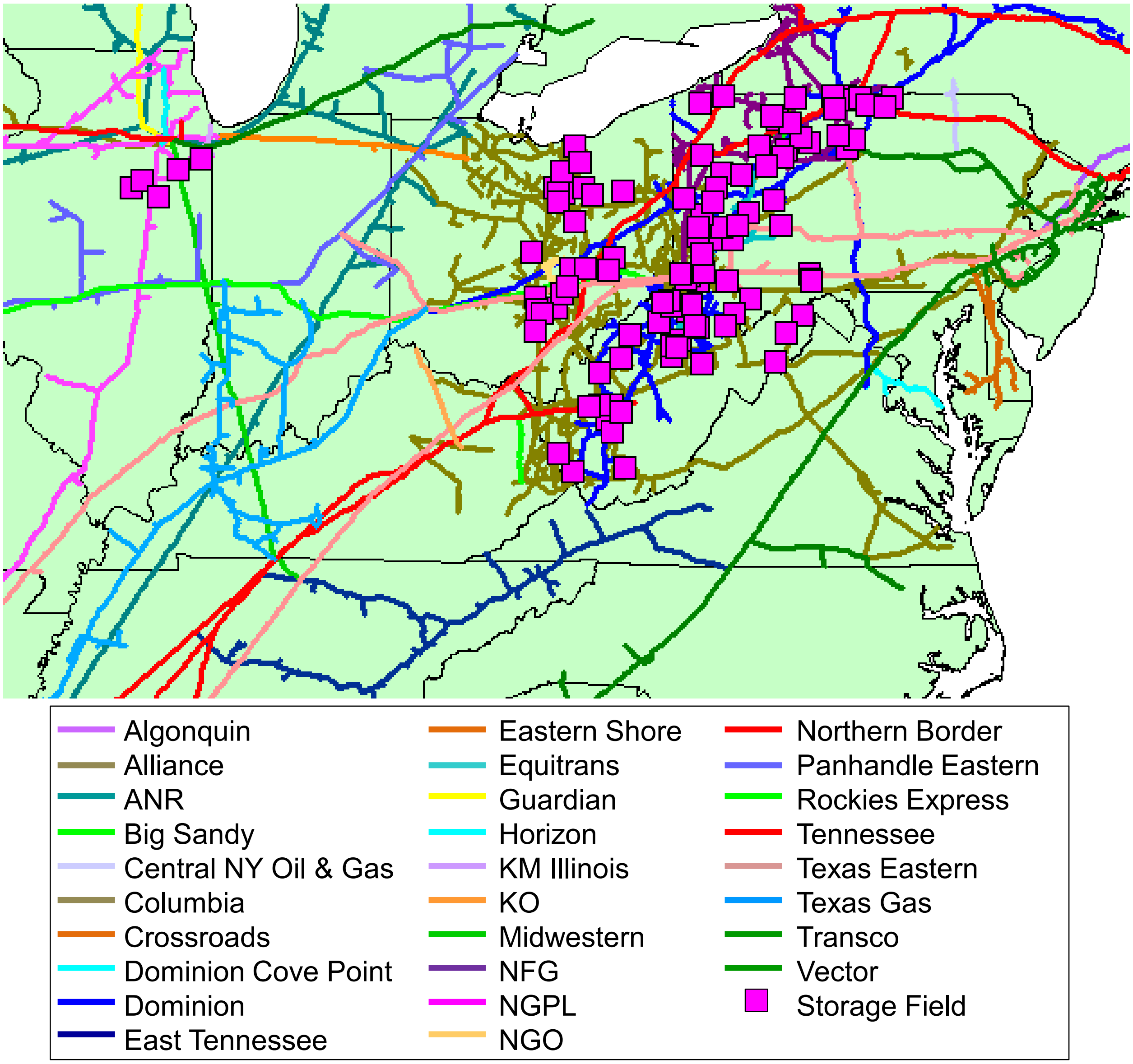


Figure 20. Underground Storage Facilities in MISO North/Central

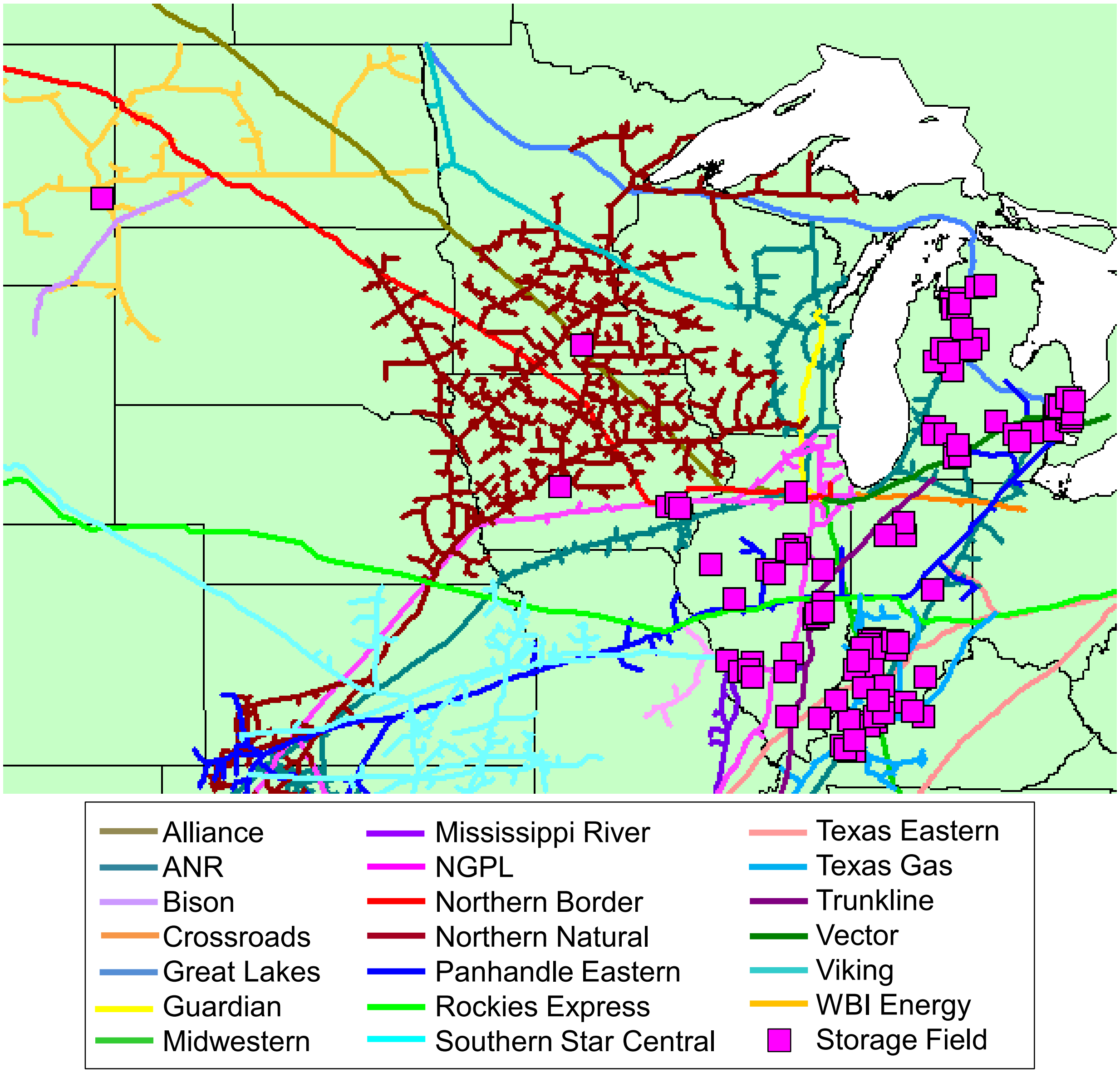


Figure 21. Underground Storage Facilities in MISO South

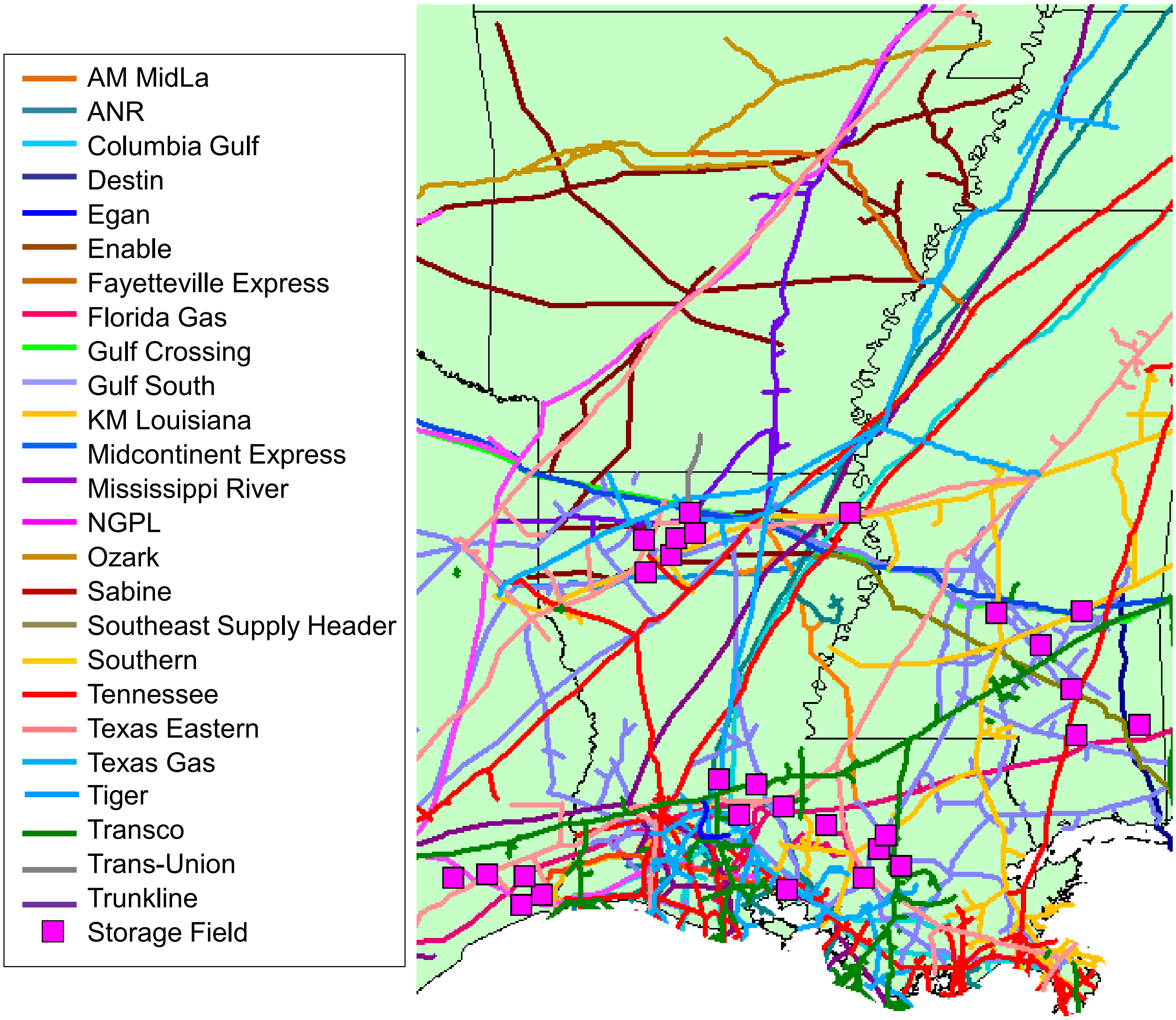


Figure 22. Underground Storage Facilities in New York

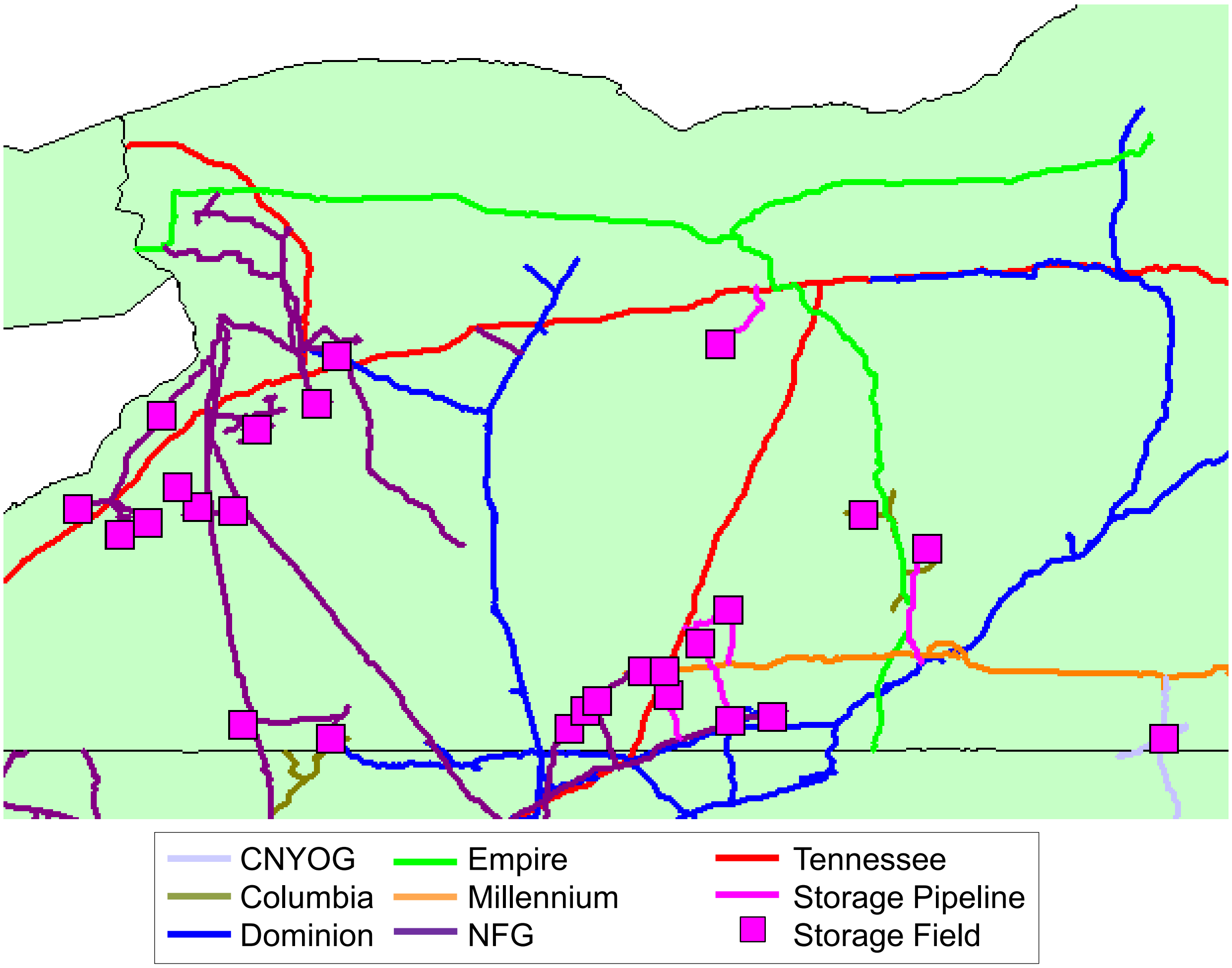
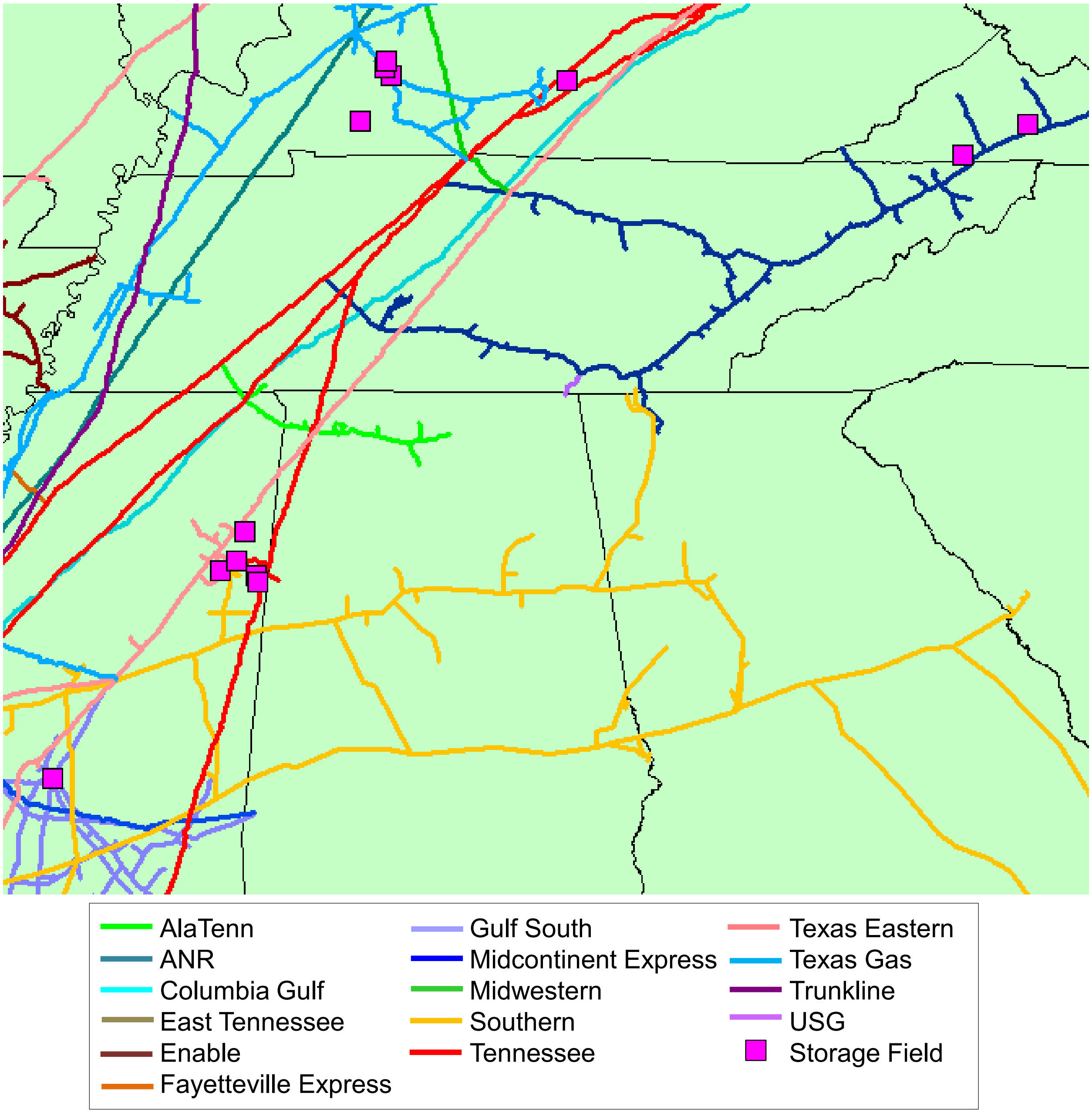


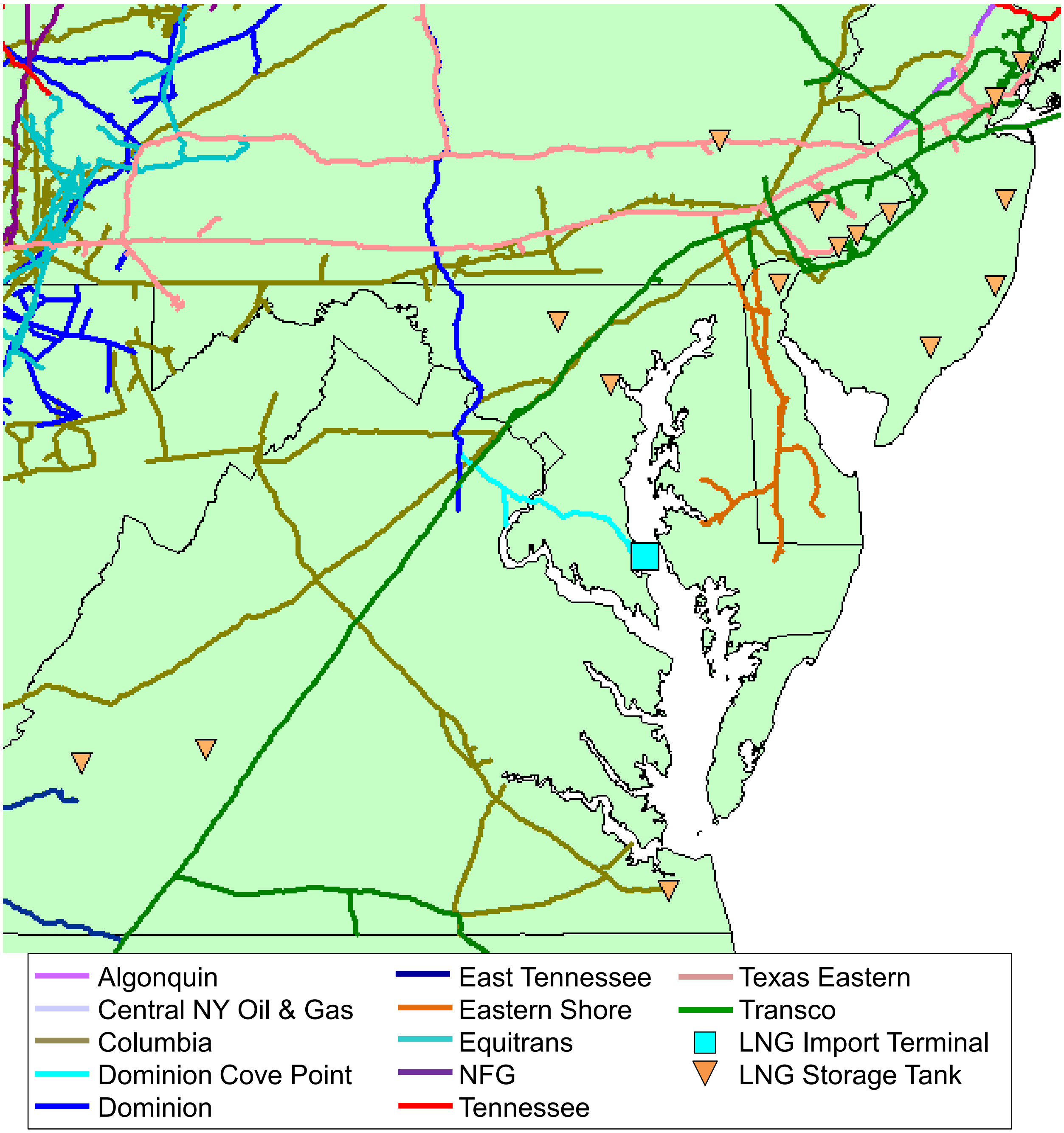
Figure 23. Underground Storage Facilities in TVA



In addition to underground storage, natural gas can also be stored as LNG at import terminals or in satellite storage tanks. LNG storage facilities are generally used for peaking service by pipelines and LDCs, or to store imported LNG for subsequent distribution to pipelines, LDCs and large end-users.

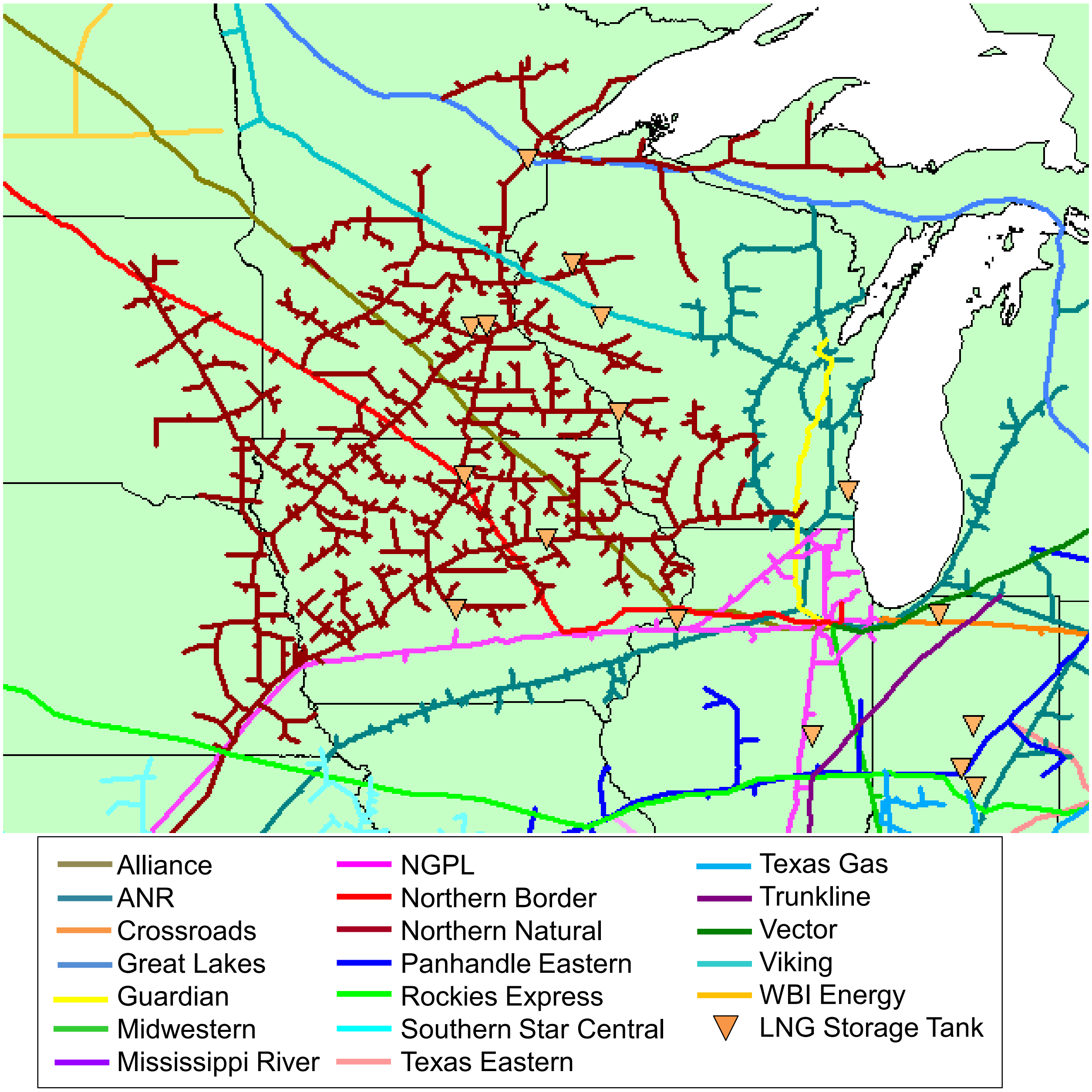
Dominion's Cove Point LNG terminal, located in Maryland as shown in Figure 24, has a storage capacity of 14.6 Bcf and a daily send-out capacity of 1.8 Bcf. Gas supplies are transported to market via the Dominion Cove Point pipeline to interconnections with Columbia Gas, Dominion and Transco.

Figure 24. LNG Facilities in PJM



There are several LNG peaking facilities located in MISO North/Central, as shown in Figure 25.

Figure 25. LNG Storage Facilities in MISO North/Central



There are six LNG import terminals in or near MISO's southern region, shown in Figure 26. The storage capacities and sendout capabilities of these facilities are summarized in Table 10.

Figure 26. LNG Import Terminals in MISO South

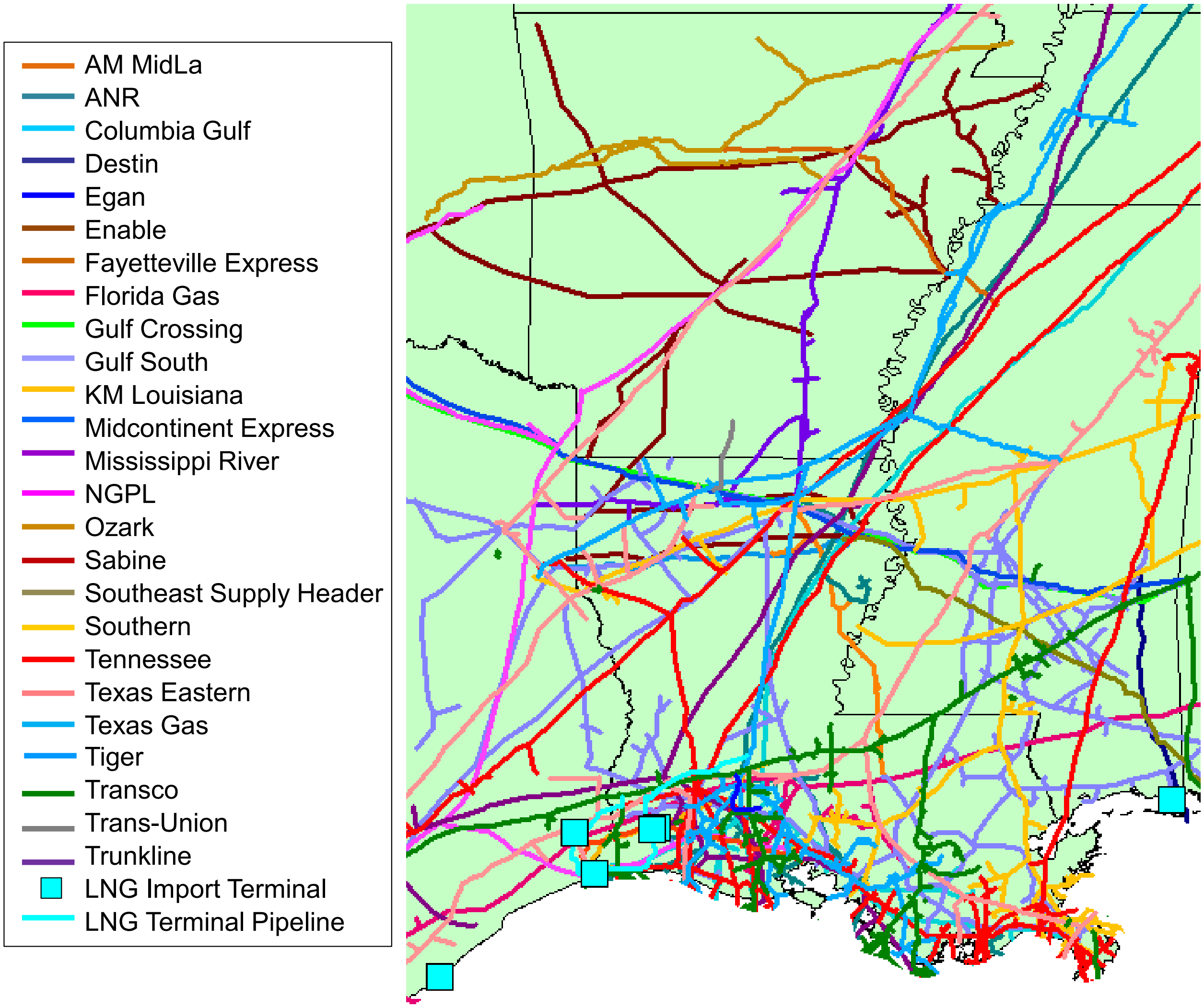


Table 10. LNG Import Terminals in MISO South

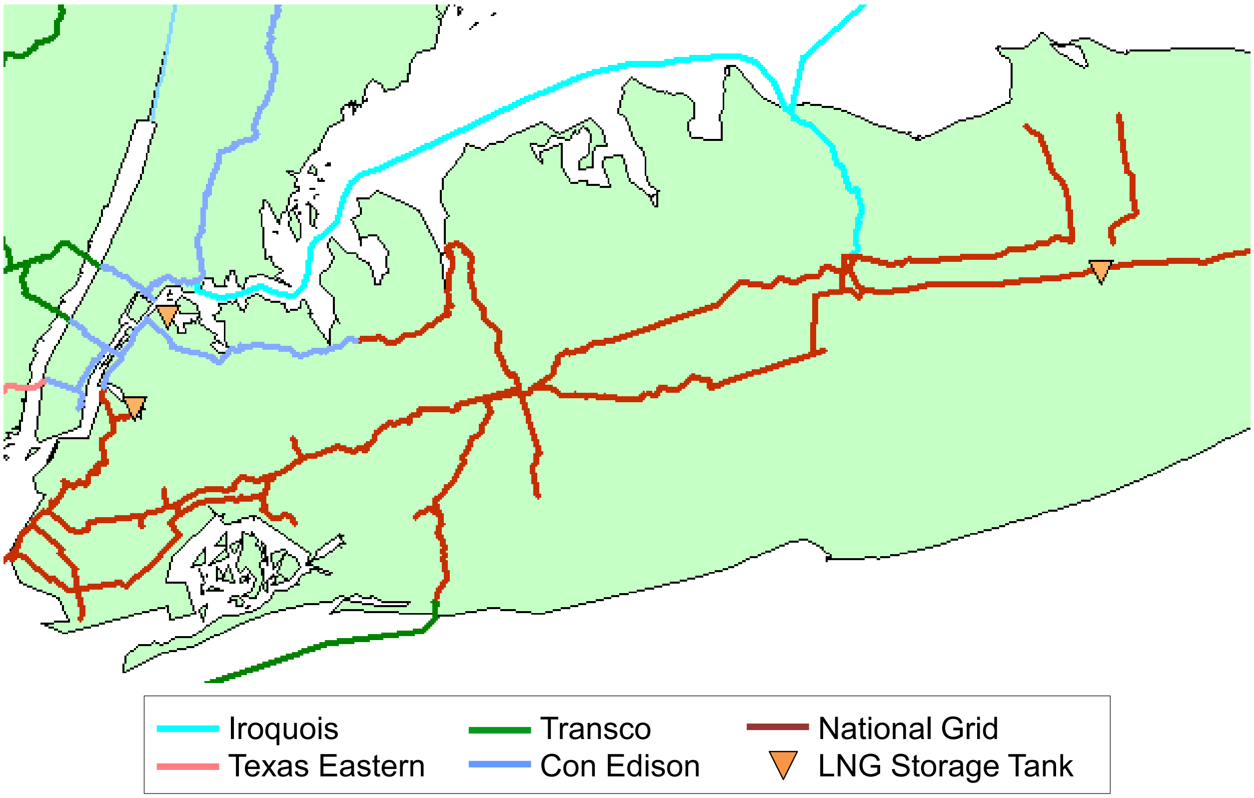
Terminal	Storage Capacity (Bcf)	Sendout Capability (Bcf/d)
Cameron	10.2	1.5
Freeport[96]	6.8	2.0
Golden Pass	16.4	2.6
Gulf	6.6	1.5
Lake Charles	9.0	2.1
Sabine Pass	17.0	2.6

There are no LNG import terminals in New York.[97] The three LNG storage facilities on the New York Facilities System are located in Brooklyn, Queens, and eastern Long Island, shown in

[96] The Freeport LNG import terminal is not in the MISO South footprint, but is located in an adjacent county.

Figure 27, are used as peak shaving facilities to meet residential / commercial customer load during periods of high demand.

Figure 27. LNG Facilities in New York



The Suez Distrigas LNG import terminal in eastern Massachusetts has an on-site storage capacity of 3.4 Bcf. Distrigas's installed maximum sendout capacity is 1 Bcf/d, and the daily sustainable vaporization / sendout capacity is 715 MMcf.[98] Suez sends out gas to the Algonquin medium pressure system around Boston and the Tennessee high pressure system. Suez also sends out gas to the NGrid low pressure system, the LDC serving the metropolitan Boston area. Suez Distrigas supplies gas to the Mystic 8&9 generating units and effectively provides Mystic 8&9 with firm deliverability throughout the year.[99] The installed capacity of Mystic 8&9, the largest combined-cycle plant in New England, is 1,700 MW. Mystic 8&9 is dependent on Suez Distrigas for all of its natural gas supply – Mystic 8&9 do not have a lateral connection with either Tennessee or Algonquin, the two pipelines that are directly served by Suez. The Distrigas facilities are shown in Figure 28. Also shown are the two offshore LNG facilities in New

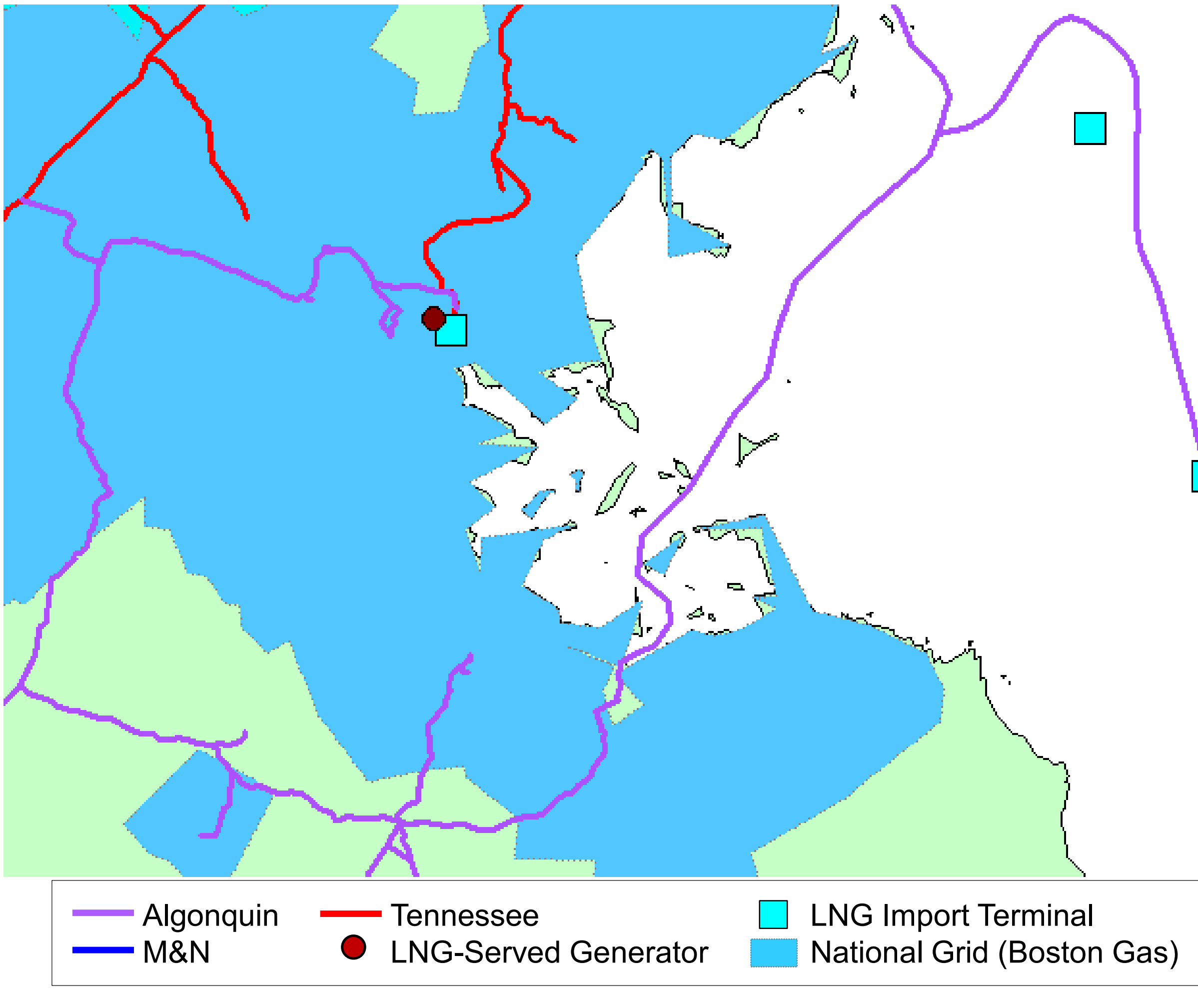
[97] New York enacted a state-wide moratorium on LNG facilities following an industrial accident in 1973. The Department of Environmental Conservation is currently in the process of developing regulations that would allow for the construction and operation of new facilities.

[98] Source: http://www.distrigas.com/ourcompanies/lngna-domac.shtml

[99] National Grid / Boston Gas owns, maintains and operates the pipeline between the Distrigas LNG terminal and Mystic 8&9.

England, Excelerate's Northeast Gateway and GDF Suez's Neptune. Both Northeast Gateway and Neptune are submersible buoy systems and therefore do not have on-site storage capacity.[100]

Figure 28. LNG Facilities in New England



In addition to its pipeline connections, Distrigas also sends out LNG by truck to LDC satellite storage facilities in the greater Northeast. There are 45 LNG satellite tanks in 30 communities across New England (shown in Figure 29) that are integral in providing supplemental pressure and flow behind the citygate during cold snaps, when pipeline rendered supply is not sufficient to serve core customers.[101] Distrigas has daily truck sendout capability equal to about 100 MMcf.[102] In 2013, according to the Northeast Gas Association, New England's LDCs held 16 Bcf of LNG storage capacity, not including storage at the Distrigas terminal. The total daily

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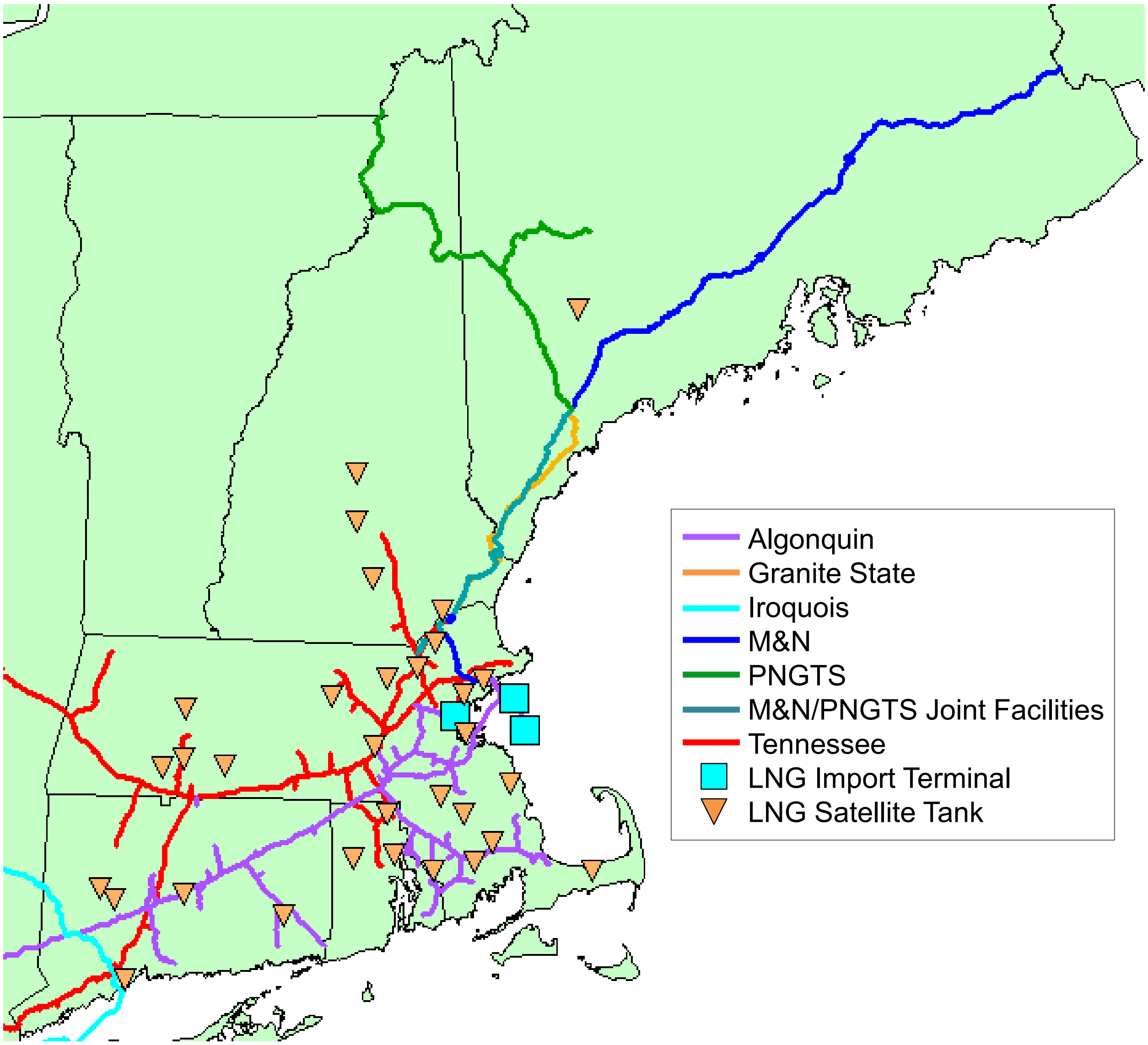
[100] Since testing and commercialization of Northeast Gateway and Neptune, neither import terminal has been used significantly for regasification of LNG into the local market.

[101] Northeast Gas Association, "2013 Statistical Guide," p. 41, http://www.northeastgas.org/pdf/statguide_13.pdf.

[102] Source: http://www.suezenergyna.com/lng-operations/

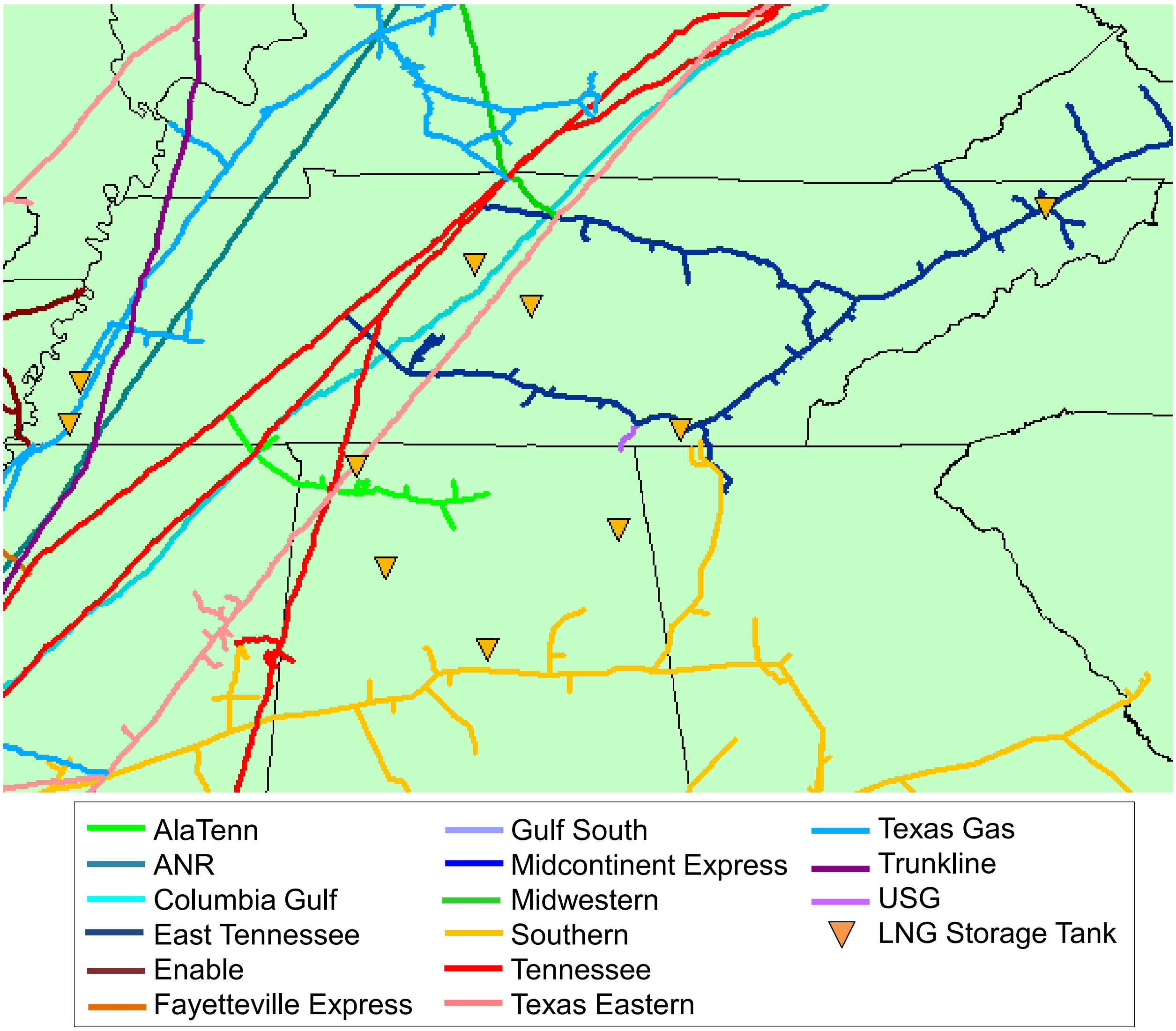
vaporization and liquefaction capacity of the peak shaving facilities was approximately 1.44 Bcf and 0.05 Bcf, respectively.

Figure 29. Peak-Shaving LNG Facilities in New England



There are also several LNG peaking facilities located in TVA, shown in Figure 30.

Figure 30. Peak-Shaving LNG Facilities in TVA



1.3 Intrastate Pipelines and Local Distribution Companies

Intrastate natural gas pipelines operate within state borders and link natural gas producers to local markets and to the interstate pipeline network.[103] In some instances, a pipeline located wholly within a single state that receives natural gas from interstate sources may remain subject to state jurisdiction if it satisfies the criteria to be a "Hinshaw" pipeline exempted from the Natural Gas Act. In particular, if the gas received by such a pipeline is consumed entirely within

[103] Although an intrastate pipeline system is defined as one that operates totally within a state, an intrastate pipeline company may have operations in more than one state. So long as the intrastate operations do not physically interconnect they are considered intrastate, and are therefore not FERC jurisdictional.

its state and if the pipeline is subject to state regulation, it will qualify for a statutory exemption from FERC regulation. LDCs typically take gas from interstate and intrastate pipelines and deliver it to local residential, commercial and industrial customers. Some large industrial customers are directly connected to intrastate pipelines, typically receiving transportation service from a lateral dedicated to the industrial customer and, in some instances, nearby gas-fired generators.

1.3.1 Regulatory Jurisdiction and Expansion Planning

State public utility commissions are charged with the regulatory oversight of intrastate pipelines and LDCs. State regulation of intrastate pipelines and LDCs is oriented around ensuring adequate supply, dependable service, and fair and reasonable rates for end-use consumers. State regulatory commissions establish the cost of service, thereby setting the regulated rate of return for jurisdictional entities. Municipal gas utilities and cooperatives are typically governed by local government, commonly through an elected or appointed board. State regulatory commissions therefore have limited or no oversight responsibilities with respect to the services offered by these entities.

State regulators have primary authority for approving the siting of new intrastate pipeline and LDC facilities, including the expansion of existing distribution networks to accommodate increased demand and for purposes of replacing obsolete infrastructure. Generally, the state's siting authority applies to projects exceeding a minimum threshold design pressure, capacity, or size. The agency or agencies responsible for approving intrastate and distribution system pipelines vary from state to state. In many states, the state public service commission's role is oriented around tariff issues, with other state and federal resource agencies responsible for issuing necessary environmental and land use permits. In some states, a centralized siting board is established, usually comprised of the commissioner of the state public service commission or his/her designee and the commissioner of the state environmental protection agency or his/her designee. Other board members commonly include a representative of the state economic development agency, elected officials, local representatives, and other members who may be appointed by the governor.

For those states with a centralized certificate process, the lead state agency is typically charged with determining whether there is a public need for the project, and balancing the need for adequate and reliable gas service at the lowest reasonable cost to consumers with the corresponding need to protect environmental and cultural resources. The application process, the burden of proof to demonstrate need, the siting and permitting requirements, and the stakeholder participation process vary from state to state within the Study Region. For example, New York's Public Service Law Article VII is similar to the FERC 7(c) process, requiring an environmental impact review of the siting, design, construction, and operation of major intrastate natural gas transmission facilities prior to Public Service Commission approval.[104] In contrast, Texas utility

[104] For more information on New York's Article VII process, see "The Certification Review Process For Major Electric and Fuel Gas Transmission Facilities" (http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/a021e67e05b99ead85257687006f393b/$FILE/Article%20VII%20Guide%20web%2010-13%20.pdf).

pipeline companies that are designated as common carriers have a statutory right of eminent domain and can obtain right-of-way without specific siting approval or permit.[105] In all cases, intrastate pipeline expansion projects must still obtain all applicable federal permits and authorizations. For example, the federal Bureau of Land Management grants permits for intrastate gas pipelines built on federal lands. Approval from the Army Corps of Engineers is required if a pipeline is constructed in U.S. waters, and the U.S. Fish and Wildlife Service participates when endangered species are known to be present within the impacted area.

One key difference is that state-jurisdictional pipelines must comply with all state regulatory requirements that might otherwise be superseded if the project were exclusively under FERC jurisdiction. For example, new gathering, storage and pipeline infrastructure projects to produce and deliver natural gas from the Marcellus shale in Pennsylvania are subject to federal permit programs (which may be delegated to the Pennsylvania Department of Environmental Protection) as well as state permits. Depending on the proposed pipeline route, these may include Water Quality Certification permits under Section 401 of the Clean Water Act, Water Obstruction and Encroachment permits, National Pollutant Discharge Elimination System permits, Submerged Land License Agreements, and Chapter 110 Water Withdrawal and Use Registration. Various other Pennsylvania state agencies issue permits as well: the Department of Transportation issues Highway Occupancy permits, the Fish and Boat Commission issues approvals for stream crossings, the Department of Natural Resources issues clearance for construction in the habitat of endangered species, the Historical and Museum Commission identifies historic and archaeologically significant sites, and the Susquehanna River Basin Commission and Delaware River Basin Commission issue Water Allocation Permits. Additionally, on the county level, the County Conservation District may require an Erosion and Sedimentation Control Plan Review.

Like FERC-jurisdictional pipelines, intrastate pipelines will negotiate right-of-way agreements with individual landowners along an expansion route. Failed negotiations can lead to land acquisition through eminent domain, a protracted process that developers prefer to avoid. There is no consistent standard for right-of-way (ROW) agreements or eminent domain authority vested in state agencies. Hence, this process is highly variable from state to state, not always transparent, and often contentious.

The time frame for intrastate pipelines to complete the state siting and permitting process for a system expansion is variable, and depends on the complexity of the project, presence of sensitive environmental resources, and extent of necessary ROW acquisition. The GAO report to Congress on pipeline permitting cites a New York State official who estimated that it typically takes 60 to 90 days for small pipelines, 3 to 6 months for medium sized pipelines, and 12 to 18 months for large pipelines to complete the state permitting process from the time a complete application is submitted, with additional variation depending on the complexity of the project and public opposition.[106] A North Dakota state official was also cited, estimating that the siting

[105] For more information on pipeline eminent domain rights in Texas, see the Pipeline Eminent Domain and Condemnation Frequently Asked Questions (FAQs) (http://www.rrc.state.tx.us/about/faqs/eminentdomain.php).

[106] U.S. GAO report, p. 26. This timeframe does not appear to include the time for pre-application and post-certification processes that must be satisfied before construction can begin.

process for intrastate pipelines takes a little over three months to complete, not including the time associated with the federal and state environmental review processes.

1.3.2 Intrastate Pipeline Safety

As previously discussed, PHMSA is responsible for developing, issuing, and enforcing pipeline safety regulations. Through delegation by PHMSA, state pipeline safety agencies may assume all or part of the inspection and enforcement responsibilities for intrastate pipelines under an annual certification process.[107] To qualify for certification, states are required to adopt at least the minimum federal regulations, and may implement additional or more stringent regulations as long as they are compatible with federal regulations. A state agency that does not satisfy the criteria for certification may enter into an agreement with PHMSA to undertake certain aspects of the pipeline safety inspection program for intrastate facilities on behalf of OPS.[108] While a state with a Section 60106 agreement will conduct inspections to ascertain compliance with federal safety regulations, probable violations are reported to OPS for enforcement action.

The National Association of Pipeline Safety Representatives (NAPSR) is an organization of state agency pipeline safety directors, managers, inspectors and technical personnel that serves to support, encourage, develop and enhance pipeline safety at the state level.[109] NAPSR maintains a compendium of state pipeline safety programs to highlight the hundreds of areas where actions have been taken at the state level to improve pipeline safety throughout the country. The 2013 Compendium revealed 1,361 state regulations, orders or legislative provisions. The most common initiatives encompass enhanced reporting, design / installation requirements, enhanced recordkeeping, and, additional direct oversight and leak tests.[110]

1.3.3 Systems Operating in Study Region

The following sections provide descriptions of the intrastate pipelines and LDCs that serve generation in each of the PPAs.[111]

<u>PJM Region</u>

The LDCs serving gas-capable generation in PJM are shown in Figure 31. The generators served by each LDC are summarized in Table 11, and each LDC's infrastructure is described in more detail in Appendix 1.

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[107] *See* 49 U.S.C. § 60105

[108] *See* 49 U.S.C. § 60106

[109] For more information, see http://napsr.org/.

[110] Source: Compendium NAPSR Second Edition - October 2013. http://www.napsr.org/Pages/Comp2013.aspx

[111] Only the systems serving more than 15 MW are included in this report. Other LDC and intrastate systems operating in the Study Region will be included in the Target 2 report.

Figure 31. LDCs Serving PJM Generators

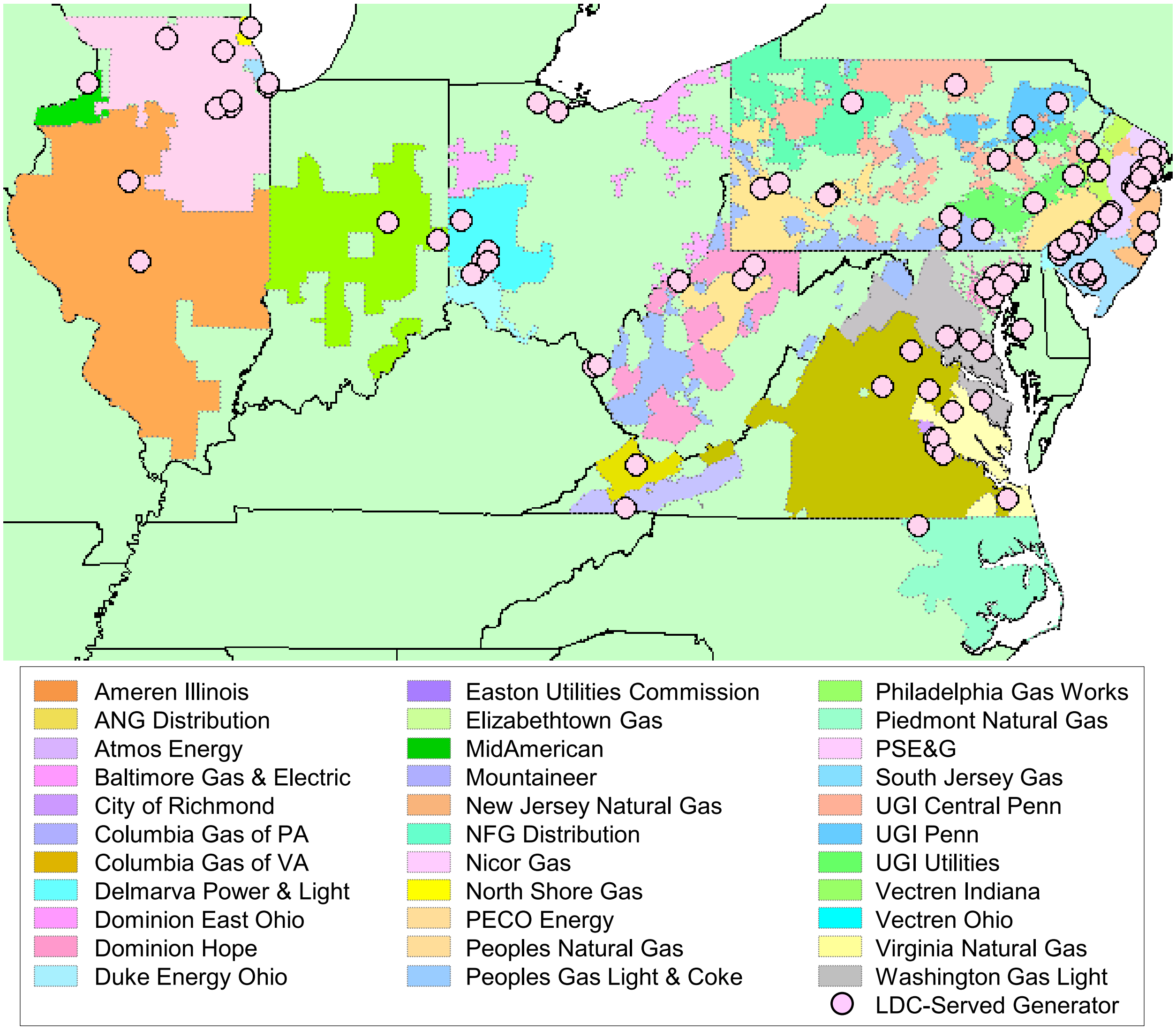


Table 11. LDC-Served Generators in PJM

LDC	Generators
Ameren Illinois	Kinkaid (1,319 MW), Powerton (1,786 MW)
ANG Distribution[112]	Buchanan (88 MW)
Atmos Energy	Wolf Hills (285 MW)
Baltimore Gas & Electric	Crane (400 MW), Gould Street (104 MW), Notch Cliff (144 MW), Perryman (192 MW), Riverside (194 MW), Wagner (1,043 MW), Westport (122 MW)
City of Richmond	Bellemeade (330 MW), Chesterfield (447 MW)[113]
Columbia Gas of Pennsylvania	Cat Tractor (69 MW), Hunterstown (869 MW)[114]
Columbia Gas of Virginia	Bear Garden (559 MW),[115] Chesapeake (122 MW), Polyester / Hopewell (71 MW), Remington (706 MW), South Anna (300 MW)
Delmarva Power & Light	Edge Moor (698 MW), Hay Road (1,098 MW)
Dominion East Ohio	Fremont (740 MW), Troy (688 MW)
Dominion Hope	Grant Town (96 MW), Pleasants (1,368 MW)
Duke Energy Ohio	Dicks Creek (117 MW), Woodsdale (490 MW)
Easton Utilities Commission	Easton (21 MW)
Elizabethtown Gas	Glen Gardner (157 MW), Kenilworth (25 MW), Union County Resource Recovery (39 MW)
MidAmerican	Cordova (691 MW)
Mountaineer	Big Sandy (342 MW), Ceredo (519 MW)
New Jersey Natural Gas	Forked River (77 MW), Lakewood (619 MW), Red Oak (750 MW),[116] Sayreville (212 MW),
NFG Distribution	Johnsonburg (60 MW)
Nicor Gas	Elwood (1,728 MW),[117] Joliet (1,320 MW), Morris (39 MW), Rockford (316 ME), Rocky Road (419 MW)
North Shore Gas	Waukegan (802 MW)
PECO Energy	DRMI (90 MW), Eddystone (1,489 MW), Fairless Hills (60 MW)
Peoples Natural Gas	Brunot Island (341 MW), Cheswick (630 MW), Conemaugh (1,872 MW), Harrison (2,052 MW), Seward (500 MW)
Peoples Gas Light & Coke	River Energy (386 MW), Southeast Chicago (407 MW)
Philadelphia Gas Works	Grays Ferry (158 MW)
Piedmont Natural Gas	Rosemary (180 MW)

[112] Appalachian Natural Gas Distribution

[113] Chesterfield is also directly connected to Columbia Gas.

[114] Hunterstown is also directly connected to Texas Eastern.

[115] Bear Garden is also directly connected to Transco.

[116] Red Oak is currently in the process of switching its gas service from PSE&G to New Jersey Natural Gas, the change is expected to be completed in October 2014.

[117] Elwood is also directly connected to Northern Border.

LDC	Generators
PSE&G	Bayonne Cogen (160 MW), Bergen (1,400 MW), Burlington (242 MW), Camden Cogen (160 MW), Edison (502 MW), Essex (596 MW), Linden (384 MW), Marcal Paper (65 MW), Mercer (653 MW), Newark Bay (156 MW), Parlin (135 MW), Red Oak (750 MW)[116], South River NUG (290 MW)
South Jersey Gas	Carlls Corner (84 MW), Cumberland (96 MW), Deepwater (155 MW), Mickleton (71 MW), Sherman Avenue (110 MW), Vineland (68 MW)
UGI	UGI Central Penn Gas: Blossburg (24 MW), Portland (194 MW), Mt. Carmel (40 MW) UGI Penn Natural Gas: Archbald (64 MW) UGI Utilities: Bethlehem (1,200 MW), Hazelton (172 MW), Hunlock (44 MW), Mountain (53 MW), Titus (36 MW)
Vectren	Indiana: Anderson (152 MW), Richmond (77 MW) Ohio: Greenville (236 MW), Hutchings (447 MW), Tait (685 MW), Yankee (126 MW)[118]
Virginia Natural Gas	Darbytown (368 MW), Four Rivers (939 MW), Ladysmith (357 MW)
Washington Gas Light	Chalk Point (1,868 MW), Panda Brandywine (230 MW), Ogden Martin / Covanta Fairfax (124 MW)

MISO Region

The intrastate pipelines that serve generation in MISO South are shown in Figure 32 and listed in Table 12. The LDCs serving MISO generators are shown in Figure 33 (MISO North/Central) and Figure 34 (MISO South), and listed in Table 13. Infrastructure details are provided in Appendix 2.

[118] Yankee is also directly connected to Columbia Gas.

Figure 32. Intrastate Pipelines Serving MISO Generators

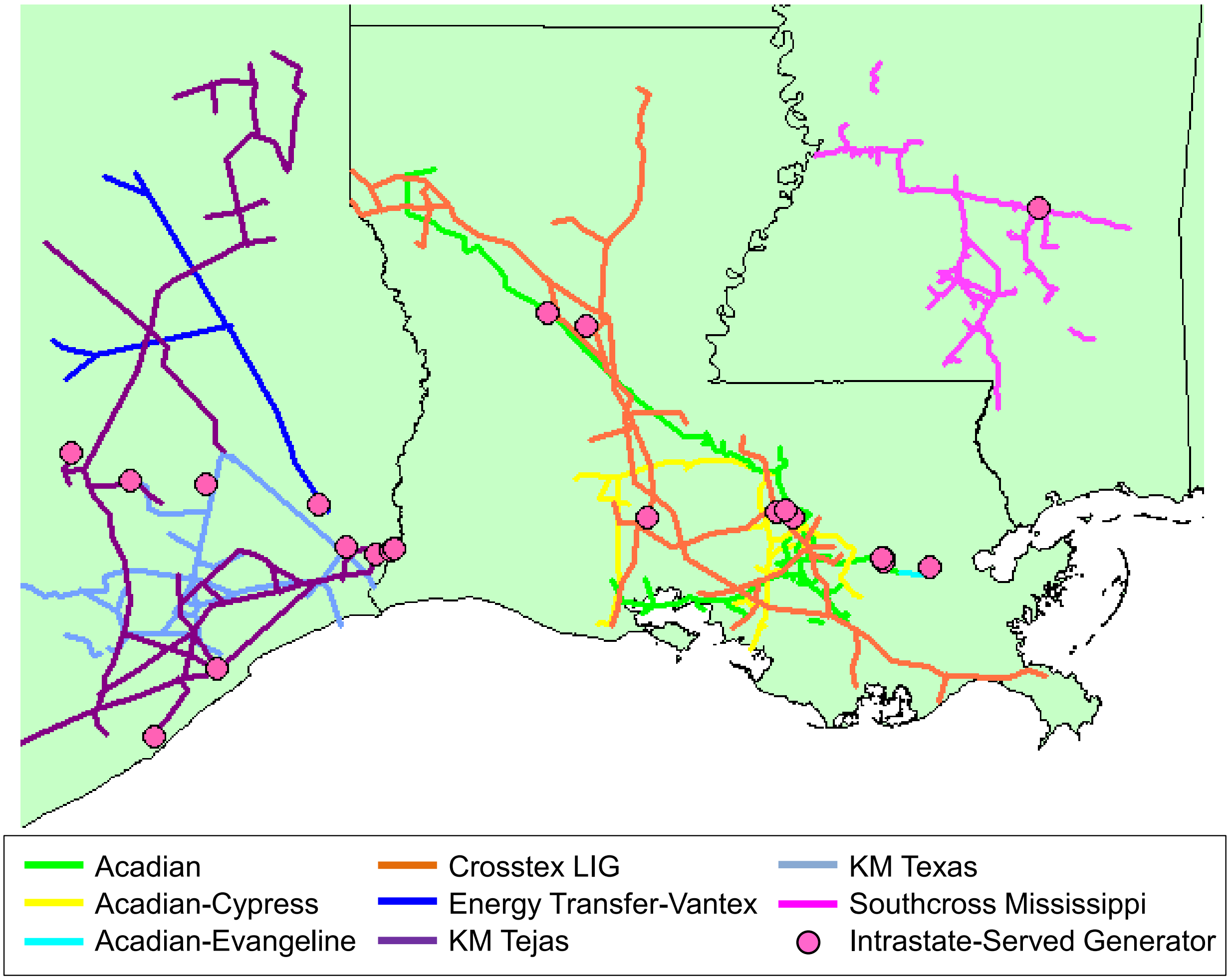


Table 12. Intrastate Pipeline-Served Generators in MISO

Pipeline	Generators
Acadian	Acadian: Carville (485 MW), Taft (866 MW), Willow Glen (650 MW)[119] Cypress: Plaquemine (360 MW) Evangeline: Little Gypsy (1,168 MW),[119] Nine Mile Point (1,564 MW),[119] Waterford (822 MW)[119]
Crosstex LIG	Bonin (171 MW),[120] DG Hunter (130 MW), Nesbitt (422 MW)
Energy Transfer-Vantex	Cypress-Hardin County Peaking (150 MW)
Kinder Morgan Tejas	Dow Chemical Texas (900 MW), Frontier (830 MW), Lewis Creek (460 MW),[121] Sabine (1,809 MW)[122], Sabine Cogen (56 MW), San Jacinto County (150 MW), SRW Cogeneration (490 MW), Union Carbide Texas City (75 MW)
Kinder Morgan Texas	Beaumont Refinery (300 MW), Lewis Creek (460 MW),[121] Sabine (1,809 MW)[122]
Southcross Mississippi	Sylvarena (135 MW)

[119] Little Gypsy, Nine Mile Point, Waterford and Willow Glen are also served directly by Gulf South.

[120] Bonin is also directly connected to Columbia Gas.

[121] Lewis Creek is connected to KM Tejas and Texas, and also has a direct connection to Texas Eastern.

[122] Sabine is connected to the KM Tejas and KM Texas intrastate pipelines, and to the Florida Gas and Texas Eastern interstate pipelines.

Figure 33. LDCs Serving MISO North/Central Generators

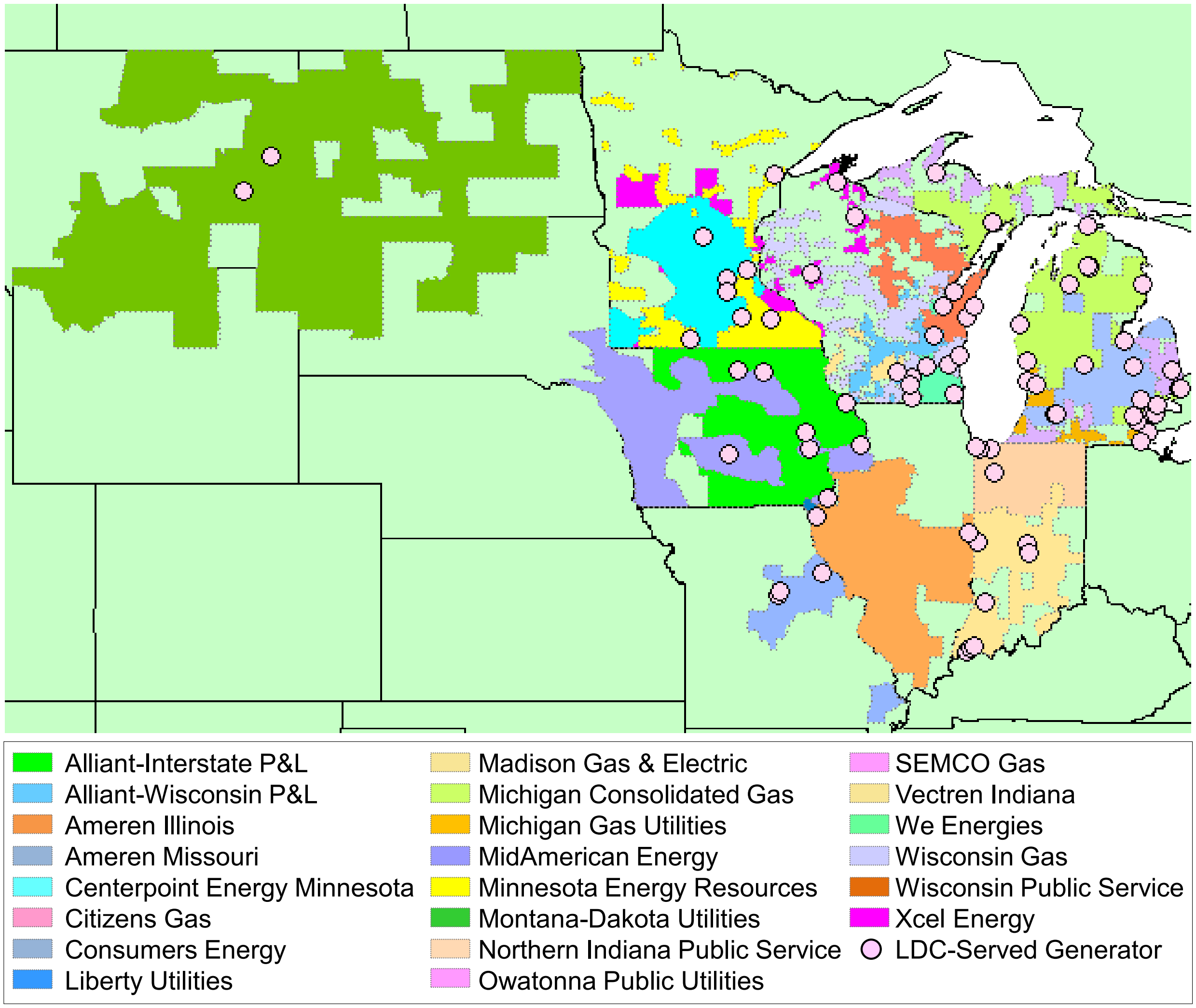


Figure 34. LDCs Serving MISO South Generators

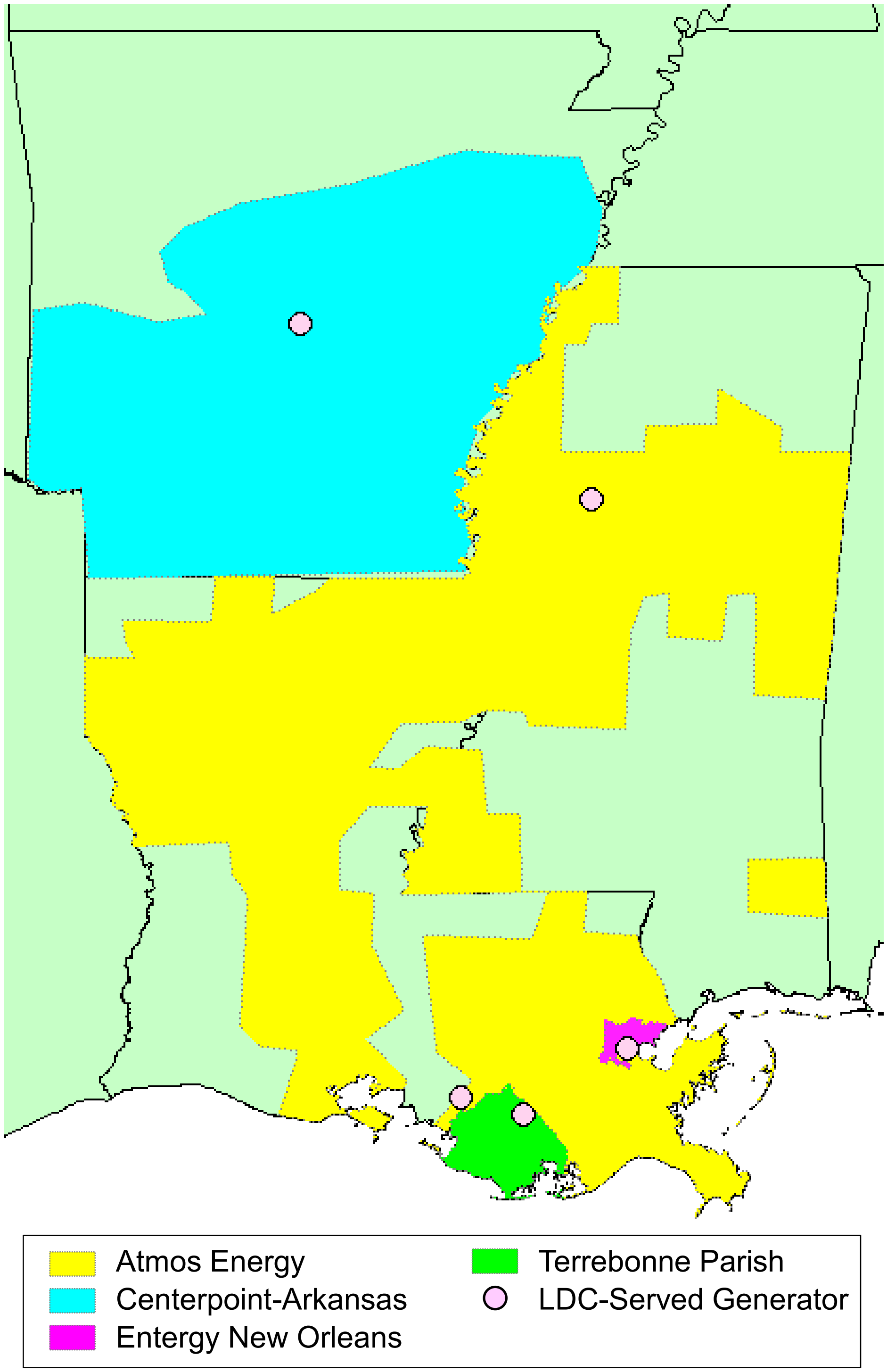


Table 13. LDC-Served Generators in MISO

LDC	Generators
Alliant Energy	Interstate Power & Light: Burlington (62 MW), Dubuque (65 MW), Emery (382 MW), Red Cedar (27 MW) Wisconsin Power & Light: Riverside (542 MW), Rock River (160 MW), RockGen (534 MW), Sheepskin (40 MW)
Ameren Illinois	Tilton (187 MW)
Ameren Missouri	Columbia (192 MW), Columbia W&L (48 MW), Peno Creek (260 MW)
Atmos Energy	Henderson (57 MW), Morgan City (51 MW)
Centerpoint Energy Arkansas	Mabelvale (26 MW)
Centerpoint Energy Minnesota	Minnesota River (48 MW), New Prague (18 MW)
Citizens Gas	Georgetown (360 MW), Harding Street (378 MW)
Consumers Energy	BE Morrow (34 MW), Hancock (183 MW), Kalamazoo (70 MW), Northeast (150 MW), Thetford (233 MW)
Entergy New Orleans	Michoud (777 MW)
Liberty Utilities	Roquette America (35 MW)
Madison Gas & Electric	West Campus Cogen (130 MW)
Michigan Consolidated Gas	BC Cobb (183 MW), Belle River (279 MW), DE Karn (1,276 MW), Dearborn Industrial (715 MW), Delray (159 MW), DTE East China (384 MW), Escanaba (18 MW), Gaylord-Consumers (85 MW), Gaylord-Wolverine (72 MW), JC Weadock (17 MW), Kalkaska (50 MW), Lincoln (18 MW), Livingston (132 MW), Michigan Power (123 MW), Renaissance (776 MW), St. Clair (23 MW), Straits (21 MW), Sumpter (340 MW), Superior (76 MW)
Michigan Gas Utilities	Fermi (75 MW), JR Whiting (17 MW)
MidAmerican Energy	Coralville (80 MW), Merle Parr (36 MW), Moline (80 MW), Pleasant Hill (194 MW)
Minnesota Energy Resources	Cascade Creek (89 MW), Fairmont (22 MW), Sappi Cloquet Mill (22 MW)
Montana-Dakota Utilities	Glendive (75 MW), Miles City (25 MW)
Northern Indiana Public Service	Bailly (31 MW), Dean H Mitchell (17 MW), RM Schahfer (155 MW), Whiting (525 MW)
Owatonna Public Utilities	Owatonna (20 MW)
SEMCO Gas	Greenwood (1,064 MW), JH Campbell (21 MW), John H Warden (18 MW), Zeeland (1,247 MW)
Terrebonne Parish	Houma (77 MW)
Vectren Energy Delivery of Indiana	AB Brown (174 MW), Broadway (135 MW), Cayuga (120 MW), Edwardsport (795 MW), Northeast (24 MW), Vermilion (720 MW)
We Energies	Concord (400 MW), Paris (400 MW), South Fond Du Lac (352 MW)

LDC	Generators
Wisconsin Gas	Combined Locks (48 MW), Germantown (93 MW), Island St. Kaukauna (61 MW), Kaukauna (16 MW), Port Washington (1,231 MW)
Wisconsin Public Service	Custer (24 MW), Point Beach (19 MW), Pulliam (108 MW)
Xcel Energy	Bay Front (21 MW), Flambeau (20 MW), Granite City (76 MW), St. Paul Cogen (40 MW), Wheaton (451 MW)

New York

The state-jurisdictional systems serving NYISO generators larger than 15 MW are shown in Figure 35. The generators served by each system are summarized in Table 14, and the intrastate pipeline and LDC infrastructure is described in more detail in Appendix 3.

Figure 35. Intrastate Pipeline and LDCs Serving NYISO Generators

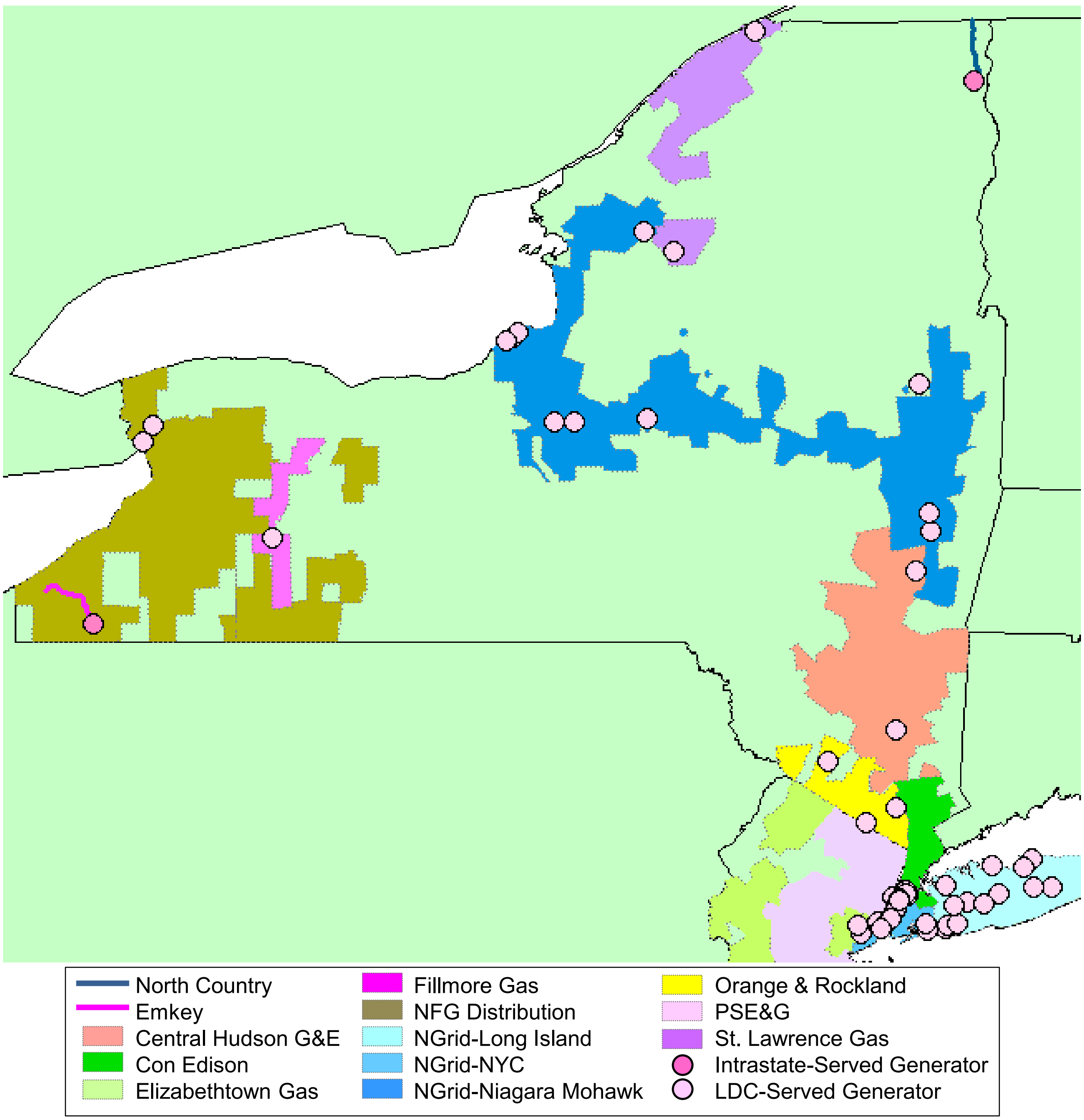


Table 14. Intrastate/LDC-Served Generators in NYISO

System	Generators
Central Hudson Gas & Electric	Coxsackie (22 MW), Danskammer (532 MW),[123] Roseton (1,242 MW)
Con Edison	59th Street (17 MW), Astoria East Energy (640 MW), Astoria Energy 2 (660 MW), East River (730 MW), Harlem River (80 MW), Hellgate (80 MW), NRG Astoria (558 MW), NYPA Astoria (576 MW), Ravenswood (2,536 MW), USPowerGen Astoria (779 MW), Vernon Boulevard (80 MW)
Emkey Transportation[124]	Carlson/Jamestown (47 MW)
Fillmore Gas	Allegany (67 MW)
National Fuel Gas Distribution	Fortistar North Tonawanda (55 MW), Indeck Yerkes (60 MW),
NGrid[125]	NGrid-Long Island: Barrett (669 MW), Brentwood/NYPA Pilgrim (MW), Caithness (375 MW), Calpine Bethpage (144 MW), Charles P Keller (30 MW), Flynn (170 MW), Freeport Electric (61 MW), Glenwood (106 MW),[126] LIPA Bethpage (96 MW), LIPA Freeport (60 MW), Northport (1,548 MW), Pilgrim/PPL Edgewood (88 MW), Pinelawn (82 MW), Port Jefferson (482 MW),[127] Stony Brook (47 MW), Trigen Nassau (55 MW) NGrid-NYC: Arthur Kill (932 MW), Brooklyn Navy Yard (322 MW), Far Rockaway (60 MW), Gowanus (320 MW), Kent (50 MW), KIAC (121 MW), Narrows (352 MW), NYPA Gowanus (100 MW), Pouch (50 MW) Niagara Mohawk: Carr Street (123 MW), Carthage (63 MW), Castleton Fort Orange (72 MW), Indeck Corinth (147 MW), Indeck Oswego (57 MW), Independence (1,254 MW), Oswego Harbor Power (902 MW), Rensselaer (104 MW), Sterling (65 MW), Syracuse (103 MW)
North Country Pipeline	Saranac (286 MW)
Orange & Rockland	Bowline (1,242 MW),[128] Hillburn (46 MW), Shoemaker (42 MW)
PSE&G	Bayonne Energy Center (512 MW)[129]
PSE&G / Elizabethtown Gas	Linden Cogen (1,035 MW)

[123] The Danskammer plant has been shuttered since sustaining significant damage during Hurricane Sandy in October 2012. On March 13, 2014, Helios Power Capital, the plant's current owner, notified the NYPSC that it intends to re-open the retirement ruling and resume operation of the plant.

[124] Previously Nornew Energy Systems. Emkey is supplied by an affiliated gathering system or by displacement from Tennessee.

[125] NGrid owns and operates three affiliated systems in New York: National Grid Energy Delivery Long Island, formerly Keyspan Energy Delivery Long Island (NGrid-Long Island), National Grid Energy Delivery New York, formerly Keyspan Energy Delivery New York (NGrid-NYC) and Niagara Mohawk Power Corp (Niagara Mohawk).

[126] Glenwood also has 126 MW of oil-only capacity.

[127] Port Jefferson also has 16 MW of oil-only capacity.

[128] Bowline also has a direct connection to Millennium via the Hudson Valley Gas Pipeline.

[129] As part of the New Jersey-New York Expansion Project, Texas Eastern built a meter station there that serves PSE&G. It does not directly tie to the energy center, but rather to a PSE& G lateral that goes into the plant. Bayonne Energy Center also has a direct connection to Transco.

St. Lawrence Gas	Beaver Falls (108 MW), Massena (102 MW)

New England

Figure 36 shows the service territories of the New England LDCs that serve electric generation relative to the locations of the region's interstate pipelines. The generators served by each system are summarized in Table 15, and the infrastructure is described in more detail in Appendix 4.

Figure 36. LDCs Serving ISO-NE Generators

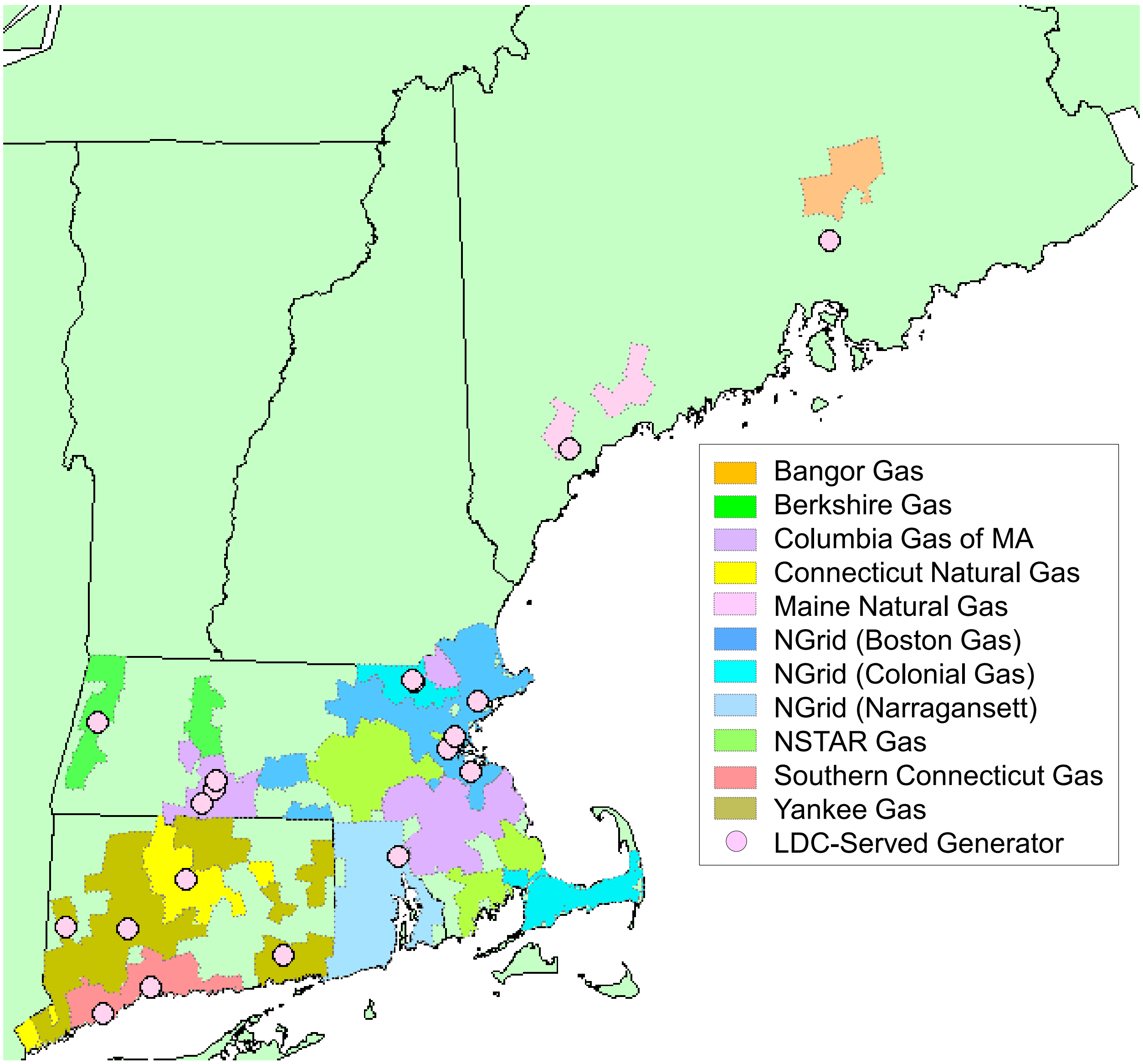


Table 15. LDC-Served Generators in ISO-NE

LDC	**LDC-Served Generator(s)**
Bangor Gas	Bucksport Energy (153 MW)
Berkshire Gas	Altresco (183 MW)
Columbia Gas of Massachusetts[130]	Mass Power (280 MW), Stony Brook (354 MW), West Springfield (194 MW)
Connecticut Natural Gas	CDECCA (61 MW)
Maine Natural Gas	Westbrook Energy Center (548 MW)
NGrid[131]	Boston Gas:[132] MATEP (49 MW), Mystic 7 (560 MW), Potter (91 MW), Waters River (68 MW) Colonial Gas: L'Energia Energy Center (78 MW), Lowell Cogen (30 MW) Narragansett Electric:[133] Pawtucket Power (61 MW)
NSTAR Gas	Kendall (244 MW)
Southern Connecticut Gas	Bridgeport Energy (534 MW), New Haven Harbor (599 MW)
Yankee Gas	Montville (82 MW), Rocky River (15 MW), Waterbury (99 MW)

[130] Formerly known as Bay State Gas.

[131] NGrid owns and operates three affiliated systems in New England: Boston Gas Company, Colonial Gas Company and The Narragansett Electric Company.

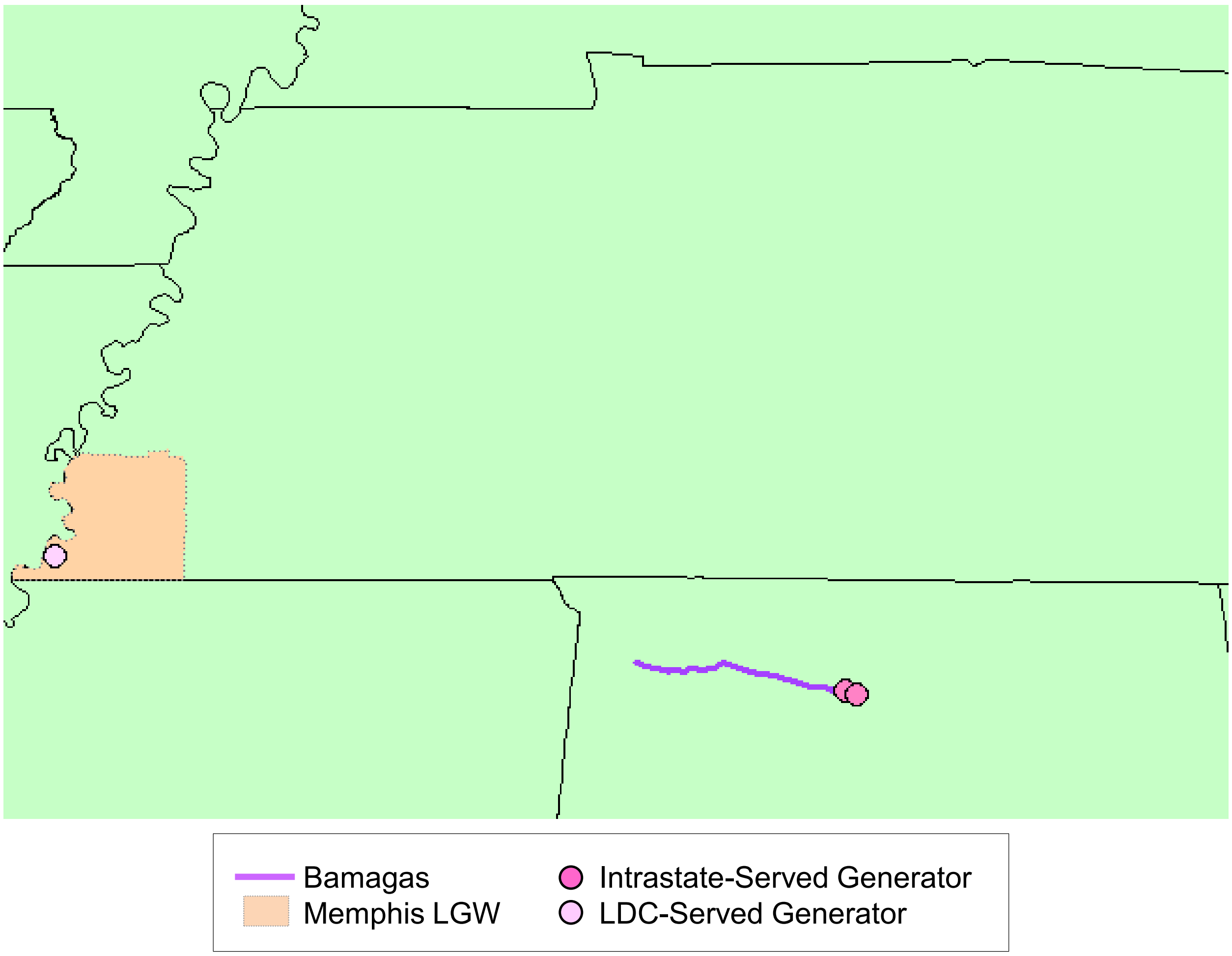
[132] National Grid / Boston Gas also owns, maintains and operates the pipeline between the Distrigas LNG terminal and Mystic 8&9.

[133] National Grid / Narragansett Electric owns, operates and maintains the pipeline between the Algonquin meter and the Manchester Street plant.

TVA Region

American Midstream's Bamagas intrastate pipeline system serves the 795-MW Decatur and 807-MW Morgan power plants.[134] The Memphis Light Gas & Water LDC serves the 572-MW Allen plant. The locations of these systems are shown in Figure 37, and with a more detailed infrastructure description in Appendix 5.

Figure 37. Intrastate Pipeline and LDC Serving TVA Generators



1.4 PIPELINE, STORAGE AND GAS UTILITY INFRASTRUCTURE IN ONTARIO

Interprovincial transportation, storage and LDC services are regulated by the NEB and the Ontario Energy Board (OEB). The NEB approves pipeline tolls and tariffs for pipelines that cross provincial or international borders. The NEB also regulates the construction and operation of interprovincial pipelines. The OEB approves rates involving the cost to transport, store and distribute natural gas in Ontario. The OEB licenses gas marketers selling to commercial and residential customers, and approves provincial gas infrastructure developments.

[134] Bamagas receives gas from the Tennessee pipeline.

1.4.1 National Energy Board

The NEB was established in 1959 as an independent federal agency authorized under Canadian law to regulate pipelines and trade within Canada as well as exports of energy to the U.S. Jurisdictional pipelines require NEB approval for all tariffs. For several decades, NEB regulation linked tariffs to cost-of-service. Like many rate cases before FERC, pipeline rate applications before the NEB were protracted. To reduce administrative costs, the NEB issued its Guidelines for Negotiated Settlements of Traffic, Tolls and Tariffs.[135] In 2002, these Guidelines were updated to enable the NEB to more effectively deal with applications based on contested settlements.

In 1995, the NEB authorized the use of negotiated settlements by approving a number of multi-year settlements. To meet the just and reasonable standard, the NEB then took, and continues to take, consideration of interested parties' views, public concerns, public safety and environmental impacts and either accepts or rejects the settlement as a package. The NEB can approve the settlement, deny the settlement and refer it for hearing, or approve the settlement on an interim basis and then hold a hearing to address appropriate issues. As part of the negotiated settlement process, the NEB established the Framework for Light-Handed Regulation to address issues regarding negotiated settlements involving gathering and processing facilities.[136] This process is used to address unique competitive issues.

A recent NEB decision regarding TransCanada's restructuring of its mainline tolls and services provides a relevant example of the NEB process. TransCanada filed the application for approval on September 1, 2011. The NEB set the application for hearing. The hearing process provided TransCanada and interveners an opportunity to argue the merits of their positions. On March 27, 2013 the NEB released its decision. Highlights included the following: the adoption of TransCanada's throughput forecasts, fixing the mainline firm transportation service under a 100% load factor toll from Empress, Alberta to Dawn, Ontario at $1.42/GJ for four and a half years.[137] On May 1, 2013, TransCanada filed a request for the NEB to review its decision. On June 11, 2013 the NEB dismissed TransCanada's Review Application for the decision.

Material commercial issues relating to TransCanada's mainline rates and service provisions have now been resolved. Reflecting the decline in exports from the Western Canadian Sedimentary Basin (WCSB) and the reduced demand by Canadian customers for long haul transportation from AECO to Ontario and Quebec, the NEB's decision reduced the mainline 100% load factor toll from Empress to Dawn from $2.58/GJ to $1.42/GJ. The changes to the pricing process for interruptible (IT) and short-term firm transportation (STFT) services will provide incentive for shippers to contract for additional FT.

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[135] https://docs.neb-one.gc.ca/ll-eng/llisapi.dll/fetch/2000/90463/157025/208496/A0E4C1_-_Letter_Decision.pdf?nodeid=208497&vernum=-2

[136] http://publications.gc.ca/collections/Collection/NE22-1-1998-5E.pdf

[137] TransCanada has pricing discretion for interruptible and short-term firm services. TransCanada is authorized to realize an 11.5% ROE.

1.4.2 Ontario Energy Board

Established in 1960, the OEB has the authority to approve intra-provincial gas infrastructure improvements, including regulating LDCs, both Union Gas and Enbridge Gas Distribution. The review and approval of interprovincial facility additions remain the responsibility of the NEB. The OEB's regulatory mandate changed significantly in 1998 with passage of the Energy Competition Act.[138] The OEB reviews and approves applications for new infrastructure developments. The OEB reviews LDC rate cases and certificate applications for facility expansions.

Issued in December 2004, the OEB's Storage and Transportation Access Rule outlined the requirements for pipelines, utilities and storage companies operating in Ontario. The rule established operating requirements to ensure open and non-discriminatory access to transportation services for both shippers and storage companies. The rule requires a pipeline to define within its tariff, the methods for allocating transportation capacity, set standards for transportation open seasons, and set standard terms of service and contract forms. The rules set similar requirements for companies offering competitive storage services.

1.4.3 Systems Operating in Study Region

Natural gas infrastructure in Ontario is shown in Figure 38. TransCanada, Union and Vector operate transmission facilities, and Enbridge and Union operate distribution facilities. The generators served by each system are listed in Table 16. The Ontario gas systems are described in more detail in Appendix 6.

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[138] See http://www.ontarioenergyboard.ca/OEB/Industry/About+the+OEB/Legislation/History+of+the+OEB)

Figure 38. Ontario Natural Gas Infrastructure

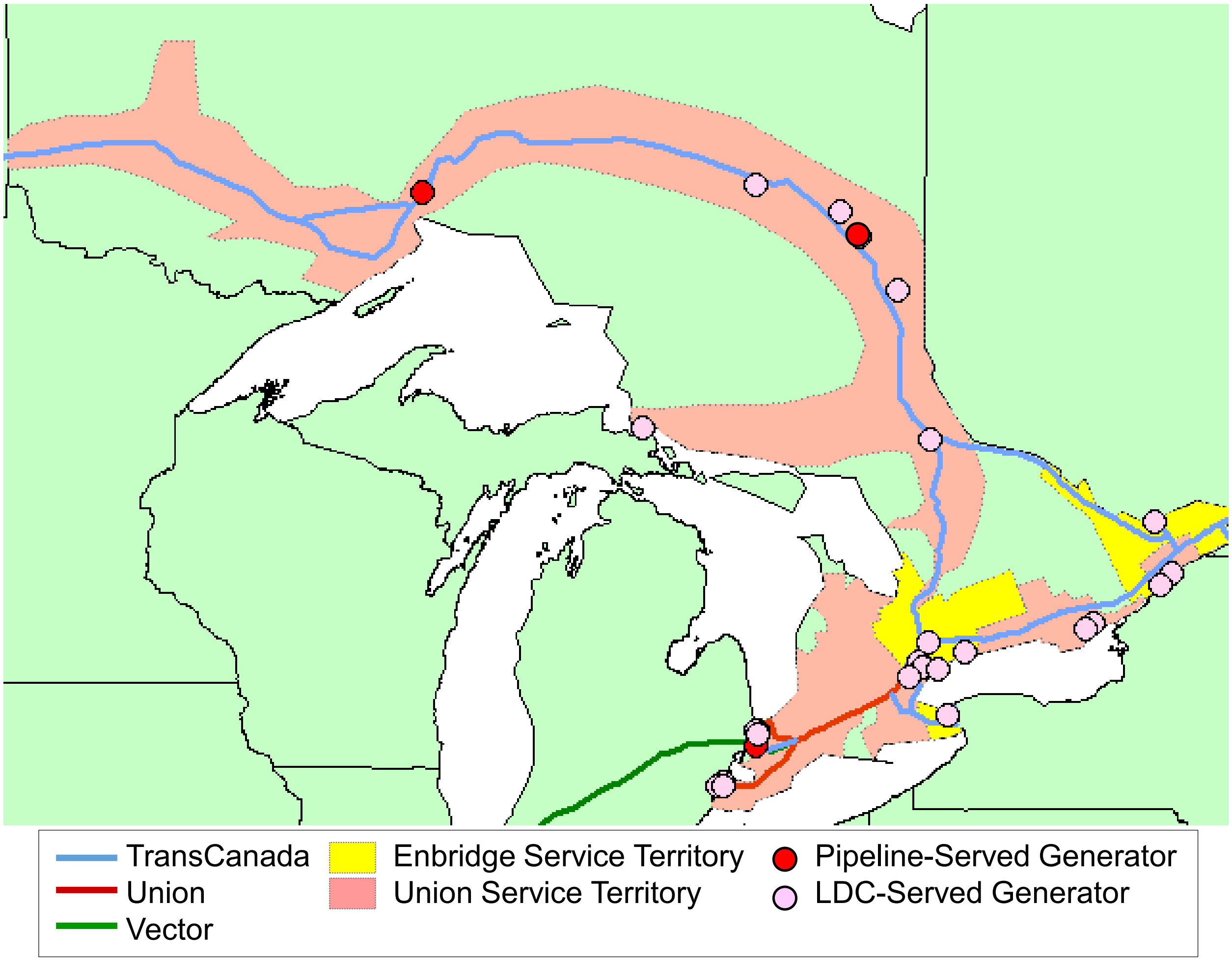
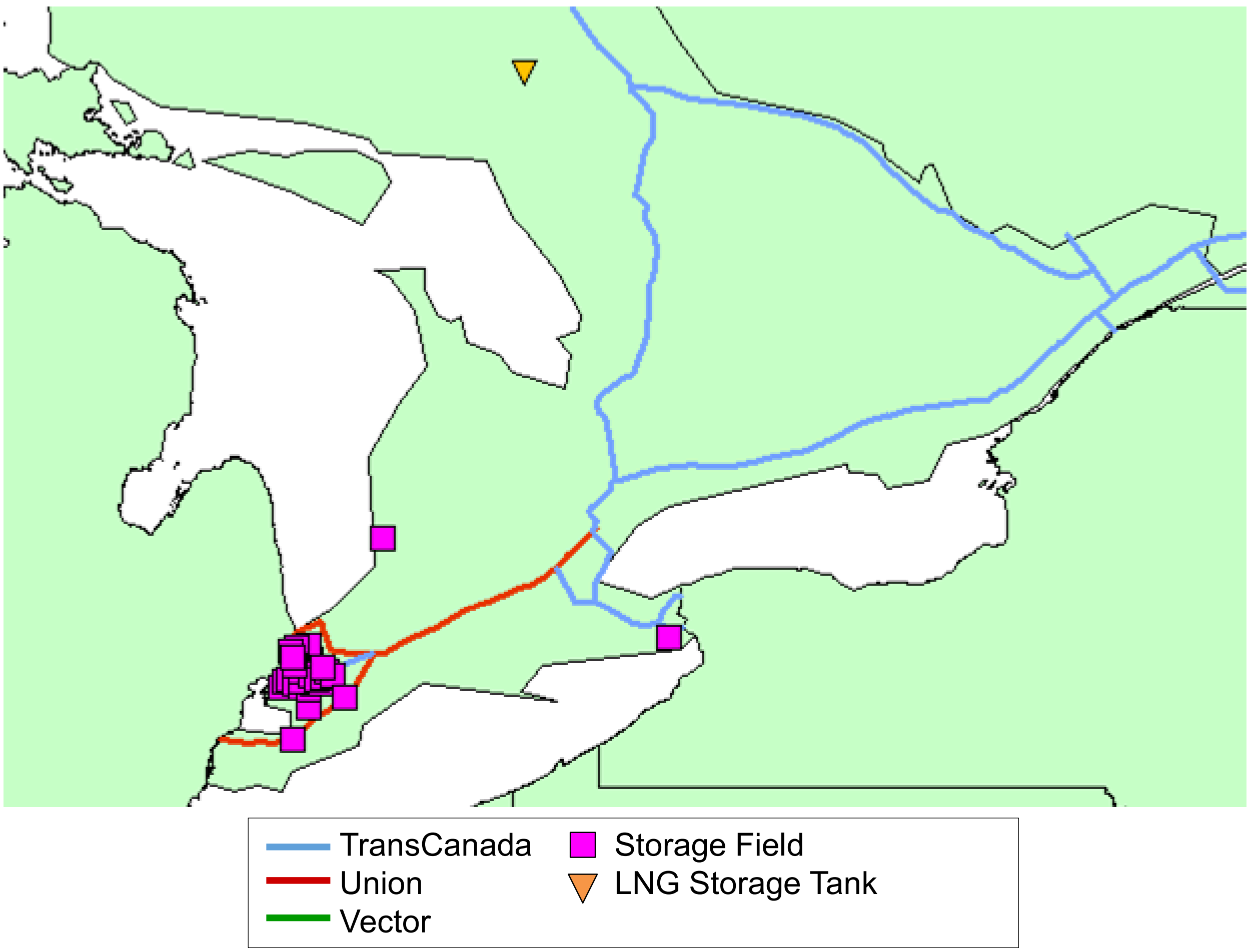


Table 16. IESO Generator Gas Connections

Pipeline / LDC	Generator(s)
Enbridge	Douglas (126 MW), Goreway (942 MW), Greater Toronto Airports Authority (128 MW), Ottawa (80 MW), Portlands (639 MW), Thorold (287 MW), Whitby (56 MW), York (438 MW)
TransCanada	Nipigon (42 MW), Tunis (60 MW)
Union	Brighton Beach (580 MW), Cardinal (184 MW), Cochrane (47 MW), Dow Chemical (100 MW), East Windsor (100 MW), Halton Hills (757 MW), Iroquois Falls (757 MW), Kapuskasking (60 MW), Kingston (140 MW), Kirkland (149 MW), Lake Superior (120 MW), Lennox (2,100 MW), Maitland (50 MW), North Bay (60 MW), Sarnia (510 MW), St. Clair (678 MW), West Windsor (128 MW), Windsor (79 MW)
Vector	Greenfield (1,153 MW)

There are 35 depleted reservoir storage fields.[139] Union Gas also operates an LNG peaking facility near Hagar, ON, which has a storage capacity of approximately 1 Bcf.[140] The locations of the underground reservoir facilities and the LNG facility are shown in Figure 39.[141] According to their latest respective storage capacity reports, Enbridge and Union hold 119.3 PJ (111 Bcf) and 168.3 PJ (157 Bcf), respectively of working gas capacity.[142] Enbridge's storage facilities have a total design withdrawal capacity of 2.656 PJ/d (2.48 Bcf/d), while Union's facilities can send out 3.157 PJ/d (2.95 Bcf/d).

Figure 39. Gas Storage Facilities in Ontario



[139] Source: Ontario Ministry of Natural Resources, http://www.mnr.gov.on.ca/en/Business/OGSR/2ColumnSubPage/STEL02_167104.html

[140] Source: Spectra Energy, http://www.spectraenergy.com/Operations/Overview-of-Operations/We-Store-Natural-Gas/

[141] A public source for the locations of the salt cavern storage facilities in Ontario could not be found, therefore these are not shown in the map.

[142] Enbridge: https://www.enbridgegas.com/assets/docs/Storage%20Design_Capacity.pdf
Union: http://www.uniongas.com/storage-and-transportation/informational-postings/design-capacity

2 STORAGE AND TRANSPORTATION OPTIONS AVAILABLE TO THE ELECTRIC SECTOR

Interstate pipeline and storage companies offer two basic services: firm transportation and/or storage, and interruptible transportation and/or storage. When built, pipeline and storage infrastructure capacity is sized to meet the demand of firm customers, with little or no excess capacity. Firm customers are those entitlement holders who pay the FERC-authorized cost of service rate to ensure guaranteed deliverability under all circumstances, except *force majeure*. *Force majeure* events are rare, and include only the most severe or unusual operating conditions when mainline segments or compression stations are not available and the pipeline cannot meet its firm service obligations, thereby reducing a pipeline's delivery capability. In exchange for this level of service reliability, firm customers must pay a fixed monthly fee designed to reimburse the pipeline for its fixed capital costs and operating expenses and a rate of return component. This fee is referred to as a reservation charge, and is charged to render service irrespective of whether the shipper uses its firm contract or not. Firm transportation customers also pay a usage fee which compensates the pipeline for variable costs that vary with throughput. A shipper only pays the usage fee if it transports gas. Pipelines may, but are not required to, discount the firm transportation rate. In contrast, interruptible service is available only when and if there is sufficient pipeline capacity after the needs of firm customers, on a primary and secondary priority, have been scheduled. Interruptible customers pay a volumetric rate only when they use the service. The volumetric rate paid by interruptible shippers for a lower quality of service in terms of delivery priority may be discounted by the pipeline. The level of interruptible transportation discounting across the Study Region varies.

Within the broad categories of firm and interruptible transportation service, there is a range of service options offered by the different pipelines doing business in the Study Region. For example, the service may be seasonal, provide enhanced hourly flexibility, or be available on a no-notice basis to serve the firm transportation and peaking requirements of small municipal and cooperative utilities that have historically leaned on the pipeline for deliverability assurance. Shippers can also obtain capacity through the secondary capacity market. In the secondary capacity market, shippers holding unused firm capacity can release this capacity for sale to other shippers. Secondary firm capacity would have a priority of service lower than primary firm transportation service if the assignee delivers gas to a different point than specified in the assignor's contract, but higher than interruptible service. These nuances are addressed in more detail in Section 2.4.

Exhibit 2 presents a summary table of the services provided by the FERC-jurisdictional pipeline and storage companies operating in the U.S. portion of the study region.[143] We will examine the various service options in detail following a brief discussion of some of the tariff terms and conditions that are of particular relevance to gas-fired generators. The following discussion generally makes reference to pipeline companies, but it is also generally applicable to storage companies.

[143] Each pipeline's current tariff can be downloaded from their respective EBBs, the URLs of which are listed in Exhibit 3.

2.1 SCHEDULING PRACTICES AND SERVICE PRIORITIES

To ensure the systematic flow of natural gas from various producing basins and storage facilities to market centers across North America, pipelines and LDCs must utilize the standardized NAESB WGQ nomination, confirmation and scheduling process that is the product of stakeholder review and FERC approval.[144] Under the current protocol, all shippers – including primary firm transportation, secondary firm transportation, interruptible shippers, and shippers obtaining primary and secondary capacity through capacity release – must first submit a nomination to the pipeline requesting the amount of gas they want a pipeline to deliver and the receipt and delivery points.[145] Shippers must have associated quantities of gas supply to support its requested nomination.

2.1.1 Standard Nomination Cycles

All pipelines operate on a standard 24-hour gas day beginning at 9:00 am (Central clock time, or "CCT"). NAESB WGQ has established four standard nomination cycles for each gas day: Timely and Evening, which occur the day before the start of the gas day, and Intra-Day 1 and Intra-Day 2, which occur during the flowing gas day. Each cycle consists of the following steps:

- Nomination – Shippers submit requested quantities to Transportation Service Providers (TSPs)
- Capacity Allocation – TSPs determine if there is sufficient capacity to transport the nominated quantities
- Interconnect Confirmation – TSPs confirm with upstream and downstream point operators the quantity of gas that the pipeline will transport from the receipt point to the delivery point and confirm that the shipper has injected sufficient volumes of gas to support its nomination
- Scheduling – the transportation quantity scheduled to flow is the lesser of the quantity nominated by the shipper, the capacity allocated by the TSP, the quantity confirmed by the upstream operator and the quantity confirmed by the downstream operator

The same nomination and confirmation process and schedule are used each day, including weekends and holidays. NAESB WGQ Standard 1.3.4, incorporated by reference in pipeline tariffs, states the importance of personnel availability to support round-the-clock scheduling.[146] Shippers have the option to submit single-day or multi-day nominations through their interstate pipeline EBB accounts. Pipelines operate seven days a week, 24 hours a day, including holidays and weekends, with staffing schedules configured to accommodate expected shipper needs. The round-the-clock nature of pipeline nomination schedules is not necessarily reflected in gas

[144] The NAESB WGQ develops the standards which interstate pipelines must comply with once FERC incorporates the standards into the Code of Federal Regulations.

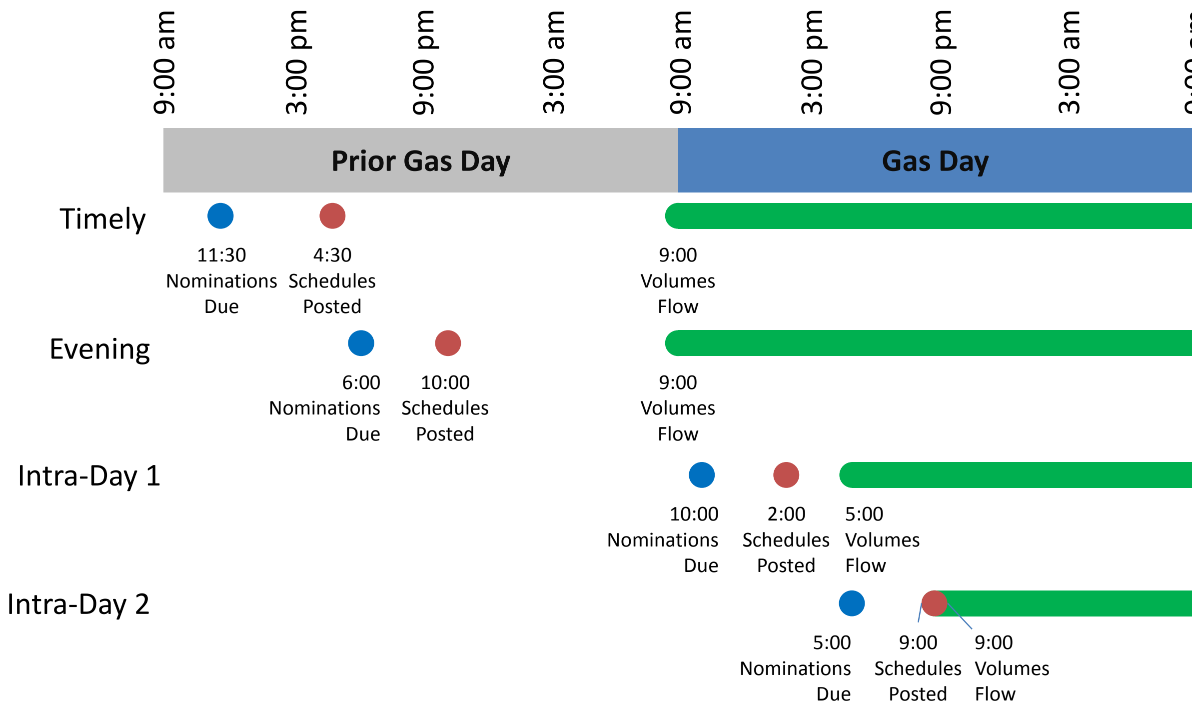
[145] For no-pathed pipelines, a shipper would not need to identify the receipt and delivery points.

[146] See, for example, Tennessee Gas Pipeline Company, L.L.C., FERC NGA Gas Tariff, Sixth Revised Volume No. 1, Fourth Revised Sheet No. 314.
http://pipeline2.kindermorgan.com/Documents/PDFView.aspx?code=TGP&fname=TGP_EntireTariff.pdf

trading markets, and obtaining gas, rather than nominating that gas to flow, can therefore become the limiting step when shippers seek to schedule gas during weekends.

Figure 40 shows a complete schedule of deadlines associated with each of the four standard NAESB cycles.

Figure 40. Standard NAESB Nomination Cycles (CCT)



For the Timely Cycle, nominations are due by 11:30 am, confirmations are due by 3:30 pm, and scheduled quantities are reported by 4:30 pm for gas flow at 9:00 am the following gas day. Nominations for the Evening Cycle, which also schedules quantities for gas flow at the start of the following gas day, are due at 6:00 pm. Evening Cycle confirmations are due by 9:00 pm and scheduled volumes are posted by 10:00 pm. In addition, there are two nomination opportunities during the gas day, for gas flow the same gas day. Nominations for the Intra-Day 1 Cycle are due at 10:00 am, one hour after the beginning of the gas day. Confirmations are due by 1:00 pm, scheduled quantities are reported by 2:00 pm, for gas flow at 5:00 pm Nominations for the Intra-Day 2 Cycle are due at 5:00 pm, confirmations are due by 8:00 pm, and scheduled quantities are posted by 9:00 pm, for gas flow starting at 9:00 pm.[147]

While the gas day operates on the same schedule across the country, electric schedules vary by control area, with the electric day typically beginning at midnight in each control area's respective time zone, meaning that each gas day bridges two electric days and *vice versa*. A

[147] More information regarding the NAESB nomination and scheduling standards and procedures is available at http://naesb.org/pdf/gectf031504w8.pdf.

second complicating factor is that gas-fired generators in all PPAs, other than NYISO, do not necessarily know when they have been scheduled to run before Timely Cycle nominations are due. NYISO posts its dispatch schedules before Timely gas nominations are due. Other PPAs are reviewing whether to move their dispatch schedules to earlier in the day, prior to the Timely gas nomination deadline at 11:30 am CCT. Across the Study Region, the Day-Ahead Market (DAM) bidding schedules are as follows (all times are CCT):

- PJM DAM bids are due at 12:00 noon and schedules are released at 4:00 pm;
- MISO DAM bids are due at 10:00 am and schedules are released at 2:00 pm;
- NYISO DAM bids are due at 4:00 am and schedules are released at 10:00 am; and
- ISO-NE DAM bids are due at 9:00 am and schedules are released at 12:30 pm.

In 2012, FERC launched an initiative to ensure that outages and reliability problems are not the result of the lack of coordination between the electric and gas industries, especially as electric sector dependence on natural gas increases. One aspect of this coordination effort is an examination of the alignment of the electric and gas operating days across the country.[148] In April 2013, FERC held a technical conference to discuss natural gas and electric industry scheduling, and issues related to whether and now natural gas and the electric industry schedules and practices could be harmonized in order to achieve the most efficient scheduling systems for both industries. In December 2013, FERC Staff reported that "members of the natural gas industry recently launched the Natural Gas Council Gas Day Initiative, to consider the benefits and consequences of potential modifications to the timing of the Natural Gas Operating Day and the nationwide schedule for natural gas nominations."[149,150] The natural gas industry is coordinating with the electric industry to discuss possible modifications to the gas and electric schedules that would benefit both industries.

On March 20, 2014, FERC issued a Notice of Proposed Rulemaking (NOPR) regarding Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities.[151] There will be a six-month process, led by NAESB, for the gas and electric industry to work to reform pipeline scheduling practices. Specifically, the draft NOPR proposes to:

- Start the natural gas operating day earlier, at 4:00 am CCT, in order to better accommodate the load increase during the morning for both the electric and natural gas systems and to ensure that gas-fired generators are not running short on gas supplies during the critical morning electric ramp periods.

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[148] Request for Comments of Commissioner Moeller on Coordination between the Natural Gas and Electricity Markets, February 3, 2012, http://ferc.gov/about/com-mem/moeller/moellergaselectricletter.pdf.

[149] Gas-Electric Coordination Quarterly Report to the Commission, December 19, 2013, http://ferc.gov/legal/staff-reports/2013/dec-report.pdf.

[150] On January 28, 2014, the Natural Gas Council, as part of its Gas Day Initiative, presented a straw-man proposal for changes to the gas day to electric sector representatives (including the ISO/RTO Council).

[151] http://ferc.gov/whats-new/comm-meet/2014/032014/M-1.pdf

- Move the Timely Cycle nomination deadline later, to 1:00 pm, to allow electric utilities to finalize their scheduling before gas-fired generators must make gas purchase arrangements and submit nomination requests for natural gas transportation service to the pipelines.

- Modify the current intraday nomination timeline to increase the number of intraday nomination cycles, to provide greater flexibility to all pipeline shippers, not just those shipping on interstate pipelines that voluntarily allow more flexible nomination opportunities. The NOPR proposes to move from two to four standard intraday nomination cycles, which would occur at 8:00 am, 10:30 am, 4:00 pm and 7:00 pm. Gas flows reflecting successful intraday nominations would become effective at noon, 4:00 pm, 7:00 pm and 9:00 pm respectively. The draft NOPR proposes to maintain the No-Bump Rule during the proposed Intra-Day 4 cycle to provide assurances for interruptible shippers that they will not be bumped without an opportunity to re-nominate their volumes. At the same time, the proposed timeline would allow bumping during the proposed new Intra-Day 3 cycle to permit firm shippers to utilize the higher priority service for which they are paying.

- In addition, the draft NOPR clarifies FERC policy concerning the ability of a pipeline to permit firm shippers to bump an interruptible shipper's nomination during any enhanced nomination opportunity proposed by a pipeline beyond the standard nomination opportunities.

- Finally, in order to permit more efficient and effective use of transportation capacity, the draft NOPR proposes to require all interstate pipelines to offer multi-party service agreements, under which multiple shippers can share interstate natural gas pipeline capacity under a single service agreement.

Following the establishment of the new scheduling practices, the RTOs will need to determine if their scheduling practices are just and reasonable and to ensure that these entities' scheduling practices correlate with any revisions to the natural gas scheduling practices that may be adopted by FERC in a Final Rule stemming from the NOPR.

2.1.2 Supplemental Nomination Cycles

Although the pipelines must offer at least the four standard nomination cycles, pipelines may elect to provide greater flexibility in their nominating procedures. In light of heightened pressure on gas-fired generators to obtain natural gas on a timely basis in accord with various ISOs/RTOs' scheduling requirements in the DAM, many pipelines in the Study Region have implemented greater scheduling flexibility to accommodate daily scheduling uncertainty in regional power markets. Increased scheduling flexibility usually takes the form of either having specific additional nomination cycles or scheduling intraday nominations on an on-going basis.

Examples of supplemental nomination opportunities offered by interstate pipelines serving the Study Region include:[152]

- Boardwalk's Gulf South and Texas Gas pipelines offer an Enhanced Hourly Nomination service that allows firm and no-notice shippers to utilize additional nomination cycles. Gulf South offers eight additional cycles, with nominations due at 6:00 am, 9:00 am, 11:00 am, 3:00 pm, 6:00 pm, 9:00 pm, 12:00 am and 3:00 am, and effective flow times three hours after each nomination deadline.[153] Texas Gas offers eleven additional cycles, with nominations due at 8:00 am, 10:00 am, 12:00 noon, 2:00 pm, 4:00 pm, 6:00 pm, 8:00 pm, 10:00 pm, 1:00 am, 4:00 am and 6:00 am, and effective flow times two hours after each nomination deadline.

- Dominion offers a Morning Cycle, with nominations due at 8:00 am for flows commencing at 12:00 noon, and an Intraday 3 Cycle, with nominations due at 9:00 pm for flows commencing at 1:00 am.

- Spectra's pipelines, including Algonquin, Big Sandy, East Tennessee, M&N and Texas Eastern, offer hourly nomination cycles and scheduling flexibility, with 42 nomination cycles available for each gas day.

- Tennessee allows shippers to change their nominations sixty minutes in advance to be effective on any hour of the day between 10:00 pm and 8:00 am, effectively offering hourly nomination cycles for the last eleven hours of the gas day.

- TransCanada's ANR and Great Lakes pipelines offer supplemental cycles. ANR offers a Late Intraday 1 Cycle, with nominations due at 3:00 pm for flows commencing at 5:00 pm and both ANR and Great Lakes offer a Last Intraday Cycle, with nominations due at 3:00 am for flows commencing at 5:00 am.

2.1.3 Scheduling Priorities

Once nominations have been submitted, the pipeline goes through the confirmation process to determine how much of the receipt and delivery quantities requested by its customers can be provided, and to confirm that the shipper has the supply to inject into the pipeline to support its nomination. The terms and conditions governing the scheduling priorities of nominated quantities are complex, multi-faceted, and vary significantly among pipelines within the Study Region, as well as within individual PPAs. Universally, the pipelines schedule FT nominations and capacity release at primary receipt and delivery points first. After scheduling all primary FT nominations and capacity release nominations at primary points, the pipeline will schedule all secondary firm services. Secondary firm refers to transportation utilizing either secondary receipt and/or delivery points, or in some cases, capacity within a rate zone which is outside of

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[152] Other pipelines in the Study Region also offer increased scheduling flexibility. These examples are meant only to illustrate the nature of the scheduling improvements available on various pipelines serving gas-fired generation in the six PPAs.

[153] The 11:00 am nomination deadline is for flows beginning at 3:00 pm, four hours later.

the primary path, and includes transportation entitlements obtained via capacity release from the primary or secondary entitlement holder if the assignee moves to a different receipt or delivery point than that in the assignor's contract. After all primary and secondary firm transportation quantities have been scheduled, leftover pipeline capacity is made available to accommodate IT nominations. On some pipelines, detailed scheduling priorities may further differentiate among various services offered within the broader categories of firm and interruptible service. Once nominations utilizing secondary capacity are scheduled, based on FERC policy, they are considered on par with primary capacity for the remaining nomination cycles for that gas day.

In establishing the scheduling priority, some pipelines make a distinction between the capacity available at a point of receipt or delivery, and the capacity available on the connecting pipeline segment. In such cases, receipt point capacity is typically allocated first to firm customers utilizing primary receipt points, then to firm customers utilizing secondary receipt points, and finally to interruptible services according to the highest transportation rate being paid. Allocation of delivery point capacity is similar. For point-based pipelines that utilize the contract entitlements at receipt and/or delivery points, secondary points "in-the-path" (*i.e.*, downstream of the primary receipt point and upstream of the primary delivery point) may be given precedence by some pipelines over secondary points that are not in-the-path. Similarly, when allocating segment capacity, preference is generally given for firm service nominated in-the-path using either primary or secondary receipt and delivery points over firm service out-of-the-path. A further distinction may be made giving priority to out-of-the-path service for which flow through the constrained segment is in-the-path over out-of-the-path service for which the constrained segment is also out-of-the-path. In all cases, interruptible service has a lower priority than firm service, and is allocated in descending order according to the rate being paid by the customer.

For example, Algonquin, a Spectra pipeline, schedules nominations in the following order of priority:

1) Firm services utilizing primary points of receipt and delivery
2) Firm services utilizing secondary points of receipt and/or delivery, in the following order:
    (a) nominations in-the-path
    (b) nominations out-of-the-path flowing through an in-the-path point of restriction
    (c) nominations out-of-the-path flowing through an out-of-the-path point of restriction
3) Resolution of firm service imbalances
4) Old interruptible services[154]
5) New interruptible services, in the following order among:
    (a) all Customers paying the maximum applicable rate,
    (b) all Customers paying a rate that is less than the maximum rate then in effect, in inverse order of the size of such discounts

[154] These include customers whose contractual entitlements resulted from the conversion of interruptible entitlements under Algonquin's former Rate Schedules T-LG, STB and SS-III.

6) Resolution of interruptible service imbalances
7) Authorized overrun gas[155]
8) Park & Loan service

Within a given level of priority, if insufficient capacity exists to provide all the requested service, quantities are scheduled *pro rata* based on customers' nominations within that priority level.

Other pipelines have similar, but by no means identical, scheduling priorities. For example, Transco considers any nomination within the path and within the contract entitlement as primary firm and nominations outside of the path or outside of the contract entitlement as secondary firm.. Transco also gives entitlements obtained through capacity release the same priority as the capacity on the originating contract, be it primary and/or secondary. In contrast, Tennessee's tariff permits replacement shippers to elevate secondary points obtained through capacity release to primary points under certain conditions, thus potentially giving replacement shippers capacity entitlements on par with those of primary firm entitlement holders. Like Algonquin, Tennessee distinguishes between in-the-path and out-of-the-path in its scheduling of secondary firm nominations, giving higher priority to the former. Tennessee has recently obtained FERC authorization to provide a scheduling priority for in-the-path secondary receipt to primary delivery points, thereby motivating long-haul shippers to retain their long-haul contracts rather than move their primary receipt point rights to shale supply regions.[156] Texas Eastern's scheduling priorities are similar to those of Tennessee, both in giving higher priority to in-the-path versus out-of-the-path secondary firm nominations, and in allowing replacement shippers under its capacity release program to request a re-designation of the shipper's primary receipt and delivery points.

As a final example, the scheduling priorities of Northern Natural distinguish between nominations for delivery in the Market Area (north of roughly the Kansas/Nebraska border) and in the Field Area (south of the Kansas/Nebraska border). Within the Market Area, all secondary delivery points are given equal priority, but in the Field Area secondary delivery points in-the-path are scheduled ahead of those out-of-the-path.

On some pipelines, even after their nominated quantities have been scheduled, interruptible customers are potentially subject to being "bumped," *i.e.*, having their scheduled quantities reduced or eliminated, during the scheduling of subsequent intraday nominations made by either firm customers or interruptible customers paying a higher rate. For example, an interruptible customer may submit a Timely Cycle nomination by the 11:30 am deadline and receive notification by 4:30 pm that their nominated quantities have been scheduled to flow commencing at 9:00 am the next morning, *i.e.*, the beginning of the gas day. However, if a firm shipper submits a nomination in the Evening Cycle that the pipeline cannot serve while also flowing the volumes scheduled for the interruptible customer during the Timely Cycle, the interruptible

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[155] Authorized overrun gas refers to any quantities nominated and scheduled in excess of the customer's contractual entitlement

[156] Opinion No. 528, 145 FERC 61,040, October, 2013.¶ The modification to scheduling priority also likely improves primary entitlement holders' ability to recoup margin through segmentation of their capacity rights in the secondary market.

customer's volumes would be reduced or possibly eliminated during the Evening Cycle scheduling process. The interruptible customer would then be notified by 10:00 pm that they may not take their previously scheduled quantities. They may also be bumped in the Intraday 1 nomination cycle, in which case they will be notified by 2:00 pm during the gas day that they may not take their previously scheduled quantities beginning at 5:00 pm.

Interruptible transportation service and unauthorized overrun service have the lowest scheduling priority. However, on some pipelines, interruptible customers can avoid being bumped by other interruptible customers paying a higher rate by agreeing to match the higher rate being paid by the other interruptible customer. Of course, there is no similar protection against being bumped by firm customers. Currently, bumping is not allowed during the Intraday 2 Cycle. The *de facto* no-bump feature of the Intraday 2 cycle means that an IT customer that was scheduled in Intraday 1 and has not received a bump notification by 2:00 pm is assured that they will not be bumped for that gas day. Hence, they may continue to take their scheduled quantities until 9:00 am the next morning. On some pipelines, if an interruptible customer agrees to match the higher rate paid by the other interruptible customer and then the pipeline is required to curtail or interrupt service, such curtailment is generally implemented *pari passu*, *i.e.*, on equal footing.

2.1.4 Curtailment

In addition to bumping, IT customers are also subject to curtailment. Curtailment occurs when conditions arise such that the pipeline cannot receive or deliver all previously scheduled quantities and has to reduce receipts or deliveries. Under normal operating conditions, including cold snaps, the pipeline is designed and operated to ensure availability of all primary firm transportation quantities. A pipeline only will schedule nominated volumes that the pipeline believes it can deliver based on current operating conditions. If a pipeline does not schedule a nomination, it is not considered a curtailment. There may be cases, however, such as during an unexpected outage or *force majeure*, when a pipeline may need to curtail previously scheduled gas. The order of curtailment generally is the reverse of the order of scheduling priority. Therefore the imposition of curtailments is generally limited to interruptible shippers as well as secondary firm shippers with flexible receipt or delivery points that are out-of-the-path. Regardless of the curtailment priorities of a particular pipeline, interruptible service is always cut first. One notable difference between the order of curtailment and the scheduling priority under FERC's policies is that all scheduled firm service generally has equal priority in curtailment, regardless of whether it is primary or secondary. There are pipelines for which this is not the case, and that give primary firm scheduled quantities priority in curtailment over secondary firm scheduled quantities. Algonquin and Texas Eastern are examples of the former, Texas Gas and Guardian are examples of the latter.

Some pipeline tariffs contain a provision for primary firm shippers to request emergency relief from curtailment when necessary to prevent irreparable injury to life or property (including environmental emergencies) or to provide for minimum plant protection, for example if a generator with firm capacity needs additional time to ramp down to avoid equipment damage. In such cases, the pipeline will adjust its curtailment / interruption of all other customers on a *pro* *rata* basis as necessary to deliver the quantities required to avoid or mitigate the threatened or actual emergency.[157] Tariff provisions typically indicate that shippers will have at least two hours from the time the curtailment notice is issued to when it is effective. Penalties also may be levied if a customer fails to comply with a curtailment order and continues to take gas in excess of their curtailed volume. These penalties are designed to discourage unauthorized takes which could weaken the pipeline's ability to deliver gas to other customers.[158]

2.2 PIPELINE SERVICES

Under the broad categories of firm and interruptible service, there is a wide range of service options offered by the interstate pipeline and storage companies, which are tailored to their customers' needs. For various reasons, it is difficult to make generalized characterizations that encompass all service options. We will describe the principal kinds of service, particularly those that are of greatest relevance to gas-fired generators, but the list is not exhaustive.

2.2.1 Receipt and Delivery Flexibility, Balancing and Penalties

As explained previously, receipt and delivery volumes are scheduled on the basis of a 24-hour gas day beginning at 9:00 am. The pipelines track both positive and negative divergences between scheduled quantities and actual receipts and deliveries on a daily basis. These positive and negative divergences are referred to as imbalances. As discussed in Section 2.4.2, the imbalances (plus or minus) are accumulated over the course of the month. Pipelines require customers that exceed a permissible balance to resolve the imbalance. As with most other tariff terms and conditions, the imbalance resolution mechanism differs significantly among pipeline companies across the Study Region as well as within any one PPA. Moreover, not all pipelines offer all of the following opportunities for imbalance resolution.

First, the customer can adjust nominations on subsequent days in order to offset a net imbalance within the current month. Second, the customer can trade imbalances with other customers through the pipeline's EBB. This means that offsetting imbalances (positive and negative) of two different customers can be combined such that the net imbalance is zero (assuming that the offsetting imbalances are equal). Such trading can take place up to 17 business days or more following the end of the month in which the imbalances occurred. Third, based on pipeline tariff provisions, some customers can elect to resolve imbalances through in-kind replacement via separate nominations of balancing quantities. Finally, the imbalance can be cashed-out. Negative imbalances (those in which deliveries to a customer exceeded the gas received by the pipeline for that customer's account) are typically cashed out starting at 100% of the applicable index price for the contract and month. The percentage gradually increases as the size of the imbalance grows relative to the actual deliveries during the month. Conversely, positive imbalances are credited with a declining percentage of the index price as the size of the

[157] Unlike LDCs, interstate pipelines do not have end use curtailment and cannot select which customers to serve. Pipeline restrictions and curtailments are made according to priority of service.

[158] The customer claiming exemption from curtailment must submit an affidavit within 24 hours giving adequate detail to support its claim for exemption. Failure to provide such support makes the customer liable for punitive damages.

imbalance grows. Shippers are therefore incentivized to keep imbalances as small as possible within the tolerance band established by the pipeline. Pipeline companies often enter into an OBA with large customers to define the daily tolerance levels and the cashout mechanism or in-kind resolution procedure. More detail about OBA conventions is presented in Section 2.2.2.

Gas taken in excess of the scheduled daily quantity or the customer's contract entitlement is classified as an overrun. Under normal conditions, pipelines will tolerate small overruns. The tolerances vary between pipelines, and may be as high as 10% of scheduled quantities. The tolerances for exceeding contract entitlements tend to be lower, usually in the range of 2% to 5%. While pipelines have tariff authority to charge penalties associated with these overruns, most pipelines do not charge penalties for overruns that are within the tolerance range. In some cases, the charges are not levied unless the pipeline gives notice to the customer; in other cases, the overrun charge is part of the posted tariff rate schedule.

In contrast to a pipeline's ability to permit overruns under normal conditions, under extreme operating conditions that threaten the integrity of the pipeline system or the ability of the pipeline to provide firm service, the pipelines require strict adherence to contractual terms. In this case, the pipeline may give notice to one or more customers, through an OFO, Flow Day Alert, Critical Notice or Action Alert, posted on the pipeline's EBB, requiring that customers bring receipts and deliveries into balance. OFOs are issued during extreme operating conditions typically after the pipeline has issued other critical notices about pipeline operations. Issuance of such restrictive orders or alerts generally limit takes to scheduled quantities, while informing the shipper of required pipeline action(s) to maintain system integrity. Failure of the customer to comply with the pipeline's directives will trigger substantial penalties or necessitate a pipeline to use flow control, if available, to restrict a customers' unauthorized use of gas in order to maintain system integrity. For example, Algonquin stipulates a penalty of three times the daily high spot market gas price for any gas taken in excess of the customer's hourly or daily entitlements only during OFO situations.[159] Columbia Gas also imposes a penalty of three times the daily spot price.[160] In addition to holding the customer liable for any actual costs borne by the pipeline, ANR imposes a penalty of $25/Dth. The penalty imposed by East Tennessee for failure to comply with a Balancing Alert (a particular type of OFO) is equal to the Henry Hub daily spot price plus $15/Dth. In all cases, the penalties are intended to be sufficiently large to deter overruns and ensure the operational integrity of the pipeline system and maintain adequate pressure and flow across the system to enable pipeline deliveries for all customers.

Pipeline tariff provisions typically state that scheduled volumes must be taken ratably throughout the day, *i.e.*, 1/24th of the daily volume per hour.[161] However, in practice, pipelines permit shippers to flow non-ratably when operationally possible. That being said, most pipeline tariffs require that the flow be uniform within certain tolerances. Some pipeline companies have rate

[159] On January 22, 2014, ICE reported the Algonquin Citygates high price of $93.00/MMBtu, and the daily average index price of $78.64/Dth. The applicable penalty on Algonquin would therefore have been as much as $279/Dth.

[160] On January 7, 2014, Columbia Gas issued an OFO stating that any overruns would be charged a penalty equal to ten times the otherwise applicable rate.

[161] Tariffs typically do not include specific penalties for taking gas non-ratably.

schedules that specifically allow for a greater degree of flexibility in hourly takes during the gas day, as indicated in Exhibit 2. In particular, no-notice service is offered by some pipelines that allow shipper variances without any advance notice to the pipeline.

Excluding enhanced flexibility services from the discussion for the moment, the allowable tolerances on hourly takes varies from pipeline to pipeline as dictated by their individual circumstances and policies. The tariff may allow for variations in hourly takes according to the needs of the customer, but limited to some fraction of the contractually-specified maximum daily quantity (MDQ) or the scheduled gas quantity. Pipelines may allow customers, including generators, to exceed these limits and take gas non-ratably if it does not interfere with providing reliable service to other customers. However, virtually all pipelines retain the right to require customers to adhere strictly to uniform hourly flows when needed to safeguard the operational integrity of the pipeline and pipeline deliverability.

In most cases, generator demand profiles call for uneven hourly profiles in order to meet the early morning ramp up and late afternoon ramp up/down requirements, as well as the evening ramp down requirements, therefore generators rely on hourly flexibility from the pipelines when it is available. FERC Order No. 698 incorporates by reference the NAESB WGQ and WEQ standards requiring generators and pipelines to establish procedures to communicate material changes affecting hourly flow rates to ensure that the pipelines have the necessary information to maintain operational integrity and reliability, as well as to inform generators whether their non-ratable takes can be honored. The standards also required electric transmission operators and generators to sign up to receive from connecting pipelines OFO and other critical notices.[162] For example, Algonquin critical notices frequently include the statement: "[Algonquin] requires all Power Plant Operators to provide information mandated by FERC Order No. 698. Information required includes the hourly consumption profile of directly connected power generation facilities." This usually requires gas-fired generators to submit hourly burn profiles of their expected gas consumption to the pipeline.

As discussed previously, generators often rely on AMAs with marketers with portfolios to reasonably assure adequate deliverability and intra-day scheduling flexibility to avoid costly imbalance resolution charges or penalties. In the alternative, generators often rely on third party arrangements with gas marketers who provide a bundled product at the citygate or plant gate under shorter term, more flexible commercial arrangements.[163]

2.2.2 Operational Balancing Agreements

In Order No. 587-G, FERC required interstate pipelines to enter into OBAs with other interstate pipelines and intrastate pipelines at all interconnection points.[164] Pipeline companies have OBAs with other pipelines at interconnects in order to account for variances between actual flow and

[162] FERC Order No. 698, p. 7.

[163] These arrangements are confidential and therefore cannot be specifically identified.

[164] See FERC Order No. 587-G: Standards for Business Practices of Interstate Natural Gas Pipelines, 31,062 at 30,676 (1998).

nominated quantities at a point. Not all pipelines have OBAs with generators. OBAs are useful operational tools for pipelines and their shippers because under these agreements, shippers are not affected by variances in deliveries. Rather, the variances are resolved between the parties to the OBA. Over the last two decades, FERC's promulgation of open access policy set forth in Order No. 636 has resulted in more widespread use of OBAs across the Study Region. Pipelines and LDCs typically offer OBAs to point operators or shippers in order to cover operating conditions when there is either an over- or under-receipt or an over- or under-delivery of the scheduled quantity of gas at the interconnecting location. An OBA does not give a shipper the right to be out of balance on the pipeline. Rather, an OBA is a balancing mechanism that sets the criteria for managing the differences that occur between scheduled volumes and actual received or delivered quantities by location at the end of the day or another period determined by the pipeline.

While pipelines are not required to file their OBAs with FERC or otherwise make them available to the public on their EBBs, FERC requires disclosure upon request. Such disclosure usually happens during a pipeline company's general rate case.[165] In addition to interconnected pipeline companies, FERC has encouraged pipelines to enter into OBAs with production point operators, direct connected gas-fired generation companies and LDCs. Pipeline OBAs with generation companies are generally formulated around the provision of non-firm transportation service. There are exceptions in the Study Region, however. While the provisions set forth in the OBA are generally the same based on the NAESB recommended standards, the pipeline company has discretion in regard to its ability to negotiate the specific terms in each OBA.

From the pipeline's perspective, the OBA sets the rules, procedures and commercial provisions for resolving imbalances in the context of maintaining efficient system operation. For shippers, the OBA specifies how imbalances are identified and the interconnection point operator's options for resolving the imbalance. Hence, the conditions underlying a pipeline's ability to accommodate a permissible deviation from the scheduled quantity are addressed within the OBA, including the financial mechanism to credit or debit the imbalance to the point operator's account. The OBA effectively protects the shippers from incurring imbalances. Usually, the OBA will specify the cost incurred for imbalance resolution in accord with varying tolerances contained within the pipeline's FERC-approved tariff. Pipelines have discretion in setting OBA terms, but these tend to be standard daily / monthly tolerances and best efforts language. While there is some NAESB standardized netting and trading language in a pipeline's tariff, the OBAs generally negate its usage.

At the local level, LDCs often enter into OBAs with large customers as well. The commercial and operating provisions established in local OBAs may mirror or substantially diverge from the commercial and operating provisions set forth in the pipeline OBA.[166] Local OBAs with gas-fired generation are subject to state commission review and typically incorporate imbalance

[165] Due to these confidentiality provisions, specific OBAs are not available for technical review.

[166] Direct connected as well as local gas-fired generation companies have different minimum gas delivery pressure requirements, technology characteristics, location, operating regime, and, to a lesser extent, gas quality requirements. Therefore pipeline companies and LDCs are permitted to differentiate the commercial and operational provisions incorporated in the OBA to account for these differences.

resolution provisions, stated tolerance requirements, and cashout procedures that are in close accord with an LDC's firm or interruptible transportation service tariff.

2.2.3 Capacity Release

Customers that hold firm capacity entitlements may choose to release all or a portion of their contracted entitlements rather than utilize them. Such released capacity is posted on the pipeline's EBB, and is transferred to the highest bidder.[167] The process of releasing and re-assigning capacity helps to ensure that the available capacity is allocated according to the best economic use.

The releasing customer, or "assignor," can specify a range of conditions for the release, including the amount of capacity, the duration of the release, whether or not the capacity is subject to recall or reput, and the conditions for recall, among other things. The release may be for a term as short as a partial gas day, or as long as the remaining term of the entitlement of the releasing customer. Released capacity may be segmented, so that different replacement customers acquire entitlements along separate portions of the original transportation path. Subject to the terms the assignor places on the released capacity, the assignee acquires entitlements that are equal in character and priority to those of the assignor.

As discussed in Section 2.4, very few generation companies actively participate in the regular assignment of capacity rights in the secondary market, opting instead to rely on gas marketers, financial entities, and/or gas suppliers for a bundled service delivered to the citygate or plant meter at the local level, or on interruptible transportation.

2.2.4 Service Options

Mainline Service

This is the basic service offered by all pipelines and is the one to which the preceding discussion of tariff terms and conditions is most generally applicable. In brief, the service consists of the pipeline receiving gas from or on behalf of the customer at the receipt point and delivering it to the delivery point, less any gas retained for operation of the system.[168] The service may be offered as either firm or interruptible. There may be a single rate paid by all customers that use any part of the pipeline; but for larger, long-haul pipeline systems, the rate that the customer pays for transportation will usually depend on which areas or zones of the system the gas traverses between the receipt and delivery points.

Many pipelines have a special class of mainline service designated as "general service" or "small customer." This service is intended for, and sometimes limited to, those customers being served by a bundled citygate sales service prior to implementation of FERC Order No. 636 in 1992. Customers under this service are typically limited to an MDQ of 5,000 to 10,000 Dth, and are not

[167] Under certain conditions, the capacity may be released through a pre-arranged agreement, and need not be subject to open bidding.

[168] The gas retained by the pipeline is referred to as "shrinkage", and is primarily used for compressor fuel.

allowed to use any other transportation service (such as interruptible or released capacity) on a given day unless they have scheduled their full entitlement under this service.

Lateral Service

When pipelines expand their system to serve new customers, the cost of expansion is often rolled-in to the existing tariff rate if the expansion provides operational flexibility or relieves system congestion to the entire system. However, when the expansion is a new lateral line to serve one or only a few customers, FERC rate policy typically assigns the incremental cost of the lateral to the benefited shipper, who is charges an incremental rate. Such would be the case for interconnecting a new gas-fired power generator on a dedicated lateral. Service on the lateral is firm, with a contract term sufficient to ensure that the pipeline recovers its cost to construct the lateral, including financial return.[169] However, unused capacity on the lateral, if any, may be sold to similarly situated customers as interruptible transportation. Many gas-fired generators built in the last 10 or 20 years rely on lateral service for gas deliveries. Although they necessarily have firm service on the lateral, they typically rely on non-firm services for mainline transportation to the primary receipt point on the lateral.

No-Notice Service

No-notice service provides customers with the contractual right to vary gas deliveries from nominated levels during the course of the gas day. Usually, the benefited no-notice customer is able to modify daily quantities relative to the nominated gas quantity. Characteristics of no-notice services can vary significantly across the pipelines in the Study Region. The ability of pipelines to provide this service varies depending upon the design and operation of their respective systems. Pipelines typically rely on line-pack and/or storage to support their no-notice services.[170] The total amount of no-notice service that they offer on a system-wide basis is restricted, and they may issue timely notifications to customers whose accumulated imbalances between receipts and deliveries exceed contractual no-notice entitlements.

Other pipelines provide no-notice service principally through reliance on upstream no-notice entitlements held by the customer. Although they may also utilize line-pack, many pipelines provide no-notice service by adjusting pipeline throughput, while maintaining a balance between customer receipts and deliveries by adjusting the upstream receipts as necessary. Utilization of line-pack offers pipeline schedulers with operational cushion to accommodate no-notice service requirements as well as deviations in hourly takes among gas-fired generators.

Many pipelines offering no-notice transportation service do so through a combination of storage and transportation; either it is offered as a bundled service or it requires the customer to hold

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[169] A shipper's firm transportation right on the lateral does not confer any upstream firm transportation right on the mainline or otherwise produce a scheduling benefit in regard to transportation service from the sourcing point to the lateral.

[170] The greater the pipeline operating pressure, the greater the amount of line-pack that can be drafted by pipeline operators to meet no-notice requirements. Operating pressures vary substantially among pipelines in the Study Region, as well as on pipelines within each PPA.

both firm storage and transportation entitlements on the pipeline. The pipeline uses storage to account for variations between scheduled nominations and deliveries and to manage any imbalances between receipts and deliveries. Most pipelines with storage capacity will provide this type of no-notice service – specific examples include Columbia Gas, Panhandle Eastern and ANR. Algonquin is an example of a pipeline offering no-notice service that does not originate in or near gas producing regions. Its primary receipt points are in New Jersey, and there are no directly accessible storage facility connections on the pipeline. Algonquin therefore provides no-notice service on its mainline from New Jersey to New England based on no-notice upstream receipts rather than incremental receipts from storage or production.

Some pipelines offer no-notice service, but pipelines are not required to do so by FERC. Generators could purchase no-notice service, but typically do not elect to do so, presumably because it is a premium service not deemed economic in relation to other transportation options. A generator covered under non-firm transportation service arrangements may see its daily confirmed volumes cut if the pipeline must subordinate the scheduling of a generation company's volumes in order to serve other customers with higher priority service – including no-notice service.

Enhanced Service

Enhanced service refers to a broad range of options that add flexibility to the customer's contractual entitlements. Given the daily profile of gas needs for a typical gas-fired generator, service options which contribute to increased flexibility in hourly gas deliveries throughout the course of the gas day are of particular interest.[171] Apart from no-notice service, this is usually accomplished by either relaxing the requirement for uniform takes during the gas day or by increasing the frequency with which nominations may be submitted beyond that offered by the four standard NAESB cycles, or by permitting the generator to consume all of its gas within an eight to ten hour period rather than over 24 hours..

One example of the relaxation of uniform takes is found in ANR's FTS-3 rate schedule. The service agreement may specify maximum hourly takes of up to 25% of the maximum daily delivery. The rate also has a short-notice option. Under the short-notice option, service can commence or shut down on two hours' notice, as well as an option that allows a cumulative imbalance between receipts and deliveries of up to 25% of the maximum daily entitlements in lieu of the imbalance otherwise allowed within the tariff's general terms and conditions. Millennium offers a similar rate schedule, HT-1 (Hourly Transportation Service), under which the maximum hourly entitlement is contractually set to a value of between 5% and 25% of the maximum daily entitlement. Other rate schedules offering hourly flexibility include PNGTS's Hourly Reserve Service and Vector's Hourly Firm Transportation Service.

[171] In terms of scale, a 660-MW combined cycle plant has an MDQ around 100 MDth, roughly 10% of NGrid's firm sendout for a design peak day in Boston. See November 2012 through October 2017 Long Range Resources and Requirements Plan, DPU Docket 13-01.

Another example is Panhandle Eastern's Enhanced Firm Transportation rate schedule. Receipts under this rate schedule are made at a uniform hourly rate, but delivery rates are generally unrestricted. Panhandle Eastern does reserve the right on notification to restrict hourly deliveries to 1/16 of that day's nomination. Trunkline's Enhanced Firm Transportation rate schedule is less flexible, but still allows hourly deliveries to vary between 50% and 150% of ratable takes.

Many pipelines offer rate schedules that provide greater nomination frequency. Vector's FT-H (Hourly Firm Transportation Service) allows intraday nominations at any time on one hour notice. Tennessee also allows hourly nominations under most of its transportation rate schedules between the hours of 10 pm and 8 am as does East Tennessee. Texas Gas offers its Enhanced Nomination Service rate schedule as an addendum to all its firm transportation services, which provides additional intraday nominations throughout the gas day. Transco does not provide for additional nomination opportunities within the gas day they do, however, provide shippers the ability to nominate directly after the end of that gas day (*i.e.* by 10:00 am).

Those gas-fired generators that are seeking enhanced pipeline services would like additional flexibility as a means to help meet the highly variable intra-day profile of gas deliveries associated with electricity production. Several pipelines offer a range of enhanced services that meet some of the generators' needs; however, these services come with price tags that do not match a generator's willingness, or ability to pay. Many of these services require support from line pack and/or storage, which usually cause a pipeline to incur additional costs.

2.2.5 Ontario Service Options

TransCanada offers a wide range of service agreements for transportation of natural gas through the mainline pipeline, including FT, IT, STFT, FT Short Notice (FT-SN), Short-Term Short Notice (ST-SN) and Short Notice Balancing (SNB). Gas-fired generators typically utilize FT, STFT, FT-SN, and ST-SN services. FT-SN and ST-SN are specifically designed to assist gas-fired generators.

FT service provides delivery between a primary receipt point and a primary delivery point under a minimum one-year term contract, and allows for diversions, assignments, and alternative receipt points. STFT service provides FT service for a shorter contract term with a minimum of seven days and a maximum of 364 days. The toll or price offered by the customer can be bid as a percentage of the applicable FT toll in effect at the time of service. The bid floor is established by TransCanada and can be no lower than the applicable FT toll.

FT-SN service provides firm transportation between a primary receipt point and a primary delivery point designed for flexible firm gas supply. The FT-SN service includes reserve capacity, diversions, alternative receipt points, and assignments. Nominations for service are allowed every 15 minutes (96 times per day). Flow controls at the delivery point and flow rate nominations are required. ST-SN service provides FT-SN service for a shorter contract term with a minimum of seven days and a maximum of 364 days. The toll is biddable as a percentage of the applicable FT-SN toll in effect at the time of service. The bid floor is established by TransCanada and can be no lower than the applicable FT-SN toll.

Gas-fired generators with FT-SN service can link that service with SNB service for balancing needs. The SNB service was designed to provide balancing for gas-fired generators that need firm and flexible gas supply. The service provides reserved capacity and the ability to make assignments through the linked FT-SN contract. Gas-fired generators can nominate into or out of their SNB account as part of their FT-SN nominations.

For all services, gas-fired generators may have to pay a Daily Balancing Fee and a Cumulative Balancing Fee. The differential which determines the balancing fees is based on the absolute difference between the daily total allocated quantity of gas delivered and the daily Total Authorized Quantity (TAQ) as per the Shipper's total services. For cumulative balancing, the Average Authorized Quantity is based on the average of the TAQ over the preceding 30 day period. Cumulative variance is the absolute value accumulation of the daily differences of gas delivered. No Daily Balancing fee is payable on variance less than 75 GJ. No Cumulative Balancing fee is paid on an absolute Cumulative Variance of 150 GJ. Shippers may decrease their Cumulative Variances through the nomination of "Payback Quantities."

Vector offers a wide range of service agreements for transportation of natural gas through its Canadian pipeline, including FT, FT Limited (FT-L), FT Hourly (FT-H) and Operational Variance Service (OVS). Gas-fired generators typically utilize FT-H and OVS. FT-H and OVS are specifically designed to assist gas fired generators.

2.3 STORAGE SERVICES

2.3.1 Basic Storage Service

Storage service consists of the operator accepting gas for injection into storage during the "summer" or injection period (typically, April through October) and then withdrawing the gas and delivering it to the customer, or customer's transporter, during the withdrawal period. The withdrawal period typically aligns with the heating season, November through March. Winter injections and summer withdrawals are usually allowed on an interruptible basis, but do indeed happen when more temperate conditions during the heating season allow storage customers to replenish working gas inventory, while summer withdrawals may be needed to supplement pipeline throughput. Service levels are defined by the total amount of gas that can be stored and by the maximum amount of gas that can be injected or withdrawn on a daily basis. Injections and withdrawals are often limited by ratchet provisions set forth in each storage company's tariff. The ratchet provisions establish the maximum daily amount of gas that can be injected as the storage facility nears its capacity, and the maximum daily amount that can be withdrawn as the storage facility approaches its minimum storage level, *i.e.*, cushion gas requirement.

Storage service can be offered as either firm or interruptible. A few storage operators offer an intermediate priority level of service, which is scheduled after firm but ahead of interruptible. Like pipeline transportation service, daily service is provided via cycles of nomination and scheduling. For those pipelines which also operate storage facilities, the scheduling of storage and transportation is an integrated process. Like transportation, storage is also subject to curtailment, and customers' entitlements can be released to others. As is the case with firm transportation, generators typically do not hold firm storage entitlements in their own name, although they can contract with marketers for products that include storage. Generators can purchase released capacity from LDCs and other firm storage customers. Actual customer utilization of storage services is difficult to determine. This is because injections and withdrawals are identified by location, not by customer.

2.3.2 No-Notice Storage Service

The distinguishing characteristic of no-notice storage is the same as that of transportation, namely, that the customer can inject and withdraw gas as required. Within the limits of the customer's no-notice entitlements, injections and withdrawals need not adhere to nominated and scheduled quantities. Many operators have no-notice storage tariffs, but NGPL offers a Firm Reverse Storage Service rate schedule that is noteworthy for being both unique and potentially applicable to gas-fired generators. It acts as a seasonal lending service, with gas first withdrawn and, optionally, delivered to the customer on a no-notice basis during the cooling season, mid-May through the end of September. Any gas so loaned must be repaid by nominated injections during the following heating season, December through February.

2.3.3 Enhanced Storage Service

As with transportation, enhanced storage service refers to changes in the typical storage service that provide increased flexibility to the customer. This typically takes the form of hourly nominations or firm off-season injection and withdrawal rights. Wyckoff Gas Storage in New York offers an unusual service option under its Firm Storage Service rate schedule which provides storage-based load following and hourly / daily balancing services that are designed to match the dispatch profiles of gas-fired electric generators and other highly-variable sources of natural gas demand. Hourly nomination and no-notice services are available depending on the nomination and dispatch procedures of interconnecting pipelines. Customers contracting for load-following and balancing services are required to maintain zero daily inventory balances or face imbalance charges for both under- and over-deliveries. In effect, it provides a daily rather than seasonal storage service.[172]

2.3.4 Peaking Storage Service

Although some storage operators provide service that is specifically designed to be used for less than the full winter season (*e.g.*, 60-day or 100-day service), we use "peaking" here to refer to operators that vaporize LNG to provide peaking gas for very short periods. For example, Dominion Cove Point offers 3, 5 and 10-day firm peaking services from its LNG import facility. A few other operators, such as Transco, East Tennessee and Total Peaking Services, have liquefaction and storage facilities near market centers that they use to provide short-term peaking service.[173]

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[172] Enhanced storage service has the potential to provide generation companies with greater intra-day scheduling flexibility, in effect, an ancillary service to hedge against intermittent generation.

[173] Total Peaking Services owns an LNG storage facility in Milford, Connecticut.

2.3.5 Park and Loan Service

Pipeline and storage operators offer a range of related services to assist customers with management of their gas supply, including balancing or load management, pooling, wheeling and gas sales. A related service of particular interest to gas-fired generators is Park and Loan service. Gas parking is in effect short-term storage on the pipeline. In this case, the pipeline receives nominated gas to be parked at some point in the system, holds it for the customer, and then later returns it at the same point. Park and Loan service is distinguishable from storage principally by the relatively short duration of the transaction as well as the transaction point. Gas loan is similar, except the pipeline first delivers gas to the customer, and later takes receipt of the loaned quantities. Park and Loan service is usually interruptible, but a few storage operators, including Arlington, Bluewater and Washington 10, and the Midwestern pipeline offer Park and Loan service on a firm basis.

2.4 LOCAL DISTRIBUTION COMPANY SERVICES

Tens of thousands of megawatts of capacity of new combined cycle plants and quick-start peakers have been added to the resource mix within the Study Region since the onset of deregulation in the late 1990s. Excluding Ontario and downstate New York, the majority of new gas-fired resources are directly connected to interstate pipelines in order to reasonably minimize the cost of transportation, exploit locational advantages, and utilize the higher delivery pressures available from interstate pipeline companies. However, significant amounts of new combined-cycle plants and peakers have also been built behind the citygates over the last two decades.[174]

In most instances, an LDC is a regulated gas utility that files tariff rates with its respective state or provincial regulatory commission. In addition to service rates, tariffs include terms and conditions regarding imbalance resolution, character and priority of service, penalty rates, and dual fuel requirements. In addition to conformance with interstate pipeline and/or storage company tariff requirements, any gas-fired generation located behind the citygate incurs incremental local charges covering transportation, imbalance resolution, penalty exposure for unauthorized use, and state/local taxes. This section begins with a general review of LDC services applicable to gas-fired generators and then discusses the characteristics of service in each PPA.[175]

2.4.1 Rates and Services

Character of Service

LDCs generally have the same designations for character of service as interstate pipelines, that is, firm and interruptible services. Firm service is normally available at all times, except

[174] In addition to the generation-only facilities located behind the citygate, there are many combined heat and power (CHP) plants. The CHP facilities often serve thermal processes and supply steam or electricity to industrial customers or large institutional loads, in particular, colleges and universities. There are other small-scale CHPs that serve commercial office buildings in urbanized market areas.

[175] The URLs of the current tariff for each LDC serving generation are listed in Exhibit 3.

potentially during a *force majeure* event. Interruptible service is available when the LDC has slack delivery capacity, that is, after all firm customers' scheduling requirements have been fulfilled. Almost always, LDC rates differentiate between firm and non-firm services. In accord with state regulatory commission-approved tariffs, many LDCs are permitted to discriminate among non-firm shippers based on willingness to pay. Common designations among the array of interruptible services include quasi-firm service, curtailable service, and fully interruptible service. Quasi-firm service tariff provisions may limit curtailments or interruptions to a set number of days per year or under limited operating conditions that are centered on a temperature trigger during the heating season. Curtailable service may include broader curtailment rights for the LDC. Fully interruptible service is typically based on whatever actions are needed by the LDC to ensure gas pressure security, and is not centered on a set number of days of curtailment or any temperature condition governing actions taken by LDC schedulers. Additionally, certain LDC services offer seasonal variation in character of service. Service may be firm during the cooling season, but either quasi-firm, curtailable or fully interruptible during the heating season, November through March. LDC customer lists are not in the public domain. Outside of Ontario, only one gas-fired generator has been identified as part of the Target 1 research as having firm local transportation service.[176]

Service Rates

LDCs maintain various service classifications which apply to gas-fired generation. Each rate typically has a flat monthly customer charge. The customer charge is almost always negligible for high-usage customers. Various state taxes are typically applicable to all customers based on throughput. All generation units pay the LDC a transportation rate for natural gas delivered to the plant. The transportation rate is expressed on a volumetric throughput basis, *i.e.*, $ per Dth. Reservation or demand rates for local transportation capacity are generally not applicable or *de minimis* largely because generation companies arrange for local transportation predominantly on a non-firm basis. Volumetric transportation rates can be stated on a fixed monthly or seasonal basis. Alternatively, they may be stated on a declining block rate, *i.e.*, a higher rate for the first 1,000 Dth, a lower rate for the next 9,000 Dth, *etc*. While transportation rates generally decline on a unitized basis for higher load factor customers, in most instances, gas-fired generators located behind the citygate do not sustain the high load factors that are characteristic of CHP and industrial cogeneration facilities.

Of course, character of service is the distinguishing criterion in regard to price. Firm customers generally pay the highest local transportation rate, which may include more permissive daily swing capability; quasi-firm shippers pay less than firm shippers, and fully interruptible shippers pay the least on a unitized basis.

Sometimes LDCs maintain a demand or reservation rate that is billed monthly based on the MDQ or similar quantity defined within the customer's service contract. This rate generally represents the cost of reserving capacity on the LDC's system, in particular, the LDC's portfolio cost to maintain pipeline and storage entitlements to meet the obligation to serve. Demand rates

[176] MidAmerican Energy Co. Firm Natural Gas Agreement with Cordova Energy Co., Illinois Commerce Commission Docket No. 09-0312, effective April 2010.

may also be seasonally differentiated. Demand charges are often applied to firm services, and are rarely applied to interruptible services.

In most states, state utility commissions permit LDCs to differentiate rates based on value of service principles. Negotiated transportation rates are typically applicable to non-firm service, *i.e*., quasi-firm, curtailable or fully interruptible service. Local transportation rates may be differentiated based on a shipper's location, the reasonableness of the threat by the shipper to bypass the LDC, a customer's alternate fuel capability, and/or other business considerations.[177] Generally, an LDC has an evidentiary burden before its state commission to establish that the negotiated rate covers the LDC's costs to serve local transportation and does not incorporate cross-subsidies from other customers. LDCs offer their tariff rates as benchmarks or ranges for such contracts. Depending on the LDC, negotiated rates, which typically require approval from the state commission, may be served under separate rate classifications. While negotiated LDC transportation rates are generally not in the public domain, both old-style gas-fired generation and new generation plants located behind the citygate are typically able to negotiate transportation arrangements that deviate from tariff benchmarks.

<u>Bundled Service</u>

The majority of LDCs in the Study Region are in states which promote retail competition for gas supply. Therefore, the LDCs offer bundled sales and transportation service and transportation-only service. Typically, gas-fired generators at the local level are transportation-only shippers who rely on third parties to deliver natural gas from the wellhead to the citygate. Some LDCs offer sales and transportation options under the same rate classification. Others maintain different service classifications. Sometimes transportation rates differ between bundled and transportation-only service, in which case, unbundled rates are invariably lower. An LDC's gas supply charge is determined by the timing of the gas procurement decisions that drive the purchase of natural gas at different physical or financial pricing points along the supply chain from producing basins to the storage centers in the Supply Region. Administrative review and approval before the state regulatory commission is required.

There is a broad lexicon of gas cost provisions in retail bills levied by LDCs across the Study Region. The sales charge may be referenced as the Gas Cost Recovery, Purchased Gas Adjustment (PGA), or Gas Supply Rate. In some instances, this charge may include the reservation and transportation commodity rates for the LDC's pipeline and storage entitlements, or short term incremental transportation or storage entitlements not previously part of the LDC's portfolio. In some instances, sales rates are indexed to a customer's alternate fuel price(s). In light of a gas-fired generator's volumetric requirements relative to core customer demands, generators typically obtain the commodity gas supply and interstate transportation service from third party marketers rather than directly from the LDC as a bundled service. Many LDCs have eliminated the provision of bundled service to generators.

[177] An LDC bypass involves the end-user gaining FERC authorization to establish a direct connection on an interstate pipeline, thereby avoiding any local service.

2.4.2 Imbalance Resolution

Imbalance resolution is a state-approved tariff mechanism allowing LDCs and their transport customers to settle their gas accounts to account for over- or under-deliveries. If the customer's interstate supplier delivers a surplus of gas or comes up short, LDCs have balancing services designed to cover the gaps. Having the obligation to serve, LDCs serve core load and ensure reliable local distribution system operations throughout the year, especially during the heating season. LDCs therefore manage the nomination and confirmation of their own gas supply to meet core system demand regardless of what actions third-party suppliers take to deliver natural gas at the citygate to serve gas-fired generators and other customers. Such activity may carry additional costs, which the LDCs pass through to the customers responsible for the imbalances. During cold snaps, there may not be any additional local system deliverability to serve gas-fired generators, even those customers holding quasi-firm transportation service. During more temperate conditions, including the peak cooling season, May through September, local system conditions may have significant slack deliverability, thereby allowing third party suppliers to sink or source excess gas or additional supply needed to meet gas-fired generation without endangering local reliability for core customers. While there may be specific costs borne by the LDC on a seasonal basis associated with the sourcing and sinking of natural gas at the local level that deviates from the nomination / confirmation schedule on any given day, there is significant variability among LDCs to resolve imbalances. In LAI's experience, actual LDC enforcement of the tariff provisions during the non-heating season is not fully transparent.[178] Balancing generally occurs on a daily and monthly level and may also be negotiable. If the LDC incurs balancing penalties from an interstate pipeline, these penalties may be distributed on a *pro rata* basis to any customers that contributed to the offense.

Positive imbalances, which are synonymous with an over-delivery or under-run, occur when the customer delivers more gas to the LDC than the customer takes out of the system. Negative imbalances, which are synonymous with an under-delivery or over-run, occur when the customer takes more gas from the LDC than it delivers. Most LDCs set tolerances, as a percentage of daily nominations or contract quantity, within which companies will not be penalized for running imbalances. Some LDCs include fees in order to allow customers to maintain or "bank" imbalances, with charges increasing if the customer elects a larger bank or tolerance size. Other LDCs may include a flat balancing fee for all customers.

Customers must use their best efforts to eliminate imbalances. If a customer is chronically running large imbalances and the LDC feels that the customer is abusing the imbalance provisions in the tariff, the LDC can choose to terminate service to the customer, although instances of customer termination for large, uncompensated swings in daily and/or monthly imbalance charges among LDCs doing business in the Study Region have not been identified.

[178] An LDC's recoupment of imbalance charges and applicable penalties for unauthorized gas use is not in the public domain. Enforcement trends at the local level may vary significantly among LDCs across the Study Region.

Daily Imbalance Resolution

Many LDCs practice daily balancing, whereby customers are charged for imbalances with daily settlements or penalties. Some LDCs practice daily cashouts where any daily imbalance gas is charged or credited to the customer based on a spot price, the LDC's weighted cost of gas, or some other administratively set supply rate. If the LDC is connected to multiple pricing hubs, negative balances are often charged at the highest pricing point while positive imbalances are credited at the lowest pricing point. LDCs often apply penalty factors for imbalances on a progressive scale.

An example of imbalance cashouts follows below.

Table 17. Positive Imbalance Schedule

Imbalance Percentage	Penalty Factor applied to Cashout
0% - 5%	1.0
5% - 10%	0.9
10% - 15%	0.8
> 15%	0.7

Table 18. Negative Imbalance Schedule

Imbalance Percentage	Penalty Factor applied to Cashout
0% - 5%	1.0
5% - 10%	1.1
10% - 15%	1.2
> 15%	1.3

A generator penalized under this graduated scale for negative imbalances to 7%, for example, would pay a cashout charge of 1.0 times the applicable index for the gas volume up to the 5% imbalance, and a penalty factor of 1.1 times the applicable index would be applied to the remaining 2% imbalance. Some LDCs maintain tolerances within which the imbalance volume is not cashed out and is instead added to a rolling or monthly imbalance. Others do not practice any daily cashouts. However, these LDCs may maintain flat penalty charges for imbalances outside of specified tolerance levels.

Like pipelines, nearly all LDCs maintain more rigorous policies for resolving imbalances under OFO or Flow Day Alert conditions. OBAs are relatively standard operating and commercial arrangements between the LDC and large shippers located behind the citygate, particularly, gas-fired generation companies. Tolerances may be reduced or eliminated during critical conditions, and penalties are usually raised such that imbalances may incur unauthorized use penalties and much larger penalty factors for cashouts. In some cases, imbalances are cashed out at two to ten times the daily index price. Some LDCs forgive imbalances or waive penalties during OFO events where the imbalance helps alleviate a gas-long or gas-short condition.

Monthly Imbalance Resolution

Daily imbalances that are not cashed out become part of the customer's monthly imbalance. Many LDCs allow trading or pooling of monthly imbalances between customers on similar rate schedules. Sometimes a transaction fee is imposed on trades but it is usually insignificant compared to the avoided cost of balancing fees. Generally, customers may not trade into a surplus as the goal of imbalance trades is to zero out the negative or positive imbalance. Monthly cashouts apply to remaining imbalances, generally in a similar manner to the daily cashouts. Monthly tolerance bandwidths and penalty factors are generally harsher than for daily cashouts because the customer has more time to resolve the imbalance.

2.4.3 Service Priority, Curtailments and Interruptions

During cold snaps or emergency situations, interruptible customers are the first to have gas service curtailed or interrupted. As previously discussed, many LDCs do not differentiate character of service among interruptible customers. In general, LDCs enjoy broad discretion in taking whatever action is needed at the local level to ensure reliability objectives. When there is no differentiated character of service among interruptible shippers, generally the largest customers are interrupted first and the smallest customers are interrupted last, but there are many instances where all interruptible shippers are curtailed or interrupted more or less at the same time. LDCs generally are able to notify generators of potential curtailment or interruption hours before the event based on anticipated operating conditions, although shorter timelines may apply during emergency conditions. The shedding of gas-fired generation load with little or no notice to preserve system integrity appears rare.

LDCs generally express the order of curtailment in their terms and conditions with a Priority of Service list. Priority of Service is typically differentiated by gas usage or customer segment. Large customers, industrial customers, or boiler fuel (for either manufacturing or electric generation) customers are typically the lowest priority service and are therefore the first customers to be curtailed or interrupted when operating conditions warrant.

Penalty Structures

Penalties for withdrawing gas during a designated curtailment are severe. Some LDCs have higher penalties specifically for electric generation customers. Penalties do not replace any normal fees. Most LDCs have a fixed adder as a penalty rate for overrun which ranges from \$10/Dth to \$100/Dth.[179] Some LDCs cash out unauthorized gas at a multiplied market index as well. Penalty rates generally do not replace other applicable service charges.

[179] Gas price super-spikes during the January 2014 Polar Vortex and the third week of January occurred at many key pricing points across the Eastern Interconnect. Penalty rates and overrun charges may be subject to review and modification going forward.

Dual Fuel Requirements

Interruptible transportation rates often require customers to have dual fuel capability. Often this requirement can be waived if the customer signs an agreement acknowledging that they may be interrupted and accepting responsibility for any consequences of interruption of service. Some LDCs require inspections or tests of alternate fuel facilities, or charge penalties for dual fuel non-performance.

Non-Ratable Takes

If an LDC's tariff sets forth hourly take provisions, it usually notes that customers are not supposed to take more than some constant portion of their MDQ per hour. Overtakes may be subject to penalty charges. Hourly takes above and beyond a customer's pro rata MDQ are not typically addressed in tariff provisions. Certain LDCs allow customers to contact the LDC, seeking permission to take gas non-ratably. Such intra-day swing that deviates from the ratable take requirement is almost always furnished on a best-efforts basis. LAI has not observed LDC tariffs that incorporate an enhanced hourly enhancement right that explicitly sets forth hourly deviations for a non-firm transportation customer.

2.4.4 PJM

Several of the LDCs serving generation in PJM have supply and/or transportation tariff rates specifically for gas-fired generation, but most do not.

Rates

Generally, LDCs in PJM provide firm Large General or Large Volume Service that may fit the service requirements for gas-fired generation. Many of these firm services include contract demand rates in addition to transportation rates. Some LDCs in Pennsylvania and Virginia allow customers to combine a firm tranche, charged a monthly demand rate based on the contracted quantity plus transportation charges, with interruptible service, where only the transportation charges apply. Like LDCs doing business in other PPAs, interruptible transportation service is the typical character of service covering local gas-fired generation.

Nicor Gas, Peoples Gas, and Duke Energy Ohio each have a service classification for gas-fired generation. Nicor Gas and Peoples Gas negotiate terms of service and rates, while Duke Energy Ohio provides a discount from the normally applicable interruptible transportation rate. The New Jersey LDCs, Pennsylvania UGI LDCs, Delmarva Power & Light (Delmarva), Vectren Indiana, and Piedmont Gas each have negotiable rate classifications for large customers.

Bundled Service

Most firm Large Volume services allow for bundled sales and transportation options. These rate classifications are often separated by Large Volume Sales versus Large Volume Transportation designations. Generally, the transportation charges are the same, but sometimes transportation charges for unbundled services are somewhat lower. LDCs in PJM do not typically offer a bundled Interruptible Sales service to generation companies.

Imbalance Resolution

Daily Balancing

There are many noteworthy differences regarding the mechanics and rate implications for daily imbalance resolution among LDCs serving gas-fired generation companies in PJM. Since LDC tariff approval is strictly state jurisdictional, it therefore follows that there are many significant structural differences among the LDCs serving generators across PJM. Vectren Indiana, PSE&G, and Vectren Ohio maintain daily balancing cashout provisions. Baltimore Gas & Electric maintains a self-balancing option that includes daily cashouts.

Washington Gas Light (WGL) has special balancing parameters for gas-fired generators. Under WGL's balancing plan for gas-fired generators, customers pay no fees within a 20% tolerance. If the cumulative daily imbalance reaches 100% of the generator's MDQ as a positive imbalance, then the imbalance is cashed out at a penalty rate of $25/Dth. WGL charges the customer 110% of WGL's calculated cost of gas for under-deliveries that reach 100% of the MDQ. The daily cumulative imbalance is reset to zero and the process begins again.

Nicor Gas and Peoples Gas allow banked gas, with a monthly fee to maintain a positive imbalance. Customers are charged for negative balances and banking over their banked gas account limit. Vectren Ohio practices daily cashouts if the daily imbalance reaches a 15% tolerance. Otherwise, Vectren Ohio permits its customers to settle remaining imbalances at the end of the month.

Elizabethtown Gas maintains daily charges for imbalances during low temperature conditions. South Jersey Gas also maintains daily balancing if the imbalance exceeds 5% in the winter or 7.5% in the summer. The daily imbalance is labeled as an Imbalance Requiring Action. If the imbalance is not quickly resolved, the shipper pays five times the Monthly Imbalance Price, which is calculated based on local market indices, for under-deliveries. When over-deliveries apply, the customer receives one-fifth of the Monthly Imbalance Price. PECO Energy and Philadelphia Gas Works maintain a 10% tolerance for imbalances in which penalties do not apply. Outside these tolerances, imbalance gas is cashed out at the company's cost of gas or at a daily index price. PECO Energy adds a $0.25/Dth penalty for over-deliveries and may bill shortfalls at a standby service rate. If the customer does not maintain standby service and is short, a $25/Dth penalty rate applies an addition to gas costs.

Most LDCs that do not cash out daily imbalances still have penalty rates for large daily imbalances or for imbalances which occur during OFOs. For example, UGI Central Penn and UGI Penn maintain a 2.5% daily imbalance tolerance. During normal conditions, the penalty is the difference in basis between local citygates and upstream supply.[180] The minimum penalty is $0.25/Dth. During OFO conditions, the penalty is increased 10-fold over the local market price. UGI Utilities maintains a 10% tolerance with a maximum $0.61/Dth penalty under normal conditions. The UGI-owned LDCs maintain no-notice service, which can be acquired on a daily

[180] The basis differential is pegged to one of many gas price indices of relevance across the Study Region versus the cost of natural gas "into-the-pipe" at a liquid sourcing point or hub.

basis and cover imbalances in excess of tolerance to avoid penalty charges. PECO Energy's tariff establishes two balancing options. The two options are differentiated by the amount of imbalance a customer can run on OFO days before penalty rates apply.[181]

Monthly Balancing

Other LDCs doing business in PJM implement monthly cashouts. Most LDCs use a progressive scale to cash out imbalances, but some LDCs, notably Dominion East Ohio, utilize flat penalty factors.

LDCs in Pennsylvania maintain certain unique provisions for monthly balancing. Columbia Gas of Pennsylvania's Elective Balancing Service allows customers to either bank gas up to 10% of the annual quantity for large customers (with cashouts occurring outside of the tolerance), or conduct monthly cashouts on a progressive scale, where the imbalance resets to zero each month. Peoples Natural Gas allows monthly balancing for General Delivery and Pooling customers. The cashout terms are similar to the daily balancing conditions for interruptible customers. PECO Energy penalizes customers who maintain a negative monthly imbalance at a rate of $25/Dth. Positive imbalances may be banked, with fees incurred on an escalating basis if the imbalance is greater than the customer's MDQ. Philadelphia Gas Works cashes out imbalances based on company cost of gas and sales and allows customers to store positive imbalances at their discretion, while retaining the right to levy additional charges. The UGI LDCs maintain monthly progressive cashouts, although customers have the option to obtain monthly balancing service which allows customers to bank up to 10% of monthly nominations as imbalances.

Service Priority, Curtailments and Interruptions

Under LDC tariffs, interruptible customers are curtailed first when operating conditions warrant. As a general rule, fully interruptible customers are curtailed first. Delmarva has quasi-firm customers that it curtails next when operating conditions warrant. Some of the Virginia LDCs' service classifications allow for customers to elect curtailable service for a portion of their load.[182]

Gas-fired generators at the local level are not typically covered under firm service agreements. If, however, there is a service priority for boiler fuel use, it is generally the lowest priority firm service. Otherwise, large industrial customers or high-usage customers are typically the first firm customers to be curtailed when operating conditions warrant.

Tariff provisions give LDC operators the right to curtail or interrupt on short notice, *i.e.*, 30 minutes to 8 hours depending on the LDC. Customarily, the LDC informs interruptible customers a day or more in advance when deliverability constraints are anticipated. In PJM,

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[181] No public information is available regarding the frequency or scope of these penalties.

[182] According to Columbia Gas of Virginia Tariff Sheet 116, "Curtailable volumes contracted by the Customer are subject to full or partial curtailment at the Company's discretion. However, the Company will contract with its supplier(s) for sufficient curtailable volumes so as to limit planned daily curtailment to ten (10) times frequency based on a fifteen (15) year normal weather winter."

many LDCs have notification standards set forth in their respective tariffs that are less than 8 hours, including Delmarva, several of the Indiana LDCs, Baltimore Gas & Electric, WGL, the New Jersey LDCs, Vectren Ohio, several of the Pennsylvania LDCs, Atmos Virginia, and Virginia Natural Gas. These provisions are consistent with conventional practice in other PPAs.

Penalty Rates

Most LDCs maintain flat penalty rates for unauthorized use. These penalties do not replace other applicable charges normally associated with service. The New Jersey LDCs charge ten times the market price for unauthorized gas use. Elizabethtown Gas sets a floor at $25/Dth and PSE&G charges the first hourly contract quantity at about $20/Dth before charging the market-based penalty. Failure to deliver charges may also apply to third party suppliers. Dominion East Ohio and Duke Energy Ohio do not maintain flat penalty rates, instead noting that unauthorized use may trigger the highest cost of gas and any attributable penalty charges from interstate pipelines, among other charges. UGI Central Penn and UGI Penn charge a progressive penalty factor that multiplies the daily basis based on the severity of the overrun.

Dual Fuel Requirements

None of the LDCs in Illinois, Maryland, North Carolina, and Ohio that serve gas-fired generation require customers to maintain alternate fuel capabilities under service classifications applicable to generators.

Delmarva does not maintain any alternate fuel requirements for the rate schedules discussed. In the event that customer-owned gas is diverted for higher priority customers, Delmarva reimburses the customer a value-based price tied to the customer's alternative fuel. For customers lacking an alternate fuel, reimbursement is made at a price equivalent to No. 2 fuel oil.[183]

There do not appear to be dual fuel requirements for any of the service classifications for Citizens Gas or Vectren Indiana. Northern Indiana Public Service Company (NIPSCO) Rate 428 is available to customers who have alternate fuel capability and whose gas requirements average at least 200 Dth per day. Rate 434 is available only to customers that have alternate fuel capability or to customers who use about 90% of their gas requirements during April 1 through November 30.

In New Jersey, PSE&G, Elizabethtown Gas, New Jersey Natural Gas, and South Jersey Gas require non-firm customers to produce an affidavit certifying alternate fuel capability. Generally, the alternate fuel capability requirement is up to seven days following interruption of service. Seven days of on-site fuel storage is not required, however. A re-supply agreement may suffice, which is typically doable in light of the residual fuel oil and ultra low sulfur diesel / kerosene infrastructure in and around Newark, NJ. If a facility does not have this capability, it

[183] Leaf 30 of Delmarva's tariff states: "In the event that Customer-owned gas is diverted for higher priority Customers, the Company will reimburse the Customer for volumes used, paying a value-based price, tied to the Customer's alternative fuel. For Customers lacking an alternate fuel, reimbursement will be made at a price equivalent to No. 2 fuel oil."

must sign an agreement stating that it will suspend operations when interrupted.[184] Under some LDCs' schedules, facilities without alternate fuel capability may also face higher rates.

UGI's LDCs require interruptible customers to have alternate fuel capability unless both the company and the customer agree to eliminate the requirement. Other Pennsylvania LDCs that maintain interruptible service require that customers either maintain alternate fuel capability or otherwise show they are willing to interrupt gas service. Peoples Natural Gas's Daily Delivery Service classification also has the same requirements.

Virginia Natural Gas requires alternate fuel capability for its Interruptible Sales rate. Alternate fuel capability is incorporated in Columbia Gas of Virginia's rates – the language indemnifies the LDC from responsibility if the customer is interrupted or curtailed, and customers may negotiate commodity rates based on alternate fuel cost. Atmos Energy's Optional Gas and Negotiated Service appear to require alternate fuel capability, with rates under the latter negotiated based on alternate fuel costs.

Customers with alternate fuel capability are often curtailed before other customers with similar usage and rate class. Transportation customers who burn alternate fuel in place of their nominated gas in critical conditions are typically reimbursed at alternate fuel costs when the LDC utilized their gas.

Non-Ratable Takes

Non-firm transportation tariffs do not permit generation companies to exceed their hourly take as a portion of their contracted MDQ. Consistent with industry convention, some LDCs may allow shippers to deviate significantly from ratable take requirements when operating conditions permit, particularly during the non-heating season when there is no impairment to core customers. Deviation from the ratable take requirement is granted solely at the discretion of the LDC.

2.4.5 MISO

Several of the LDCs serving MISO generators have rates specifically for gas-fired generation. Most do not, however. There is significant variance in how these service classifications are treated by LDCs. Discussion of rates, imbalance resolution, service priority and curtailments, penalty structures, and other service characteristics follows.

Rates

Atmos Mississippi, Alliant-Wisconsin, Madison Gas & Electric, We Energies, Wisconsin Gas, Wisconsin Public Service, Nicor Gas, and Citizens Gas have rate schedules specifically for gas-fired generators. Atmos Mississippi's Municipal Power Generation Service maintains a flat transportation rate, to which an additional Boiler Gas rider applies. The Wisconsin LDCs with electric generation rates have varying rate structures and characters of service. Alliant-

[184] See New Jersey Natural Gas, Tariff Sheet 78, Issued October 8, 2008.

Wisconsin's electric generation rates include transportation and demand charges, and generators may elect firm or interruptible service. Generation customers may choose between sales and transportation service. Madison Gas & Electric maintains interruptible and firm rates for electric generators, which both include a flat transportation rate. Generators may choose between sales and transportation service. We Energies maintains service classifications with both negotiated rates and fixed transportation and delivery rates for electric generators. It appears these services are available for transportation only. Wisconsin Gas maintains negotiated rates for interruptible electric generation service. Wisconsin Public Service offers electric generators interruptible sales service and firm/interruptible services with transportation charges set for all usage rates and demand charges in place for high usage rates. Citizens Gas of Indiana maintains a Retail Power Generation rate which is negotiated on a case-by-case basis. Nicor Gas maintains a negotiable rate, where the nature of the gas services is discussed in the service agreement.

Table 19. Characteristics of Electric Generation Service Classifications in MISO

LDC	Bundled Service Available	Available Characters of Service	Negotiated Rates Available
Atmos-Mississippi	Yes	Interruptible	Yes
Alliant-Wisconsin	Yes	Firm / Interruptible	No
Madison Gas & Electric	Yes	Firm / Interruptible	No
We Energies	No	Interruptible	Yes
Wisconsin Gas	Yes	Interruptible	Yes
Wisconsin Public Service Corp.	Yes	Interruptible	No
Citizens Gas	No	Firm	Yes
Nicor Gas	Yes	Firm / Interruptible	Yes
MidAmerican	No	Firm / Interruptible	Yes

Notably, most LDCs in MISO do not offer a specific service classification for gas-fired generators. Generators would likely be served under Large Volume or Large General Service rates. Many LDCs negotiate rates with large customers, including generation companies, either as a separate contract rate classification or by providing upper and lower bounds for transportation rates that may be negotiated within Large Volume or Large General service classifications.

Bundled Service

As seen in Table 19, many tariff options designed expressly for gas-fired generators allow for bundled sales service. However, the bundled sales service appears to be an artifact of longstanding state-approved rates for local generation.[185] Generally, local generation companies do not rely on LDCs for their gas supply. Large General Service and Large Volume

[185] Many LDCs throughout the Study Region enter into bundled sales arrangements with third-party marketers on a day to day basis, in lieu of capacity release. These arrangements are strictly volumetric in nature and therefore do not incorporate contractual obligations under one or more tariff services at the local level.

classifications also generally allow for bundled service. However, these rates may incorporate increased transportation rates or extra demand charges.

Imbalance Resolution

Daily Imbalance Resolution

Ameren Illinois, Ameren Missouri, MidAmerican, Citizens Gas, and Vectren Indiana practice daily balancing cashouts on a progressive scale. Some LDCs practice limited daily balancing where imbalances during OFO conditions are cashed out at a penalty rate. Most LDCs that do not allow for daily cashouts maintain flat penalty rates for various levels of daily imbalances. Nicor Gas, Ameren Illinois, and Peoples Gas utilize banked gas arrangements. Paying a monthly fee to maintain a daily imbalance tolerance is usually an option for transportation customers. Ameren Illinois gives customers both daily and monthly cashout options.

LDCs in Louisiana do not have any transportation services in their tariffs. Hence, there are no balancing provisions in the tariffs. Any balancing provisions necessary would be set in the terms of any negotiated transportation service agreement. In Mississippi, terms may be similarly set in individual service contracts.

Monthly Imbalance Resolution

Most LDCs cash out imbalances on a monthly basis. Progressive scales for penalty factors are widely used. Cashout prices are determined using a monthly index, Gas Cost Recovery / Purchased Gas Adjustment rates, or the company's weighted average cost of gas.

Many LDCs allow pooling and trading of imbalances between customers in similar rate classes or locations. Imbalance trades are often charged a small service fee and generally cannot create a negative imbalance for either party; the goal for imbalance trades is to eliminate the imbalance.

Service Priority, Curtailments and Interruptions

Under LDC tariffs, interruptible customers are curtailed first when operating conditions warrant. If there is a service priority for boiler fuel use, it is typically the lowest priority firm service. Otherwise, large industrial customers or high-usage customers are usually the first customers to be curtailed under conditions of *force majeure.*

Customers can expect anywhere from one to four hours of notice prior to interruption or curtailment. LDCs generally inform LDCs of OFO conditions on the day before operating limitations expose customers to curtailment or interruption.

Under the Michigan LDCs' tariffs, firm sales and transportation customers are treated the same with regard to service priority. Non-residential facilities with alternative fuel capability are low priority with Large Commercial & Industrial customers just above them. Each Michigan LDC's tariff contains language concerning gas-fired generation:

> "During an emergency curtailment of gas service, public utilities that generate and distribute electricity shall be granted Priority One service for that portion of the

> gas requirements of owned or firm contracted generation necessary to the discharge of the utilities' obligation to provide essential services and for which no practical alternatives exist."[186]

Electric utilities must still minimize their use of gas by switching to alternate fuels if possible, interrupting service to controlled/interruptible load, and taking other measures to limit gas usage. Notices for curtailments and interruptions are given as soon as possible, but there is no explicit notification requirement set forth in the tariffs.

Penalty Structures

Most LDCs maintain flat penalty rates for unauthorized use. These penalties do not replace any other applicable charges normally associated with service. In MISO, flat penalties range from $10/Dth to $100/Dth.

Offending shippers are charged the highest gas cost or local market index price for unauthorized gas use. Missouri LDCs also include a charge of 150% of the LDC's highest cost of gas for the day.

Dual Fuel Requirements

Most MISO LDCs do not specify any dual fuel requirements for their rate classes. Alternate fuel customers are generally reimbursed at the cost of the alternate fuel if their delivered gas is displaced by the LDC, and are given lower service priority during emergency conditions.

In South Dakota, Xcel Energy requires that interruptible customers either maintain alternate fuel capability or acknowledge that they may be interrupted and will cease operations when so notified by the LDC. The Minnesota LDCs require that interruptible customers either maintain alternate fuel capability or sign an affidavit acknowledging that they may be interrupted and will cease operations when so notified by the LDC.[187] The LDC may request proof that alternate fuel capability is operational. NIPSCO maintains dual fuel rates as described in the PJM section. There do not appear to be dual fuel requirements for any of the Michigan LDCs' service classifications. If a customer utilizing alternate fuels is curtailed and gas is diverted to other customers, they are guaranteed to recoup their alternate fuel costs incurred by the curtailment.

Non-Ratable Takes

Most LDCs do not explicitly permit customers to deviate from uniform hourly takes in relation to their MDQ. However, customers are generally permitted to request deviations from hourly takes when operating conditions warrant, particularly during the non-heating season when there is no impairment to core customers. The request is granted at the sole discretion of the LDC.

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[186] See DTE (Michigan Consolidated) Tariff Sheet C-23.00.

[187] Centerpoint's interruptible customers are served under the Dual Fuel Service tariff.

2.4.6 NYISO

LDCs operating in New York have generally consistent service characteristics.[188] The service classification for gas-fired generation is described generally as "Interruptible Transportation Service to Electric Generation Facilities." This service is available to gas-fired generators with a capacity of 50 MW or greater.

Highlights of the important differences in service classifications, LDC rates, imbalance resolution provisions, curtailment priorities, and penalty structure are discussed below.

<u>Rates</u>

LDCs in New York have state commission support to negotiate rates and terms covering non-firm service. Firm tariff-based rates for core customers reflect traditional cost of service principles, but under certain circumstances the LDC is permitted to negotiate a rate based on value of service considerations, including the threat of bypass. Actual agreements between the LDC and the non-firm shipper are commercially sensitive and therefore not available for public review.

Fixed Volumetric Charges

Transportation rates typically incorporate a fixed volumetric rate stated on a $ per Dth basis. Benchmark transportation rates are set in the LDCs' tariffs, but rates for electric generation service classification may be negotiated. Negotiations for the transportation rate are based on value of service principles and typically require the benefited shipper to make a contribution to the LDC's overall system cost. Under New York Public Service Commission (NYPSC) rate authority, LDCs have management discretion to enter into other value-added services with the generation company under the interruptible rate schedule(s).

Value Added Charge

Unique to New York State, LDCs levy a value added charge (VAC) to non-firm transportation services applicable to gas-fired generators behind the citygate. VAC payment obligations reflect a relatively complex calculation methodology. While the calculation methodology is the same for all generators, the input parameters to the calculation method can vary significantly. Generation plants served by Con Edison and NGrid on the New York Facilities System account for most of the VAC paid by generators in New York to LDCs. Under NYPSC policy, the LDC determines VAC by calculating the difference between the hourly spark-spread for the generator during unit operation in relation to the spark-spread first quantified for a base year operation. This difference is then multiplied by the energy (MWh) produced each hour. Generally, the VAC equals 5% of this amount. To derive VAC, the LDC calculates an annual charge comparing a test year to a base year. A reconciliation charge is incorporated to settle the actual

[188] LDCs in New Jersey also serve electric generation at the local level that is electrically dedicated to New York City. See the PJM section that begins on page 88 for discussion of applicable NJ LDC tariff provisions.

calculated VAC against the estimated Test Year VAC.[189] The VAC therefore varies among generation plants based on vintage, location, and capacity factor. Finally, if the VAC is negative, it is treated as zero rather than as a credit to the shipper's monthly transportation cost obligation.

Minimum Bill Obligation

Non-firm customers under quasi-firm or 30-day interruptible service are obligated to reimburse the LDC if the actual amount of natural gas transported to the generation plant falls below a specified percentage of the MDQ in any contract period or calendar year. While local transportation is paid for on a volumetric basis throughout the year, lower than anticipated dispatch below a target threshold triggers a fixed cost obligation. Non-firm shippers are generally required to pay an annual bill equivalent to the charges that would be associated with 50% of a customer's MDQ in annual demand. NGrid-Long Island sets the minimum bill obligation based on 60% of the MDQ rather than 50%. Certain incumbent generators have been able to negotiate deviations from the tariff language, however.

Bundled Service

While bundled gas sales service is available to retail customers on a non-firm basis, gas-fired generation is typically served under non-firm transportation-only arrangements. Generation companies in New York generally rely on third-party marketers to obtain commodity gas supply delivered to the citygate.

<u>Imbalance Resolution</u>

Daily Imbalance Resolution

LDCs in New York generally apply daily imbalance resolution through cashout provisions. Generation customers are given a certain threshold of their nominated quantity for which no daily imbalance charges apply. The deadband is often ±2%. Once the imbalance exceeds the 2% tolerance, the customer is required to cash out the imbalance. Most LDCs maintain a progressive scale for daily balancing cashouts. Some LDCs utilize an upstream pricing point to pay customers for surpluses, while using a downstream point to bill them for shortfalls. Some LDCs maintain additional penalty rates in the form of adders for under-delivery during OFOs.

Monthly Imbalance Resolution

Daily imbalances that are not cashed out become part of the customer's monthly imbalance. Consistent with NYPSC policy, the "hunt for zero" supports similarly situated customers trading monthly imbalances. Transaction fees may be imposed on trades, but they are typically insignificant in relation to the avoided cost of imbalance charges for volumes that exceed the ±2% deadband. Generally, customers may not trade into a surplus position. Monthly cashouts apply to remaining imbalances in a manner that is similar to the daily cashout mechanism.

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[189] Heat rates are needed to determine the spark spreads. There are four heat rate tiers that are differentiated by technology and vintage. The appropriate gas indices and zonal LBMPs are specified in each tariff.

Service Priority, Curtailments and Interruptions

Curtailment service priorities place fully interruptible customers first in line when operating conditions warrant the reduction in local transportation quantities. During curtailment periods, quasi-firm service customers are next in line to experience curtailment or interruptions when operating conditions warrant.[190] NGrid-Niagara Mohawk curtails electric generators after other Large Volume Interruptible Service customers. LDCs are required to notify customers of pending curtailments or interruptions two to four hours in advance of the event, but industry practice often results in timely communication between the LDC and the generation company the day before the anticipated curtailment.[191]

Penalty Structures

Penalties for withdrawing gas during a designated curtailment are designed to be punitive. Some LDCs have higher penalties oriented around non-firm customers, in particular, electric generation. Penalties are in addition to, not in lieu of, normal transportation costs. Most LDCs have a fixed adder as a penalty rate for overruns. Many LDCs charge $25/Dth, but fixed adder charges can range up to $100/Dth. Several LDCs enforce a penalty rate of 120% of the electric generation service rate at the time of the overrun. The penalty rate is levied on a volumetric basis. This mechanism deters generators from exploiting the spread between the penalty rate and the cost of gas when electric energy prices are high due to scarcity conditions. Some fixed-rate penalty charges are added to the commodity cost as described above, while others may replace it. Still other penalty charges multiply the market price of the fuel during a curtailment period by a set factor to determine the penalty rate.

Dual Fuel Requirements

Some New York LDCs require dual fuel capability under their electric generation service classifications. LDCs generally reserve the right to inspect the facility and may require customers to prove the backup generation and fuel storage capability of the facility. Penalties for non-compliance – discoverable either through inspection or failure to switch to a backup fuel during an interruption -- are generally tied to the price of a backup fuel. Penalty rates range from 110% to 130% of the backup fuel costs. Some LDCs also consider allowing penalties to be 110% to 130% percent of the actual variable gas rate, whichever is higher. The penalty rates are designed to facilitate the restoration of functional dual fuel capability.[192]

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[190] Quasi-firm service is typically limited to 30 days or 720 hours per year.

[191] When LDCs inform interruptible customers of anticipated restrictions during the following gas day, the generation company will either switch to oil if doing so is in merit, or operate on oil out-of-merit if so instructed by NYISO in the DAM. Therefore there may not be a timely gas nomination for next day delivery due to the anticipated restrictions on local delivery. In this study a generator company's failure to nominate due to anticipated local delivery constraints is deemed synonymous with a curtailment or interruption even though gas is not nominated on a timely basis and therefore not technically curtailed or interrupted.

[192] In addition to LDC dual fuel requirements, NYSRC reliability rules I-R3 and I-R5 set the requirements for assurance of energy supply to the electric load in NYC and Long Island zones, respectively, under a single gas facility contingency. In particular, rule IR-3 requires that the power system be operated so that the loss of a single

Non-Ratable Takes

Permissive deviations from LDC ratable take provision are not memorialized in the tariffs. However, significant deviations from the ratable take provision in the interruptible transportation tariffs may be permitted when operating conditions warrant, in particular, during the cooling season when slack deliverability at the local level is frequent.

2.4.7 ISO-NE

Of the LDCs serving gas-fired generation behind the citygate in New England, none offer a specific gas supply, transportation or bundled service product applicable to gas-fired generation. As discussed in this section, there are significant differences among LDC service classifications, rates, imbalance resolution procedures, curtailment priorities, and penalty structures.

Rates

Berkshire Gas, Columbia Gas of Massachusetts, and NGrid (Boston Gas and Colonial Gas) offer firm rates for High Use with Low and High Peak designations regarding load factor. Columbia Gas of Massachusetts, Berkshire Gas, and Boston Gas also offer firm rates for Extra High Use. LAI is not aware of any generation customers at the local level being covered under a firm sales or transportation rate for year-round service. Consistent with Massachusetts Department of Public Utilities precedent, LDCs are able to negotiate interruptible transportation rates on a case by case basis.

LDCs serving generators in Connecticut include Yankee Gas, Southern Connecticut Gas, and Connecticut Natural Gas. Consistent with the negotiating flexibility the LDCs have in Massachusetts and several other states, the Connecticut LDCs are permitted by the Public Utilities Regulatory Authority to negotiate interruptible transportation rates. Applicable tariffs covering gas-fired generation at the local level include a volumetric charge based on the economic rationale for the transportation rate, and a commodity charge that is indexed to the delivered cost of natural gas to the relevant pricing point in Connecticut. Large firm customers are covered under the Large General Service rates, which include a demand charge.

The Maine LDCs (Bangor Gas, Maine Natural Gas) also have Large General Service rates, which do not include a demand charge. Interruptible rates that apply to gas-fired generation at the local level are negotiated.

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gas facility does not result in the loss of electric load within NYC. Similarly, according to rule IR-5, the power system shall be operated so that the loss of a single gas facility does not result in the uncontrolled loss of electric load on Long Island. Hence, NYSRC IR-3 and IR-5 rules require certain generators in NYC and Long Island, respectively, to maintain dual fuel capability and to operate on liquid fuel above certain specified load levels. There are not explicit reliability rules governing dual fuel capability in other zones in NYCA. These rules are not included in LDC tariffs. For a more detailed discussion of oil infrastructure capability in NYISO and the NYSRC minimum oil burn compensation programs, see "Fuel Assurance Operating and Capital Costs for Generation in NYCA," prepared for NYISO by LAI, May 22, 2013.

NGrid-Narragansett in Rhode Island is able to negotiate Non-Firm (interruptible) Transportation Service arrangements with gas-fired generators.

Imbalance Resolution

Daily Imbalance Resolution

LDCs in Massachusetts do not appear to maintain daily cashout provisions, but do maintain penalties for imbalances outside of a given tolerance. If the imbalance is outside of the tolerance level, the difference is penalized at a fraction of the Daily Index. The penalty factor and tolerance vary based on system conditions. On critical days, if over- or under-deliveries are deemed "aggravating", *i.e.*, impairing system integrity, they are billed at a high penalty rate.

Connecticut LDCs practice daily imbalance resolution with cashout provisions. Customers are generally given a certain threshold of their nominated quantity for which no daily imbalance charges apply. Connecticut LDCs set a threshold of 10%. Tolerance provisions may not apply during OFO conditions. Once the imbalance exceeds the 10% tolerance, the customer is required to cash out. A premium of 25% above the gas cost set in the LDC's filed Purchased Gas Adjustment is charged to the customer for any quantities above the threshold amount used by the customer. When gas is "sunk" into the local distribution system, the LDC credits the customer for the surplus gas, but at a 25% discount against the PGA.[193] In addition, some LDCs also maintain additional penalty rates for failure to deliver during OFOs, generally at the greater of three times a market rate or an adder of $25/Dth for winter and twice the indexed price in the summer.

Maine Natural Gas uses a daily cashout provision for imbalance resolution. Like other LDC jurisdictions in New England, Maine's LDCs price a shortfall or surplus either sold or purchased by a customer at a premium or discount to the index price of natural gas delivered to Northern New England. Maine Natural Gas provides a 5% tolerance where no cashout penalties apply. Tolerance provisions may not apply during OFO conditions. Once the imbalance exceeds the 5% tolerance, the customer is required to cash out. Maine Natural Gas maintains a progressive scale for balancing cashouts and charges a Maximum Index Price for charges and a Minimum Index Price for credits.

NGrid-Narragansett practices daily imbalance resolution. Balancing is performed by marketers, which may aggregate their customers into pools. Daily balancing maintains seasonal on- and off-peak tolerances of 10% and 15%, where the marketer will not incur charges for imbalances. If charges occur, they are equivalent to 0.1 times the Daily Index for off-peak and 0.5 times the Daily Index for on-peak use outside the tolerance bandwidth. Extra charges may apply for unauthorized use on Critical Days. The overrun penalty would be five times the Daily Index.

[193] Sinking gas into the local system is tantamount to an unauthorized underpull.

Monthly Imbalance Resolution

Daily imbalances that are not resolved become part of the customer's monthly imbalance. Trading or netting of monthly imbalances among customers on similar rate schedules and locations is generally allowed. Sometimes a transaction fee is imposed on trades, but the transaction fee is insignificant relative to the imbalance resolution cost otherwise triggered under the tariff. LDCs in New England maintain a progressive scale for monthly balancing cashouts. For the Massachusetts LDCs and NGrid-Narragansett, over-deliveries are billed starting at the monthly average of the Daily Index. Under-deliveries are billed at the highest average of seven consecutive Daily Indices for the month. Other LDCs use a monthly index calculation for all cashouts. One noteworthy exception is Connecticut Natural Gas' use of an annual balancing provision.

Service Priority, Curtailments and Interruptions

Across New England, LDCs maintain infrastructure capability to meet the requirements of core customers under firm service schedules. Electric generators at the local level are non-firm customers and, like other non-firm users behind the citygate, are typically the first to be curtailed or interrupted when operating conditions warrant. The LDCs typically give non-firm customers day-ahead notice of anticipated restrictions on gas use, but not less than one to three hours' prior notification of a pending interruption.

Reflecting deliverability constraints on Tennessee as well as the local system throughout the heating season, Columbia Gas of Massachusetts' IT Agreement contains the following language:

> "Service to Customer shall be interrupted beginning on December 1st of each year and shall remain interrupted through the following March 31st. As applicable, Customer is responsible for securing its alternate fuel to meet its full requirements, or for preparing for interruption or curtailment of natural gas service, during the period of unavailability of natural gas service each winter. At its sole discretion and at no cost to Customer, [Columbia Gas of Massachusetts] may manually shut-off gas service to the Customer's meter during the winter period interruption. In the event that service is shut-off, [Columbia Gas of Massachusetts] shall charge Customer to turn on gas service at the start or during the Non-peak Period."[194]

Penalty Structures

The Massachusetts LDCs and NGrid-Narragansett charge customers the applicable firm service rate and five times the Daily Index price in the event of a failure to curtail: "All Gas Usage in excess of the Supplier's maximum hourly flow rate will be subject to an unauthorized overrun

[194]See tariff DPU No. 137, page 4.

penalty for each Dth delivered of 5 times the Daily Index. The Company will notify the Supplier of the Supplier's maximum hourly flow."[195] See the penalties for daily balancing above as well.

The Connecticut LDCs have a fixed adder as a penalty rate for overruns. Connecticut Natural Gas charges $15/Dth while Southern Connecticut Gas and Yankee Gas charge $30/Dth. The overrun penalties are in addition to other commodity charges pertaining to administration of the imbalance resolution provision, as well as the rates associated with normal gas service. Interruptible Service customers also have the option to pay an Emergency Gas Rate in the case that gas is needed to start up an alternate fuel unit. The customer has an affirmative notification requirement to use the Emergency Gas Rate. Natural gas used under these conditions is charged a $10/Dth adder.

Dual Fuel Requirements

Berkshire Gas's IT rate does not require dual fuel capability. Columbia Gas of Massachusetts' IT Agreement implies that the customer must maintain alternate fuel service during the heating season.

All facilities under Connecticut's Interruptible Service Rates are required to have alternate fuel capability. LDCs require customers to prove the backup generation and fuel storage capability of the facility. There do not appear to be penalties associated with failure to maintain fuel storage, but the LDCs maintain the right to terminate the rate if the customer fails to demonstrate alternate fuel capability.

Facilities under Bangor Gas interruptible sales and transportation rates are required to have alternate fuel capability for a "reasonable" duration of interruption.

All facilities under NGrid's non-firm rates are required to have alternate fuel capability. It is unclear how NGrid inspects or penalizes non-compliance with dual fuel capability.

Non-Ratable Takes

Interruptible Service customers taking service from Bangor Gas set forth a Maximum Hourly Flow. This flow will appear on pipeline EBB notices and is available upon customer request. Any takes exceeding the Maximum Hourly Flow will be penalized at a rate of $20/Dth. It is unclear whether there is any mechanism to request takes in excess of the Maximum Hourly Flow.

Other LDCs in New England do not allow generators to "flex" their intra-day profile of gas use, but may accommodate such deviations when operating conditions allow for non-ratable takes, particularly during the cooling season when there is no impairment to core customers.

[195]See Bay State tariff Term's and Conditions, DPU No. 106, page 11-3, 11.6.1.

2.4.8 TVA

Only Memphis Light Gas & Water serves gas-fired generation at the local level. A review of its service classifications, rates, imbalance resolution provisions, curtailment priorities, penalty structure, and other tariff highlights follows.

Rates

Memphis Light Gas & Water has five rates that may apply to gas-fired generation: Large General Service (G8/G9), Large Gas Service – Interruptible Sales (G10/G12), Large Gas Service – Interruptible Market Sales (G10/G12 Market), General Firm Transportation (FT-1), and Negotiated Firm Transportation (FT-2). Each service classification includes a fixed Transportation Charge that is applied to a customer's actual monthly volumes. Large General Service customers also pay a Demand Charge that is expressed on a fixed monthly basis.

Bundled Service

Memphis Light Gas & Water maintains separate rates for sales and transportation.

Imbalance Resolution

Daily Imbalance Resolution

Memphis Light Gas & Water does not charge any fees on daily imbalances within a 10% tolerance. For imbalance volumes in excess of 10%, a flat penalty charge of $0.167/Dth is assessed. During OFO conditions, any imbalance within the 10% tolerance is charged a penalty rate of $15/Dth. Daily imbalances greater than the 10% tolerance level can trigger a penalty charge of $60/Dth.

Monthly Imbalance Resolution

Daily imbalances become part of the customer's monthly imbalance. At the end of each month, the monthly imbalance is cashed out at an index price, also including transportation costs. Memphis Light Gas & Water maintains a progressive scale for monthly balancing cashouts.

Service Priority, Curtailments and Interruptions

Interruptible Market Sales customers covered under the G10/G12 rates are curtailable. There is no curtailment provision applicable to FT-1 and FT-2 customers, excluding *force majeure*.

Penalty Structures

Applicable penalties for unauthorized gas use during a designated curtailment are heavy. Interruptible customers are penalized $25/Dth for unauthorized gas use during a curtailment within 10% of the contract demand. Any gas taken in excess of 10% is billed at $100/Dth, and may also allow Memphis Light Gas & Water to apply other charges normally applicable to gas service.

Dual Fuel Requirements

Memphis Light Gas & Water customers served under interruptible rate schedules are required to have alternate fuels and/or operational procedures that will prevent plant equipment from sustaining any significant damage during a curtailment.

Non-Ratable Takes

There is no explicit tariff language that permits G10/G12 customers to vary their hourly takes. The tariff language appears to permit gas-fired generators to deviate from ratable takes when operating conditions warrant, subject to whatever scheduling restrictions Memphis Light Gas & Water may enforce to ensure system integrity throughout the year.

2.4.9 IESO

Enbridge and Union Gas serve gas-fired generation in IESO. Enbridge maintains one set of rate classifications that apply across its entire Southern Ontario service area while Union Gas differentiates the services it offers by region. Enbridge does not provide any service classifications specifically for gas-fired generation, but offers Large Volume services that are generally applicable to generation at the local level.

Union Gas's Southern Operations Area tariff does not provide any service classifications specifically for gas-fired generators. Rate T1 and Rate T2 storage and transportation services are the primary options for gas-fired generators. These services provide flexible options for gas delivery and management services to meet the needs of various gas-fired generators.

The T1 and T2 services provide gas-fired generators with the ability to manage gas supply through different combinations of firm and/or interruptible transportation, storage, and balancing services.

In its Northern and Eastern Operations Areas, Union Gas does not provide any service classifications specifically for generators, but there are three rate schedules which are potentially applicable: Medium Volume Firm Service (Rate 20), Large Volume Interruptible (Rate 25), and Large Volume High Load Factor Firm Service (Rate 100).

<u>Rates</u>

Enbridge Large Volume rates (125, 300) each maintain demand charges for firm customers' MDQ. Interruptible customers, which may take service under rate 300, do not pay demand charges but instead pay transportation charges for gas delivered. Large Volume rates are only offered as a distribution service.

In the Union Gas Southern Operation Area, T1 and T2 transportation services can be a combination of firm and interruptible service. Firm transportation rates are regulated by the OEB and are associated with firm contract demand in the T1 and T2 services. They include demand and transportation charges. Interruptible transportation rates and the associated interruptible contract demand are negotiated with Union Gas and consider the amount of interruptible transportation gas-fired generators are willing to contract, anticipated load factor for interruptible transportation quantities, interruption or curtailment provisions, and other commercial factors of relevance in the establishment of transportation rates.

Union's Northern and Eastern Operation Areas service classifications may include sales and transportation service. Firm services (Rates 20 and 100) may also include storage or bundled transportation (transportation and storage) service. Large Volume Interruptible customers only pay transportation charges associated with gas delivered, while firm customers will pay additional demand rates associated with the contracted daily quantity.

Imbalance Resolution

Daily Balancing

Enbridge maintains flat fees or daily imbalances. There are two imbalance tiers where fees apply; Tier 1 is for 2-10% imbalances, while Tier 2 is for imbalances 10% and above. A penalty fee also applies if the imbalance is greater than a specified contract amount.

In the Southern Operations Area, Union maintains flat fees for daily imbalances. For authorized overruns on injection, withdrawals, and transportation, flat imbalance rates apply to quantities that are in excess of 103% of the Contract parameters. Overruns are automatically authorized if injections are made for days when a gas-fired generator has been interrupted.

In the Northern and Eastern Operations Areas, Union allows transportation customers to contract for Customer Balancing Service (CBS). Customers are allowed to maintain cumulative daily imbalances which are settled with an escalating flat rate based on negotiated tolerance levels. Balancing service customers also pay a flat daily fee for balancing service. If tolerance levels are exceeded, overrun charges may apply.

If Union Gas determines that CBS services are not available and the CBS account is positive or negative, the generator will be notified that the balance must be removed within five days. If the CBS balance was positive and remains positive at the end of the five days, upon three days' notice from Union Gas, the CBS balance will be forfeited to Union Gas without recourse. If the CBS account was negative and remains negative at the end of the five days, the negative balance will be purchased by the generator at the Rate 25 price that was currently in effect.

Monthly Balancing

Enbridge allows cumulative imbalances for the month to be traded or placed in storage if the customer maintains a storage service. Enbridge maintains flat fees for monthly imbalances.

Union Gas (all of the Operations Areas) allows for ten different transaction services to help customers cure imbalances: In-Franchise Transfer, Ex-Franchise Transfer, Underground In-Franchise Transfer, Daily Contract Quantity Assignment, Suspension, Diversion, Incremental Supply, Loan, Short Term Storage, and Discretionary Gas Supply Services. These services allow for various transactions between customers, affiliates, and Union in order to reduce imbalances.

Service Priority, Curtailments and Interruptions

For Enbridge distribution service, it is unclear what service priority Large Volume customers maintain during emergency conditions. Customers can usually expect at least four hours' notice of curtailment or interruption.

Enbridge charges a flat penalty for unauthorized use, and also charges unauthorized overrun and underrun gas at 50% markup charges and discount credits, respectively. Interruptible users who draw unauthorized gas also pay an additional penalty rate. Enbridge may raise customers' contracted MDQs in the case of unauthorized overruns above the contract quantity.

On Union, unauthorized overruns carry flat penalty rates. Storage in excess of the maximum contract storage quantity is charged at a particularly punitive rate.

Dual Fuel Requirements

No service classifications discussed require dual fuel capability.

Non-Ratable Takes

Enbridge and Union do not allow customers to exceed an hourly flow calculated as a portion of their contracted MDQ without the company's prior consent.

2.4.10 Key Findings and Observations

There are many common trends at the local level regarding the applicability of various LDC tariff provisions affecting service to gas-fired generation behind the citygate. From a character of service standpoint, all or nearly all gas-fired generators 15 MW or larger rely on non-firm service for local transportation, in many cases on dedicated laterals. Due to data availability limitations, outside of Ontario only one generator was found to rely on firm transportation service at the local level. There may be others, however. While some generators may rely on LDCs in part or in full for a bundled gas supply delivered to the plant, the common procurement practice is for generators to rely on third party marketers or asset managers to obtain natural gas delivered to the citygate or the meter. This reliance can be structured under ad hoc commercial arrangements or under a more rigid AMA. While generators typically realize scheduling flexibility during the non-heating season when slack deliverability at the local level poses no risk for core customers, operating conditions during the heating season typically expose gas-fired generators to potential curtailment or interruptions, particularly during cold snaps.

Other key findings or observations are as follows:

- LDCs across the Study Region serving gas-fired generators generally have specific service classifications oriented around electric generators. The character of service is generally non-firm, but permissible limitations on curtailment levels may be negotiated under state commission ratemaking policy. Transportation rates may be negotiated based on value-of-service principles.

- LDC services for gas-fired generation are predominantly related to transportation service, but also include imbalance resolution. The bundling of commodity gas sales with transportation and imbalance resolution is no longer a common distribution company practice.
- There are many cashout mechanisms among LDCs across the Study Region. Generally, a monthly balancing cashout mechanism coupled with daily cashouts or penalties applicable to extreme daily imbalances, are the most common form of imbalance resolution. However, some LDCs settle imbalances entirely with daily cashouts. Information regarding actual imbalance / penalty charges paid by generators is not publicly available, but the incentives to avoid imbalances are strong across the Study Region.
- Any gas-fired generator engaged in unauthorized overpulls during Flow Day Alerts or OFOs will likely be heavily penalized by the LDC through either high cashout multipliers applied to the daily market index or large adders.
- Some LDCs allow banking of natural gas, particularly in PJM and MISO. Transaction fees apply to this service. LDC ownership and operation of storage infrastructure in Ontario provides gas-fired generators behind the citygate with a large array of storage services that obviate the need to bank gas.
- LDC tariffs generally provide operators with the ability to interrupt or curtail non-firm customers on short notice. Most LDCs have broad discretion regarding how best to effectuate curtailments or interruptions to maintain system integrity. Usually, LDCs inform interruptible customers of likely delivery constraints the day before action is taken to ensure local deliverability.
- LDCs in NYISO, ISO-NE and eastern PJM maintain the strictest dual fuel requirements for interruptible customers, in particular, gas-fired generators, including tariff provisions oriented around the ability to burn an alternate fuel when natural gas is not deliverable. These requirements are a product of state regulation. Reliability rules in downstate New York formalize the use of oil when natural gas may otherwise be deliverable, but electric load levels trigger fuel diversity requirements.[196]
- Dual fuel requirements are much less common in LDCs serving gas-fired generation in PJM's Western zones and MISO.
- Fixed adder penalty rates for unauthorized use range from \$10/Dth to \$100/Dth. Some unauthorized use penalties also include penalty multipliers applied to the cost of gas or the wholesale electricity price.
- Most LDCs do not maintain tariff language that permits generators to deviate from uniform hourly takes. However, LDCs have broad discretion to permit non-ratable takes when operating conditions warrant.

[196] For a detailed discussion of the NYSRC's minimum oil burn compensation program, see Fuel Assurance Operating and Capital Costs for Generation in NYCA, prepared for NYISO, Levitan & Associates, Inc. , May 22, 2013, pps. 24-25.

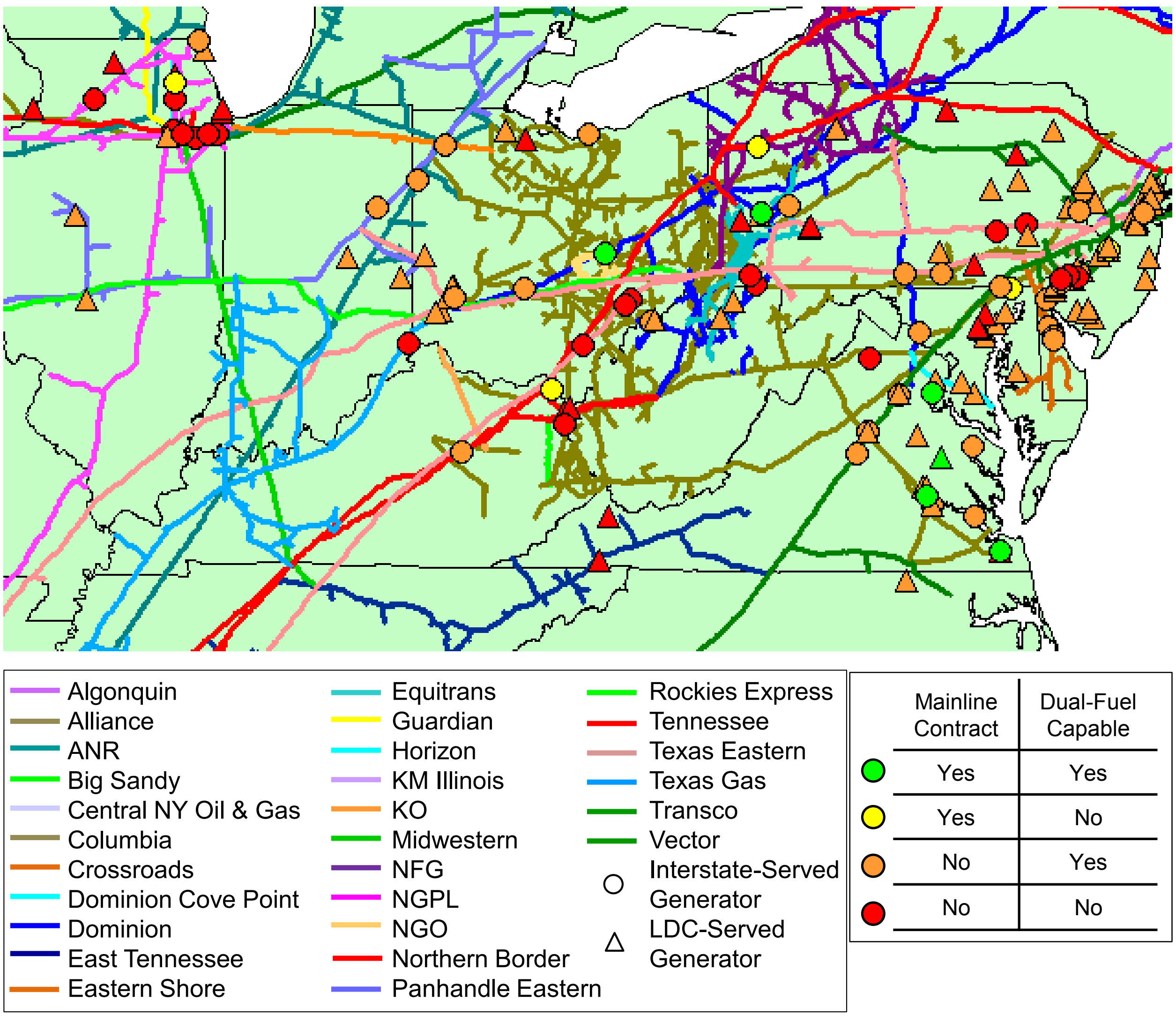
3 GENERATOR CONTRACTING AND FUEL ASSURANCE PRACTICES

The transportation contracts that are discussed in this section and listed in Exhibits 4 through 9 are those held by generators in their own names, as determined from a review of pipeline customer indices. Firm transportation arrangements through gas marketers or other parties are not included due to limitations on publicly-available data. Similarly, contracts for LDC transportation service are not included. Generators can also utilize released capacity to meet their transportation needs, as discussed in Section 2.4.

3.1 PJM REGION

Figure 41 shows the PJM generators, color-coded by fuel assurance approach as indicated in the legend. The generators in each category and the gas transportation contract details are presented in Exhibit 4.

Figure 41. PJM Generator Fuel Assurance Practices



Highlights of the PJM generator contract review include:

- Virginia Power Services Energy holds 40 MDth/d of capacity on Columbia Gas from the Leach interconnection with Columbia Gulf to the Elizabeth River plant. Virginia Power Services Energy also holds 42.5 MDth/d of firm no-notice capacity on Dominion to serve the Chesterfield power plant.

- Appalachian Power Company holds 109 MDth/d of capacity on Dominion from Oakford to the Dresden plant through 1/31/2022, sufficient to fuel nearly all of the plant's capacity.

- AmerenEnergy Medina Valley Cogen holds 24 MDth/d of capacity on Horizon from an Alliance interconnection to the Elgin plant through 5/10/2015, sufficient to fuel approximately one-quarter of the plant's capacity.

- Virginia Power Energy Marketing holds 100 MDth/d of capacity on Transco from Leidy to Fairless Energy through 10/31/2018, sufficient to fuel approximately half of the plant's capacity.

- Exelon Generation Company holds 14 MDth/d of capacity on NFG to the Handsome Lake plant, sufficient to fuel approximately one-quarter of the plant's output.

- The Hanging Rock plant is served by a portfolio of marketer entitlements. On Tennessee, DTE Energy Trading and Cargill hold 20.5 MDth/d and 40.5 MDth/d of capacity from Texas to the plant through 12/31/2014. Also on Tennessee, Southwestern Energy Services holds 50 MDth/d of capacity from Marcellus receipt points to the plant through 10/31/2028. On Texas Eastern, EQT Energy holds 120 MDth/d of capacity from Marcellus receipt points through 10/31/2014 and Duke Energy Commercial Asset Management holds 10 MDth/d of capacity from a Marcellus receipt point to the Hanging Rock lateral header through 10/31/2015.

- Columbia Gas of Virginia holds a firm contract for 15 MDth/d on Columbia Gas deliverable to Hopewell Cogen through 4/30/2026.

- Greys Ferry Cogen and Liberty Electric hold firm entitlements on Texas Eastern's Philadelphia lateral.

- Virginia Power Services Energy Corporation holds 95 MDth/d of capacity on Dominion Cove Point from Loudoun and Pleasant Valley to the Possum Point plant's lateral through 4/30/2025, sufficient to fuel approximately half of the plant's output.

- EP Rock Springs and Old Dominion Electric Cooperative, which share ownership of the Rock Springs generator station, each hold 135 MDth/d of capacity on Columbia Gas from Downingtown and Eagle to the plant through 10/31/2028.

- Allegheny Energy Supply Company holds 95 MDth/d of capacity on Dominion from Oakford to the Springdale plant through 5/31/2016, sufficient to fuel all or nearly of the plant.

- South Jersey Resources holds 41.4 MDth/d of capacity from on Transco Texas to Marcus Hook through 2/29/2016.
- Hess holds a firm contract for 6 MDth/d deliverable to Pedricktown through 10/31/2021.
- EQT Energy holds 5 MDth/d of firm delivery rights at the Washington plant through 10/31/2014.

3.2 MISO REGION

Figure 42 and Figure 43 show the generators in MISO North/Central and MISO South, respectively, color-coded by fuel assurance approach as indicated in the legend. The generators in each category and details of the gas transportation contracts are and listed in Exhibit 5.

Figure 42. MISO North/Central Generator Fuel Assurance Practices

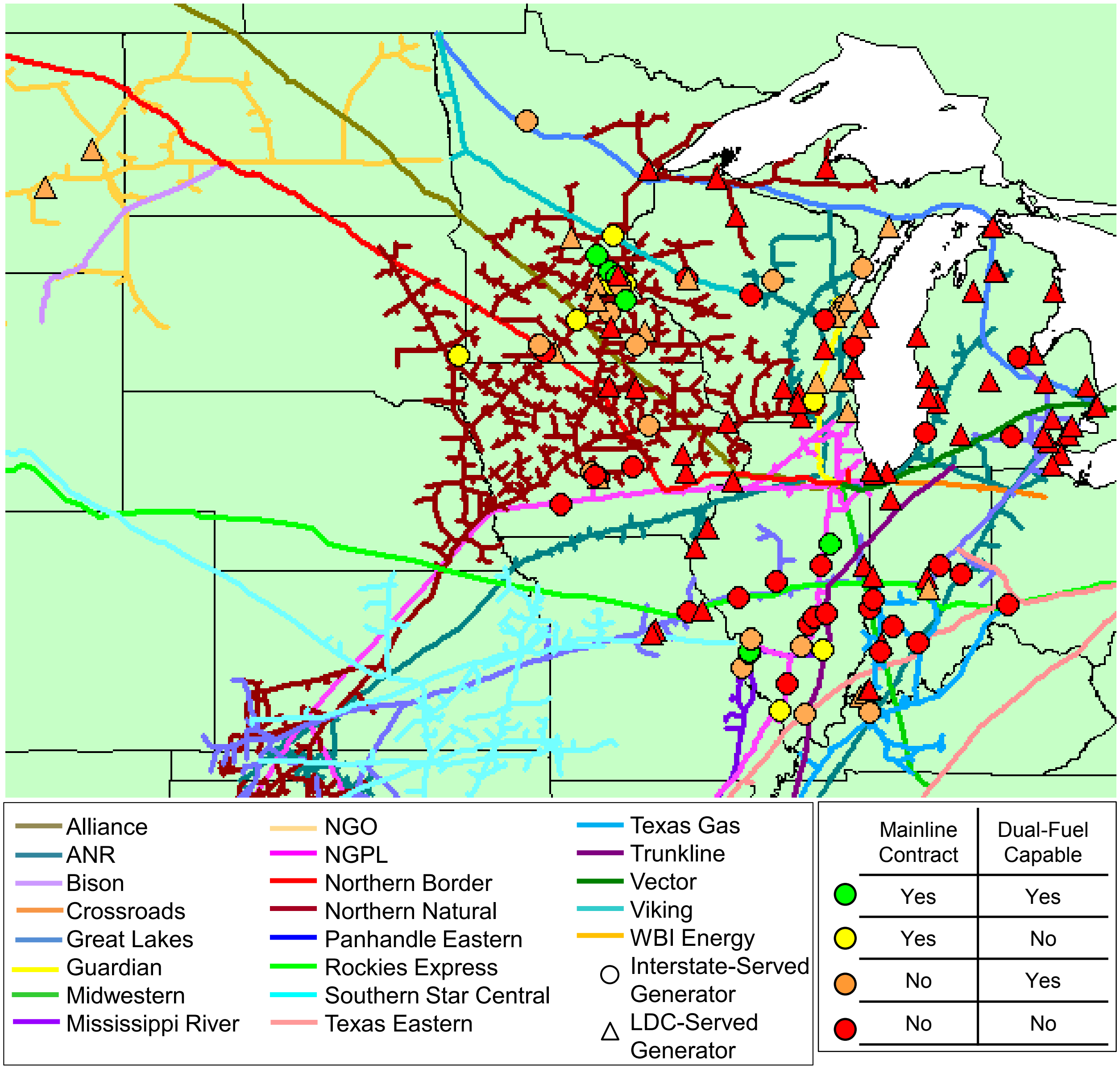
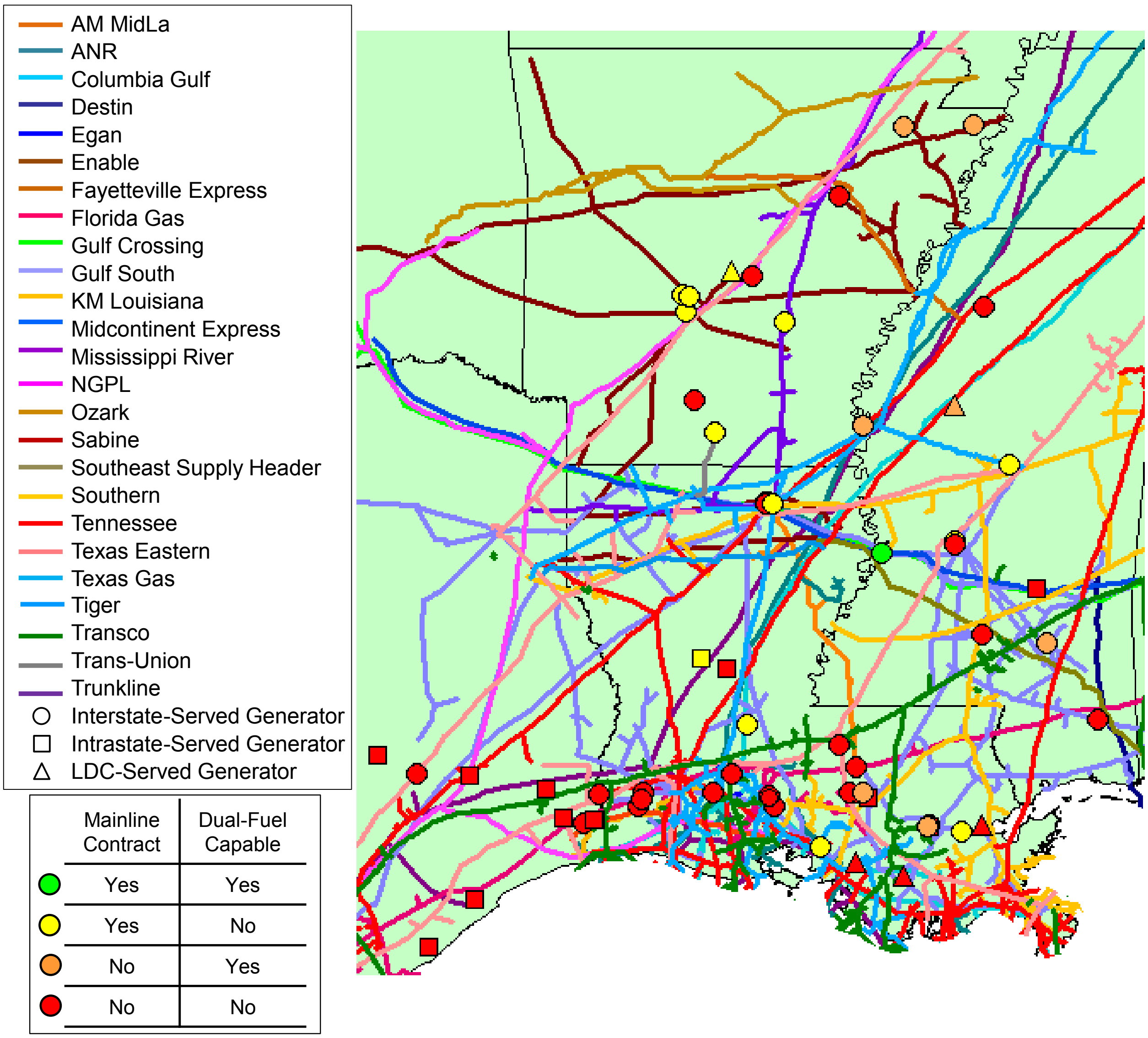


Figure 43. MISO South Generator Fuel Assurance Practices



Highlights of the MISO generator contract review include:

- Entergy Arkansas and Entergy Gulf States hold a total of 148 MDth/d of firm capacity on AM MidLa from the Fairbanks interconnection with Tennessee to the Ouachita power plant; the one-year contract will end on 2/28/2014.

- Entergy Arkansas holds 100 MDth/d on Texas Eastern to transport gas from an interconnection with Texas Gas to the header of the Hot Springs plant lateral.[197] Both the mainline and lateral contracts end on 6/16/2031. Entergy Arkansas also holds a 50 MDth/d contract on Gulf South to serve this plant.

[197] The lateral capacity is 112 MDth/d.

- Entergy Arkansas holds a contract on Enable to deliver 124.8 MDth/d to the Lake Catherine plant and 5 MDth/d to the Arkansas Gas citygate for the Mabelvale plant.

- Entergy Louisiana holds 66.7 MDth/d of firm capacity on Gulf South for the Nine Mile power plant through 11/30/2020.

- Entergy Mississippi holds 50 MDth/d of Texas Gas capacity through 6/30/2015 and 40 MDth/d of Texas Eastern through 12/31/2015 to serve the Attala power plant. The Tennessee contract does not have any primary receipt points, but has secondary receipt rights in Louisiana. Entergy Mississippi also holds a firm contract on Columbia Gulf to serve the Baxter Wilson plant with 225 MDth/d through 12/31/2022

- Entergy Mississippi holds capacity on Texas Eastern with secondary receipt rights in East Louisiana through 3/31/2022. The contract volume varies throughout the year: 30 MDth/d in January and February, 5 MDth/d in March, 30 MDth/d in April, 35 MDth/d in May, 80 MDth/d in June through August, 60 MDth/d in September and 5 MDth/d in October through December.

- AmerenEnergy Medina Valley holds a firm transportation contract on NGPL for service to the Gibson City (5 MDth/d) and Grand Tower (12.5 MDth/d) power plants. It also holds a second contract for 18 MDth/d of capacity to only the Grand Tower plant.

- Xcel Energy holds several firm contracts on Northern Natural to serve generator loads, including 5.6 MDth/d from April to October for Cannon Falls, 62.3 MDth/d year-round for Riverside, 62.4 MDth/d year-round to Black Dog, 70.5 MDth/d year-round to High Bridge, 78.2 MDth/d from April to October for Blue Lake, 71.6 MDth/s April to October and 1 MDth/d November to March for Angus Anson, and 12.2 MDth/d year-round and 27.4 MDth/d year-round to the Mankato Energy Center.

- Ameren Missouri holds a firm transportation contract on Mississippi River for 30 MDth/d to the Venice plant.

- Cottage Grove holds 34.1 MDth/d of firm transportation capacity on Northern Natural. This contract is support by a storage entitlement that includes 1,000 MDth of capacity with injection and withdrawal rates of 11 MDth/d and 17.3 MDth/d, respectively.

- LS Power holds two contracts for service to the Whitewater power plant, a storage contract with a capacity of 500 MDth and injection/withdrawal rates of 5.5 MDth/d and 8.7 MDth/d, respectively, and a transportation contract for 30.4 MDth/d.

- Union Power Partners holds the full 430 MDth/d capacity of Trans-Union to provide service to the Union Power plant.

- Great River Energy holds a firm transportation contract for 30 MDth/d from April to October, divided evenly between the Cambridge and Elk River power plants.

- Pine Bluff holds 40 MDth/d of firm transportation capacity on Enable through 6/8/2021.

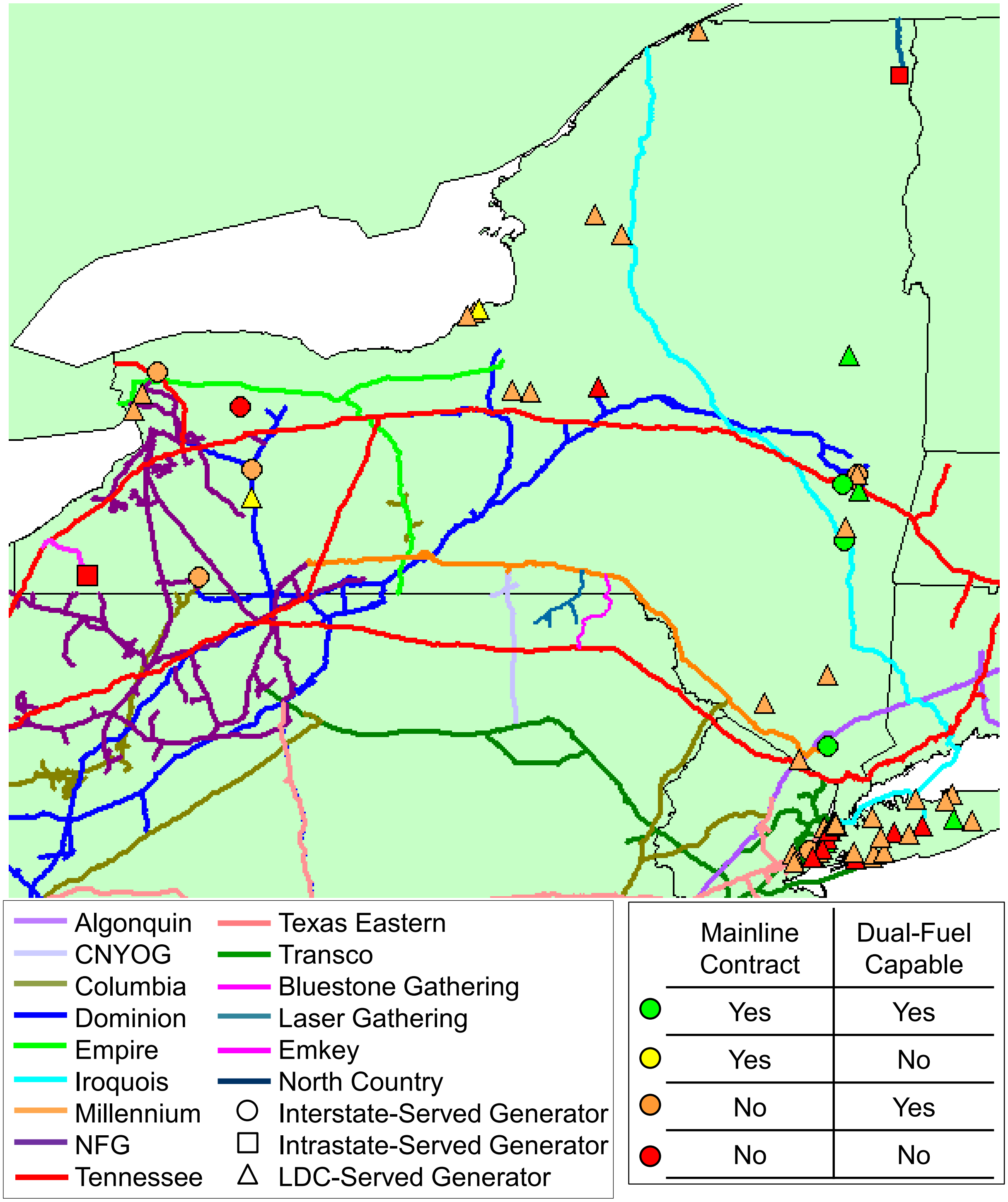
- The Arkansas Electric Cooperative holds 80 MDth/d of firm transportation capacity on Enable for the Magnet Cove power plant.

- Union Electric holds a Quick Notice Transportation contract on Trunkline, which allows hourly nomination adjustments, for service to the Raccoon Creek plant through 3/31/2021.
- Bluewater Gas Storage holds an FT-H contract on Vector for transportation from Bluewater to the Kinder Morgan Jackson plant, the contract expires on 3/31/2014.

3.3 NEW YORK

Figure 44 shows the NYISO generators, color-coded by fuel assurance approach as indicated in the legend. The generators in each category and contract details are presented in Exhibit 6.

Figure 44. NYISO Generator Fuel Assurance Practices



Highlights of the NYISO generator contract review include:

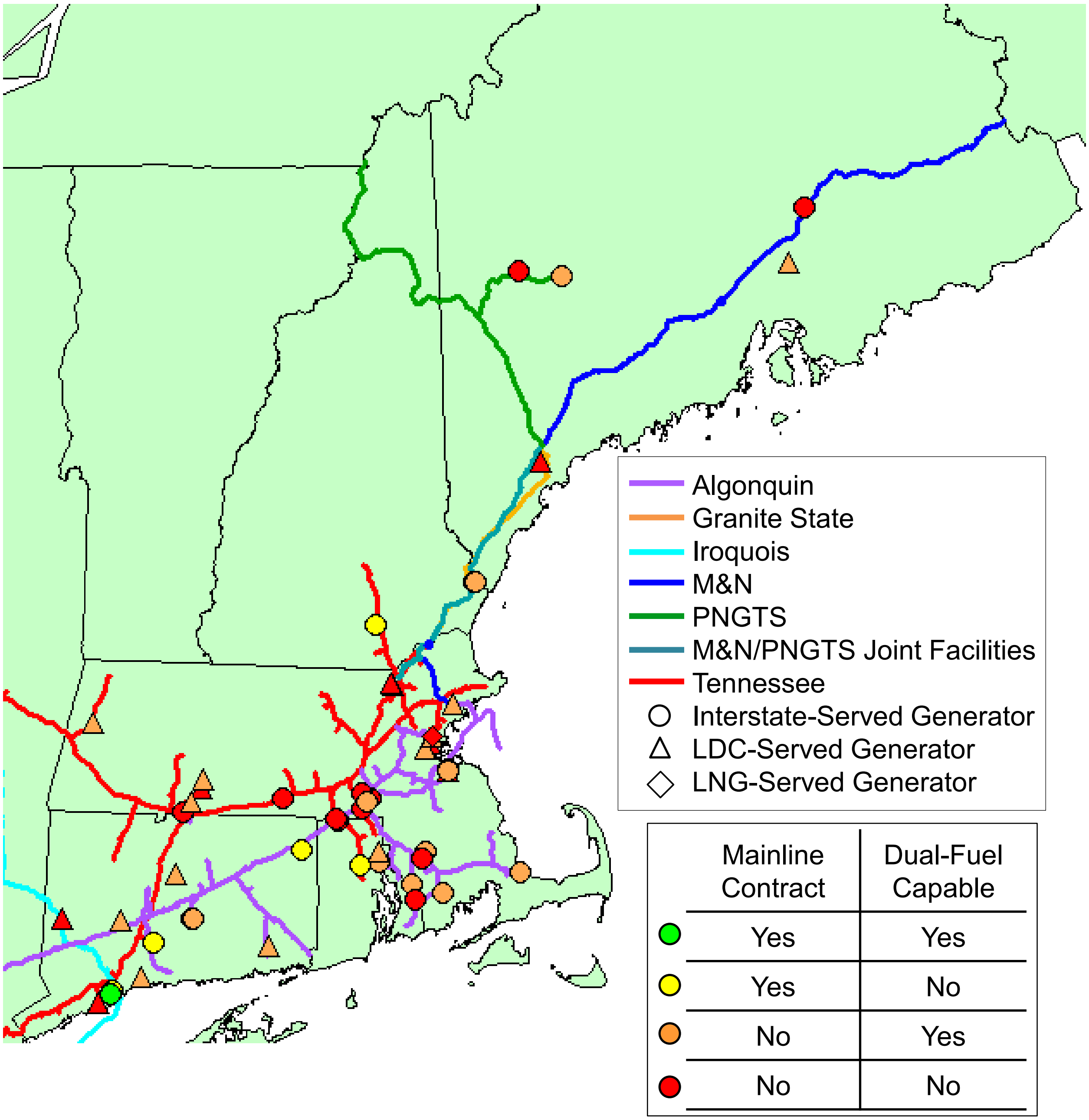
- Allegany holds an FT contract through 3/31/2014 for 12.1 MDth/d of firm transportation on Dominion from Ellisburg, sufficient to support all or nearly all of the plant's 67 MW of capacity.

- Athens holds a contract for 70 MDth/d of firm transportation capacity from Wright, sufficient to support approximately 25% of the plant's 1,323-MW capacity through 9/1/2018.
- Brooklyn Navy Yard Cogen holds 25.5 MDth/d of firm transportation capacity on Iroquois from Waddington through 10/1/2016, sufficient to fuel between one-third and one-half of the 322-MW capacity.
- Castleton Fort Orange holts 14.3 MDth/d of firm transportation capacity on Dominion from the Marilla, NY interconnection with Tennessee through 10/31/2032, sufficient to support the full 72 MW output of the plant
- The New York Power Authority holds a firm transportation contract on Transco for 30.8 MDth/d from Leidy through 3/31/2017, sufficient to fuel all or nearly of the Flynn plant's 170 MW capacity.
- Indeck Corinth holds 26.2 MDth/d of capacity on Dominion from an interconnection with ANR in Lebanon, OH through 7/1/2015, sufficient to fuel all or nearly all of the plant's 147-MW capacity.
- Sithe Independence holds 185.6 MDth/d of firm transportation on Empire from Chippawa through 12/9/2014 for delivery to the NGrid-Niagara Mohawk line providing dedicated service to the plant, sufficient to fuel approximately three-quarters of the 1,254-MW capacity.
- Ravenswood holds 40 MDth/d of firm capacity on Iroquois from Waddington to Hunts Point through 3/1/14 for delivery into the New York Facilities System.
- Selkirk holds firm contracts on Iroquois and Tennessee for service from Waddington through the Wright interconnection to the plant meter through 11/1/2014. The Iroquois contract is for 55 MDth/d and the Tennessee contract is for 55.6 MDth/d to accommodate shrink. Selkirk also holds a firm transportation contract on TransCanada from Empress to Waddington for 58.5 GJ (55.4 MDth/d) through 10/31/2014.
- NRG Power Marketing holds 75 MDth/d of capacity on Millennium from Ramapo to Bowline through 2/28/14, sufficient to fuel approximately one-third of the plant’s capacity of 1,242 MW.
- USPowerGen Astoria held a short-term contract through 2/1/14 for 50 MDth/d of firm transportation on Iroquois from Waddington to Hunts Point, sufficient to fuel approximately 1/3 of the plants 779 MW

3.4 New England

Figure 45 shows the ISO-NE generators, color-coded by fuel assurance approach as indicated in the legend. The generators in each category, along with firm contract details where applicable, are listed in Exhibit 7.

Figure 45. ISO-NE Generator Fuel Assurance Practices



Highlights of the ISO-NE generator contract review include:

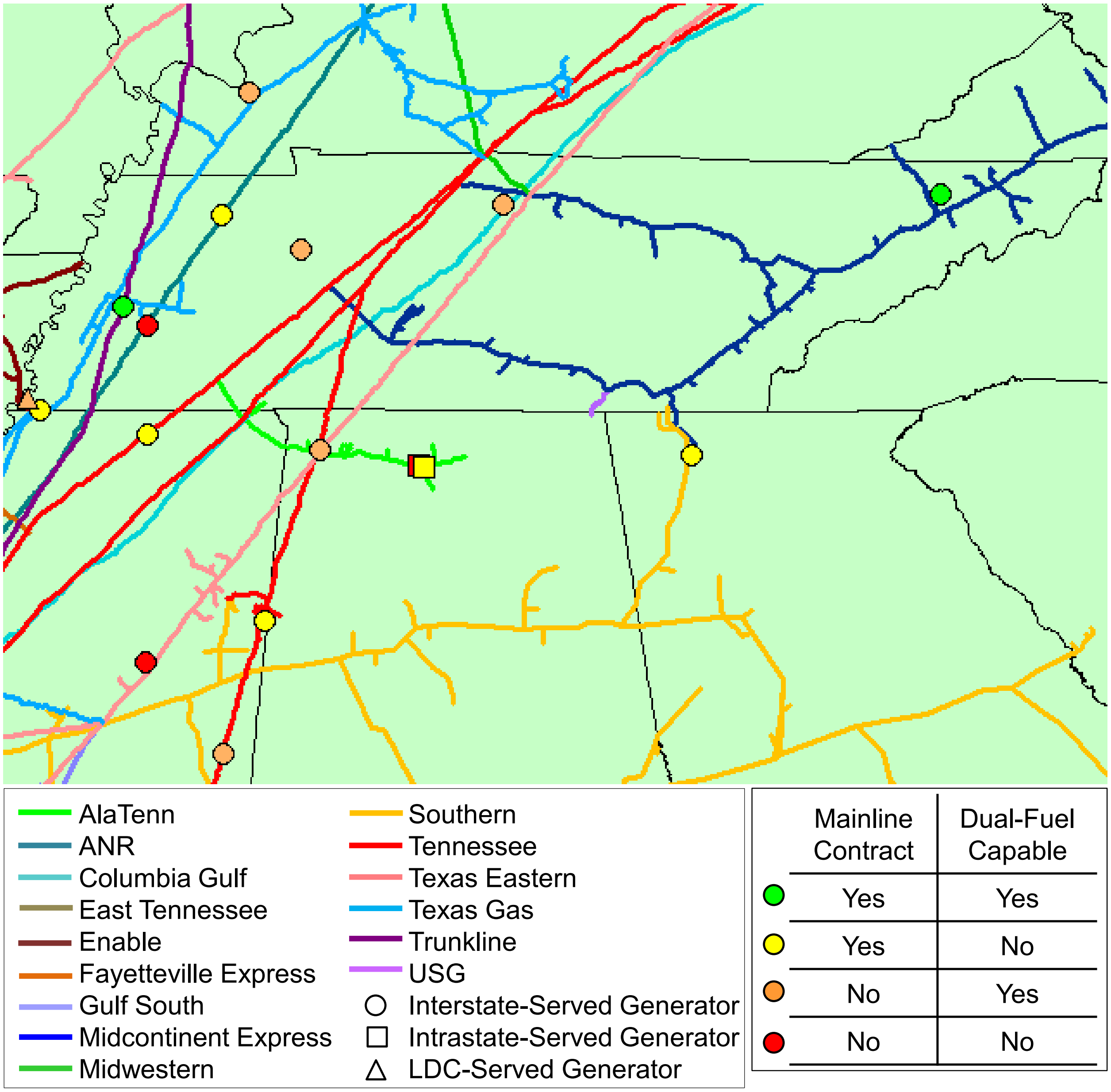
- Granite Ridge holds a contract through 10/6/2021 for firm transportation on Tennessee from Dracut for 130 MDth/d, sufficient to support all or nearly all of the plant's 770-MW capacity.
- RISEP holds a contract through 1/31/2016 for firm transportation on Tennessee from Dracut for 45 MDth/d, sufficient to support approximately half of the plant's 617 MW of capacity.

- Milford Power (CT) holds a contract through 4/1/2026 for firm service on Iroquois from Waddington for 35 MDth/d, sufficient to support approximately one-third of the plant's capacity of 569 MW.
- Wallingford holds a contract through 10/31/17 for firm service on Iroquois from Waddington for 10 MDth/d, sufficient to support approximately one-fourth of the plant's 244-MW capacity.
- Lake Road holds a contract through 10/31/2014 for firm transportation on Algonquin from Mahwah, Mendon and Lambertville for 40.3 MDth/d, sufficient to support approximately one-third of the plant's capacity of 857 MW.
- GDF Suez holds contracts through 10/31/2014 for firm transportation on Algonquin from Everett to ANP Bellingham (5 MDth/d) and NEA Bellingham (6 MDth/d).
- NRG Power Marketing is the agent on a Connecticut Light & Power contract for firm service on Iroquois from the Shelton interconnection with Tennessee to Devon that expires on 7/1/2014.
- Sequent Energy Management, a gas marketer, holds a contract through 10/31/15 for 4.3 MDth/d of firm service on Tennessee from Texas with a primary delivery point at Berkshire Power.

3.5 TVA REGION

TVA operates fourteen gas-fired generating plants, and holds mainline firm transportation contracts for eight of them. Figure 46 shows these generators, color-coded to identify plants with firm contracts and/or dual fuel capability. The generators in each category and contract details are provided in Exhibit 8.

Figure 46. TVA Generator Fuel Assurance Practices



Key findings of the TVA generator contract review include:

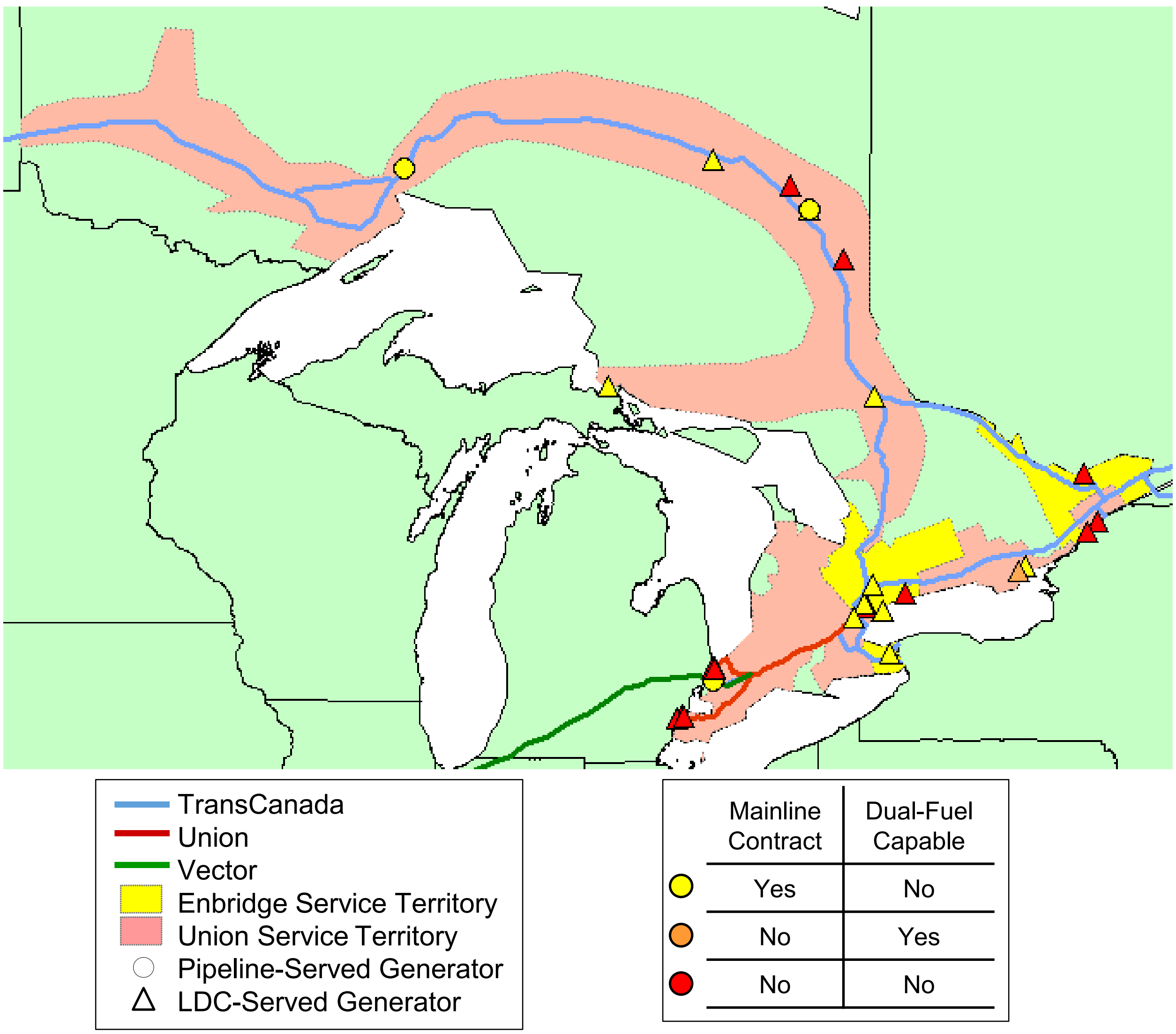
- TVA holds firm contracts for service to the Caledonia, Decatur, Gleason, John Sevier CC, Lagoon Creek, Lagoon Creek CC, Magnolia and Southaven plants.
- Oglethorpe Power holds 165 MDth/d of firm transportation on East Tennessee at a negotiated rate to serve the Smith power plant.
- Contract volumes are sufficient to support full or nearly full output, with the exception of the Lagoon Creek plant.

- Contracts are sourced from upstream pipeline and storage interconnections, including several for service from the Egan Hub storage facility.
- Most contracts are long-term, expiring in 2019 or later.

3.6 IESO

Figure 42 shows the IESO generators, color-coded by whether they hold mainline contracts in their own name or are dual fuel capable as indicated in the legend. The generators in each contracts and available contract details are included in Exhibit 9.

Figure 47. IESO Generator Fuel Assurance Practices



Highlights of the IESO contract review include:

- Goreway holds 140,000 GJ (312.7 MDth/d) of capacity on Union and TransCanada from Dawn. Goreway also holds storage rights at Dawn, with a storage quantity of 600,000 GJ (568.7 MDth) and injection/withdrawal rates of 128,000 GJ/d (121.3 MDth/d).

- Greater Toronto Airports Authority holds 7,500 GJ/d (7.1 MDth/d) of capacity on Union and TransCanada from Dawn to Enbridge through 10/31/2018.

- Greenfield holds 211,011 GJ (200 MDth) of storage capacity at Dawn, with injection/withdrawal rates of 42,402 GJ/d (40.2 MDth/d), and 92,845 GJ/d (88 MDth/d) of firm transportation capacity on Union from Dawn to Union's interconnection with Vector through 10/31/2018. Greenfield also holds transportation contracts on Vector that terminate on 3/31/2018 and 10/31/2023.

- TransCanada Energy holds contracts on TransCanada and Union to serve the Halton Hills plant. The TransCanada contract, for service from Dawn, is for 100,000 GJ/d (94.6 MDth/d) and ends on 12/31/2018. The Union contract, for service from Dawn to Parkway, is for 132,000 GJ/d (125.1 MDth/d) and ends on 10/31/2018.

- Iroquois Falls holds 20,874 GJ/D (19.8 MDth/d) of capacity on TransCanada from Empress, deliverable to Union, through 8/31/2016.

- Atlantic Power holds 17,900 GJ (17 MDth/d) of firm transportation capacity from Empress that is deliverable to Union for service to the Kapuskasking and North Bay power plants. These contracts have end dates between 10/31/2014 and 10/31/2016.

- Kingston Cogen holds 21,045 GJ/D (19.9 MDth/d) of capacity on TransCanada from Empress, deliverable to Union, through 8/31/2016.

- Lake Superior Power holds 10,100 GJ/d (9.6 MDth/d) of capacity on TransCanada from the Sault Ste. Marie interconnection with Great Lakes for delivery to Union through 12/31/2016.

- Atlantic Power holds 6,400 GJ (6.1 MDth/d) of firm transportation capacity on TransCanada from Empress to Tunis with end dates ranging from 10/31/2014 to 10/31/2016.

- Portlands Energy Centre holds 100,000 GJ/d (94.8 MDth/d) of firm capacity on Union from Dawn to Parkway and on TransCanada from Parkway to Enbridge. The TransCanada and Union contracts end on 11/30/2016 and 10/31/2028, respectively. Portlands also holds 500,000 GJ (473.9 MDth) of storage capacity at Dawn, with injection/withdrawal rates of 40,000 GJ/d (37.9 MDth/d).

- Thorold Cogen holds 49,500 GJ/d (46.9 MDth/d) of capacity on Union from Dawn to Kirkwall and on TransCanada from Kirkwall to the plant. The TransCanada contract expires on 8/31/2019 and the Union contract expires on 8/31/2029. Thorold Cogen also holds rights at Dawn, with a storage quantity of 170,000 GJ (161.1 MDth) and injection/withdrawal rates of 44,000 GJ/d (41.7 MDth/d).

- Atlantic Power holds 8,100 GJ (7.7 MDth/d) of firm transportation capacity on TransCanada from Empress to Tunis through 10/31/2014.

- York Energy Centre holds 175,000 GJ (165.9 MDth/d) of storage capacity at Dawn, with injection/withdrawal rates of 87,654 GJ/d (83.1 MDth/d), and also has 87,654 GJ/d (83.1 MDth/d) of firm transportation capacity on Union from Dawn to Parkway and on TransCanada from Parkway for delivery to Enbridge. The Union transportation capacity is held in two contracts that expire on 3/31/2015 and 10/31/2022 and the TransCanada contract ends on 4/30/2022.

4 CAPACITY RELEASE AND SECONDARY MARKETS

Interstate pipelines are initially built to provide service of the primary firm entitlements, mainly LDCs. Through capacity releases and nominations, firm shippers can segment their capacity and utilize secondary firm entitlements. LDCs typically use their primary firm pipeline entitlements fully or near fully to meet the needs of their core customers throughout the heating season. During the non-heating season, LDCs' core sendout materially declines, lessening their reliance on primary firm pipeline transportation arrangements. This provides an opportunity for LDCs to release some portion of their primary firm entitlements during the non-heating season. In addition, LDCs can release their secondary firm entitlements. Such releases may be subject to recall provisions that safeguard the LDC's ability to rely on the entitlements on short notice if a peak in demand results in a need to increase sendout. The secondary market for firm capacity entitlements allows shippers holding excess capacity to redeploy this capacity to other shippers. Shippers holding the unused entitlements can recover some of their costs by reselling what they do not need.

Additionally, an LDC's entitlements may become underutilized due to changes in market economics. As discussed below, shale gas production has supplanted production from the traditional onshore and offshore sources from the Gulf Coast, the Rocky Mountains, and Western Canada. As a result, many LDCs holding long haul primary entitlements from traditional Gulf onshore and offshore production sources no longer regularly utilize various upstream pipeline segments linking the Gulf Coast to the storage facilities in western Pennsylvania and/or New York. While deliveries from the Gulf Coast or Western Canada have been made redundant due to the abundance of regional shale gas production, LDCs in the Northeast may still realize valuable operating benefits associated with their primary receipt point capability in the Gulf Coast when operating contingencies occur. Such operating contingencies can limit the availability of shale gas. Regardless of cause, when primary firm entitlements are not fully utilized, the holders of such capacity may take action to release all or a portion of these entitlements, thereby recouping some value from an otherwise unused asset. Existing FERC rules support LDCs' ability to segment their capacity rights in order to release the upstream segment.

In conducting this study, LAI worked closely with the Interstate Natural Gas Association of America (INGAA) in order to compile publicly available data posted on pipeline EBBs reporting the release of capacity in the secondary market.[198] Responses were received from about 40 pipelines. Relying on the information furnished by the pipelines operating across the Study Region, LAI reviewed the capacity release transactions over the twelve-month period, October 2012 through September 2013. For every release, the database contains the identity of the assignor, the assignee, specification of receipt and delivery point(s), the quantity transacted, the inclusion or not of a subject-to-recall right, and, in many cases, price. In addition to LAI's professional judgment, the database was utilized to support LAI's examination of the structure of the secondary capacity market described in this section.

[198] An information request was submitted to INGAA on November 7, 2013. INGAA members provided extensive information to support the Target 1 research effort. Selected non-INGAA pipelines were contacted directly by EIPC and have also provided the requested information to supplement the INGAA response.

LAI reviewed the transaction data for each pipeline across multiple zones, even in instances where the pipeline operates in more than one PPA or outside the Study Region. While we have inspected transaction trends for multiple assignors, to keep this research from becoming unwieldy, we highlight meaningful trends underlying one large assignor's portfolio of releases on selected pipelines in each PPA, excluding Ontario, as explained below. In each case the selected assignor is an LDC. The selected entitlement holder and the pipelines on which its releases were reviewed are shown in Table 20.

Table 20. Release Portfolios Reviewed

PPA	Releaser	Releases on
New England	NGrid	Algonquin, Tennessee
New York	Consolidated Edison	Transco, Texas Eastern
TVA	Atmos Energy Kentucky	Texas Gas
PJM	WGL	Columbia Gas, Dominion
MISO	Black Hills	Northern Natural, NGPL
Ontario	N/A	TransCanada

In conducting Target 1 research, LAI contacted diverse market participants to discuss the trading dynamics underlying transactions in the secondary market.[199] Information and perspectives shared by market participants have helped guide the research efforts conducted in this task as well as the observations and findings presented herein.

4.1 COMMON TRENDS ACROSS THE STUDY REGION

One noteworthy trend common to most PPAs is the limited participation of gas-fired generators in the primary or secondary market for pipeline capacity entitlements. In most cases, electric generators do not hold primary entitlements from liquid sourcing points to the plant, nor are they among the most active participants in the secondary markets. However, as discussed in the individual PPA sections below, there are exceptions in MISO, Ontario, and, to a lesser extent, PJM.

Where generators do not generally hold firm contracts or released capacity, there can be a gap between generator gas requirements and the ability to schedule gas. Gas marketers bridge that gap. Gas marketers may enter into *ad hoc* commercial arrangements for relatively short term supply obligations at the citygate or plant gate. Often, a marketer or gas supplier will enter into an AMA with a generation counterparty to fulfill all or a portion of the generator's gas requirements in the DAM or RTM.[200] The pricing of bundled gas supply services under either an

[199] Due to commercial nature of the information discussed, the content of these conversations is not available for publication.

[200] AMAs are commercial contractual relationships where a party agrees to manage gas supply and delivery arrangements for another party for an agreed to payment.

AMA or agency agreement reflects market prices, *i.e.*, the value of natural gas delivered to the consuming region.[201]

LAI has selected the releases of a single, active primary entitlement holder for detailed analysis in order to represent transaction trends characteristic of other prominent assignors across the Study Region. Generally speaking, the entitlement holder was selected because it the most active or one of the most active releasers of capacity in the secondary market.

The following sections provide summary descriptive statistics and analysis of the structure of the secondary market in PJM, MISO, NYISO, ISO-NE, TVA and the IESO. Unless otherwise noted, references to receipt and deliver points generally represent the points on the pipeline where gas enters the system and where it is delivered to the end user, respectively.

4.2 PJM

The key pipelines serving PJM for which secondary release data were provided include Columbia Gas, Dominion, Texas Eastern, and Transco. There are other interstate pipelines as well that have active EBBs where entitlement holders routinely exchange capacity. In PJM, particular focus has been placed on Columbia Gas and Dominion, on which prominent holders of firm transportation entitlements and assignors of underused capacity are LDCs. Table 21 lists the ten most active assignors of capacity ranked by the number of transactions executed. A ranking by the quantity of gas released would yield similar results.

Table 21. Most Active Assignors on Columbia Gas

Assignor	Releases	% of All Releases	Aggregate %
Columbia Gas of Ohio	2,137	32.1%	32.1%
NYSEG	999	15.0%	47.2%
UGI Utilities	672	10.1%	57.3%
Orange & Rockland	547	8.2%	65.5%
Central Hudson Gas & Electric	380	5.7%	71.2%
WGL	263	4.0%	75.2%
Columbia Gas of Pennsylvania	239	3.6%	78.8%
Vectren Energy Delivery of Ohio	234	3.5%	82.3%
Columbia Gas of Virginia	160	2.4%	84.7%
Columbia Gas of Kentucky	136	2.0%	86.7%

Table 22, below, shows the same data for Dominion. On both pipelines, a relatively small number of assignors, mostly LDCs, account for most releases.

[201] AMAs are not regulated as swaps under Dodd-Frank by the U.S. Commodity Futures Trading Commission.

Table 22. Most Active Assignors on Dominion

Assignor	Releases	% of All Releases	Aggregate %
Energy East Corporation	603	29.3%	29.3%
Niagara Mohawk Power Corporation	562	27.3%	56.6%
Rochester Gas and Electric Corporation	549	26.7%	83.2%
East Ohio Gas Company	36	1.7%	85.0%
Boston Gas Company	31	1.5%	86.5%
Peoples Natural Gas of Pittsburgh	31	1.5%	88.0%
Bay State Gas Company	19	0.9%	88.9%
UGI Energy Services Inc.	19	0.9%	89.8%
Washington Gas Light Company	18	0.9%	90.7%
CNX Gas Company LLC	18	0.9%	91.6%

WGL is one of the largest assignors of capacity on both pipelines, responsible for nearly 4% of the capacity release transactions on Columbia Gas and 1% of the transactions on Dominion, making it one of the largest releasers of capacity on the secondary market in PJM on both pipelines.

WGL holds four contracts on Dominion and seven contracts on Columbia Gas. WGL's MDQ is 172,000 MMBtu and 911,066 MMBtu on Dominion and Columbia Gas, respectively. During the period for which the data were reported, WGL released capacity through 263 separate transactions on Columbia Gas and 18 transactions on Dominion. Despite the large number of transactions, shows that there were only two pipeline paths on which capacity was released. On Columbia Gas, releases were of capacity that specified to the WGL citygate near the Capital District as the only receipt point, as shown in Table 24.

Table 23. Top Delivery / Receipt Points for WGL Releases on Columbia Gas

Delivery Point			Receipt Points		
Location	State	Deals	Location	State	Deals
WGL 30	VA	263	TCO-Leach	KY	241
			RP Storage Point	WV	22

Table 24. Delivery and Receipt Points for WGL Releases on Dominion

Delivery Points			Receipt Points		
Location	State	Deals	Location	State	Deals
WGL	VA	18	Texas Eastern – Oakford	PA	18

The 18 transactions on WGL are from primary entitlements that specify the WGL citygate in Fairfax, VA as the delivery point, and the interconnection with Texas Eastern in PA as the receipt point.[202] WGL does not appear to segment its capacity entitlements. As discussed in

[202] All the capacity released by WGL on Dominion "flows through" the Title Transfer Point, part of the liquid trading hub, *i.e.*, Dominion-South Point. None of this capacity either originates or terminates at this hub.

greater detail below, segmentation of capacity rights is a much more important dynamic in other markets.

Over the 12-month period reviewed, WGL's counterparties were predominantly energy marketers or unregulated gas suppliers. Table 25 shows the ten largest assignees on Columbia Gas and Dominion, ranked by total MMBtu transacted.[203]

Table 25. Top Assignees of WGL Capacity on Columbia Gas and Dominion

Columbia Gas			Dominion		
Assignee	**MMBtu**	**Deals**	**Assignee**	**MMBtu**	**Deals**
Washington Gas Energy Services	33,203,758	33	Washington Gas Energy Services	3,141,374	5
NOVEC Energy Solutions	1,781,205	15	CNE Gas Supply	1,536,472	9
Hess Corporation	1,458,870	14	UGI Energy Services	119,222	4
UGI Energy Services	873,075	13			
Bollinger Energy	633,944	15			
Compass Energy Gas Services	506,779	14			
PEPCO Energy Services	393,735	8			
Metromedia Energy	337,707	16			
Smart One Energy	301,230	8			
Stand Energy	143,371	14			

On both Dominion and Columbia Gas, the most frequent assignee is Washington Gas Energy Services. Washington Gas Energy Services is the unregulated gas marketing affiliate of WGL. Other assignees are either marketers or gas suppliers. Merchant based gas-fired generation companies or electric utilities are not assignees of WGL's capacity rights.

WGL released all of its capacity for terms of 31 days or less, as shown in Table 26, below:

Table 26. Deal Count by Term Length on Columbia and Dominion

Term Length	Columbia Gas	Dominion
7 days or less	6	0
8-31 days	257	18
32-365 days	0	0
366 days or longer	0	0

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[203] The total MMBtu of a capacity transaction is calculated as the daily capacity, measured in MMBtu/d, multiplied by the number of days covered by that transaction. The convention is utilized throughout this section.

WGL's releases on Dominion and Columbia Gas were recallable by WGL at the utility's discretion. How frequently WGL exercised its recall rights is unknown.

4.3 MISO

Among the pipelines serving MISO, LAI has analyzed releases by entitlement holders on Centerpoint, NGPL, Northern Natural Gas, among others. Unlike other PPAs where the primary entitlement holders and assignors are overwhelmingly LDCs, in MISO, both gas marketers and electric utilities hold significant primary entitlements. Both gas marketers and electric utilities are also frequent assignors. Table 27, below, lists the ten most active assignors on Northern Natural, measured by number of transactions. Similar results would be observed had LAI ranked assignors by the volume of capacity released rather than the number of transactions. The five most active assignors account for roughly 60% of all capacity released on Northern Natural. The largest assignor, U.S. Energy Services, is a marketer. MidAmerican Energy, owned by Berkshire Hathaway, is an electric utility. Black Hills is a utility holding company. SEMCO Energy and Minnesota Energy Resources are both LDCs.

Table 27. Most Active Assignors on Northern Natural

Assignor	Releases	% of All Releases	Aggregate %
U.S. Energy Services	300	29.1	29.1
MidAmerican Energy	125	12.1	41.3
Black Hills	103	10.0	51.3
SEMCOEnergy	43	4.2	55.4
Minnesota Energy Resources	42	4.1	59.5
Midwest Natural Gas	29	2.8	62.3
Agri-Energy	22	2.1	64.5
Wisconsin Gas	22	2.1	66.6
Integrys Energy Services	18	1.7	68.3
Northwestern Corporation	17	1.7	70.0

Table 28 shows the same data for NGPL, indicating a mix of marketers, LDCs, and electric utilities among the most active assignors. For both pipelines, a small handful of releasers account for a large majority of the total transactions. Overall, there are fewer releases on NGPL.

Table 28. Most Active Assignors on NGPL

Assignor	Releases	% of All Releases	Aggregate %
Northern Indiana Public Service	112	34.9	34.9
Arkansas Electric Cooperative	72	22.4	57.3
MidAmerican Energy	23	7.2	64.5
Liberty Energy (Midstates)	16	5.0	69.5
Black Hills	12	3.7	73.2
Ameren Illinois	9	2.8	76.0
Border Energy	8	2.5	78.5
Direct Energy Services	8	2.5	81.0
Nordic Energy Services	8	2.5	83.5
Santanna Natural Gas	8	2.5	86.0

The frequency with which electric utilities appear among major assignors on both pipelines may reflect the vertically integrated nature of the utility markets in various Midwest states. Electric utilities may, in some instances, have state regulatory commission support to hold primary firm entitlements for all or a portion of their natural gas requirements. Under such circumstances, electric utilities are generally able to pass through the cost of firm entitlements in their cost of service regardless of how much net margin is recouped through capacity release.[204]

LAI has also reviewed the transaction history of Black Hills in the secondary market. Black Hills owns three energy companies: Black Hills Energy, a gas and electricity supplier to customers in Colorado, Iowa, Kansas, and Nebraska; Black Hills Power, a generator serving customers in South Dakota, Wyoming, and Montana; and, Cheyenne Light, which has electric and gas customers in Wyoming. Based on the location of the Northern Natural and NGPL route systems, it appears that Black Hills regularly assigns its capacity rights to Black Hills Energy and Black Hills Power. The allocation of deliverability and economic benefits to the company's gas and electric customers is unknown.[205]

Black Hills holds 30 entitlements on Northern Natural Gas for a total MDQ of 1,339,362 MMBtu and 6 entitlements on NGPL for a total MDQ of 79,027 MMBtu. During the study period, Black Hills released capacity through a total of 102 separate transactions on Northern Natural Gas and 12 transactions on NGPL, representing 10% and 5%, respectively, of all releases from those pipelines.[206]

[204] In other PPAs where gas-fired generation is largely merchant based, such generators can be at-risk for recoupment of their pipeline transportation costs. Adverse financial exposure may deter merchant generators from obtaining capacity entitlements in their own name, among other reasons.

[205] Black Hills' large entitlements on Northern Natural likely support Black Hills LDC customer obligations. Review of Black Hill's regulatory filings before state commissions is outside the scope of Target 1 research objectives.

[206] The data provided from Northern Natural's EBB indicate the pipeline segment for which each release was transacted, but specific receipt and delivery points are not defined.

Details regarding the most frequently transacted pipeline segments for Black Hills' releases on Northern Natural are shown below. Northern Natural does not specify receipt and delivery points in its release data. It does flag each location as either a "Field" or a "Market" location. The most points at which Black Hills released the capacity most often for each of these two categories is shown in Table 29.

Table 29. Top Transaction Locations on Northern Natural[207]

Market Locations			Field Locations		
Location	**State**	**Transactions**	**Location**	**State**	**Transactions**
NBPL/NNG Ventura	IA	67	Argus Zone Black Hills	SD	25
Zone ABC – Black Hills	SD	59	CIG Garden City Interconnect	MN	21
Zone D – Black Hills	IA	37	Cheyenne Plains	KS	14
NBPL/NNG Welcome	MN	14			
NBPL/NNG Grundy Center	IA	10			

The most frequently specified delivery and receipt points for capacity released by Black Hills on NGPL are shown in Table 30, below.

Table 30. Delivery and Receipt Points for Black Hills Releases on NGPL

Delivery Points		Receipt Points	
Location	**Transactions**	**Location**	**Transactions**
CEM/NGPL OK Extension – Grady	6	Aquila N. / NGPL Lincoln	9
CIG/NGPL Forgan Beaver	5	Black Hill / NGPL	3
EPNG/NGPL Jal Lea	1		

Black Hills' capacity releases on both pipelines were obtained solely by gas marketers. Counterparties for releases on both pipelines are shown in Table 31.[208]

[207] A single release may indicate multiple Market or Field locations as delivery and receipt points. Therefore, the total number of segments indicated may total to more than the total overall number of releases.

[208] Black Hills also executed a multi-year release of storage-related capacity on NGPL with Tenaska Gas Services that has been omitted. Because of the long duration off the contract, the total MMBtu of the single transaction would have made Tenaska Gas Services the single largest assignee of Black Hills secondary capacity on NGPL. The transaction was not deemed relevant and has therefore been omitted.

Table 31. Top Assignees of Black Hills Releases

Northern Natural Gas			NGPL		
Assignee	**MMBtu**	**Deals**	**Assignee**	**MMBtu**	**Deals**
Mieco	14,239,496	36	BP Canada Marketing	2,140,000	1
Encore Energy Svcs.	7,091,924	11	Concord Energy	1,520,000	3
Seminole Energy Svcs.	6,270,175	15	CNE Gas Supply	887,578	1
CNE Gas Supply	6,138,977	12	Enserco Energy	830,000	2
Concord Energy	1,660,000	2	Oneok Energy Services[209]	280,000	1
U.S. Energy Services	862,000	3	CIMA Energy	230,000	1
Integrys Energy Services	687,500	4	Seminole Energy Services	166,704	1
CIMA Energy	601,028	2	Heartland Natural Gas	3,157	2
Tenaska Marketing Ventures	600,000	1			
Reeve AgriEnergy	385,900	3			

Black Hills' most active assignees are marketers, not merchant generation companies or electric utilities, consistent with the findings on other pipelines in other PPAs.

The terms of transactions among Black Hills' releases varied somewhat widely, as indicated below. Nearly all deals were one year in length or less.

Table 32. Deal Count by Term Length for Black Hills Releases

	Northern Natural	**NGPL**
7 days or less	21	0
8-31 days	49	7
32-365 days	30	5
366 days or longer	2	0

Among these transactions, regardless of term length or pipeline segment, all capacity releases on both pipelines were recallable at the assignor's discretion. How frequently recall rights were exercised is unknown.

4.4 NEW YORK

Data were provided for capacity releases on the interstate pipelines that provide gas to New York, including Transco, Texas Eastern, Tennessee, and Empire, among others. LAI selected

[209] In June 2013, Oneok indicated that it will be discontinuing its energy services business. http://ir.oneok.com/phoenix.zhtml?c=120070&p=irol-newsArticle_Print&ID=1828595&highlight

capacity release activity on Transco and Texas Eastern. As in most PPAs, the largest primary entitlement holders and most active assignors are LDCs. Table 33 shows the ten most active assignors on Transco based on the number of released parcels.

Table 33. Most Active Assignors on Transco

Assignor	Releases	% of All Releases	Aggregate %
Atlanta Gas Light	962	18.2%	18.2%
Con Edison	708	13.4%	31.5%
NGrid-New York	547	10.3%	41.8%
NGrid-Long Island	454	8.6%	50.4%
Piedmont Natural Gas	386	7.3%	57.7%
PECO Energy Company	256	4.8%	62.5%
South Jersey Gas Company	177	3.3%	65.8%
UGI Utilities Inc	150	2.8%	68.7%
Public Service Company (NC)	136	2.6%	71.2%
Municipal Gas Authority (GA)	117	2.2%	73.5%

On Transco, the ten most active assignors are LDCs, though not all are located in New York. This group of assignors accounts for approximately 74% of all releases in the secondary market. Con Edison was selected for in-depth analysis because of the size of its portfolio and the frequency of Con Edison's releases across the supply chain from the Gulf Coast to the New York Facilities System.

Con Edison holds seven entitlements on Transco for a total MDQ of 416,751 MMBtu and six entitlements on Texas Eastern for a total MDQ of 288,245 MMBtu. During the period under review, there were 694 and 148 transactions on Transco and Texas Eastern, respectively.

Most of Con Edison's releases on Texas Eastern were of entitlements that were deliverable to the NGrid citygate on the New York Facilities System in Brooklyn, NY. There were also a significant number of capacity releases at Texas Eastern's interconnection with Columbia Gas in Eagle, PA as a primary delivery point. The number of transactions for capacity deliverable at each location is shown below:

Table 34. Delivery Points for Con Edison Releases on Texas Eastern

Delivery Location	Releases
Brooklyn, NY	114
Eagle, PA (Columbia Gas Interconnect)	34

Con Edison released capacity on Texas Eastern with primary receipt points in the Gulf Coast as shown in Table 35, below.[210]

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[210] Because some transactions offer the assignee the option of receiving gas at one of multiple points within a market zone, we have reported receipts by zone. Each transaction denotes one or more pipeline receipt points.

Table 35. Receipt Points for Con Edison Releases on Texas Eastern

Receipt Location[211]	Releases
Access Zone "STX"	87
Access Zone "WLA"	3
Access Zone "ELA"	58

Current FERC policy permits entitlement holders to segment capacity rights to accommodate the resale of a portion of an entitlement holder's long haul rights from the Gulf Coast to the market center. As previously discussed, entitlement holders are also permitted to substitute receipt points for delivery points, and *vice versa*. Entitlement holders may also use other receipt points or delivery points not previously delineated in a transportation service agreement on a subordinated basis. These capacity market attributes facilitate broad stakeholder participation in the secondary market and give primary entitlement holders the opportunity to lower the cost of transportation by redeploying such rights, while giving assignees the opportunity to compete for limited pipeline capacity at market prices. As shale gas has largely displaced production from the Gulf Coast, western Canada and the Rocky Mountains across the Study Region, the flexible nature of the capacity release markets on the interstate pipelines serving PJM, NYISO and ISO-NE, in particular, provide entitlement holders with the opportunity to recoup significant value from Marcellus.[212]

The data provided by the pipeline EBBs provides limited information regarding the assignor's rights. The EBB data do not reveal pertinent information about the segmentation of capacity rights and the mechanics of the transaction, that is, the substitution of primary or secondary receipt and delivery points to effectuate the release. As such, a receipt point indicated in the release may actually be treated as a delivery point by the assignee, and a delivery point may be treated as a receipt point.[213] As we understand it, Con Edison, and other primary entitlement holders in the greater Northeast, may transact capacity releases from the Gulf Coast to a delivery point in New York, or, in the alternative, from a secondary receipt point in or around Marcellus to a delivery point that accommodates north-to-south flow toward the Gulf Coast. Some secondary receipt point capacity may be used in accord with Con Edison's segmentation rights to accommodate receipt of shale gas in Pennsylvania for redelivery to both primary and secondary delivery points, including out-of-the-path delivery points reflecting north-to-south flow.

Receipt points specified in the entitlements released by Con Edison on Transco are shown in Table 36.

[211] Access Zone "STX" extends from the southern tip of Texas Eastern's system north to Huntsville, TX and east to the Texas-Louisiana border. Access Zone "WLA" encompasses Texas Eastern's southern line through Louisiana from the Texas-Louisiana Border to Opalousas, LA. Access Zone "ELA" extends from Opalousas in central Louisiana into southeastern Mississippi.

[212] Capacity transactions that move gas in the same direction as the flow are forward-haul rather than back-haul transactions.

[213] If an assignee of released capacity utilized that capacity to support its own gas requirements, that assignee is the user. If the assignee is a marketer that re-sells the entitlement to a third party, the counterparty in that transaction is the user.

Table 36. Receipt Points for Con Edison Releases on Transco[214]

Receipt Location	State	Quantity (MMBtu)
Pooling Station 65	LA	19,569,010
Pooling Station 62	LA	15,097,726
Pooling Station 45	LA	10,512,129
Pooling Station 50	LA	7,725,728
Station 30	TX	7,413,284
Leidy National Fuel	PA	6,959,234
Pooling Station 85	AL	1,050,000

Like other PPAs, Con Edison's assignees on both Transco and Texas Eastern are predominantly gas marketers, and, to a lesser extent, unregulated suppliers. Hess, an energy conglomerate with a large gas marketing presence in the greater Northeast, is by far the largest assignee. The ten most active assignees of capacity on Texas Eastern and Transco are shown on Table 37.

Table 37. Top Assignees of Con Edison's Capacity on Texas Eastern and Transco

Transco			Texas Eastern		
Assignee	MMBtu	Deals	Assignee	MMBtu	Deals
Hess Corporation	41,143,446	25	Hess Corporation	9,110,035	3
Plymouth Rock Energy	9,503,292	27	Plymouth Rock Energy	1,803,081	3
Big Apple Energy	9,057,820	30	Big Apple Energy	1,691,710	4
Robison Energy	4,895,290	30	Energy America	839,500	3
Colonial Energy	4,464,848	67	BBPC, LLC	739,125	5
Global Montello Group	4,369,768	28	Global Companies	708,465	3
Hudson Energy services	3,275,364	26	S.J. Energy Partners	703,355	2
BG Energy Merchants	3,240,000	4	Colonial Energy	684,375	3
Macquarie Energy	3,216,072	91	Just Energy (NY)	669,775	3
BBPC, LLC	3,191,400	25	Robison Energy	662,475	3

The term of Con Edison's released capacity on Texas Eastern ranges from less than one month to one year. The majority of the released capacity is for terms greater than one month up to one year. In contrast, Con Edison's term structure covering released capacity on Transco is predominantly one month or less. A significantly portion of the parcels released on Transco are for one week or day to day.

[214] A single release may specify multiple receipt points. Therefore, the total of the segments reported may be greater than the total number of releases indicated.

Table 38. Deal Count by Term Length on Transco and Texas Eastern

	Transco	Texas Eastern
7 days or less	230	0
8-31 days	986	1
32-365 days	407	147
366 days or longer	0	0

Regardless of term, Con Edison's capacity release transactions on Texas Eastern all included a subject-to-recall right. On Transco, 1,395 of 1,623 transactions were subject-to-recall, or 86% of the total transaction level of the period we reviewed.

4.5 NEW ENGLAND

LAI has analyzed releases on each of the key interstate pipelines serving New England: Algonquin, Tennessee, M&N, Iroquois and PNGTS. Algonquin and Tennessee were selected for analysis for two reasons: first, Algonquin and Tennessee are the primary interstate pipelines serving New England; and, second, Algonquin, through a variety of upstream interconnections with both affiliated and unaffiliated pipelines, and Tennessee link New England with both Marcellus shale gas and the Gulf Coast. Like other PPAs, the LDCs in New England systematically release capacity on the secondary market and represent the largest assignors of released capacity.

Table 39 and Table 40 list the ten most active assignors during the historic period on Algonquin and Tennessee, respectively, based on the number of transactions. Again, had the ranking tracked the quantity of released capacity, the results would be about the same.

Table 39. Most Active Assignors on Algonquin

Assignor	Releases	% of All Releases	Aggregate %
NGrid	268	15.6%	15.6%
New England Gas Company	209	12.1%	27.7%
Bay State Gas	167	9.7%	37.4%
BBPC, LLC	160	9.3%	46.7%
Colonial Gas[215]	157	9.1%	55.8%
BP Energy Merchants, LLC	125	7.3%	63.0%
Yankee Gas Services	91	5.3%	68.3%
New York State Electric & Gas	89	5.2%	73.5%
Narragansett Electric	60	3.5%	77.0%
Connecticut Natural Gas	56	3.3%	80.2%

[215] Colonial Gas and Narragansett Electric are owned by and do business as NGrid.

Table 40. Most Active Assignors on Tennessee

Assignor	Releases	% of All Releases	Aggregate %
Central Hudson Gas & Electric	874	12.2%	12.2%
New York State Electric & Gas	629	8.8%	21.0%
NGrid	557	7.8%	28.8%
National Fuel Gas	486	6.8%	35.6%
Columbia Gas of Ohio	485	6.8%	42.4%
Con Edison	428	6.0%	48.4%
Orange & Rockland	323	4.5%	52.9%
Metromedia Gas	287	4.0%	56.9%
Bay State Gas	279	3.9%	60.8%
BBPC, LLC	266	3.7%	64.5%

On both Algonquin and Tennessee, there is a high concentration ratio of assignors. On Algonquin, the ten largest assignors represent more than 80% of all transactions. Capacity releases on Tennessee are somewhat less concentrated, perhaps a reflection of Tennessee's route system from the Gulf of Mexico through Marcellus to New England, as well as its pipeline segment in upstate New York that has been reversed to accommodate shale gas deliveries into Ontario. The top ten assignors on Tennessee account for roughly 65% of all transactions.

As the data indicate, NGrid is one of the largest assignors on each pipeline. NGrid holds eight entitlements on Algonquin for a total MDQ of 311,849 MMBtu. On Tennessee, NGrid has fifteen entitlements for a total MDQ of 387,650 MMBtu. During the twelve-month period we reviewed, NGrid released capacity under 557 separate transactions on Tennessee. There were 268 transactions on Algonquin. Released capacity incorporated receipts from the Gulf of Mexico, as well as to counterparties located strategically at pipeline interconnects across the supply chain, including storage facilities.

Table 41 and Table 42 show the frequency of delivery and transaction points on Tennessee and Algonquin. Tennessee's deliveries are summarized by number of transactions while the Algonquin deliveries are by total capacity (MMBtu). To show how the rankings differ by pipeline, transaction levels on Tennessee are reported for the five most frequently transacted delivery and receipt points, but the total quantity of released capacity on Algonquin is shown.

Table 41. Top Delivery and Receipt Points for NGrid Releases on Tennessee

Delivery Points			Receipt Points		
Location	State	Transactions	Location	State	Transactions
Arlington	MA	214	Northern Storage Withdrawal	PA	211
Haverhill	MA	148	Agua Dulce	TX	183
Mendon	MA	100	Wright SMS	NY	99
Revere	MA	53	Niagara River	NY	82
Acton	MA	33	Johnson Bayou	LA	55

Table 42. Delivery and Receipt Points for NGrid Releases on Algonquin

Delivery Points			Receipt Points		
Location	State	Total Quantity (MMBtu)	Location	State	Total Quantity (MMBtu)
Ponkapoag	MA	90,833,967	Lambertville	NJ	87,831,294
Wellesley	MA	5,038,903	Mendon	MA	7,843,787
Polaroid	MA	4,730,486	Salem	MA	7,765,413
Norwood	MA	4,642,692	Algonquin – Lambertville	NJ	6,846,664
East Braintree	MA	2,934,131	Centerville – Transco	NJ	1,355,690
Everett	MA	2,036,613			
Waltham	MA	740,859			
Medford	MA	682,138			

The extent to which NGrid segmented its capacity rights to accommodate north-to-south flow from Marcellus is not known.

Consistent with other PPAs, the majority of released capacity is held by marketers or unregulated gas suppliers. Table 43 shows the ten largest assignees on each of Tennessee and Algonquin, ranked by total MMBtu transacted. Merchant gas-fired generators throughout New England are not among the most active assignors or assignees on Tennessee or Algonquin.

Table 43. Top Assignees of NGrid Capacity on Tennessee and Algonquin

Tennessee			Algonquin		
Assignee	MMBtu	Deals	Assignee	MMBtu	Deals
Hess Corporation	20,282,432	70	Energy America, LLC	41,109,952	65
Energy America, LLC	12,102,320	76	Hess Corporation	22,183,687	14
Santa Buckley Energy	8,008,690	47	Metromedia Energy	11,872,083	14
Sprague Operating Resources	6,025,108	46	Barclays Bank	7,061,661	5
Emera Energy Services	5,707,295	11	Buckley Energy Group	6,226,134	25
NGrid[216]	4,454,069	3	Sprague Operating Resources	3,485,698	30
BP Energy Company	4,427,920	21	Sequent Energy Management	3,424,000	1
Metromedia Gas	3,951,190	36	Spark Energy Gas	3,390,179	19
NJR Energy Services	3,679,986	1	Emera Energy Services	3,336,685	2
Barclays Bank	1,621,056	6	BBPC, LLC	2,691,841	36

Unlike the term structure of capacity released in PJM and NYISO, the majority of capacity released in New England is for terms that range from over one month to one year. Table 44 reveals the deal count by term length on Tennessee and Algonquin.

[216]Tennessee reported a number of intercompany transactions conducted by NGrid.

Table 44. Deal Count by Term Length on Tennessee and Algonquin

	Tennessee	Algonquin
7 days or less	22	0
8-31 days	385	38
32-365 days	1,234	230
366 days or longer	0	0

All capacity released by NGrid was subject-to-recall based on NGrid's discretion. The frequency of NGrid's recall of its released capacity on Tennessee and Algonquin is unknown.

4.6 TVA

LAI reviewed capacity release data on Texas Gas, Columbia Gulf, and other pipelines serving TVA. Emphasis has been placed on released capacity transactions on Texas Gas, the primary pipeline serving gas-fired generation in the PPA.

Identification of prominent assignors on Texas Gas required different filtering techniques than that used in other PPAs. Elsewhere, LDCs were the most active assignors when measured by either quantity (MMBtu) released or number of transactions. While LDCs on Texas Gas systematically release capacity throughout the year in terms of MMBtu, we observe a smaller number of large parcels changing hands in TVA, including released capacity from gas marketers. Unlike the term structure of releases in other PPAs, released capacity rights on Texas Gas have comparatively longer terms, but the transaction levels in TVA are much lower than other PPAs, thereby limiting LAI's assessment of the secondary market in TVA.

Table 45 shows the ten most active assignors on Texas Gas based on total MMBtu. Table 46 provides the same information for the ten assignors engaged in the largest number of transactions.

Table 45. Most Active Assignors on Texas Gas, Measured by Quantity Released

Assignor	Total MMBtu	Releases
Atmos Energy Kentucky	188,998,120	4
Citizens Energy Group	63,280,000	1
Indiana Gas	53,677,794	3
Duke Energy Ohio	22,356,250	2
Niagara Mohawk Power	19,050,810	5
Integrys Energy Services	17,427,928	1
Midwest Natural Gas	10,489,850	2
ProLiance Energy, LLC	9,137,031	62
BHP Billiton Petroleum (Fayetteville)	9,125,000	1
Southern Indiana Gas & Electric	9,079,764	1

Of the largest assignors in terms of number of releases, eight are LDCs. ProLiance Energy is a marketer and BHP Billiton is an industrial customer. Measuring assignors by number of transactions reveals a high concentration of gas marketers, in particular, ProLiance and Relius Energy.

Table 46. Most Active Releasers on Texas Gas, Measured by Total Transactions

Assignor	Total MMBtu	Releases
ProLiance Energy, LLC	9,137,031	62
Relius Energy, LLC	8,894,499	53
Jackson Energy Authority	803,495	14
BGC	7,279,540	11
Anadarko Energy Services Company	4,726,500	10
CIMA Energy, Ltd.	2,191,980	9
Lincolnland Agri-Energy, LLC	182,500	8
NGrid-New York	792,244	7
NextEra Energy Power Marketing	3,394,000	5
Atmos Energy Kentucky	188,998,120	4

The relatively low number of transactions indicates that the secondary release market is not active. As shown in Table 45, the largest assignor, Atmos Energy Kentucky (AEK) executed four separate transactions, all of which were to affiliate companies (as discussed below). The lack of a robust secondary market on Texas Gas is in part explained by the existence of hourly imbalance charges which expose assignees to additional transportation costs for released capacity.[217]

Based primarily on its overall share of the secondary release market in terms of MMBtu, LAI has centered the research in TVA on AEK as a broad indicator of the transaction attributes characteristic of other LDCs on Texas Gas.[218]

AEK Releases

AEK holds 14 entitlements on Texas Gas for a total MDQ of 290,900 MMBtu. Over the 12-month period, AEK released capacity via four separate transactions. AEK released each parcel to its unregulated affiliate, Atmos Energy Marketing. Details for each transaction are shown in Table 47.

Table 47. AEK Releases on Texas Gas

Contract No.	Assignee	Start Date	End Date	Quantity (MMBtu/day)
31447	Atmos Energy	6/1/11	11/1/15	13,500
31449	Atmos Energy	6/1/11	10/31/15	45,500
31451	Atmos Energy	6/1/11	10/31/15	54,896
32850	Atmos Energy	1/4/13	3/31/15	6,328

[217] Texas Gas's Hourly Overrun Transportation (HOT) charge can trigger costly imbalance resolution charges for released capacity, a portion of which may be avoidable when obtaining capacity directly from the pipeline under the interruptible transportation rate schedule.

[218] Atmos Energy Mississippi also released capacity via a single transaction, as did Atmos Energy, also known as AEK.

Each of the transactions affords the assignee options as to both the receipt and delivery locations. The zones at which gas can be received and delivered are indicated in Table 48.

Table 48. Receipt and Delivery Zones of AEK Releases on Texas Gas

Contract No.	Receipt Zones[219]	Delivery Zones
31447	South Louisiana,1,3,4	4
31449	South Louisiana,1,2,3	2
31451	South Louisiana,1,2,3	3
32850	2	4

Flow patterns on Texas Gas have not changed significantly in recent years, reflecting the lack of connectivity to Marcellus. Although volumes vary, throughput patterns continue to be from south-to-north to accommodate gas production from East Texas as well as the Permian Basin via the Texas intrastate pipelines. Whether or not entitlement holders on Texas Gas realize the value of capacity segmentation and flexible receipt or delivery points is not known.

Capacity released by each of the four transactions is recallable by Atmos Energy – Kentucky.

4.7 ONTARIO

In our analysis of the secondary capacity release markets in each of the PPAs shown above, LAI has relied on publicly available data detailing release transactions executed by firm entitlement holders. Because reporting requirements in Canada for data on releases are much less stringent than the U.S., a similarly detailed analysis of the market in Ontario is not possible. Instead, LAI has relied primarily on information in the Contract Demand Energy (CDE) report available on TransCanada's website, as well as secondary sources to develop a general understanding of the secondary market dynamics in Ontario. LAI has assessed how these dynamics are likely to change in the near future in the wake of emerging regulatory changes spurred by a recent major decision by the NEB.[220]

The CDE report provides a list of FT shippers, receipt and delivery points, the total amount of contract demand energy, the amount of operational demand (contract energy demand used by the FT shippers), as well as the quantity of temporary assignments (differences between the contract demand and operational demand). No price information is available on the temporary assignments; however the underlying FT shipper must commit to pay to TransCanada the approved toll on the full contract demand. The price paid by parties taking a temporary assignment of FT capacity is strictly a commercial matter between the FT shipper and the party acquiring the capacity. The difference between the price of the assignment and the FT tolls accrues to the account of the assignor. An important data limitation is the commingling of

[219] Texas Gas South Louisiana (SL) is the southernmost point on the Texas Gas line. Zone numbers increase as the line moves from south to north.

[220] http://www.transcanada.com/customerexpress/docs/ml_contracts/CDE_Report.pdf

permanent assignments with contract energy demand, thereby hindering any meaningful differentiation from the other contract demand entitlements.

According to the CDE report, Enbridge and Union Gas are the largest firm entitlement holders on TransCanada. Assignees of secondary capacity in Ontario include gas marketers, and, to a lesser extent, other shippers relying on secondary capacity to augment their FT entitlements on TransCanada. TransCanada's loss of market share in Ontario, New York and New England is explained largely by the ascent of shale gas. TransCanada also increased its tolls in response to the reduced throughput further exacerbating the competitiveness of its long-haul FT service. To remain a viable transporter in the primary market, TransCanada is now better positioned to compete with assignors of released capacity through flexibly priced IT as well as STFT. Until recently, shippers were able to take advantage of the Risk Alleviation Mechanism (RAM), which was implemented by TransCanada under NEB approval. The RAM allowed shippers to get credits for unutilized FT capacity which could be applied against the cost of IT in contracted for in the same month. The RAM contributed to the active secondary market in Ontario by providing monetary credits for unused FT.

A decision by the NEB last year has had a significant impact on the TransCanada tolls, the utilization of the TransCanada system and the structure of the secondary capacity market in Ontario and elsewhere in Canada.[221] In that decision, the key underlying issue is the decreasing utilization of the TransCanada Mainline due to economic factors and TransCanada's various responses to the financial losses associated therewith.

In response to declining throughput on TransCanada from the WCSB, tolls had risen substantially above historical levels and were not competitive with delivered supplies from other basins most of the year. The 100% load factor benchmark toll from Alberta to Dawn in 2012 was \$1.893/GJ. The RH-003-2011 decision reduced this toll to \$1.42/GJ, in an effort to make WCSB supplies competitive in Ontario, a 25% reduction. TransCanada was also given greater discretion in setting the tolls for IT and STFT. The NEB decision has done two things. With TransCanada having pricing discretion on IT and STFT, TransCanada raised the price of these services to the point that customers that previously relied on these services to meet their firm winter needs, are now contracting for 1 year FT service as FT service is cheaper than contracting for IT and STFT at the elevated price levels. This surge in contracting for FT capacity appears to have weakened the secondary market for released capacity in Ontario, thereby revitalizing TransCanada's ability to compete as the primary transporter into and within the province. The RH-003-2011 decision also eliminated the RAM. By eliminating the RAM, and given TransCanada's pricing discretion, the cost of IT is significantly higher. A less robust secondary market in Ontario, relative to historic trading activity now appears likely over the study horizon.

In LAI's view, the probable impact of the NEB decision supports three primary conclusions. First, FT shippers appear to use most of their capacity entitlements. 87% of the contract demand energy in Ontario is treated as operational demand. The remainder is accounted for by various contract demand shifts or temporary assignments to third parties. Second, Enbridge and Union

[221] RH-003-2011 Section 8.1 – March 2013

Gas account for 1.91 PJ/d of FT capacity of the total TransCanada FT capacity under contract of 6.65 PJ/d or 28.7% of mainline contract demand, but engage in only 10% of the temporary assignments.[222,223] These LDCs maintain FT contract capacity to meet a potential peak demand throughout the winter. While they can assign this capacity to third parties during the off peak period, the demand for this capacity and the value is substantially less than during these off peak periods. Third, industrials, municipalities, marketers, traders and electric generators account for a significant share of the temporary assignments. JP Morgan Commodities, a prominent gas marketer, accounts for nearly half of these transactions. This is consistent with observations elsewhere in the Study Region.

There is approximately 9,200 MW of gas-fired power generation in Ontario. Of this total approximately 3,460 MW is situated in Union's Southern region (in and around Dawn), 3,080 MW is situated in Union's Northerly and Easterly region (Northern and Eastern Ontario which follows the TransCanada transmission line corridor), and 2,660 MW in the Enbridge franchise (in and around Toronto and Ottawa). Many of these generators hold FT capacity to meet all or the majority of their requirements. According to the CDE report, gas-fired generators hold approximately 500,000 GJ/d of capacity. Many of the generators situated in Union's Southerly region can buy gas at Dawn for delivery to their plant and not have to hold any TransCanada FT capacity. Gas-fired generators in Enbridge's and Union's Northern and Eastern franchise areas will need to contract with TransCanada in some form to get gas to their plant(s). Many of the generators are dispatchable and face financial penalties if they do not generate when called upon. It is difficult for them to assign FT capacity under these circumstances. Those generators that do not hold FT capacity have, in the past, relied on the secondary market to acquire the capacity required to meet their requirements. With the decline in the secondary market, some generators may revert back to the primary transportation market in one form or another to meet daily gas requirements.

TransCanada had also filed an application in 2013 to make several changes to its tariff. Among the proposed changes was a change to the ability of a FT shipper to temporarily change its receipt or delivery point. TransCanada proposed that that alternate receipt points or the ability to divert to an alternate delivery point were to be restricted to in-the-path points. This would prevent most shippers from accessing liquid points such as Dawn to Iroquois. The NEB denied TransCanada's request.

TransCanada has recently filed another application with the NEB[224] to make significant changes to the FT tolling structure. If approved, the changes to the tolling structure would become effective in 2015 and would result in the Alberta to Dawn toll increasing from $1.42/GJ to $1.69/GJ, a 19% increase. This application was based on a settlement agreement that TransCanada entered into with the three LDCs in Ontario and Quebec. TransCanada has again proposed that the NEB authorize certain tariff changes which would restrict shippers' access to

[222]January 24 2014 CDE Report

[223] Ibid.

[224]Application filed December 20, 2013

alternate receipt and delivery points, which, if approved, will limit the ability of FT shippers to resell their capacity in the secondary markets.

4.8 LIMITATIONS ON DATA

The database reviewed by LAI has a number of limitations affecting the characterization of the secondary market across the Study Region.[225]

First, the data do not provide any information regarding the actions of the assignor or assignee subsequent to the transaction. Therefore, LAI cannot address the frequency that capacity released subject-to-recall was indeed recalled by the assignor, where such capacity was recalled, and what the notification requirements were affecting the exercise of the recall right.

Second, analysis of the transaction levels provides an incomplete characterization of the overall liquidity of the market at any given time. Moreover, the pipeline's ability to sell leftover transportation capacity under the IT schedule has not been reported. Only anecdotal information is available in regard to the amount of IT that is sold directly by the pipelines, the extent to which out-of-the-path secondary capacity rights are subordinated to primary entitlements or in-the-path released capacity, or, for that matter, the extent to which assignees redeploy their entitlements to replacement shippers in a tertiary market.

Third, the database provides no information regarding the ultimate disposition of released capacity. Regarding service to gas-fired generators, marketers enter into short term arrangements or AMAs with gas-fired generators. Generally, marketers package primary and secondary rights to meet the flexibility and commodity requirements of the generation company, including imbalance resolution. Transaction highlights available on pipeline EBBs do not provide meaningful insight into the deal structure between the marketer and gas-fired generators throughout the Study Region.

Fourth, the data available from the pipeline EBBs provides little useful information regarding the segmentation of capacity, if any, by either the primary entitlement holder or any assignee which ultimately acquires the capacity. The specification of delivery and receipt points relates only to the contract specifications of the primary entitlement.

4.9 KEY FINDINGS AND OBSERVATIONS

These findings support a number of key conclusions:

- Gas marketers are the most active assignees of released capacity, thereby aggregating secondary capacity entitlements, both in-the-path and out-of-the-path, with other contract entitlements under AMA structures to serve gas-fired generation.

- Gas-fired generators generally do not hold primary or secondary entitlements, opting instead to conduct business with gas marketers or gas suppliers under short term

[225] We have not undertaken any effort to confirm the reasonableness of all data provided by the participant pipelines.

marketing arrangements, or more formal AMAs. In both cases, the commodity is typically bundled just in time to meet the scheduling requirements in the DAM or RTM. There are exceptions, however. Some vertically integrated utilities in MISO have firm entitlements. TVA has firm transportation entitlements. Also, most gas-fired generators in Ontario have firm entitlements on both TransCanada and the LDC to meet all or the majority of their daily fuel requirements.

- Nearly all transactions are recallable by the assignor. Released capacity generally does not provide the assignee with fuel assurance throughout the heating season. We understand that recall rights are most often exercised during the heating season. Hence, secondary capacity rights do not provide fuel assurance to the assignee during cold snaps or outage contingencies. There is little or no financial incentive for LDCs to release capacity without recall rights. Moreover, inclusion of the right-to-recall provides primary entitlement holders with valuable option benefits on long-haul rights from the Gulf of Mexico.

- Segmentation and receipt / delivery point flexibility provide entitlement holders with valuable opportunities to recoup margin from innovative transactions oriented around shale gas production from Marcellus. These features of the secondary market are beneficial to assignor and assignee, alike.

- Capacity releases across the Study Region are generally short-term in nature, for one year or less, more often for one month or less. TVA is an exception, however.