Eastern Interconnection Planning Collaborative

Phase 2 Report:

Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios
And
Gas-Electric System Interface Study

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10 Gas-Electric System Interface Study Target 3: Natural Gas and Electric System Contingency Analysis

Executive Summary

Previously in the Eastern Interconnection Planning Collaborative (EIPC) Target 1 and Target 2 studies, the databases have been assembled and the gas infrastructure assessed for its ability to supply the demands of electric generation in the various Participating Planning Authorities' (PPAs) regions. This Target 3 Study describes the impacts and consequences of selected gas and electric contingencies under various scenarios for both winter and summer peak day conditions in 2018 and 2023. Emphasis is placed on the physical capability of the consolidated network of pipeline and storage infrastructure across the Study Region to maintain service to residential, commercial and industrial (RCI) and gas-fired generation customers following a postulated gas-side contingency. Hence, a pipeline's contractual obligations are not explicitly recognized in the study approach. In accordance with their tariffs, pipelines would limit deliveries to non-firm customers following occurrence of a contingency event if necessary to preserve their ability to meet contractual firm customer demands. In order to determine the probable outer bound of how long service to an affected gas-fired generator could potentially be maintained following a specific contingency, a physical study was conducted, consistent with the Statement of Work, that did not differentiate between the character of service of RCI and generation customers. This approach examines (i) post-contingency pressures and flows in the event that system conditions do not require pipelines to limit generator deliveries in order to protect service to RCI customers; (ii) potential service duration to gas-fired generators in the event that they are relying on firm transportation either through third-party arrangements or an entitlement held in their own name; and (iii) how much time a PPA may have to redispatch other generators, both gas-fired and non-gas fired, to replace affected gas-fired generation. The results of the study support PPA awareness of the adaptability and resiliency of the consolidated network of pipeline infrastructure after a contingency.

In the Target 3 Study, the PPAs and Levitan & Associates, Inc. (LAI) have formulated gas- and electric-side contingencies in order to gauge the ability of the pipeline system in each PPA to continue to provide gas service to generation which is running to serve electric load pursuant to the dispatch results produced by the electric simulation model. serving gas-fired generators within each PPA region as well as across the Study Region. The amount of generation that may not be dispatched on natural gas due to pipeline and/or local distribution company (LDC) infrastructure constraints following the postulated event is referred to as "affected generation." Affected generation does not necessarily imply unserved electric energy. This is because some gas-fired generators are dual-fuel capable and could switch over to fuel oil upon notification by system operators of adverse operating conditions following a contingency on either the gas delivery system or the bulk electric system. Also, non-gas power plants or gas plants on other pipelines or LDCs may increase their generation to fill the gap. Target 3 results also provide the names and locations of gas-fired plants that might trip off line due to declining gas pressure at the plant gate, and the time interval between the commencement of the event and the resultant loss of gas supply to the generation plant, referred to as the "time-to-trip." While the same post-contingency pressure differentials affecting generation customers would also affect RCI customers, this study has not analyzed the extent to which RCI customers would be able to

continue operation following contingency events. Generally, LDCs can likely continue to serve RCI customers at delivery pressures below the cutoff trigger defined for generators.

While affected generation may face loss of full or partial gas supply relative to the pre-contingency scheduled dispatch profile, electric operators in control rooms across the Study Region have procedures to redispatch the system when a gas or electric-side contingency happens. Specific analysis of overall reliability of the electric grid within the Study Region is outside the scope of the Target 3 inquiry. Target 3 results provide the names and locations of gas-fired plants that have the undeliverable gas-fired energy following a postulated gas or electric equipment failure, and their time-to-trip intervals. The PPAs may consider the results of this analysis, as appropriate, in their respective reliability analyses. Lacking access to pipeline and LDC operational data in Ontario, the deliverability assessments in the Independent Electricity System Operator of Ontario (IESO) were performed by the pipeline company and the LDCs based on input from LAI.

<u>Key Results</u>

The primary Target 3 results follow:

- In the pre-contingency baseline for the 2018 Winter Peak Day, generator gas demands are undeliverable at several plants in Independent System Operator-New England (ISO-NE), Midcontinent ISO (MISO), New York ISO (NYISO) and PJM. In ISO-NE, NYISO and PJM, these undeliverable volumes are due to (i) prioritization of RCI customer deliveries and (ii) delivery pressures below 485 psig to affected generators. In MISO, the undeliverable volumes are due to delivery pressures below 485 psig to affected generators served by Northern Natural. Hence, the starting point or baseline analysis of gas system capability prior to the postulated contingency event captures anticipated deliverability constraints on the Winter Peak Day in 2018.

- In the pre-contingency baseline for the 2018 Summer Peak Day, MISO and NYISO have less undeliverable generation than on the Winter Peak Day, although low pressures continue to limit gas deliveries to some plants. ISO-NE has more undeliverable generation than on the Winter Peak Day due to delivery pressures below 485 psig on Algonquin in southeastern Massachusetts. PJM has more undeliverable generation than on the Winter Peak Day due to greater total deliveries on Eastern Shore and Texas Eastern's Philadelphia Lateral that result in delivery pressures below 485-psig to affected plants.

- On a relative basis, the most substantial gas-side contingency impacts on the ability to supply the demands of electric generation during the Winter Peak Day in 2018, measured in terms of time-to-trip intervals and total affected generation, happen in ISO-NE. Affected generation in PJM, NYISO, and Tennessee Valley Authority (TVA) on the Winter Peak Day in 2018 is limited to isolated pockets of gas deliverability constraints following the postulated events. For purposes of this analysis and given data limitations, following contingencies scheduled deliveries to both RCI and generation customers are maintained at baseline levels. Therefore RCI customers experience the same post-contingency effects as generation customers, although pressure triggers taking RCI demand offline have not been applied. In actual operations, RCI customers may not be subject to the same delivery pressure triggers that are assumed to take generators offline, and therefore may be able to continue operation when generators cannot, although line break contingencies representing full cessation of flow would result in gas no longer being delivered to downstream RCI customers. Affected RCI customers with access to alternative, unaffected pipeline supplies may be able to transfer their demands in some cases, but this capability has not been evaluated.

- In the MAAC area of PJM, the Lower Hudson Valley (LHV), Capital District, and downstate New York in NYISO, and TVA, much of the affected generation potentially impacted by the postulated gas-side contingencies is dual-fuel capable, which makes those PPAs' regions potentially more resilient to gas supply constraints, if resources are managed well. The aforementioned zones in PJM and NYISO also have non-gas generation resources that can supplant lost gas-fired generation following the postulated event. In contrast, the majority of affected generation in ISO-NE lacks dual-fuel capability, most apparent on the Winter Peak Day in 2018 when low probability, high impact gas-side contingencies are postulated.

- In MISO North/Central, the "rest of Regional Transmission Organization (RTO)" area of PJM (other than the MAAC area) TVA, and IESO, the consolidated network of pipeline and storage infrastructure is highly resilient in response to postulated gas-side contingencies on the Winter Peak Day in 2018, thus resulting in negligible incremental affected generation relative to the baseline. At the LDC level, for gas-side contingencies tested under somewhat milder winter temperature conditions, when interruptible service would not normally be interrupted, the study identified specific pockets of gas deliverability constraints affecting individual gas-fired generators. Affected generation at the LDC level is dependent on the operational configuration of the local gas distribution system as well as the location of the postulated event. Affected generation at the LDC level in many instances reflects the non-firm nature of local transportation arrangements to serve gas-fired generators during the peak heating season coupled with the LDC's need to maximize service to RCI customers following a postulated gas-side contingency that materially lessens gas delivery into the local system. Nearly all gas-fired generators served by an LDC in PJM and NYISO lack firm transportation rights on the LDC systems, either by choice or due to lack of availability of such a tariffed service. Therefore, when a postulated gas-side contingency is tested at a specific winter temperature, one or more gas-fired generator(s) may be among the first local load(s) to be curtailed or interrupted in order for the LDC to maintain service integrity to RCI customers. Under the contractual terms of the LDC's non-firm transportation service arrangement with gas-fired generators, the LDC's ability to continue to serve gas-fired generators post-contingency is on a *best efforts* basis and generally depends on the LDC's ability to more fully utilize available capacity at other pipeline gate stations that are not impacted by the contingency.

- Across the Study Region, the consolidated network of pipeline infrastructure is highly resilient in response to postulated gas-side contingencies on the Summer Peak Day in 2018, thus resulting in negligible affected generation, except for line break contingencies which limit or eliminate deliveries to downstream generators and cannot be mitigated.

- Line pack is a source of operational flexibility, not a source of incremental capacity. On a Peak Day, particularly a Winter Peak Day, pipelines' contractual obligations may result in little or no excess line pack being available to provide shippers, including gas-fired generators, with flexibility beyond scheduled transportation in some locations. Following a *force majeure* event, the affected pipeline(s) would curtail scheduled volumes as needed in order to protect deliveries to firm customers based on tariff priorities, and to preserve required line pack for purposes of system integrity. For purposes of this physical study baseline deliveries to RCI customers and gas-fired generators are maintained following a postulated gas-side contingency, resulting in some cases in drawdown of line pack downstream of the contingency location. Study results show that this use of line-pack on a Winter Peak Day or Summer Peak Day in 2018 or 2023 can help sustain service to affected gas-fired generators located downstream of the contingency. On the Winter Peak Day, line pack is needed to fulfill firm transportation obligations. This approach identifies the probable outer bound of how long service to an affected gas-fired generator could potentially be maintained following a specific contingency.

Study Approach

The formulation and prioritization of gas- and electric-side contingencies was guided by the frequency and duration of pipeline congestion effects derived in the Target 2 study. The primary Target 2 results centered on the identification of gas pipeline segments in each of the PPAs that exhibited constraints of gas supply to gas-fired generation in 2018 and 2023 under three different demand scenarios as well as a broad array of case sensitivities. In this Target 3 study, steady state and transient hydraulic simulation analyses have been performed in order to test the resiliency of the consolidated network of gas pipeline and storage facilities when gas or electric equipment failures are postulated in the vicinity of gas-fired generators in each PPA region. Insofar as affected generation is not tantamount to unserved electric energy, it is important to note that additional non-gas fueled resources or other gas generation in non-constrained locations may be dispatched or ramped up to replace the energy from the affected gas-fired units.

Two gas demand scenarios, the Reference Gas Demand Scenario (RGDS) and the High Gas Demand Scenario (HGDS), of the Target 2 analysis for the winter and summer coincident (gas and electric across the Study Region) peak days have been evaluated to identify and quantify the amount of affected generation as well as the time interval between the start of the contingency and the time when gas-fired generator(s) would shut down (trip) due to the inability to obtain gas at sufficient pressure to sustain operation. A delivery pressure of 485 psig has been applied consistently across the Study Region as the threshold below which gas-fired generators cannot continue to operate. The modeled peak days for the RGDS cover 2018 and 2023, but only 2018 peak days were assessed for the HGDS. On a PPA-specific basis, the same gas-side and electric-side contingencies were evaluated for both the RGDS and the HGDS on the Winter Peak Day and the Summer Peak Day.

Gas-side contingencies include mainline ruptures, the loss of strategically located compression stations, or the loss of major storage deliverability. Based on the location and concentration of gas-fired generation identified in the Target 1 Study in relation to gas pipelines, common types of gas-side contingencies were performed at specific locations for each PPA. The majority of the gas-side contingencies represent very low-probability but high-impact events in terms of the anticipated reduction in deliverability to gas-fired generators downstream of the event, and, perhaps, to electric generation located behind LDC citygates as well.

Electric-side contingencies include outages of large non-gas generators or the loss of large transmission lines. The loss of generation plant(s) or a transmission line were performed at specific locations for each PPA designed to stress the gas delivery system based on the results of the Target 2 Study and other background resource planning information available to each PPA. Assessments of electric-side contingencies are limited to replacement of lost electricity supply by gas-fired and other generators, and do not include the potential effect of lost electricity supply to pipeline compressor stations. The resultant post-contingency redispatch of generators was simulated in order to produce the hourly gas demands by generator following the postulated event. The majority of electric-side contingencies represent low probability, but moderate to high impact events in terms of the consequential increase in post-contingency gas burns. In order to represent sub-hourly gas demand profiles during start-up and ramping intervals, fuel input profiles by generic technology were applied during generator start-up, ramp-up, and ramp-down intervals. These profiles were incorporated within the hydraulic models to simulate operational constraints with increased granularity.

To formulate the baseline levels of gas use by power plant absent the contingency events, the hydraulic pipeline models were used to simulate the operation of the consolidated network of pipeline and storage infrastructure in and around the location of the gas-side or electric-side contingency. The contingency event was postulated to occur on a Winter Peak Day and a Summer Peak Day in 2018 or 2023. Prior to running the contingency event, the baseline level of gas deliverability was formulated in order to reveal any undeliverable gas volumes to gas-fueled generators due to prioritization of RCI demands and/or delivery pressure limitations. The delineation of the baseline level of gas deliverability incorporated the generator gas demands from the electric simulation model combined with the RCI demands from the Target 2 analysis. Following contingency events, the hydraulic models capture the ability of the pipeline to use line-pack to sustain deliverability to all customers receiving gas during baseline operations, as well as the use of spare horsepower available at specific compressor stations. Line pack is the volume of gas contained within a pipeline that allows gas in one area of the pipeline's system to be delivered simultaneously elsewhere on the system. Adding new gas at a receipt point, without a corresponding delivery, increases pressure ("packs" the line), while removing gas at a delivery point, without a corresponding receipt, decreases pressure ("drafts" the line). Pipelines use line pack to manage operational changes and to provide flexibility for diverse operating conditions. Line pack must be kept reasonably stable across the entire pipeline system to preserve delivery pressure and system capacity. Line pack is finite and cannot be overdrawn without operational consequences both for the pipeline and its shippers. The hydraulic models do not incorporate all of the individual pipeline operators' remedial actions following the contingency as such remedial actions are unique to each pipeline. Reflecting the non-firm character of service typical of local transportation service to almost all gas-fired generators located behind the citygate in those LDCs evaluated in PJM and NYISO, a temperature level of 20°F during the winter was tested. This temperature level, although somewhat mild relative to typical design days, was chosen in order to provide a greater probability of local service to the gas-fired generator(s) in the baseline pre-contingency mode.

The hydraulic model reveals the time interval during which line-pack can support electric sector fuel deliverability following a contingency event.[1] Transient flow simulations therefore reveal operational impacts and system responses, representing the pressure flow dynamics affecting the sustainability of gas-fired generation post-contingency. Hence, a pipeline's contractual obligations, and its scheduling and curtailment priorities based on the firmness of transportation service, are not explicitly modeled in the hydraulic analysis. Since the multitude of the pipelines' contractual obligations are not embedded in the model, the study's conclusions may differ from how a pipeline would act, pursuant to its tariff, in an actual contingency event. The simulated pressure profiles of the gas pipeline system at the various gate stations reveal whether sufficient pressure and flow are available to sustain power plant operations for up to 24 hours following the start of the gas- or electric-side contingency. The post-contingency pressure profiles identify which generators are "at-risk" of their pressures dropping below the assumed cutoff level.

<u>General Results</u>

Output results are reported for the time period following the postulated event to identify affected generation that is likely to either trip off-line or fuel switch to maintain operation. Across the Study Region, the main findings follow:

- Robust natural gas production from Marcellus has resulted in major new gas gathering and pipeline infrastructure additions, a trend that will continue through 2018, perhaps later. Gas sector infrastructure improvements have resulted in much greater operational flexibility across the pipelines and storage infrastructure in PJM, MISO, and NYISO that heighten the resiliency of the network to compensate for brief intervals when highly disruptive gas-side contingencies are tested. The addition of new infrastructure to accommodate production from Marcellus has lessened, but not eliminated the critical dependency on conventional underground storage fields to maintain system integrity during the peak heating season, including the Peak Winter Day when these contingency events are postulated, particularly in the MAAC portion of PJM and NYISO.

- To mitigate the impact of gas-sector contingencies, the modeled pipeline system uses line-pack, increased interconnect flows from neighboring pipelines, increased utilization of spare horsepower from downstream compression stations, and/or the reversal-of-flow across key pipeline segments. Following the postulated event, whether or not an interconnected pipeline could permit increased interconnect flows, use of line-pack, or

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[1] Absent specific information from generators regarding minimum pressure requirements and the availability of on-site compression, LAI incorporated a minimum pressure requirement of 485 psig as the "cut-off" point to capture any impediment to generator operation. While most combustion turbine units can operate at reduced load at pressures significantly below this minimum pressure, based on LAI's judgment the 485 psig cutoff pressure, including a 25-50 psig allowance for metering and regulation losses, represents a reasonable minimum level of fuel input pressure for many combustion turbine types in the Study Region. Technology types requiring higher fuel inlet pressures would typically warrant the installation and use of on-site pressure boosters.

the reversal-of-flow across key pipeline segments is not known with certainty and would vary based on the unique circumstances of the contingency event and the pipelines' operating conditions. Again, under a real contingency event, firm service obligations would govern the pipeline's response. Other mitigation measures may also be available, but would require infrastructure investments that were not incorporated in the model solutions. Pipeline tariff provisions governing the nomination, confirmation, and scheduling process and daily imbalance resolution were not incorporated in the hydraulic models because this analysis was based on the physical impacts on delivery in the event of a contingency.

- With respect to the gas-side contingencies tested, the most resilient and adaptable segments of the consolidated gas network across the Study Region are located in MISO North/Central, the rest of RTO area of PJM, TVA, and IESO. The pipeline system in MISO South appears to be highly resilient and adaptable, but was not hydraulically tested due to the quantity of pipe, access to storage, and the highly interconnected and expansive pipeline infrastructure network configuration of regional infrastructure emanating from the Gulf of Mexico and East Texas.

- During the winter, the less resilient and less adaptable segments of the gas pipeline network, which are less able to sustain gas-fired generation, are found in the MAAC area of PJM (both SWMAAC and EMAAC), the LHV and Capital District zones in NYISO, and ISO-NE. In New England, the NEMA/Boston, SEMA/Rhode Island, and Connecticut areas are not resilient or adaptable, reflecting the region's critical dependence on west-to-east flows into New England on Algonquin and Tennessee and the assumed limitations on use of LNG. Across the Study Region, by far the most severe gas-side impacts on the Winter Peak Day in 2018, measured in terms of time-to-trip intervals and total affected generation, happen in ISO-NE. While PJM and NYISO also experience affected generation following gas-side contingencies, generators are spread across more pipelines, and individual contingencies are therefore less impactful than in ISO-NE. Moreover, dual-fuel capability is available in the MAAC area of PJM, and the LHV, Capital District and downstate New York in NYISO.

- During the summer, when RCI demand is low, a variety of short-term operational responses incorporated in the model solutions are likely to sustain continued gas deliverability to gas-fired generators across the Study Region.

- In PJM and NYISO, the same types of gas-side contingencies were tested at the LDC level. In PJM, the impact of contingency events on gas-fired generation was assessed in Illinois, SWMAAC, and EMAAC. In NYISO, the impact of various contingencies was assessed in New York City and Long Island, as well as the LHV. In Ontario, the impact of the contingencies was evaluated at the provincial level with particular emphasis on the Greater Toronto Area, assuming an average temperature of 0°F. Other than in Ontario, local delivery analyses reflected an average temperature of 20°F, much milder than the Winter Peak Day. The milder temperature conditions were selected for testing infrastructure adequacy at the local level, rather than the Winter Peak Day, in order to simulate local system responsiveness when the LDC would be much more likely to serve gas-fired generation prior to the adverse event. The results of the hydraulic analyses are highly sensitive to the proximity of the postulated event to the LDC's system, and whether or not the LDC has in place dedicated laterals from the pipeline terminus to the plant gate or instead operates a grid-like system.

- In Illinois, the LDC systems were found to be largely resilient following gas-side contingency events, with the exception of a line break interrupting gas supply to a nearby generator. This is a reflection of the LDCs' system configurations, operational criteria, and specific generators' dependence on an individual pipeline's delivery capability. In some instances, post-contingency mitigation measures are ineffectual given the nature of the contingency event and the generator's proximity to the postulated line break. SWMAAC and EMAAC have more affected generation during the winter, which partly reflects the LDCs' respective system configurations and the lack of slack deliverability for non-firm shippers at 20°F. Depending on location, modeled contingencies can result in scheduling constraints affecting sustainability of gas-fired generation at the LDC level, particularly where a dedicated lateral is the pathway between the pipeline gate station and the generation plant gate.

- For the LDC analysis in the LHV, a higher dispatch level was tested, relative to the RGDS. Based on this higher postulated dispatch regime there are significant scheduling restrictions in the LHV during the winter affecting the LDC's ability to transport gas to certain gas-fired generation plants, reflecting high RCI sendout at 20°F in relation to local deliverability. There is not significant affected generation in New York City or Long Island in the winter. There is no affected generation in the LHV, New York City, or Long Island during the summer.

- At an average temperature condition of 0°F, there is very little affected generation in Ontario due to the Ontario gas transmission and the LDCs' design modifications in and around the Greater Toronto Area to incorporate redundancy in gas deliverability. Due to much colder temperature conditions in Ontario versus NYISO or PJM, the 0°F average temperature condition was selected rather than the 20°F average temperature condition used in PJM and NYISO in order to evaluate the resiliency of the provincial gas infrastructure under extreme cold, but not design criteria.

- In terms of the array of PPA-specific electric-side contingencies tested, the gas constraints varied significantly by PPA. Results for the RGDS 2018 Winter Peak Day by PPA follow:

  - Each of the three PJM contingencies results in delivery pressures dropping below the threshold for generator operation. The results project losing gas supply after 9 to 11 hours in most cases. However, the continuation of gas supply for specific gas-fired generators for up to 9 to 11 hours following the event would normally be expected to provide control room operators with sufficient time for remedial action.

  - None of the ISO-NE contingencies resulted in the diminution of gas pressure below the threshold for gas-fired generators. However, there is substantial incremental undeliverable gas for energy at plants that could not be scheduled to burn gas in the baseline. Most gas-fired generation plants across the PPA lack dual-fuel capability.

  - Only two of the six NYISO contingencies resulted in gas delivery pressures dropping below the threshold for plants. These effects were seen after 11 to 12 hours, and nearly all affected generation is at plants with dual-fuel capability which can switch to liquid fuel supplies.

  - MISO contingencies resulted in negligible incremental amounts of affected energy at plants that could not receive gas in the pre-contingency baseline.

  - No constraints were observed for the TVA and IESO contingencies.

- Like ISOs/RTOs, pipelines are well-positioned to provide mutual assistance to interconnected pipelines when severe operating conditions or contingencies occur. A pipeline may be able to lend capacity to an interconnected pipeline if it operationally can do so without reducing deliverability on its system and without compromising its operational integrity. However, these arrangements are voluntary and there is no mandate to do so. Likewise, LDCs are also organized to provide mutual assistance to neighboring LDCs when severe operating conditions or contingencies occur. Pipeline operator protocols are incorporated in the model solutions that mitigate the adverse impact of a gas or electric-side contingency on gas-fired generation. Such pipeline protocols may include the use of line-pack, reversal-of-flow of downstream pipeline segments, more complete loading of pipeline interconnects, and enhanced use of spare or idled compression prior to the onset of the gas-side contingency. The implementation of such pipeline protocols is highly dependent on pipeline flexibility, weather, and primary firm shipper needs at the time of the contingency on both the pipeline experiencing the contingency and interconnected pipelines. Communication initiatives among the PPAs, pipelines, and/or LDCs have the potential to strengthen the usefulness of available mitigation measures in response to heightened gas/electric interdependencies across the Study Region in 2018 and 2023. Finally, pipeline tariff innovations and continued efforts to promote harmonization between the gas and electric day scheduling procedures can also provide both gas and electric control room operators with greater flexibility when gas or electric-side contingency events occur.

<u>Specific Contingency Results</u>

Summaries of gas-side contingency and electric-side contingency impacts on scheduled gas-fired generation on the RGDS 2018 Winter Peak Day are presented in Figure ES 10-1 and Figure ES 10-2, respectively, for five of the six PPAs. Lacking access to pipeline and LDC operational data, no independent hydraulic analysis was performed for IESO; however, results of the Ontario companies' assessment of contingency effects are presented separately in the Appendix of the Critical Energy Infrastructure Information (CEII) version of this report. The magnitude of the impact of the contingencies is reported based on two criteria: first, the time interval before any affected generation is no longer scheduled on natural gas due to gas pressure dropping below the threshold; and, second, total affected energy production. For example, in Figure ES 10-1, on the second row labeled “Line Break” in ISO-NE, the decay in line pressure would no longer support a generation plant’s scheduled output after 11 minutes and 3 seconds. The gas-side contingencies studied generally have greater impacts on the deliverability of gas to electric generation than the electric-side contingencies. For the gas-side contingencies, in the “First Trip” column, “None” indicates that none of the plants downstream of the contingency drop below the pressure threshold cutoff during the first 24 hours after the outage. “N/A” indicates that no plants downstream of the contingency are dispatched.

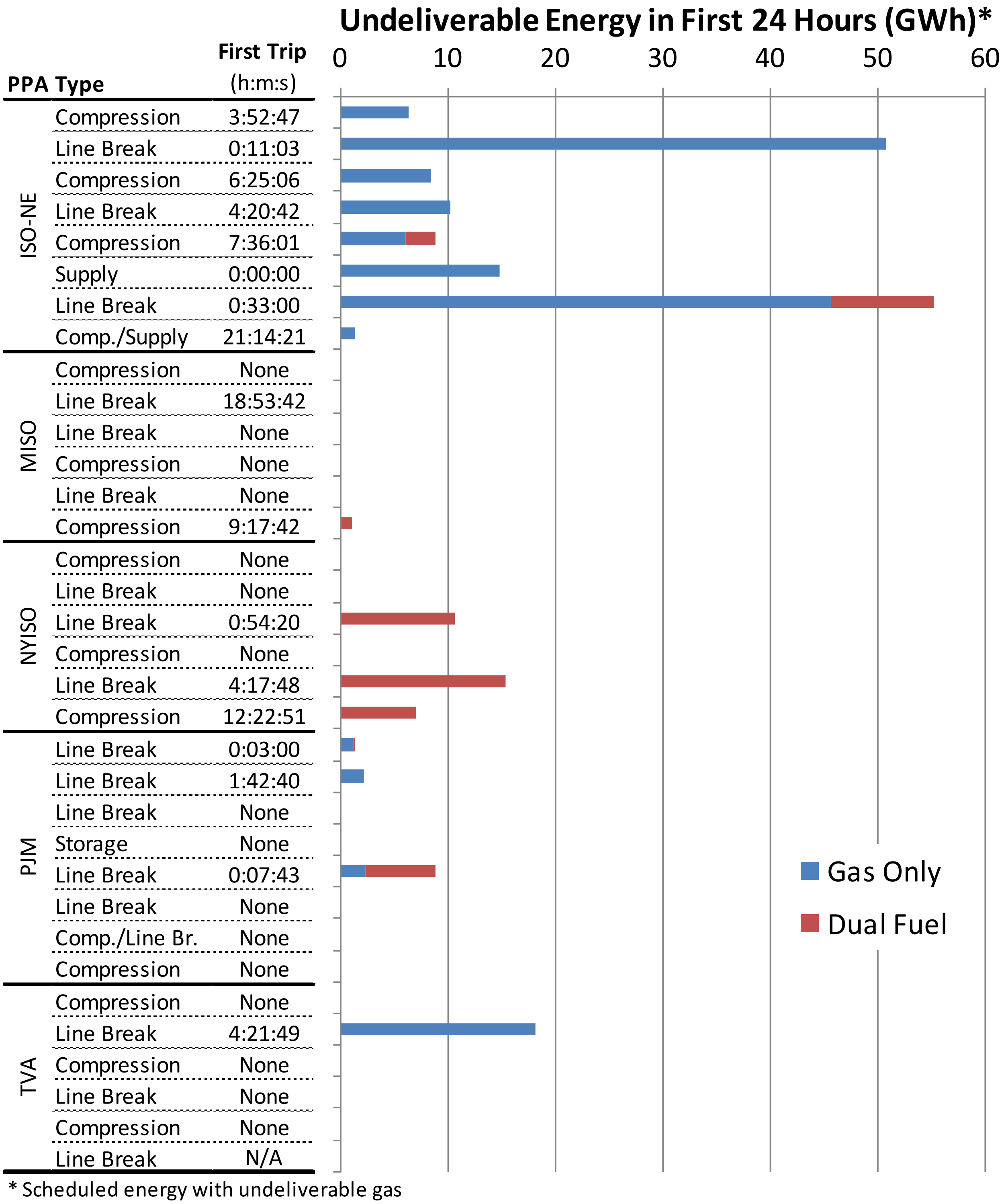
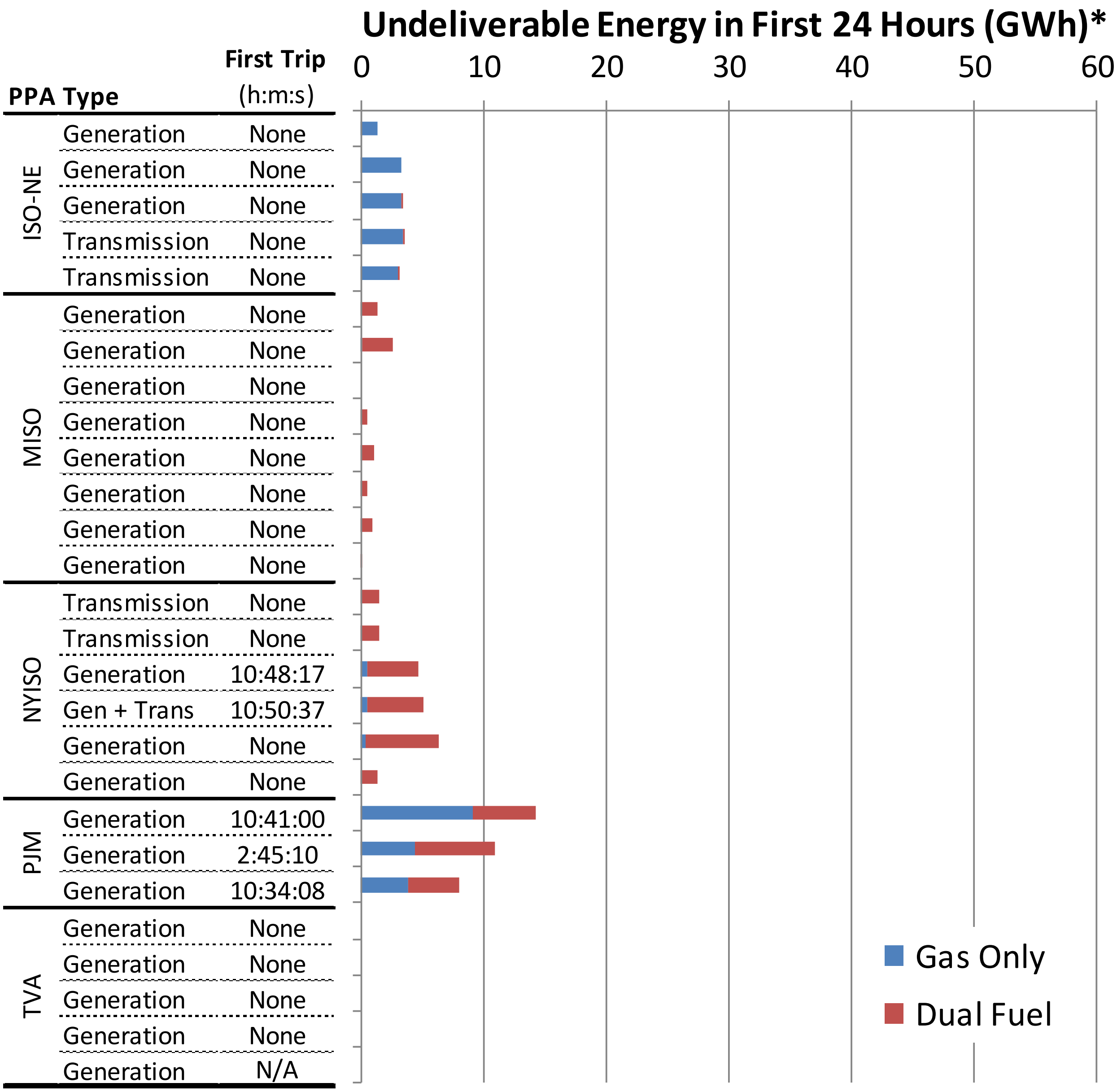


Figure ES 10-1. Summary of RGDS 2018W Gas-Side Contingency Results

For the electric-side contingencies, in the "First Trip" column, "None" indicates that none of the plants with incremental generation following the contingency drop below the pressure threshold cutoff during the first 24 hours after the outage. "N/A" indicates that the contingency did not impact electric system operations. Undeliverable energy in conjunction with a "None" indicator in the "First Trip" column means that incremental generation is scheduled following the contingency at plants that could not receive gas in the pre-contingency baseline.



* Scheduled energy with undeliverable gas

Figure ES 10-2. Summary of RGDS 2018W Electric-Side Contingency Results

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List of Acronyms

Bcf	Billion cubic feet
Btu	British thermal units
CCGT	Combined cycle gas turbine
CCT	Central clock time
CEII	Critical Energy Infrastructure Information
CRSG	Contingency Reserve Sharing Group
DOE	Department of Energy
DR	Demand response
Dth	Dekatherm
EBB	Electronic bulletin board
EFT	Enhanced First Transportation
EIA	Energy Information Agency
EIPC	Eastern Interconnection Planning Collaborative
EISPC	Eastern Interconnection States Planning Council
EMAAC	Eastern Mid-Atlantic Area Council
ERS	Electric Reliability Service
FERC	Federal Energy Regulatory Commission
FOA	Funding Opportunity Announcement
FT-H	Hourly Firm Transportation Service
GJ	Gigajoule
GT	Gas Turbine
GW	Gigawatt
HGDS	High Gas Demand Scenario
HRSG	Heat Recovery Steam Generator
IC	Internal combustion
ICAP	Installed capacity
IESO	Independent Electricity System Operator of Ontario
INGAA	Interstate Natural Gas Association of America
ISO	Independent System Operator
ISO-NE	Independent System Operator – New England
LAI	Levitan & Associates, Inc.
LDC	Local distribution company
LGDS	Low Gas Demand Scenario
LHV	Lower Hudson Valley
LNG	Liquefied natural gas
MAAC	Mid-Atlantic Area Council
Mcf	Thousand cubic feet
MDth	Thousand dekatherms
MDth/d	Thousand dekatherms per day
MHDO	Maximum Hourly Delivery Obligation
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
NEMA	Northeast Massachusetts
NGrid	National Grid
NOPR	Notice of Proposed Rulemaking
NPCC	Northeast Power Coordinating Council
NREL	National Renewable Energy Laboratory
NYFS	New York Facilities System

NYISO	New York Independent System Operator
OBA	Operational Balancing Agreement
OFO	Operational flow order
PAL	Park and Loan
PJ	Picojoule
PJM	PJM Interconnection, LLC
PPA	Participating Planning Authority
psig	pounds per square inch gauge (pressure relative to atmospheric pressure instead of relative to zero)
RCI	Residential, commercial, industrial
RGDS	Reference Gas Demand Scenario
RPM	Reliability Pricing Model
RTM	Real time market
RTO	Regional Transmission Organization
scf	Standard cubic feet
SCGT	Simple cycle gas turbine
SEMA	Southeast Massachusetts
SSC	Stakeholder Steering Committee
SWMAAC	Southwestern Mid-Atlantic Area Council
TVA	Tennessee Valley Authority
VACAR	Virginia-Carolinas

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
Creole Trail	Cheniere Creole Trail Pipeline, LP
CNYOG	Central New York Oil and Gas LLC
Columbia Gas	Columbia Gas Transmission LLC
Columbia Gulf	Columbia Gulf Transmission LLC
Constitution	Constitution Pipeline Company
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
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 Transmission	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
Sabal Trail	Sabal Trail Transmission, 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.

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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 Dth is equal to ten therms or one MMBtu. 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.

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

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

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 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 SSC, and its work to model public policy "futures" through the use of macroeconomic models. This first work effort examined eight futures chosen by the SSC. The final undertaking in Phase 1 was for the SSC 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 of the transmission options, and developing generation and transmission cost estimates for each of the three scenarios.

This project has been carried out in close interaction with the Eastern Interconnection Topic B recipient of DE-FOA-0000068, the National Association of Regulatory Utility Commissions, and their awardee, the EISPC. EISPC comprises regulatory representatives from the 39 states of the Eastern Interconnection, along with the District of Columbia, and the City of New Orleans. While the detailed report on the EISPC work will be published separately, this report includes results provided to EIPC as required for use in the Topic A work scope. The work has also benefited from close interaction with an SSC representing a wide range of interests. DOE is additionally supporting the program through work at selected national laboratories. The EIPC is grateful to DOE and to all the above participants for their contributions.

This Target 3 study is based on the existing and planned gas pipeline and storage infrastructure, generation and electric transmission resources, and other market conditions known to the PPAs and LAI as of April 2014.

10.1 Introduction and Background

This report encompasses Target 3 of the EIPC's Gas-Electric System Interface Study, the natural gas and electric system contingency analysis. For this Target 3 study, the PPAs and LAI relied upon the results of the Target 2 study to identify electric and gas infrastructure contingencies which may have the greatest potential to disrupt gas deliveries to electric generators across the Study Region, shown in Figure 10-1. Using steady state and transient gas infrastructure models, LAI analyzed the potential impacts on electric system reliability following postulated disruptions on the regional gas and electric systems. Consistent with the goals of the reliability assessment, the Target 3 analysis focuses on an array of potentially severe gas and electric-side contingencies in each PPA within the Study Region. For each identified gas and electric-side contingency, the potential mitigation measures have been proposed.

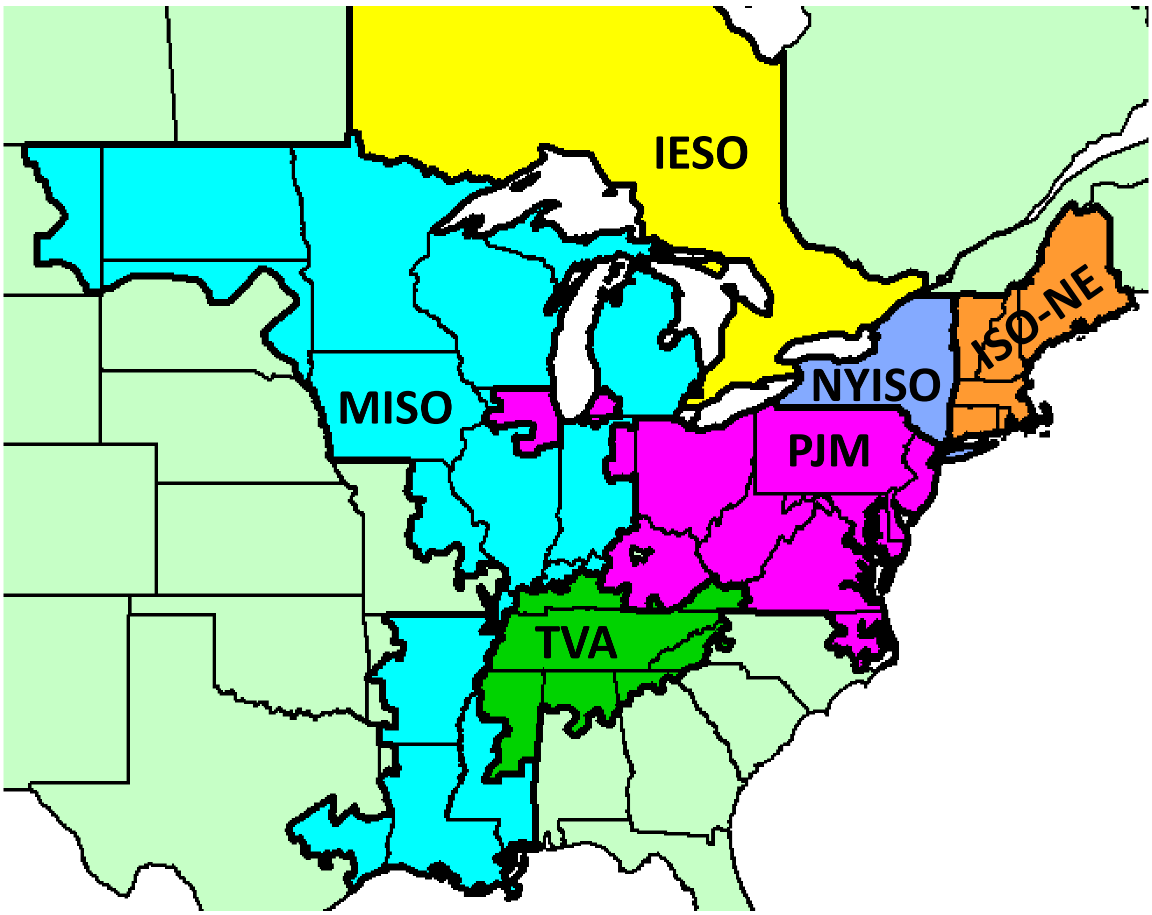

Figure 10-1. Geographic Overview of Study Region

The model components that constitute the Target 3 analysis are highlighted in Figure 10-2. This schematic shows key inputs, outputs, and data transfers between model components. Target 2 produced the hourly gas usage for both RCI load and electric generation on a locational basis.[2]

[2] The industrial portion of the RCI load is treated equivalent to residential and commercial loads even though some portion of industrial load across the Study Region has a character of service

In Target 2, the combined gas usage and the capability of the gas infrastructure were evaluated under three future gas demand scenarios, the *Reference Gas Demand Scenario (RGDS)*, the *High Gas Demand Scenario (HGDS)* and the *Low Gas Demand Scenario (LGDS)*, as well as under multiple case sensitivities. The Target 2 Report describes the resources, electric transmission infrastructure, electric and RCI loads, fuel prices, emission allowance prices, and other assumptions that were used to construct the gas demands across the Study Region for the RGDS, HGDS, and LGDS. Formulation of the three *Gas Demand Scenarios* was intended to reveal the level and profile of gas demand under a defined set of market, regulatory and operating conditions formulated to test the capability of natural gas infrastructure across the Study Region to meet the coincident gas requirements of RCI customers and gas-fired generators on both a winter and summer peak day.

Working in close consultation with the PPAs and with the requested input from the pipelines and LDCs in the Study Region, LAI formulated the gas-side contingencies to be evaluated in each PPA region. The PPAs identified the most important electric side contingencies to be evaluated in Target 3. Only the RGDS S0 and HGDS S0 cases from the Target 2 analysis are used as the basis for the contingencies analysis so as to model impacts during stressed conditions on the electric and pipeline / LDC infrastructure systems.[3] For the RGDS, both 2018 and 2023 winter and summer seasons are modeled, while for the HGDS, only the 2018 winter and summer seasons are analyzed. Given the more speculative nature of the 2023 demand scenarios and the potential for additional pipeline build-out by 2023, it was deemed appropriate to focus the Target 3 HGDS analysis on the more near term 2018 results.

The pre- and post-contingency assessment requires the use of WinFlow, a steady state model, and WinTran, a transient flow model.[4] The combined hourly gas demands by location for the RGDS and HGDS are the key input data into the WinFlow steady-state model.[5] The WinFlow steady-state model incorporates the average gas demand level for RCI customers and gas-fired generators over a 24-hour period. The steady-state model of each pipeline system was constructed based on data from the Target 1 and Target 2 analyses, supplemented by CEII obtained from pipelines' filings at the Federal Energy Regulatory Commission (FERC). The FERC filings included the Form 567 and Part G Forms filed as part of each pipeline's certificate application(s) seeking FERC approval for facility additions or new pipelines. The CEII contains detailed information regarding capacity and hydraulic parameters for each pipeline segment, compressor station, pipeline interconnect, and other system components. As discussed in Section 10.2.1.2, after the steady-state hydraulic models for pipeline systems of interest were tested and calibrated, they were converted into WinTran transient models, wherein hourly

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that is non-firm. As discussed in the Target 1 analysis, LAI was not able to identify the firm versus non-firm industrial loads by PPA.

[3] The "S0" case reflects average monthly gas price basis by pricing point across the Study Region, and therefore does not represent more volatile, and generally higher, delivered gas prices on the Winter Peak Day.

[4] Lacking access to pipeline and LDC operational data in Ontario, LAI did not utilize WinFlow and WinTran to conduct the assessment in IESO. The deliverability assessments in IESO were conducted by TransCanada, Enbridge and Union with input from LAI.

[5] The hydraulic models used in the Target 3 analysis are licensed by Gregg Engineering, Inc.

profiles of system operating conditions and demand profiles are simulated throughout the gas day, differentiated between RCI and generation customers.[6]

Gas-side contingencies were modeled in WinTran as disruptions in the gas supply, storage, line breaks, or loss of horsepower at compressor stations located near gas-fired generators. As shown in Figure 10-2, electric-side contingencies were first modeled using AURORAxmp electric simulation software.[7] Assumed bulk power system outages were modeled in AURORAxmp, which produced hourly generator gas demands as input to the steady-state WinFlow model of each pipeline operating in the steady-state condition.

Gas and electric side disruptions were applied to the validated transient models to simulate specific contingencies under the RGDS and HGDS in order to examine the resulting gas pressure and flow trends following each contingency event. The pressure and flow decay following a disruption allowed quantification of how long a particular power plant or group of power plants could continue to burn gas following the postulated event. While, RCI deliveries are prioritized in the baseline, following a contingency event, flows to both RCI and generation customers and are maintained at baseline levels in order to determine the physical capabilities of the pipeline network. Model solutions in WinTran also revealed whether there are viable pipeline work-arounds, including the more complete utilization of line-pack flexibility to enable "affected generation" to continue to operate longer. Affected generation is defined as gas-fired generators that may be curtailed or interrupted following the event. Importantly, a distinction is drawn between affected generation and at-risk generation insofar as many generators are dual-fuel capable and would therefore be expected to switch to ultra-low sulfur distillate, distillate oil, kerosene, or residual fuel oil following the contingency – both gas-side and electric-side contingencies. Model solutions in WinTran encompass the utilization and management of line-pack as a possible short-term mitigation measure to sustain continued gas-fired generation when outage contingencies are tested.[8] Other mitigation measures built into the reoptimization of natural gas flow following a postulated event include more complete utilization of pipeline interconnects, reversal-of-flow, and use of spare horsepower at compressor stations downstream of the postulated event.

[6] The pipelines were given the opportunity to review the modeling of their respective systems and many constructive comments were received and incorporated.

[7] AURORAxmp is licensed by EPIS, Inc.

[8] Solutions in WinTran utilize available line-pack to bolster line segment pressures for purposes of sustaining gas-fired generation without degrading service to RCI customers. The delay in line pressure and, perhaps, flow following the event is location specific. WinTran solutions do not incorporate any reduction in RCI volumes to sustain pressure and flow to gas-fired generators.

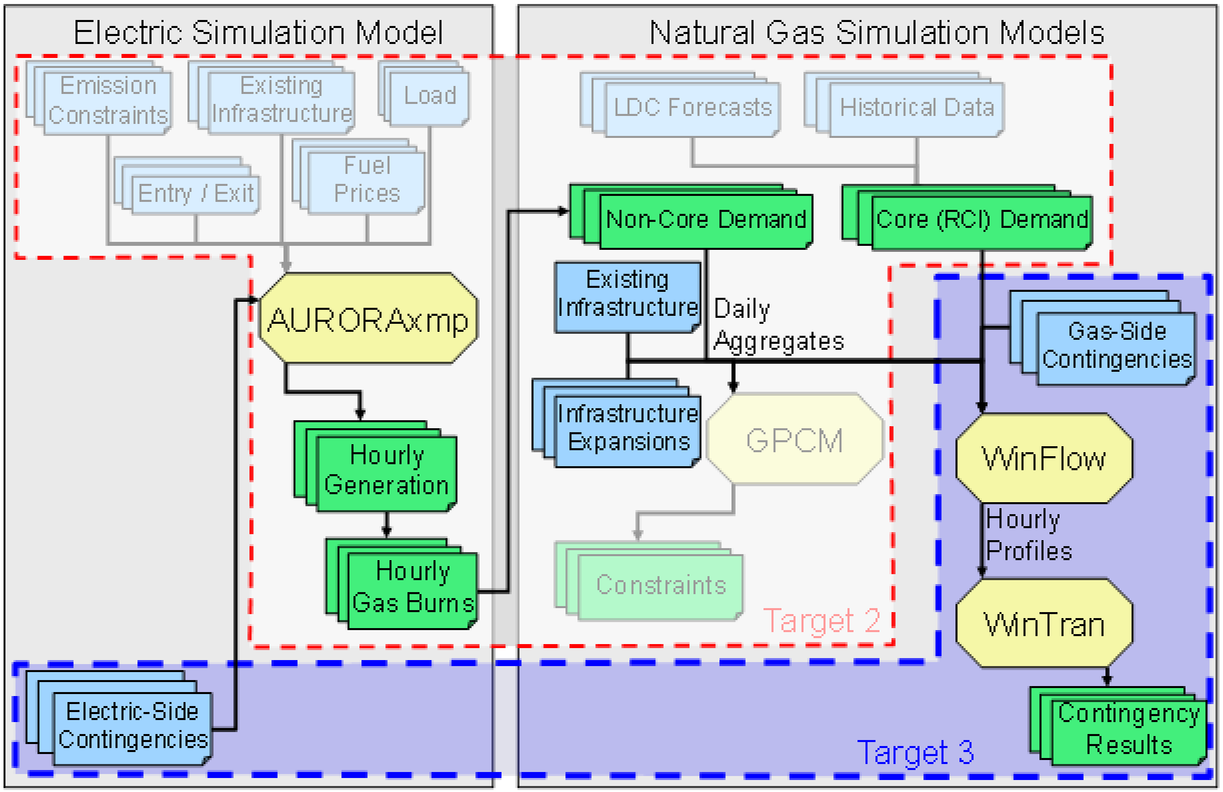

Figure 10-2. Target 3 Model Components

10.2 Modeling Approach

For both the gas-side and electric-side contingency analyses, the base (no contingency) cases were the Reference Gas Demand Scenario Update (RGDS S0) and High Gas Demand Scenario Update (HGDS S0) cases formulated for the Target 2 analysis. In summary, the RGDS S0 case uses expected electric load growth, regional fuel prices consistent with the Energy Information Agency's *2013 Annual Energy Outlook* Reference Case prices, and generation resource and transmission infrastructure projections for 2018 and 2023 consistent with the EIPC 2013 Roll-Up analysis, updated to reflect topology and resource changes as of early 2014.[9] As discussed in the Target 2 report, the RGDS and HGDS delivered gas prices across the Study Region represent the average monthly delivered basis to primary pricing points across the Eastern Interconnection rather than the higher daily spot delivered gas prices on a Winter or Summer Peak Day defined under the "S1" spot pricing case sensitivity. All results reflect total peak day gas demand under average monthly gas pricing. For purposes of this study, the peak day represents coincident peak day RCI gas demand and peak day electric generation gas demand.[10] Throughout the Target 3 report, LAI has omitted the "S0" reference to the updated scenarios in presenting the results for the contingency cases.

Six separate demand and resource scenario conditions were analyzed for each of the contingencies: RGDS Winter and Summer 2018, HGDS Winter and Summer 2018, and RGDS Winter and Summer 2023. See the Target 2 report for details regarding the RGDS S0 and HGDS S0 modeling assumptions and data.

10.2.1 Natural Gas Hydraulic Modeling

As previously noted, the pre- and post-contingency assessment requires the use of WinFlow, the steady state model, and WinTran, the transient flow model. Using these modeling platforms and data obtained from FERC, including Form 567 filings and Certificate of Public Convenience and Necessity Exhibit G's, LAI has formulated hydraulic representations of the pipelines serving generation in ISO-NE, MISO North/Central, NYISO, PJM and TVA.[11,12] Technical input parameters include pipeline diameters, segment lengths, compressor horsepower, discharge temperatures, velocities, maximum allowable operating pressure, and elevation, among other factors. As shown in Figure 10-3, the models incorporate compressor stations, pipeline segments, interconnections, receipts from production and other supplies, storage injection / withdrawal points, and deliveries to LDCs, other RCI customers and generators. Other model

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[9] Includes both resource additions and attrition.

[10] The intraday profile of coincident peak day RCI gas demand is the same across the Study Region. The intraday profile of peak day electric generation gas demand is from AURORAxmp and therefore reflects individual market dynamics in six PPAs.

[11] LAI did not perform hydraulic modeling in IESO due to the lack of pipeline and LDC data. MISO did not require hydraulic modeling in the MISO South area due to the extensive labyrinthine network of pipelines, gathering and storage facilities in relation to the amount of gas-fired generation.

[12] The majority of the pipeline FERC filings used to support model development were submitted to FERC from 2012 through 2014.

attributes pertaining to fluid flow in a pipe in relation to frictional losses require general flow equations. LAI exercised judgment where necessary to capture pipeline efficiency factors.[13]

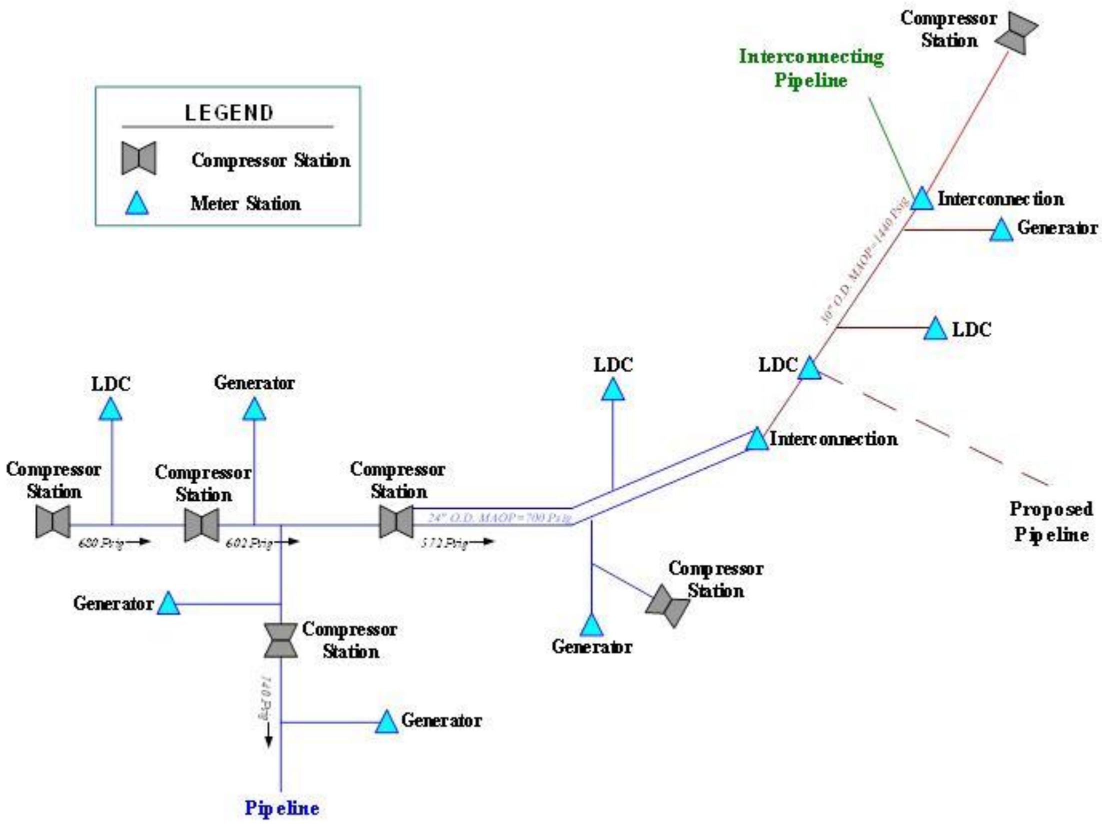

Figure 10-3. Example Hydraulic Model Schematic

Individual pipeline companies were given the opportunity to review LAI's formulation of the steady state model(s) in WinFlow in order to provide technical feedback on LAI's interpretation of the available source materials for an individual pipeline.[14] Technical commentary received from those pipeline companies who elected to comment was limited to the accuracy of the technical input parameters affecting deliverability, including interconnect flows. In almost all cases, when an individual pipeline recommended a specific refinement to factor inputs to WinFlow, LAI incorporated the suggested change. Following validation of the individual pipeline models, LAI consolidated contiguous pipelines into a working network flow model in order to account for interconnect flows and other pipeline operator actions that may be implemented following a gas-side or electric-side contingency. This consolidated network flow

[13] There are many different equations that can be used to correlate measured friction factors to different flow conditions, Colebrook-White and AGA being the two most popular. Panhandle A or B are also sometimes used as well as Weymouth for distribution lines. To ensure model validity, measured friction factors have been calibrated against actual flow measurements for a particular pipeline in order to provide accurate results.

[14] The pipeline review process was conducted in Q4-2014 and January, 2015. Although requested to comment, not all pipeline companies provided technical comments.

model of contiguous pipelines operating in the vicinity of the postulated event serves as the foundation for the transient flow analysis conducted in WinTran. Whereas WinFlow represents system operations based on ratable takes over a 24-hour period,[15] the transient flow model allows LAI to observe the change in pressure and flow within the gas-day in hours, minutes and seconds.

At the local level, analysis was conducted in consultation with various LDCs in PJM, NYISO and IESO where there is a substantial amount of gas-fired generation located behind the citygate. In some cases, the LDCs performed the gas-side and, where relevant, electric-side contingency assessment based on study design and model assumptions provided by the PPAs and LAI. In other cases, LAI conducted the analysis. In PJM local analysis was conducted for, and with substantial input from Peoples, Nicor Gas, Public Service Electric & Gas, New Jersey Natural Gas, Washington Gas Light, and Baltimore Gas and Electric.[16] In NYISO local analysis was conducted for Central Hudson Gas & Electric, whereas Con Edison and National Grid (NGrid) performed the analysis for their respective facilities which comprise the New York Facilities System (NYFS). In IESO local analysis was conducted for Enbridge and Union Gas, with substantial input from both companies as well from TransCanada. Like analysis was not conducted in MISO, ISO-NE or TVA.[17] The results of the LDC analyses can be found in the Appendix of the CEII version of this report. All of the LDC analyses are CEII.

10.2.1.1 Steady-State Modeling Approach

The WinFlow steady state pipeline model simulates the interconnected pipelines and storage infrastructure serving the Study Region. The starting point for the steady-state model development was each pipeline's FERC Form 567 filing for 2012.[18] Each model was then updated to include incremental facilities with in-service dates after December 31, 2012, including both projects that are currently in service and planned future expansions. Consistent with the Target 2 analysis, new pipeline projects were included if precedent agreements sufficient to support a project's construction were publicly known prior to April 22, 2014 based on FERC filings, open season notices, or other pipeline announcements or press releases.[19] These projects are listed in Table 10-1 below, with detailed descriptions in Appendix 15.

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[15] The ratable take provision in a pipeline's tariff generally means taking 1/24th of the daily confirmed volume each hour. Some pipelines have ratable take provisions that allow for hourly takes that are somewhat higher than 1/24th per hour for several hours during the gas day.

[16] Electric contingency analysis was not conducted for the Nicor Gas and Peoples systems because the postulated PJM electric contingencies occur in Maryland and New Jersey and would therefore not significantly impact generation in Illinois.

[17] MISO, ISO-NE, and TVA did not request technical assessment of LDCs' delivery capability in response to postulated gas or electric-side contingency events.

[18] These filings represent pipeline operations from January 1, 2012 to December 31, 2012, and were filed primarily in May 2013 for a May 31, 2013 filing deadline.

[19] INGAA facilitated pipeline commentary and input to the delineation of pipeline and storage infrastructure additions included in the various Gas Demand Scenarios.

Table 10-1. Future Pipeline Expansions Included in the Hydraulic Pipeline Models

Pipeline	Project	FERC Docket #
Algonquin	Algonquin Incremental Market	CP14-96
	Atlantic Bridge (with M&N)[20]	PF14-5
	Salem Lateral	N/A
ANR[21]	Glen Karn 2015	N/A
	Southeast Mainline Flow Reversal	N/A
Columbia Gas[22]	East Side Expansion	CP14-17
	Giles County	CP13-125
	Line 1570	CP13-478
	Smithfield III Expansion	CP13-477
Constitution	Constitution Pipeline	CP13-499
Dominion Cove Point	Cove Point Liquefaction	CP13-113
Dominion	Allegheny Storage	CP12-72
	Clarington Project[23]	CP14-496
	Natrium to Market	CP13-13
East Tennessee	Kingsport Expansion	CP13-534
	Wacker	CP12-484
Eastern Shore	TETCO Supply Expansion	CP14-67
	White Oak Lateral	CP13-498
Empire	Tuscarora Lateral (with NFG)	CP14-112
Equitrans	H-164	CP14-90
	H-305	CP14-130
	Jefferson Compressor Station Expansion	CP13-547
	West Uprate and Blacksville Compressor Station Expansion	RP14-543
Great Lakes	Maximum Allowable Operating Pressure Reduction	CP14-116
Iroquois	Wright Compressor Station	CP13-502
NFG	Mercer Expansion	CP13-530
	Northern Access 2015	CP14-100
	West Side Expansion and Modernization	CP14-70
NGPL	2012 NGPL Storage Optimization	CP11-547
Northern Natural	West Leg 2014	CP13-528
Rockies Express	Seneca Lateral Project	CP13-539

[20] 100 MDth/d of incremental capacity associated with the Atlantic Bridge Project is included in the three Gas Demand Scenarios. The remainder of the project's capacity is included in Sensitivity 13.

[21] The Lebanon Lateral 2014 Reversal Project is not listed here because it is already in service.

[22] The VEPCO-Warren County Project is not listed here because it is already in service.

[23] The Clarington Project was previously known as the WV West Project.

Pipeline	Project	FERC Docket #
Tennessee	Broad Run Expansion	N/A
	Broad Run Flexibility	N/A
	Connecticut Expansion	N/A
	Niagara Expansion	CP14-88
	Rose Lake Expansion	CP13-3
	Uniondale Expansion	CP13-526
	Utica Backhaul Transportation	N/A
Texas Eastern	OPEN	CP14-68
	TEAM 2014	CP13-84
	Uniontown to Gas City	CP14-104
Texas Gas[24]	Ohio-Louisiana Access	N/A
Transco	Atlantic Sunrise	PF14-8
	Dalton Expansion	PF14-10
	Leidy Southeast	CP13-551
	Northeast Connector	CP13-132
	Rock Springs Expansion	PF14-6
	Rockaway Delivery Lateral	CP13-36
	Virginia Southside Expansion	CP13-30
	Woodbridge Delivery Lateral	CP14-18
Trunkline	Mainline Abandonment	CP12-491

The forecast of RCI gas demand for the tested scenarios was allocated to specific pipeline meters by applying each meter's share of the peak day demands from the pipelines' FERC filings to the relevant customer's total forecast demand as calculated in Target 2. The example in Table 10-2 illustrates that 660 MDth/d of forecast demand in RGDS winter 2018 was allocated *pro rata* to individual meters based on 2012 peak day meter demands.

Table 10-2. RCI Demand Allocation Example

Meter	2012 Peak Day Demand (MDth/d)	% of Total Peak Day Demand	RGDS W18 Demand (MDth/d)
A	112	17.9%	118
B	157	25.1%	166
C	54	8.6%	57
D	73	11.7%	77
E	85	13.6%	90
F	144	23.0%	152
Total	625		660

Demand associated with generators that are served by LDC systems with multiple pipeline connections was allocated to the LDC delivery meters based on the proximity of the generator to

[24] The Texas Gas Abandonment Project is not listed here because it was withdrawn from FERC consideration.

the relevant gate stations, existence of dedicated laterals, contracted volumes and other factors. Individual generators were reviewed on a case by case basis, examples of how this allocation was done are shown in Figure 10-4. Notably, administration of LDC tariff provisions governing the scheduling of local transportation service to gas-fired generators were not part of the technical assessment of gas and electric-side contingency impacts.

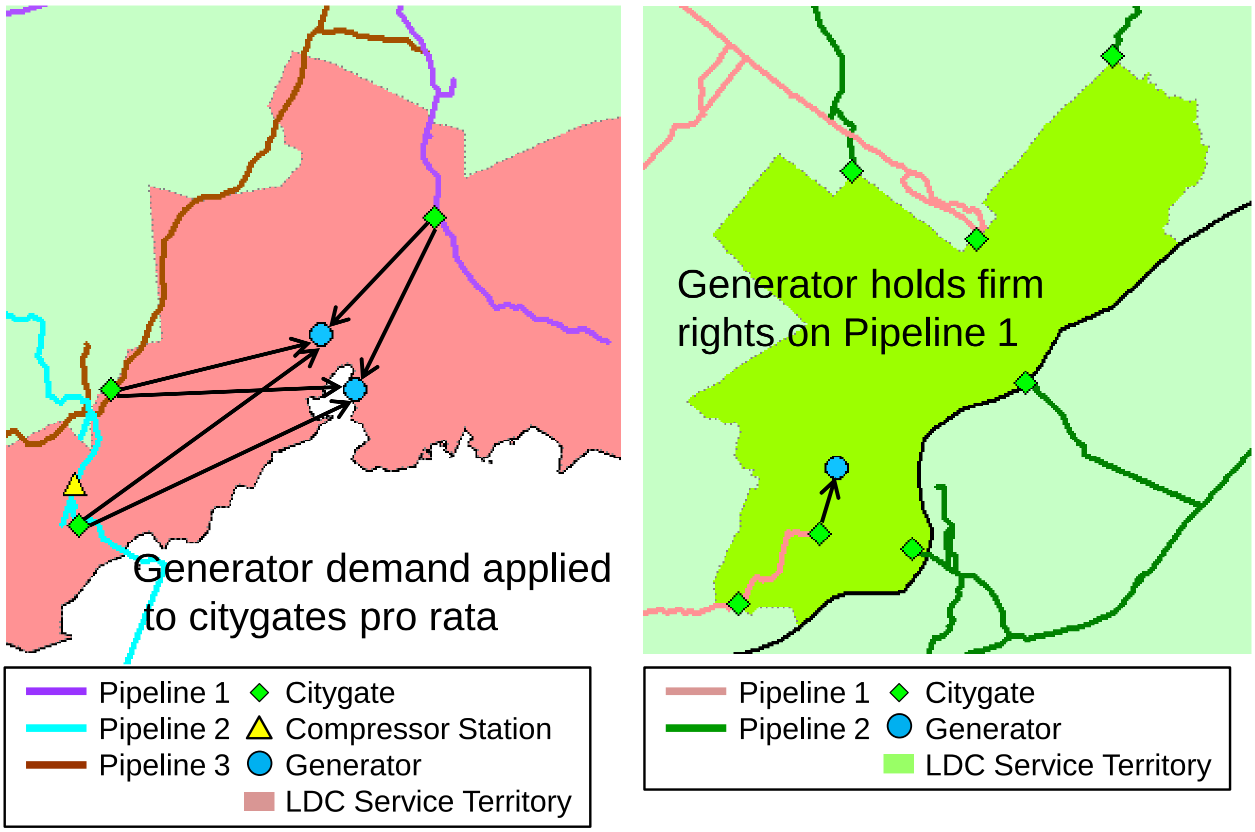

Figure 10-4. LDC-Served Generator Demand Allocation Examples

Under LAI's modeling methodology, the steady-state solutions seek to *minimize* total unserved generation. Importantly, AURORAxmp solutions incorporate electric transmission limitations between zones. However, AURORAxmp solutions regarding the scheduling of gas-fired generation on a seasonal peak day do not address system security constraints within transmission constrained zones following the loss of gas-fired generation. Hence, there was no AURORAxmp modeling of gas-side contingencies. The AURORAxmp solutions incorporated in the Target 3 analysis reflect the scheduled generation on both the Winter and Summer Peak Days in RGDS for 2018 and 2023 and in HGDS for 2018. For the electric contingencies, the AURORAxmp solutions reflect post-contingency dispatch conditions, adjusted as described in Section 10.2.2.

To initialize each steady-state WinFlow run, LAI assumed that each gas-fired power plant, whether directly connected to an interstate pipeline or served by an LDC, received its respective scheduled fuel nominations, *i.e.*, the daily quantity derived in AURORAxmp. When the pipeline and storage infrastructure were not adequate to meet the total combined RCI and generation demand, or when boundary gas flow constraints precluded the delivery of the specified gas volume derived in AURORAxmp, LAI decreased or eliminated gas deliveries to power plants along constrained segments of the consolidated pipeline network until an equilibrium was achieved. The equilibrium state is defined as the sum total of available receipts, including interconnect flows, to meet the aggregate demand of the RCI plus that portion of scheduled gas-fired generation that is deliverable following the postulated event. The constraint parameters are pipeline operational in nature, are associated with specific locations, and dictate how generator demand reductions are allocated, if applicable. Details are described in the relevant results sections. Where multiple generators could be reduced to relieve a gas constraint, generators with firm transportation and/or gas-only capacity were decremented last.[25]

The process of reaching convergence often required multiple iterations in WinFlow. If electric transmission security constraints required natural gas to be delivered to a specific generation plant that LAI deemed unavailable in order to reach convergence, another "solution" may be feasible, with the fuel shortfall applied to a different generator. Unlike the transportation deficits reported in the Frequency-Duration analysis highlighted in the Target 2 report, in Target 3 LAI calibrated the responsiveness of the consolidated network of pipeline and storage infrastructure following a gas-side or electric-side contingency. Hence, resultant fuel shortfalls affecting gas-fired generator availability capture deliverability constraints. Deliverability constraints are hydraulic in nature rather than mathematical representations derived through GPCM.[26] Because pipeline operations are simulated in the hydraulic model, model solutions capture the requisite pressure and flow enabling gas-fired generators to perform in accord with the scheduled profiles derived in the Target 2 report.

10.2.1.2 Transient Modeling Approach

The major difference between the steady-state WinFlow model and the transient WinTran model is WinFlow's ability to simulate the dynamics of line-pack in normal operation and WinTran's ability to simulate the pipelines' response to contingencies. The transient reporting function reveals the time interval during which line-pack can support deliverability following a contingency. WinFlow model results can be directly imported into WinTran for contingency analysis across the six PPAs. Transient flow simulations reveal operational impacts in real-time and foster useful simulations of complex pressure-flow dynamics affecting the sustainability of gas-fired generation following adverse contingencies.

LAI produced model solutions in a sequence of time intervals that were complemented by panoramic and zoom views of pipeline system performance. For example, in order to evaluate the pressure trends at generators located downstream of a compressor station failure, the transient

[25] Following a postulated gas-side contingency, the normal curtailment priority would cut shipments to non-firm generators first and would adjust shipments to RCI and gas-fired generators holding firm entitlements on an equiproportional basis. Following an event of *force majeure*, pipeline operators would implement whatever actions are required to maintain system integrity downstream of the event.

[26] The hydraulic modeling is a non-linear dynamic modeling process conducted in WinFlow and WinTran. The mathematical model used in the Target 2 report is a static mass balance representation using linear programming conducted in GPCM.

model was run for a 24-hour period following the contingency event to measure delivery pressure trends at generator gas delivery meters as previously illustrated in Figure 10-3.

Model solutions in WinTran require the incorporation of a pressure cutoff level below which the generation plant either cannot operate at any output level or cannot operate at full power output. Absent specific information from generators regarding minimum pressure requirements and the availability of on-site compression, LAI incorporated a minimum pressure requirement of 485 pounds per square inch gauge (psig) as the cut off point to capture any impairment in operation.[27,28] Although most combustion turbine units can operate at reduced load at pressures significantly below the minimum pressure for full load operation, the 485 psig cutoff pressure, including a 25-50 psig allowance for metering and regulation losses, represents a reasonable pressure level for many technology types in the Study Region.[29] While the same post-contingency pressure differentials affecting generation customers would also affect RCI customers, RCI customers may not be subject to the same delivery pressure triggers that are assumed to take generators offline, and therefore may be able to continue operation when generators cannot. This study has not analyzed the extent to which RCI customers would be able to continue operation following contingency events. Generally, LDCs can likely continue to serve RCI customers at delivery pressures below the 485-psig cutoff trigger defined for generators.[30]

LAI evaluated local deliverability issues following postulated gas and electric side contingencies at the local level for many LDCs in PJM, NYISO and IESO. In PJM, those LDCs that conducted independent hydraulic analysis of their respective local distribution systems included BGE, Nicor Gas, and Peoples. In NYISO, Con Edison and NGrid conducted independent hydraulic analysis. In IESO, TransCanada, Enbridge and Union Gas conducted independent analysis. The aforementioned LDCs utilized internal information about generator-specific minimum pressure

[27]Differentiation of pressure cutoff levels by turbine type and location across the Study Region was outside the scope of the Target 3 analysis. To the extent that the PPAs have such information for specific generators, it is confidential and therefore not incorporated in the report. LAI relied upon information in the public domain regarding turbine technology types. Older gas turbines generally have lower compression ratios, and lower fuel pressure requirements. New aeroderivative units and LMS100's have high minimum pressures, *i.e.*, 725 psig or higher, and typically have on-site pressure boosters to supplement pipeline rendered supply. New aeroderivatives and LMS100's would therefore typically require on-site compression. The 485 psig threshold was selected to enable continued operation of GE 7F units and Siemens SGT6-5000F units without on-site compression to continue operation. For lower delivery pressures, the frame units would have compression from the minimum delivery pressure to about 500 psig. A drop to the range between minimum contractual pressure and 485 psig would not impair operation of these turbine types.

[28] Using units of psig rather than psi indicates that the pressure is reported relative to atmospheric pressure instead of relative to zero.

[29] Units requiring higher minimum pressures, such as LMS100 units, would likely have compression on-site even if located on one of the super-high pressure lines with delivery pressures averaging 900 psig.

[30] Distribution pipelines typically operate at pressures up to 200 psig, but the operating pressures of individual LDCs depend on the system configuration and customer requirements, among many other factors.

requirements rather than the 485 psig minimum pressure cutoff level used elsewhere in the Study Region.

Importantly, model solutions in WinTran reflect the reoptimization of gas flows and pressures based on the technical input parameters to the hydraulic models, including the use of spare or strategically located horsepower from available compressor stations following an event. As discussed in Section 10.4, LAI has not attempted to incorporate specific additional pipeline operator actions – extrinsic mitigation measures in nature – that have the potential to mitigate the magnitude of the adverse operating impact on affected generators.

10.2.2 Electric Sector Contingencies Gas Demand Modeling

Thirty electric sector contingencies were modeled in nine separate AURORAxmp simulation runs. Each of the nine simulation runs included two to four contingencies, which were located distant from each other to minimize any combined impacts. Each of the nine simulation runs (encompassing 30 contingency cases) was modeled for the six separate demand and resource scenario conditions. Each electric sector contingency begins on the coincident seasonal peak gas demand day at the times specified or agreed to by each PPA. The coincident seasonal peak gas demand day is the same day in the winter or summer across the Study Region rather than each PPA's respective non-coincident peak gas demand day.

The electric system simulation runs were done for at least one week around the coincident peak electric day, when the contingencies occur, in order to have the commitment and dispatch of resources closely approximate that of the annual non-contingency runs performed in the Target 2 study. However, for the gas hydraulic modeling, generator gas demand results for only 24 hours prior to the contingency and 24 hours following the start of the contingency are needed. Hence, LAI provided PPA-specific hourly results for the three days around the coincident peak day for PPA review, consisting of:

- Changes in natural gas usage by resource
- Changes in generation by resource
- Changes in inter-zonal power flows by link.

Research objectives centered on the examination and identification of the effects that hourly swings from gas capable generation have upon on the resiliency of the gas delivery system. Hence, LAI's approach relied on the same AURORAxmp hourly simulation model used in the Target 2 modeling. The dispatch of units and gas demand may suddenly change by a large magnitude starting at the time of the contingency event. The approach adopted was to not allow anticipation of the contingencies in the commitment of units at the start of the day with the contingency events. Any additional commitment decisions in response to the contingencies could only be made after a minimum start-up time elapses. In the second and following electric days, different commitment schedules were allowed to be made without incurring additional production costs. Hence, some of the additional dispatch resulted from ramping online generators and some from additional commitment of units. A conservative aspect of the post-contingency modeling approach is that hydroelectric resources, which are often relied upon to provide additional generation after a contingency, were not redispatched due to a model limitation. Instead, the model tended to rely more on power imports.

The modeling of operating reserves recognized that a PPA, as a Balancing Authority, is allowed to lean on neighboring Balancing Authorities for part of lost energy following a contingency. North American Electric Reliability Corporation Standard BAL-002-1 (Disturbance Control Performance) rules regarding the post-electric contingency recovery process require:

- each Balancing Authority or Reserve Sharing Group to have Contingency Reserve sufficient to cover the most severe single contingency;
- the Contingent Balancing Authority to provide at least 50% of the loss, with the remainder allocated among the Assisting Balancing Authorities; and
- a Balancing Authority shall not be requested to provide more assistance than is traditionally required to cover its own largest contingency.

The six PPAs participate in the following Contingency Reserve Sharing Group (CRSG) agreements:

- The Northeast Power Coordinating Council Reserve Sharing Group includes the New Brunswick, Quebec, New England, New York, and Ontario Balancing Authority areas.
- The MISO and Manitoba Hydro CRSG
- The TEE CRSG of TVA and LG&E/KU Services Company
- The PJM (Dominion Virginia Power) and VACAR (Duke Energy – Carolinas, Duke Energy – Progress, South Carolina Electric & Gas, and South Carolina Public Service Authority) CRSG.

As a practical modeling decision, no additional constraints were placed on inter-PPA power flows following an electric contingency. That is, the various rules in the CRSG agreements were not modeled. The impact of this approach is non-conservative with respect to the need to rely on internal PPA resources rather than increased imports (or reduced exports). In actual operations, the PPAs normally schedule the commitment of units so as to minimize any reliance on neighboring PPAs for contingent energy imports.

All of the generator and transmission facility contingencies were modeled as immediate forced outages. Each contingency was modeled as lasting 24 hours or more, which allows modeling load conditions over a daily diurnal cycle. Unlike the Target 2 annual simulations, the Target 3 contingency case simulation periods were restricted to a few days surrounding the coincident peak winter or summer day when the contingency events were assumed to occur.

Target 2 AURORAxmp modeling was done with an hourly time-step, whereby most gas-capable units were able to ramp up or down between minimum and maximum operational load within one hour, and start-up time lags were not modeled. For Target 3, in order to adequately represent generator gas demands for use in WinTran at sub-hourly granularity and to account for start-up time lags, two types of adjustments were made to generator gas demand time profiles.

First, generators in each PPA that were offline in the no contingency case at the time of each of its contingencies were restricted from ramping up to their minimum load for a number of hours, based on their technology type, in the contingency cases. For example, in the first post-contingency hour(s), it would not be possible to immediately bring online a CCGT, which has a minimum notice and run-up time of more than one hour. The assumed generic start time restrictions by unit type are listed in Table 10-3.

Table 10-3. Start Time Restrictions by Unit Type

Generator Type	Start Time to Full Load (hours)
SCGT, Small (≤ 100 MW)	0
SCGT, Large (> 100 MW)	2
CCGT	4
Steam, Oil/Gas	8
Steam, Coal	12

Second, in order to represent gas demand during start-up and ramping intervals with sub-hourly granularity, LAI developed a procedure for representing fuel input profiles by generic technology to apply during generator start-up, ramp-up, and ramp-down intervals. These profiles were in general agreement with information or confirmation received from the PPAs. The resultant time profiles are piecewise linear demand segments of variable duration.

The following five generic profiles for typical gas-fired generator technologies and operational modes were applied to sculpt the hourly results from AURORAxmp. This procedure modifies the stair-step profile of the AURORAxmp gas demands at hourly intervals into profiles that have less than vertical ramps for time durations that are more fine-grained than hourly. Each profile is shown normalized to 100% of maximum gas use at full load output. The fuel input profiles include natural gas used during warm up before power output begins, and for the run-up interval before output reaches minimum operational load. The set points represented by the red boxes are the basis for the profile adjustments. These profile timelines do not include any delay time from the moment of the electric-side contingency and the control signal to the generator to start-up or ramp-up.

The few internal combustion (IC) generators that use natural gas were represented as reaching full load in two minutes, shown in Figure 10-5. No specific technical source for this representation has been relied upon.

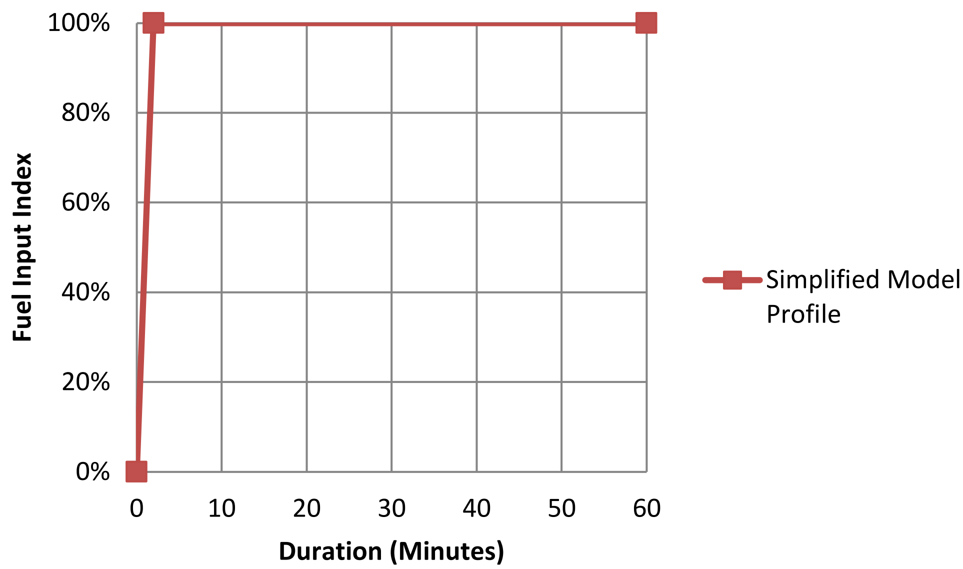

Figure 10-5. IC Generator Start-Up Fuel Input Profile

For simple cycle gas turbine (SCGT) generators smaller than 100 MW, an example profile, shown in Figure 10-6, was developed from data in the most recent installed capacity (ICAP) demand curve analysis for NYISO.[31] The profile is appropriate for newer frame turbines that are capable of fast-start operation as well as aeroderivative turbines. From the available technical parameters, fuel input set points were estimated to indicate a 3-minute purge (no fuel input) and the amount of fuel used for start-up, the ramp rate, and heat rates at minimum and full load. The slight curvature in the fuel input set points is well-represented with a single linear segment between the 3-minute point at the start of fuel input to the approximately 13-minute point at full load.

[31] NERA, "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator," final report, August 2, 2013.

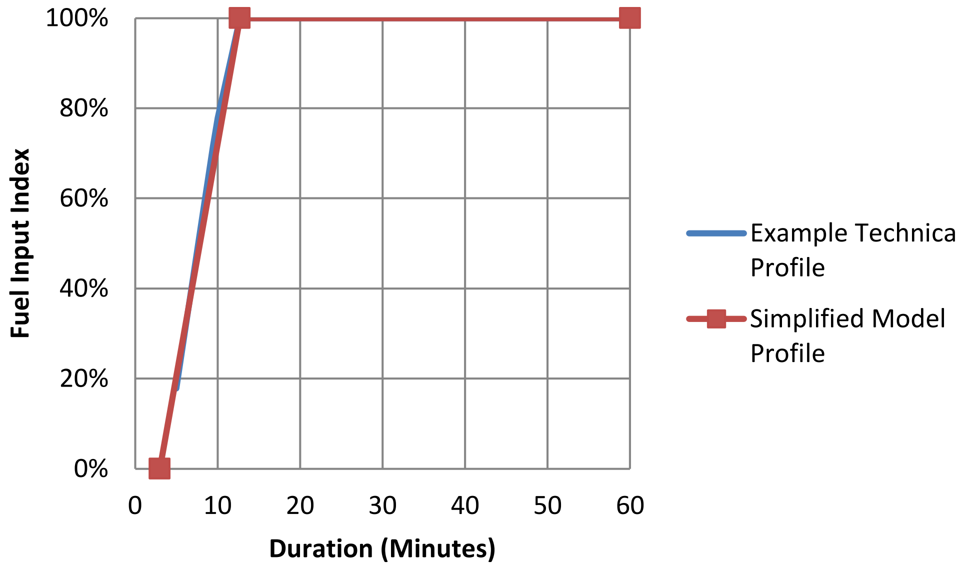

Figure 10-6. Small SCGT Generator Start-Up Fuel Input Profile

For SCGT generators larger than 100 MW, LAI applied a technical fuel use profile, shown in Figure 10-7, that begins with a 3-minute purge (no fuel input), followed by 5-minute set points until full output at 28 minutes.[32] The slight curvature in the 5-minute fuel input set points is well-represented with a single linear segment between minimum and maximum fuel input levels.

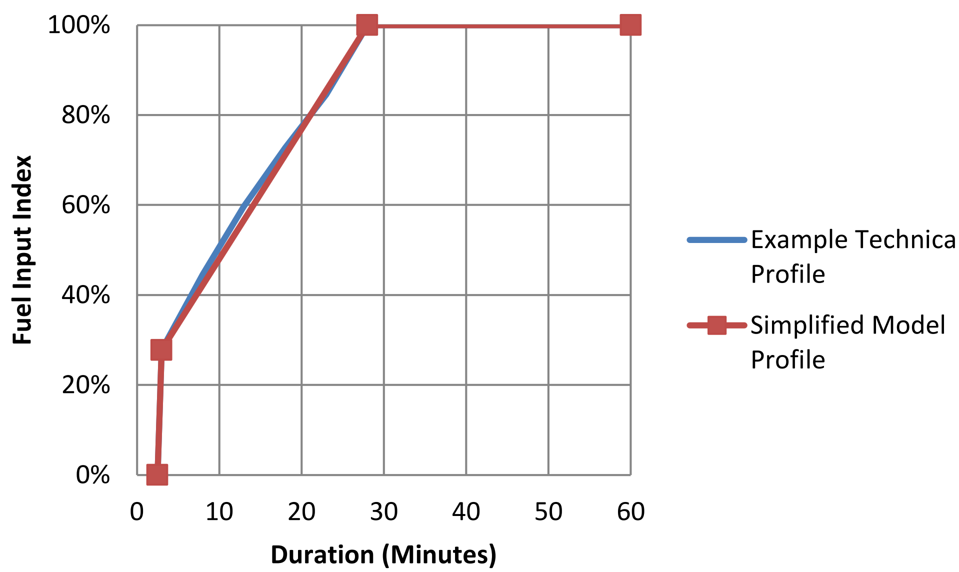

Figure 10-7. Large SCGT Generator Start-Up Fuel Input Profile

For combined cycle gas turbine (CCGT) plants, a profile for the typical 2x1 plant configuration of two gas turbines (GTs) and two heat recovery steam generators (HRSGs) feeding into one steam turbine generator was represented, as shown in Figure 10-8. The plant is assumed to start

[32] Adapted from J.J. Macak III, "Evaluation of Gas Turbine Startup and Shutdown Emissions for New Source Permitting," (ca. 2001), Table 1.

cold in the mode that allows ramping operation to full output. In this cold start mode, one GT is first lightly loaded while warming the HRSG, then the steam turbine is loaded, and finally the second GT is started. This operational mode results in a fuel input profile that remains at a relatively low level for over two hours, and then quickly ramps up to maximum fuel input. Despite the twists of the technical fuel input profile at 15-minute intervals, the profile is reasonably represented as three linear segments until full fuel input is reached.[33]

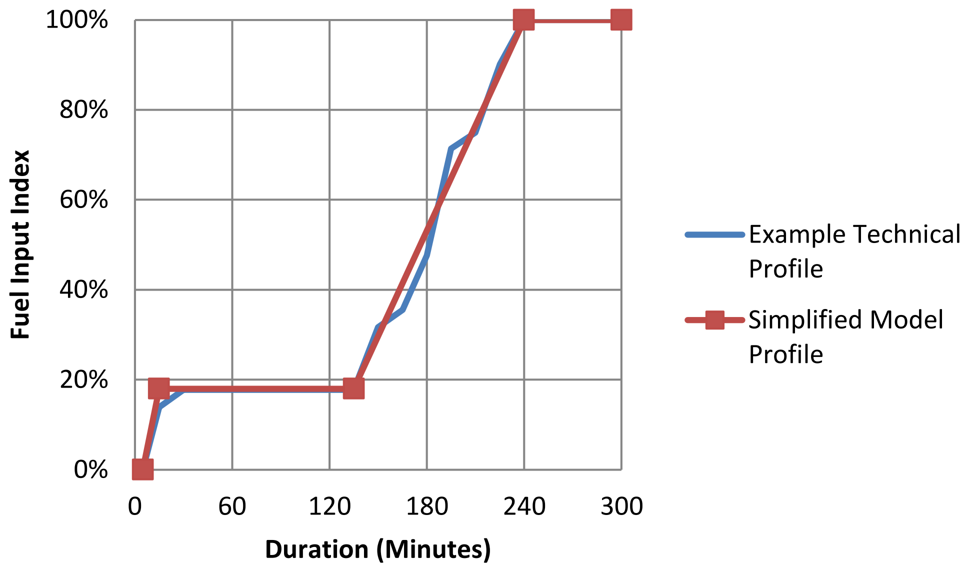

Figure 10-8. CCGT Generator Start-Up Fuel Input Profile

Oil/gas steam generators have a wide range of start-up times and start fuel requirements, depending on their technology and how long they have been offline (*i.e.*, cold, warm, or hot start). LAI assumed that stations selected to provide replacement power after an electric-side contingency would be those that have been offline for shorter periods (warm start), thus available to provide power sooner than other (cold start) steam generators. A warm-up period of six hours before ramping up to full output is assumed, representative of a warm start time. LAI relied on confidential generator information and a recent National Renewable Energy Laboratory (NREL) report to represent the technical fuel profile curve, shown in Figure 10-9.[34] This profile is adequately represented with three linear segments before full fuel input is reached after eight hours.

[33] Adapted from Kenectrics Inc., "Commitment Techniques for Combined-Cycle Generating Units," prepared for ISO-NE and NYISO, December 2005, Table 2.

[34] Kumar, N., et al., "Power Plant Cycling Costs," prepared by Intertek APTECH, April 2012. NREL report NREL/SR-5500-55433.

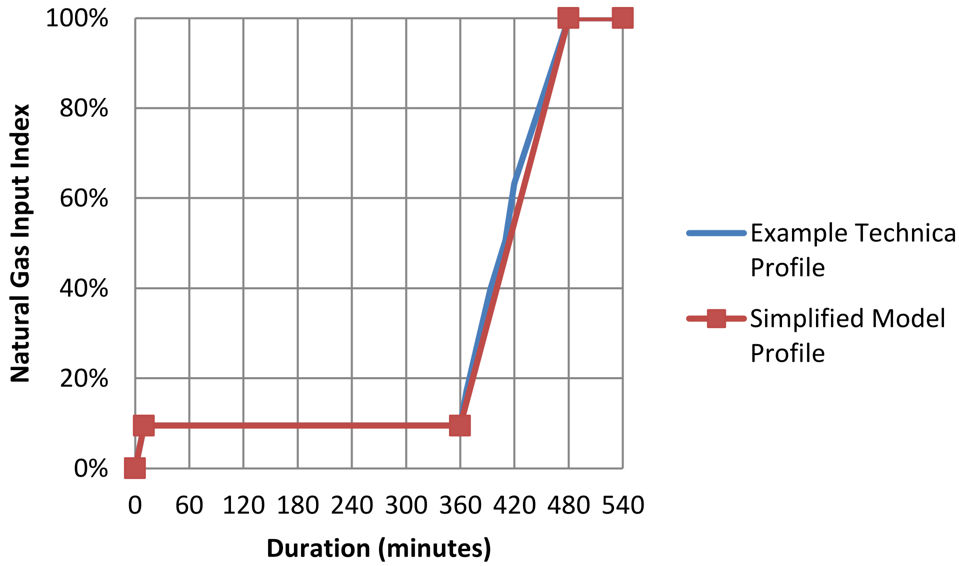

Figure 10-9. Steam Generator Start-Up Fuel Input Profile

In the contingency simulations in AURORAxmp, some gas-fired generators ramp down during the first 24 hours after the contingency. Output ramp-downs are typically slightly faster than ramp-ups. To model fuel input during ramp-down, a single linear segment for fuel input was assumed, with a rate specific to each of the generator technology categories. The ramp-down parameters and their corresponding time intervals starting from full fuel input (at full load) are shown in the following table.

Table 10-4. Fuel Ramp-Down Parameters by Unit Type

Generator Type	Fuel Input Ramp-Down Rate (% of full fuel input/minute)	Ramp-Down Time from Full Fuel Flow (minutes)
IC	50.0%	2
SCGT	20.0%	5
CCGT	3.3%	30
Steam Turbine	1.7%	60

The duration of the gas hydraulic simulation analysis spanned the 24 hours prior to the contingency event to 24 hours after the event. An automated procedure was developed to transform the hourly gas use profiles from AURORAxmp by applying these sub-hourly start-up and ramping profiles. The sub-hourly profiles were aligned so as to not allow start-ups or ramp-ups that occurred in response to the contingency to begin prior to the time of the contingency. Thus, incremental start-ups or ramp-up in the contingency case simulations begin *after* the time of the contingency event. Aside from these constraints, start-up and ramp-up profiles begin before the hour with higher load, and ramp-down profiles begin after the hour with higher load. The automated procedure also added data points to represent both ends of each constant flow time segment. Time points were calculated at the resolution of seconds. The adjusted demand profiles for these 48-hour periods were then fed to WinTran, which then summed the flows of multiple generator units at the same meter location.

10.3 Baseline Hydraulic Analysis

Before assessing the selected contingencies, the transient models were run with the S0 generator gas demands without applying any contingencies, in order to ensure that all RCI load is served and determine whether the full scheduled fuel quantities are deliverable to generators before the systems are stressed. This is considered the baseline condition. The reported GWh of deliverable and undeliverable energy were calculated on the basis of each unit's full load heat rate and the amount of deliverable and undeliverable gas during the 24 hours following the start of the contingency. Baseline results for undeliverable energy differ from those of Target 2 because it used a different model, GPCM, that was not hydraulic, and therefore did not incorporate pressure considerations. Additionally, Target 2 reported constraints only during the seasonal peak hour, rather than the 24-hour reporting period used in Target 3.

The HGDS includes numerous additional new CCGT plants in order to maintain required reserve margins to compensate for the higher zonal electric loads and increased deactivations of coal plants in that scenario, relative to the RGDS. These new plants were specified in the Target 2 analysis, and are labeled throughout this report as "Generic CC" plants.

10.3.1 IESO

The natural gas infrastructure in Ontario is shown in Figure 10-10. The main pipelines that serve Ontario consist of multiple parallel pipes that provide access to supplies from Western Canada, the Marcellus/Utica gas plays, other U.S. producing basins, and to storage supplies from the Dawn / Tecumseh storage hub in southwestern Ontario. TransCanada, Union, and Vector operate transmission facilities, and Enbridge and Union operate distribution facilities as well as storage facilities. While there is a sizeable amount of direct-connected gas-fired generation to Vector and, to a much lesser extent, TransCanada, the majority of gas-fired generation in the province is located at the local level behind the Enbridge and Union Gas systems. Results of the Ontario companies' assessment is provided in the Appendix of the CEII version of this report.

As previously noted, technical assessment of Ontario's pipeline, LDC, and storage infrastructure capability was performed by TransCanada, Enbridge, and Union Gas (the Ontario companies). This assessment focused on gas deliverability at the local level into the Enbridge or Union Gas systems, in particular, the Greater Toronto Area. In assessing the resiliency of the consolidated network of pipeline, storage, and LDC infrastructure in IESO, the Ontario companies defined the relevant changes in pipeline infrastructure affecting gas deliverability in 2018.[35]

[35] Since they performed an independent analysis, the Ontario companies' assumptions regarding new pipeline projects are not identical to the infrastructure changes as defined in the RGDS and HGDS in Target 2 and Target 3. For example, the Ontario companies incorporated the anticipated reversal-of-flow across the Iroquois Zone 1 segment of the Iroquois route system following the commercialization of the Constitution Pipeline. Iroquois's reversal-of-flow is referred to as the "SoNo" project, and was not incorporated in the Target 2 and Target 3 definition of infrastructure changes. The post-contingency impact of the SoNo project in NYISO and ISO-NE has not been evaluated in the Target 3 study.

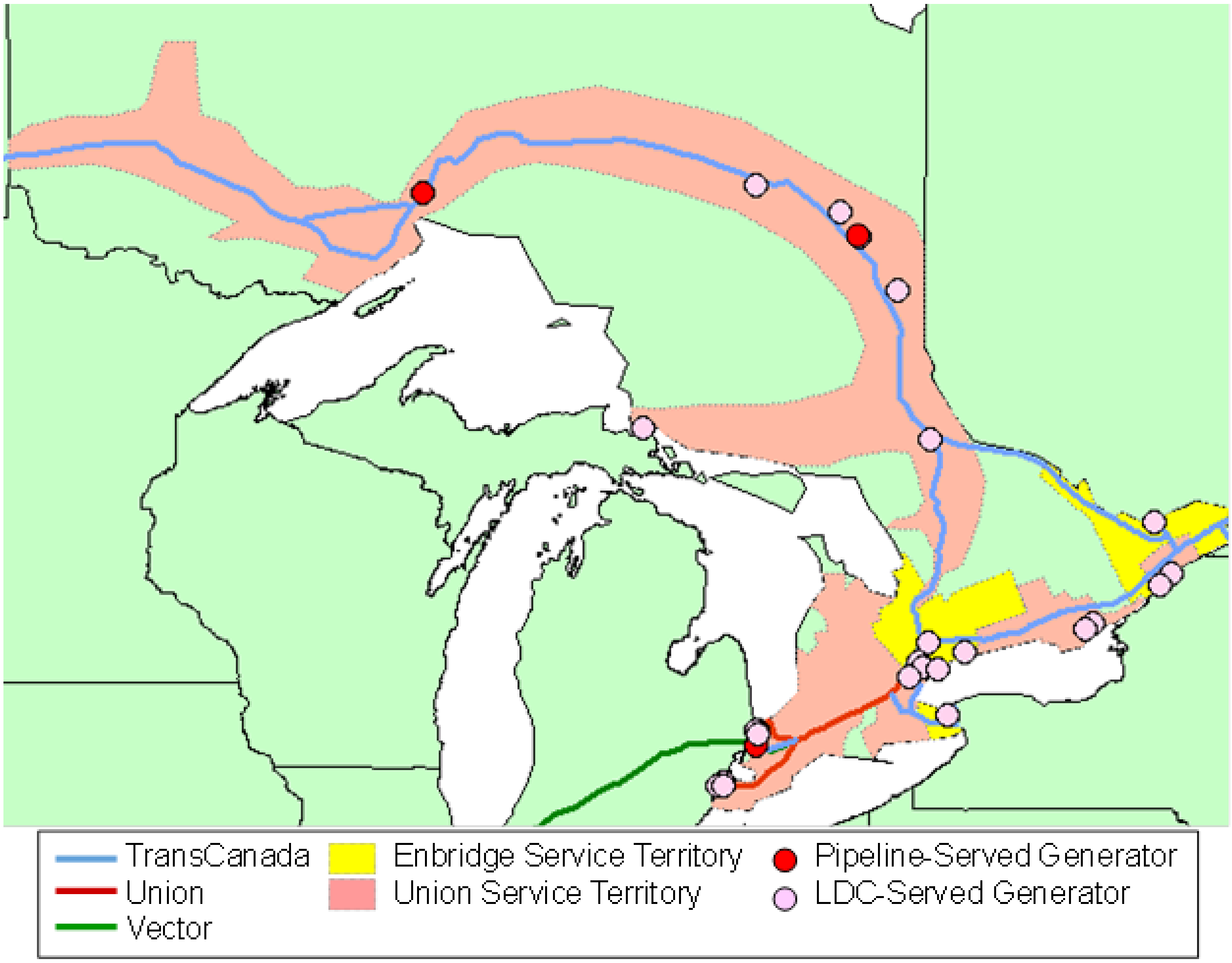

Figure 10-10. Ontario Natural Gas Infrastructure

10.3.2 ISO-NE

The New England pipeline map and the consolidated hydraulic model are shown in Figure 10-11 and Figure 10-12, respectively. The hydraulic model includes the five interstate pipelines that serve generation in New England: Algonquin, Tennessee, Iroquois, M&N, and PNGTS.[36] In total, these systems encompass approximately 2,200 miles of pipe, and are represented by 430 nodes and 535 legs.[37,38] The impact of gas flowing from western and Atlantic Canada is captured at northern boundary points, including M&N's receipts from the M&N Canadian

[36] Granite State is not included in the model because it serves only RCI customers. Therefore deliveries to Granite State by M&N, PNGTS, and Tennessee are classified as RCI deliveries.

[37] Any pipe segment, compressor, or valve in the system is called a "leg." The connections between legs are called "nodes." Each Leg must have one Node at each end. Nodes are also volumetric input/output points.

[38] The details of the pipeline infrastructure that defines the nodes and legs are taken from CEII filings at FERC and are therefore not included in this report.

system at Baileyville, ME and PNGTS's receipts from TransCanada's Trans-Quebec Maritimes system at Pittsburg, NH.[39]

The consolidated New England model also includes receipt points on Algonquin and Tennessee from the Suez Distrigas LNG import terminal outside Boston in Everett, MA, and a receipt point on M&N from the Repsol Canaport LNG import terminal in Saint John, New Brunswick.[40] As discussed in the Target 2 report, LAI has assumed that no LNG from either Canaport or Distrigas will be delivered to M&N and Algonquin / Tennessee, respectively. Consistent with the goals of the reliability study, the assumed limitations at Canaport and Distrigas reflect the PPAs' and LAI's then current understanding of the commercial impediments affecting both Repsol's and Suez's willingness to bear market risk in New England in light of rival counterparties' willingness to pay in the Eurozone, United Kingdom, South America and Asia. Such limitations were strictly commercial in nature rather than any physical regasification constraints at both LNG import facilities.[41,42] The resultant loss of regasified LNG into M&N for north-to-south flow into northern New England and pressure-boosting east-end deliveries into the high-pressure Tennessee pipeline and medium-pressure Algonquin pipeline around Boston, stresses the New England pipeline system.

[39] The potential reversal-of-flow across Iroquois Zone 1 from Wright, NY, to Waddington, NY following the commercialization of the Constitution Pipeline would not be expected to affect the baseline deliverability conditions in NYISO or ISO-NE. However, a number of gas-side contingencies in NYISO would have direct impacts on Iroquois and other pipelines that serve the LHV and downstate New York. If, for whatever reason, incremental volumes cannot be scheduled at the Waddington receipt point following the start-up of the SoNo project, Iroquois's post contingency response to various postulated gas side contingencies could result in increased affected generation in NYISO, and, perhaps, in ISO-NE as well.

[40] Distrigas's sendout to Mystic 8&9 and truck deliveries to satellite LNG storage facilities are not included in the hydraulic model, because they do not interact with the interstate pipeline network. To the extent that the LDCs' LNG storage tanks and, to a lesser extent, propane air tanks are filled by regasifying supplies received from the pipelines, those volumes are included in the RCI deliveries to the various citygate meters.

[41] The LNG dispatch regime at the Canaport and Distrigas LNG import facilities was defined in Q3-2014 and therefore does not capture the collapse of world oil prices in Q4-2014 and/or the change in oil-gas parity ratios affecting the scheduling of gas-fired generation in the RGDS or HGDS.

[42] After completion of the Target 2 analysis in 2014, there were increased LNG shipments to New England during the 2014-15 winter season. This change may or may not be indicative of market dynamics in 2018 and/or 2023. The impact of significant regasification at Canaport and Distrigas is addressed in Sensitivity 16 of the Target 2 study.

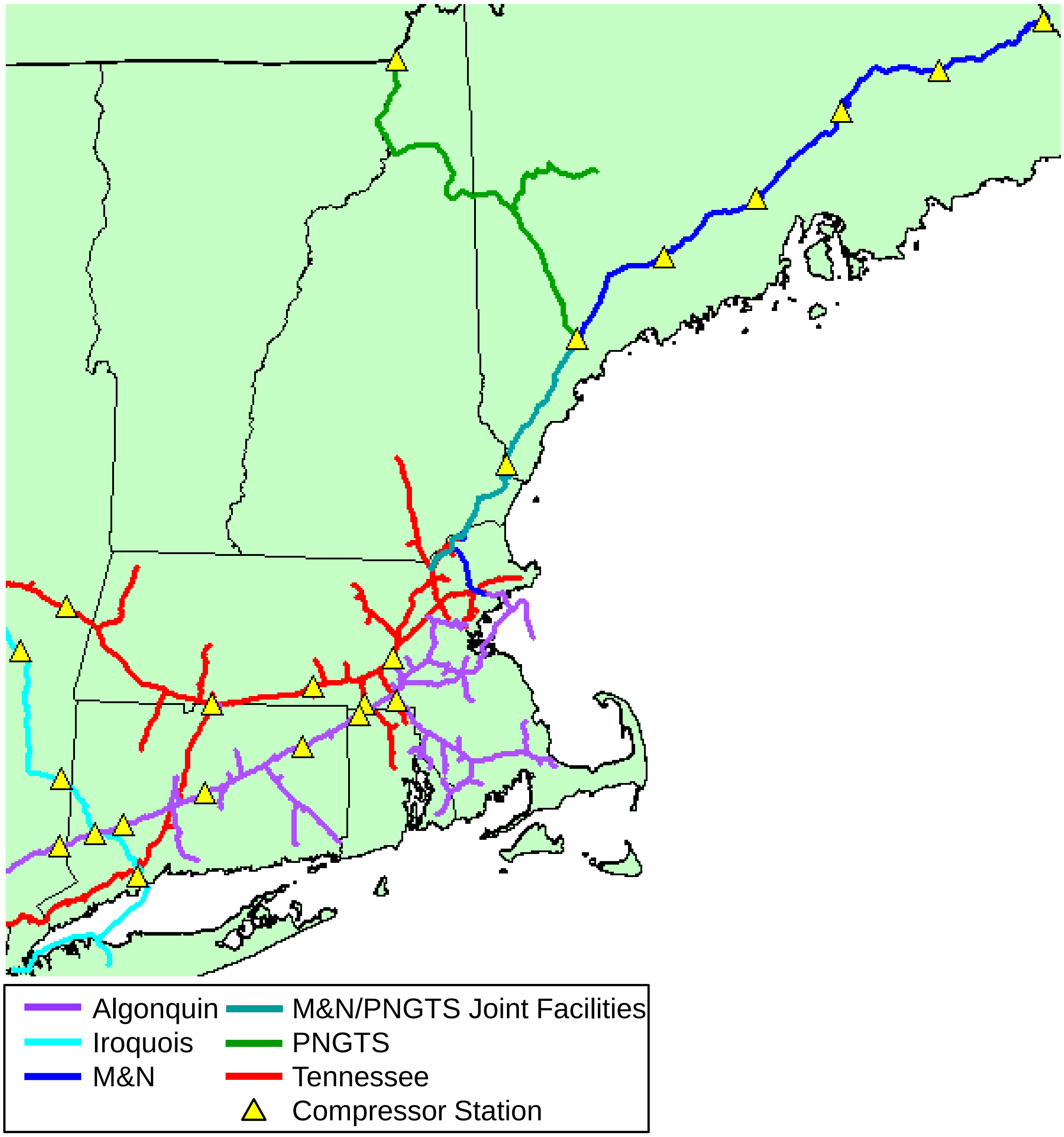

Figure 10-11. New England Gas Pipeline Map

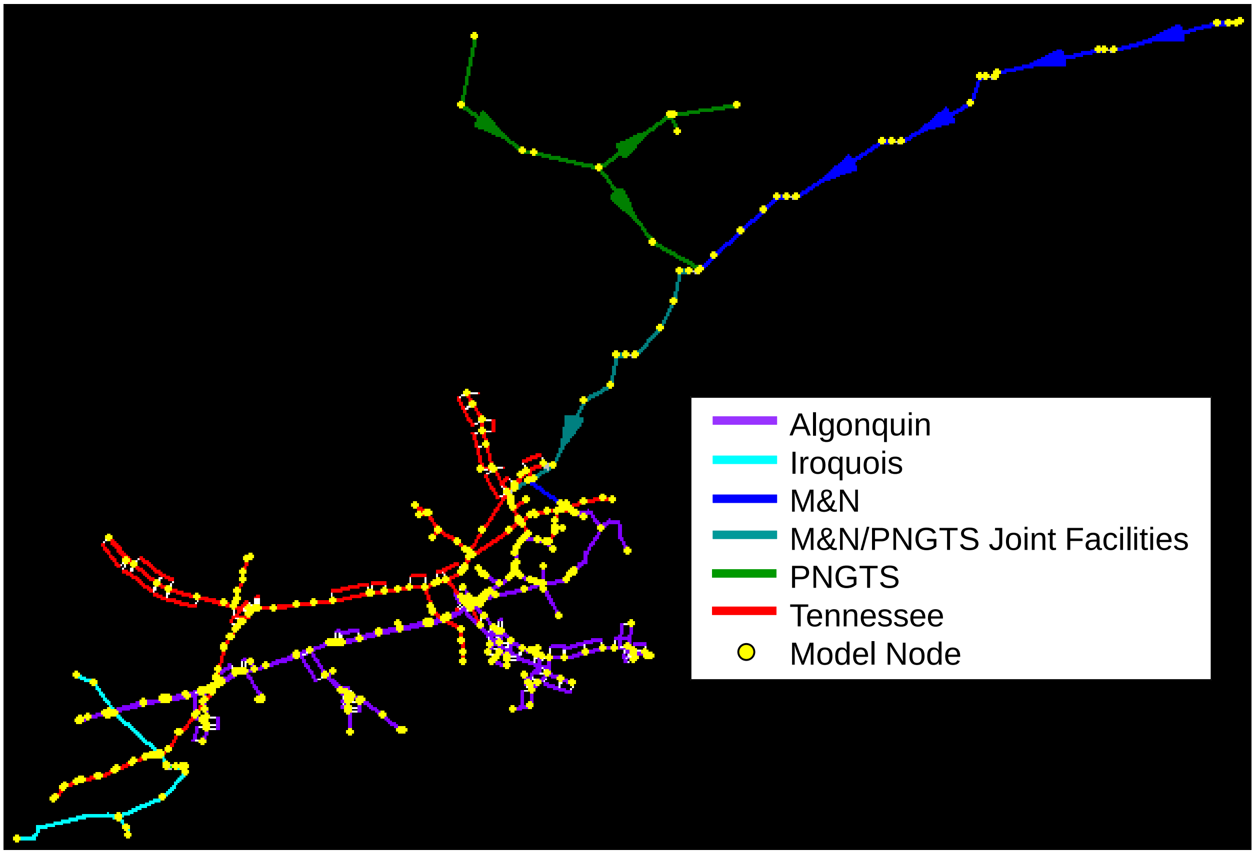

Figure 10-12. Consolidated New England Hydraulic Model

Total seasonal peak day gas demand for electric generation by pipeline, including both directly connected and LDC-served loads, is shown in Table 10-5.

Table 10-5. ISO-NE Total Peak Day Gas Demand for Electric Generation by Pipeline

Pipeline	RGDS W18 (MDth)	RGDS S18 (MDth)	HGDS W18 (MDth)	HGDS S18 (MDth)	RGDS W23 (MDth)	RGDS S23 (MDth)
Algonquin	515	1,137	477	1,168	554	1,150
Iroquois	134	178	203	262	132	178
M&N	104	232	118	233	120	231
PNGTS	69	144	79	149	82	145
Tennessee	314	595	424	689	365	592
Total	1,136	2,286	1,301	2,500	1,253	2,297

Figure 10-13 and Table 10-6 show the deliverability of generator peak day gas demands and associated scheduled energy under baseline conditions.

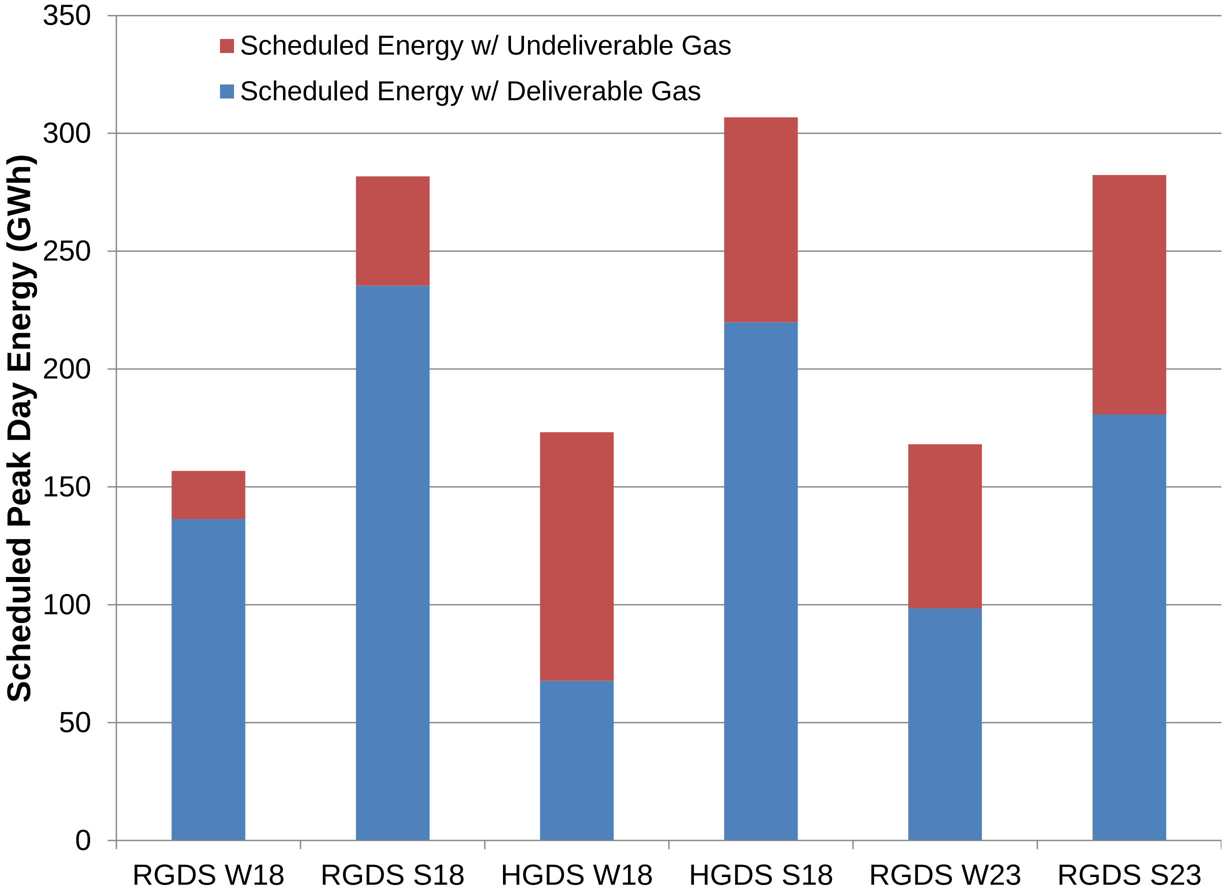

Figure 10-13. ISO-NE Baseline Energy Deliverability

Table 10-6. Summary of ISO-NE Baseline Results

Season	Scheduled Gas (MDth)	Scheduled Energy (MWh)	Scheduled Energy with Undeliverable Gas (MWh)	Scheduled Energy with Undeliverable Gas (%)
RGDS W18	1,136	156,821	19,979 (gas-only) 489 (dual-fuel)	13
RGDS S18	2,286	281,745	5,905 (gas-only) 40,469 (dual-fuel)	16
HGDS W18	1,301	173,209	94,407 (gas-only) 11,064 (dual-fuel)	61
HGDS S18	2,500	306,805	44,968 (gas-only) 41,980 (dual-fuel)	28
RGDS W23	1,253	168,148	59,373 (gas-only) 10,388 (dual-fuel)	41
RGDS S23	2,297	282,342	58,894 (gas-only) 42,679 (dual-fuel)	36

10.3.3 MISO

The MISO North/Central pipeline map and the corresponding consolidated hydraulic models are shown in the following four figures.[43] The hydraulic model was divided into multiple regions to streamline contingency evaluation. The first consolidated MISO model, which covers primarily Iowa and Minnesota, includes Alliance, Great Lakes, NGPL, Northern Border, Northern Natural, and Viking.[44] The second consolidated MISO model, which covers primarily Michigan and Wisconsin, includes ANR, Great Lakes, Panhandle Eastern, and Viking. The third consolidated MISO model, which covers primarily Illinois, includes Mississippi River, NGPL, Panhandle Eastern, Rockies Express, and Trunkline. In total, these models include 2,438 nodes and 2,987 legs, and represent 19,932 miles of pipe. Gas generally flows across the PPA from west to east and south to north, with more complex flow patterns in Michigan's Lower Peninsula due to the extensive network of storage fields in that area. Given the extensive connectivity of the pipeline and storage infrastructure in MISO North/Central, formulation of consolidated network models has required professional judgments regarding the gas/electric interdependencies of relevance in different parts of North/Central where there is a comparatively high concentration of gas-fired generation.

[43] MISO did not require hydraulic modeling in MISO South due to the extensive labyrinthine network of pipelines, gathering and storage facilities in relation to the amount of gas-fired generation.

[44] The Bison and WBI Energy pipelines in the northwestern portion of MISO North/Central are not included in the hydraulic model because they have limited interconnections with other pipelines and serve only 100 MW of generation, located behind the Montana-Dakota Utilities LDC system.

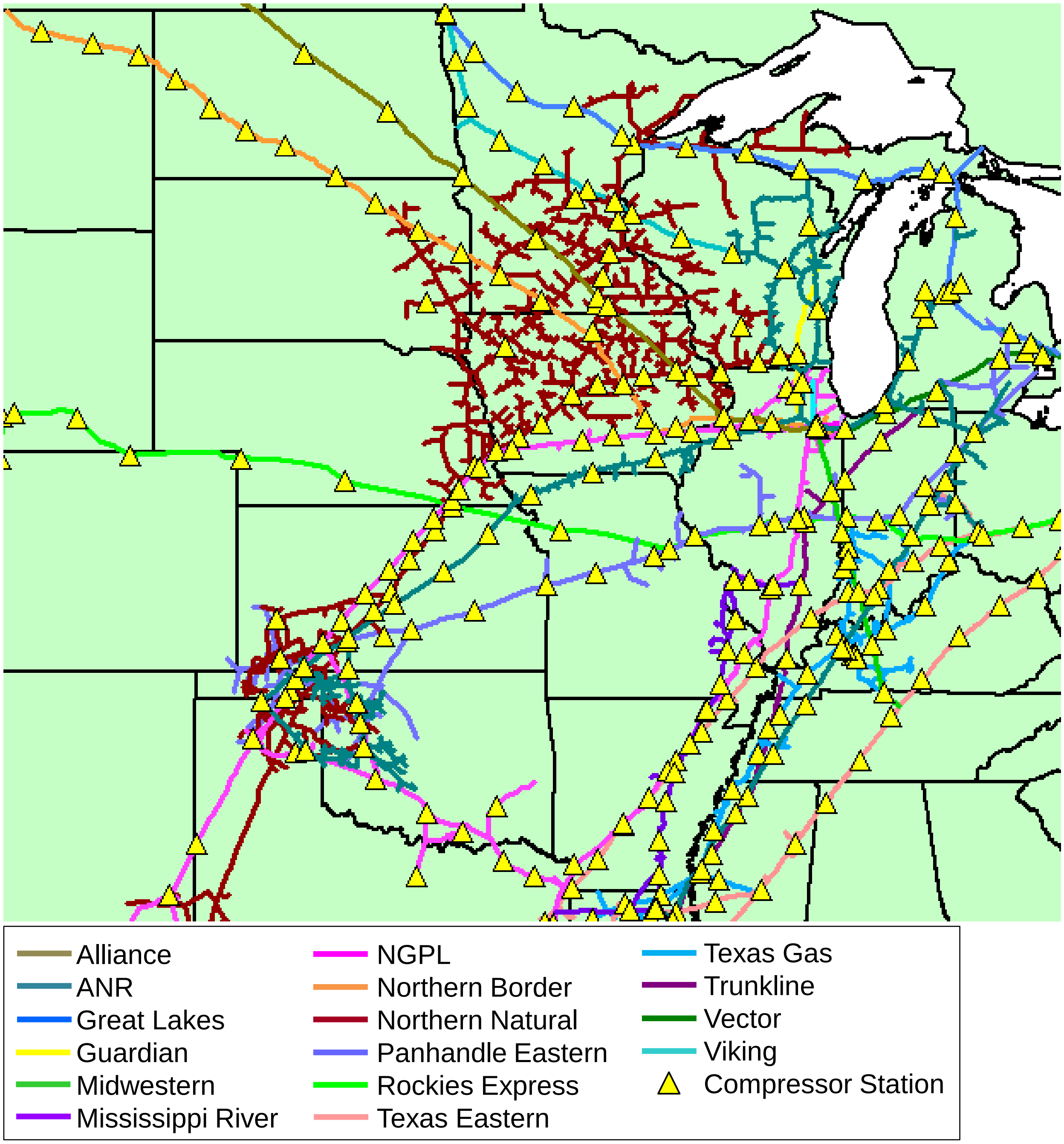

Figure 10-14. MISO Pipeline Map

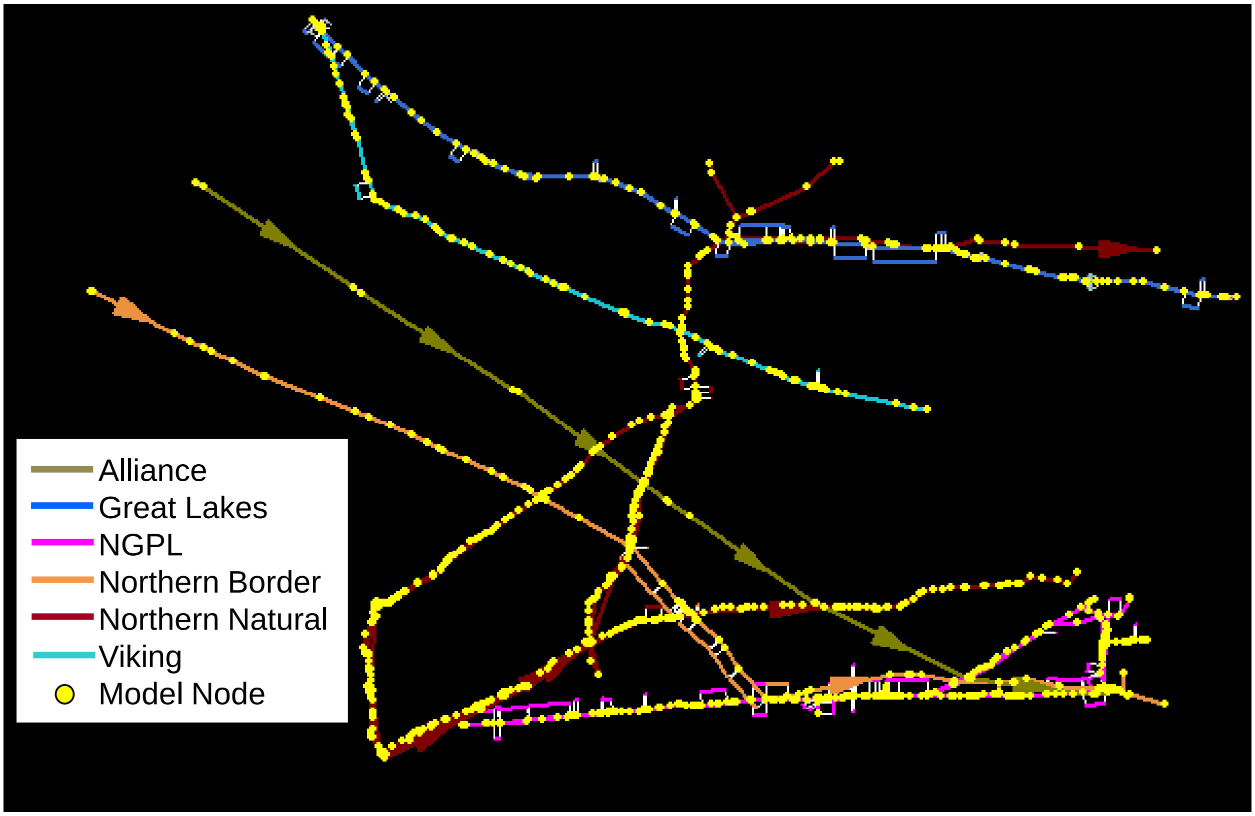

Figure 10-15. Consolidated MISO Model: Iowa and Minnesota[45]

[45] Designation of nodes and segments for individual pipelines generally track operational information available by pipeline in FERC Form 567 reports and Exhibit G's. Along route segments that do not incorporate meters serving gas-fired generators, roll-up of RCI meters is sometimes implemented to facilitate model consolidation.

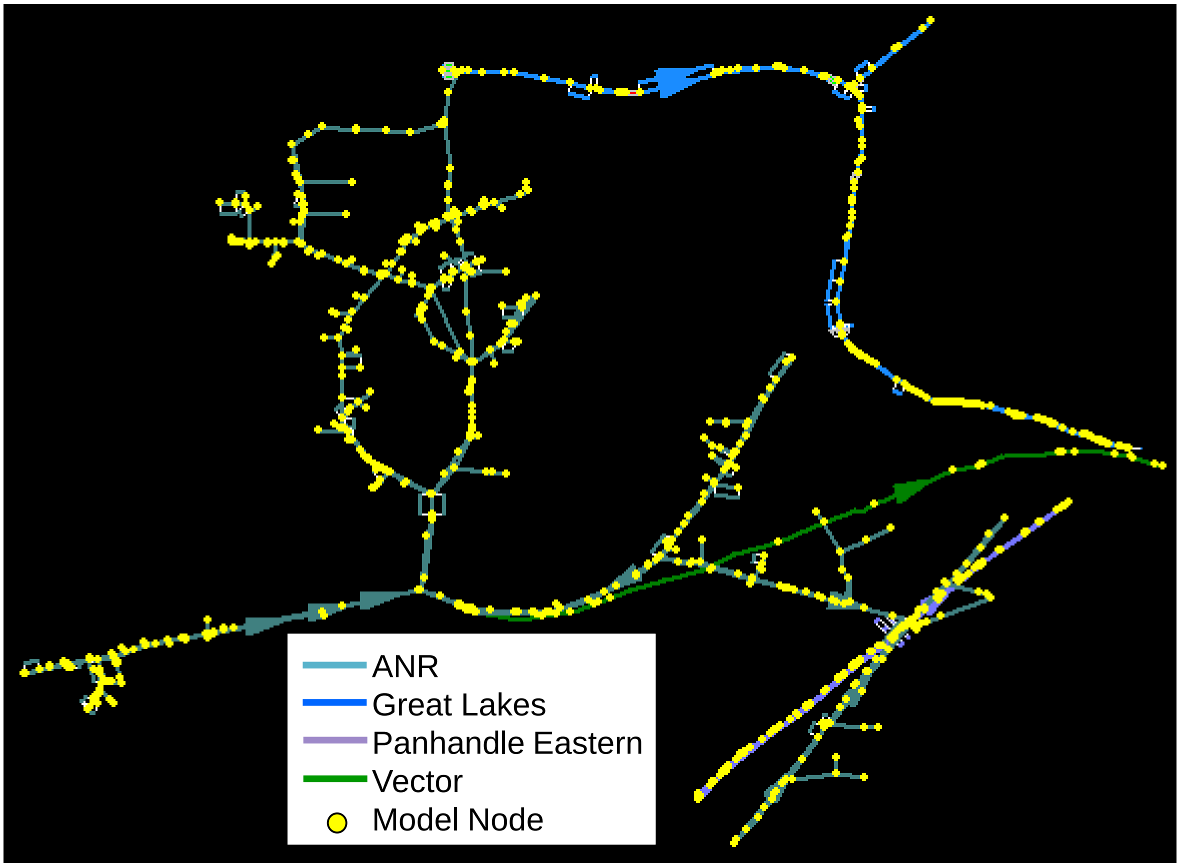

Figure 10-16. Consolidated MISO Model: Michigan and Wisconsin

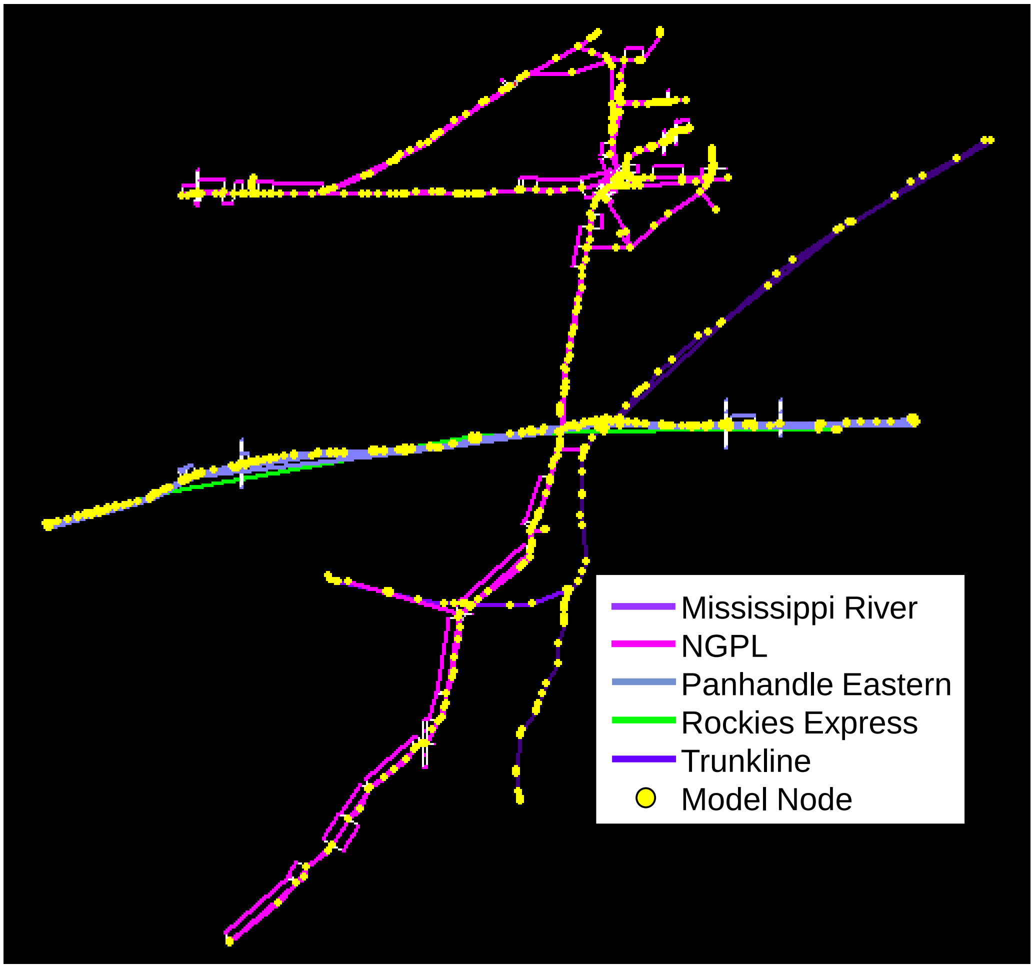

Figure 10-17. Consolidated MISO Model: Illinois

Total seasonal peak day gas demand for MISO electric generation by pipeline within the hydraulic model footprints, including both directly connected and LDC-served loads, is shown in Table 10-7.

Table 10-7. MISO Total Peak Day Gas Demand for Electric Generation by Pipeline

Pipeline	RGDS W18 (MDth)	RGDS S18 (MDth)	HGDS W18 (MDth)	HGDS S18 (MDth)	RGDS W23 (MDth)	RGDS S23 (MDth)
ANR	487	947	1,599	1,603	88	917
Great Lakes	299	421	569	766	219	390
Mississippi River	0	6	30	24	0	8
NGPL	168	240	567	523	0	246
Northern Border	46	60	118	109	17	58
Northern Natural	611	658	1,183	1,159	363	656
Panhandle Eastern	146	243	502	500	114	265
Trunkline	0	43	126	95	0	46
Vector	106	118	220	201	44	106
Viking	11	8	16	12	7	7
Total	1,874	2,744	4,929	4,991	852	2,699

Figure 10-18 and Table 10-8 show the deliverability of generator peak day gas demands and associated scheduled energy under baseline conditions. Pipeline utilization maps along key route segments in MISO North/Central, in particular, and for the Study Region, in general, have been incorporated in Exhibit 25.

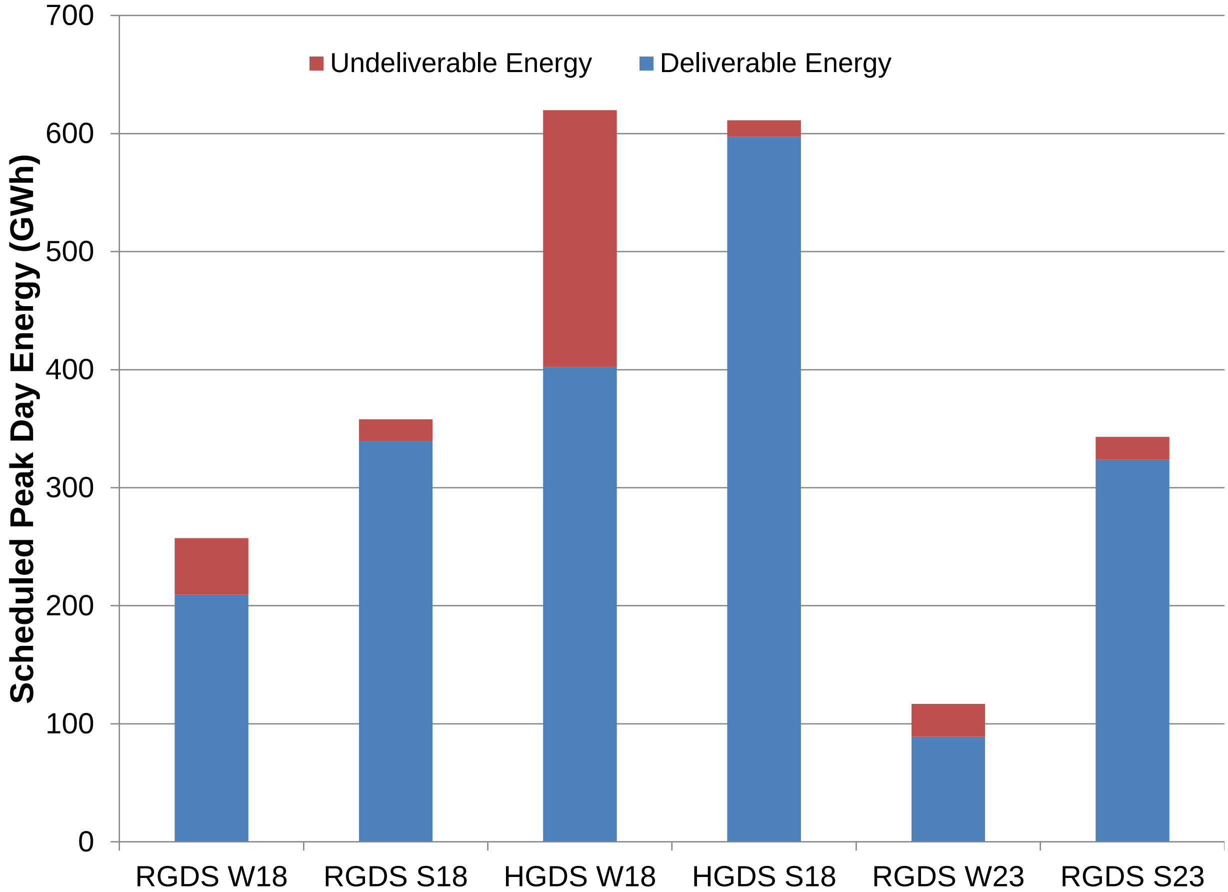

Figure 10-18. MISO Baseline Energy Deliverability

Table 10-8. Summary of MISO Baseline Results

Season	Scheduled Gas (MDth)	Scheduled Energy (MWh)	Scheduled Energy with Undeliverable Gas (MWh)	Scheduled Energy with Undeliverable Gas (%)
RGDS W18	1,874	257,301	26,655 (gas-only) 21,352 (dual-fuel)	19
RGDS S18	2,744	358,026	12,254 (gas-only) 6,471 (dual-fuel)	5
HGDS W18	4,929	619,890	176,652 (gas-only) 41,050 (dual-fuel)	35
HGDS S18	4,991	611,352	3,326 (gas-only) 10,699 (dual-fuel)	2
RGDS W23	852	116,916	21,385 (gas-only) 6,496 (dual-fuel)	24
RGDS S23	2,699	343,050	13,156 (gas-only) 6,100 (dual-fuel)	6

10.3.4 NYISO

The NYISO pipeline map and the corresponding consolidated hydraulic model are shown in Figure 10-19 and Figure 10-20, respectively. The hydraulic model includes the eight interstate pipelines that operate in New York: Algonquin, Dominion, Empire, Iroquois, Millennium, NFG, Stagecoach, and Tennessee.[46] In total, these systems encompass approximately 4,810 miles of pipe, and are represented by 722 nodes and 940 legs. Gas generally flows across the PPA from west to east.[47] The NYFS is not included in the consolidated model, although analysis regarding deliverability to downstate generators under study conditions was evaluated by Con Edison and NGrid, and is included in the Appendix of the CEII version of this report.

[46] Texas Eastern and Transco also serve downstate New York, but those delivery segments are not included in the consolidated hydraulic model because they are not interconnected with the other pipelines serving New York. The relevant New York City and Long Island delivery points are included in the PJM consolidated hydraulic model to account for generation or transmission that is electrically dedicated to New York City or Long Island.

[47] The potential reversal-of-flow across Iroquois Zone 1 from Wright, NY, to Waddington, NY following the commercialization of the Constitution Pipeline would not be expected to affect the baseline deliverability conditions in NYISO or ISO-NE. However, a number of gas-side contingencies in NYISO would have direct impacts on Iroquois and other pipelines that serve the LHV and downstate New York. If, for whatever reason, incremental volumes cannot be scheduled at the Waddington receipt point following the start-up of the SoNo project, Iroquois's post contingency response to various postulated gas side contingencies could result in increased affected generation in NYISO, and, perhaps, in ISO-NE as well.

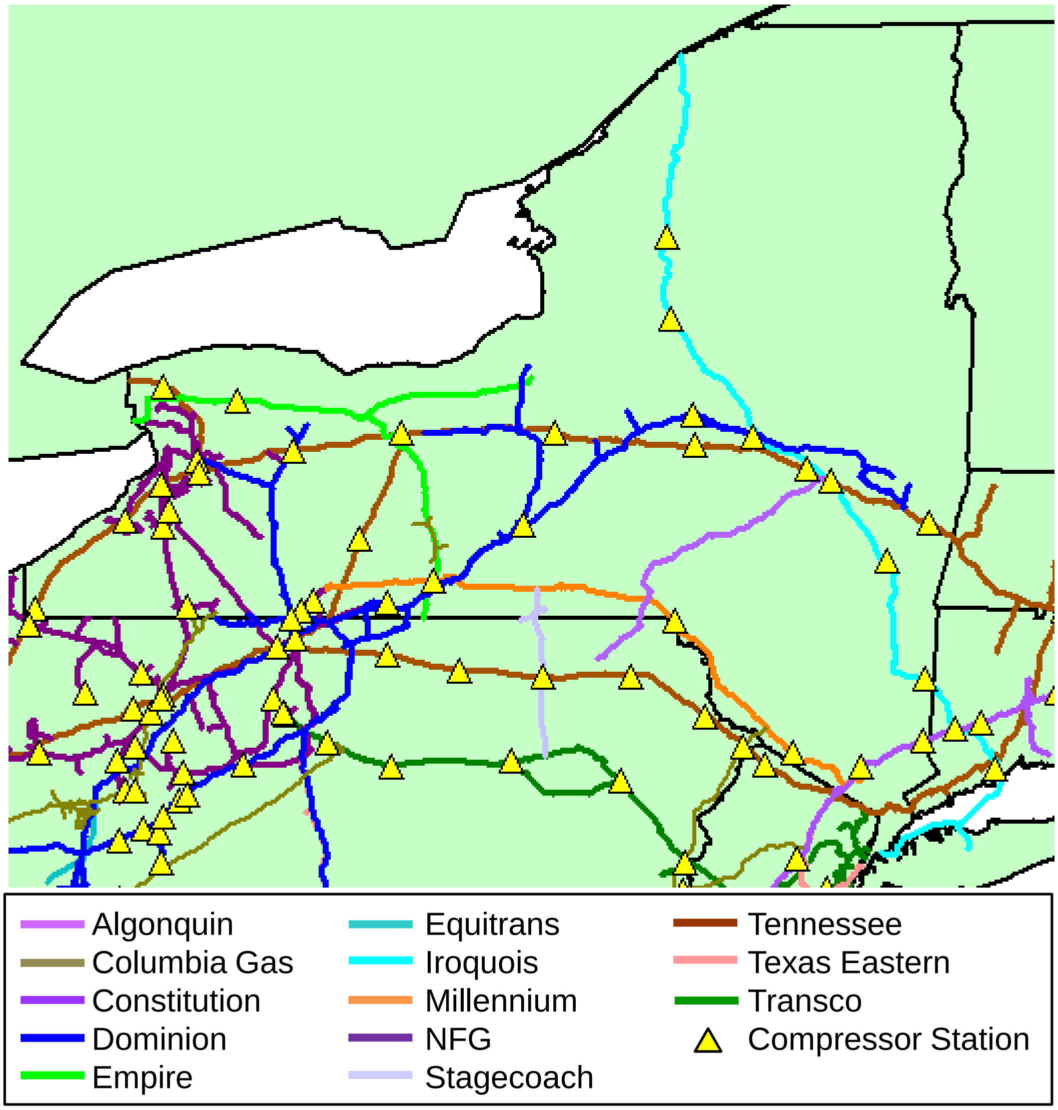

Figure 10-19. NYISO Pipeline Map[48]

[48] Gathering infrastructure, including the Bluestone and Laser systems in Pennsylvania and New York, were not part of this analysis and are therefore not included in the maps and models.

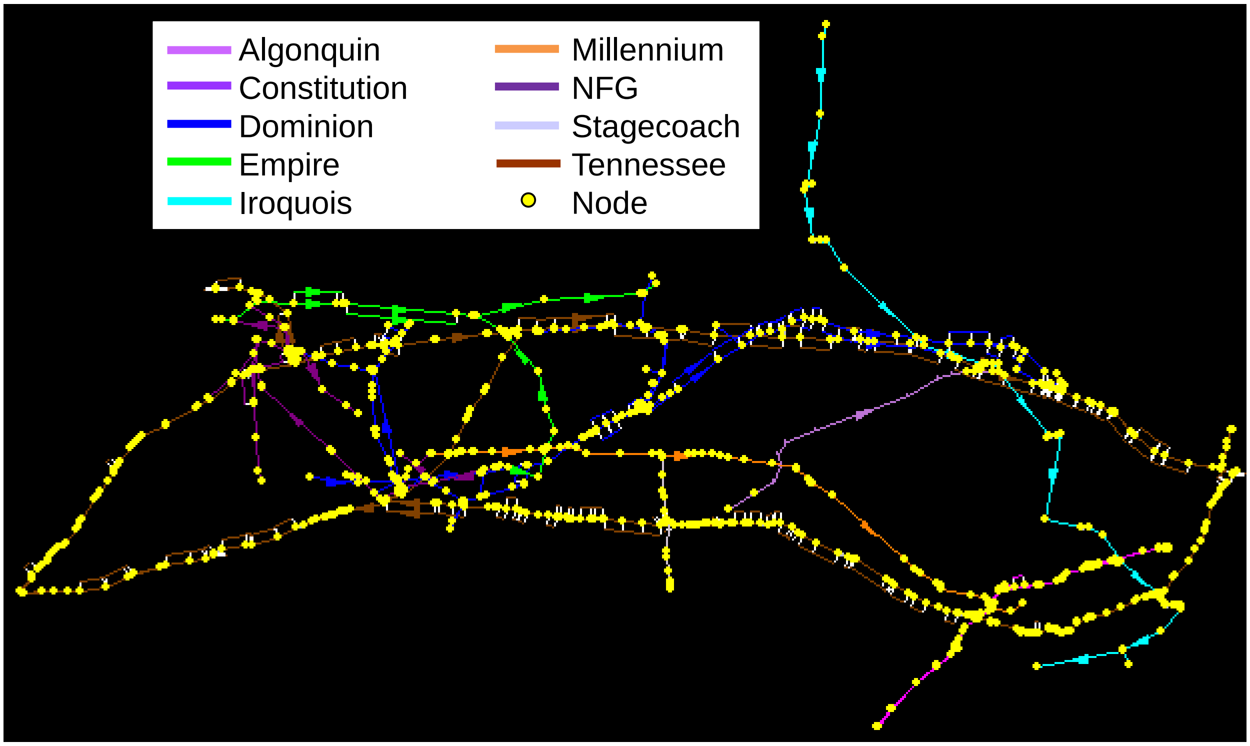

Figure 10-20. Consolidated NYISO Model

Total seasonal peak day gas demand for electric generation by pipeline, including both directly connected and LDC-served loads, is shown in Table 10-9. These results include deliveries to the Northport station that is, in effect, directly connected to Iroquois, but not all other generators served by either Con Edison or NGrid through the NYFS. These analyses can be found in the Appendix of the CEII version of this report.

Table 10-9. NYISO Total Peak Day Gas Demand for Electric Generation by Pipeline[49]

Pipeline	RGDS W18 (MDth)	RGDS S18 (MDth)	HGDS W18 (MDth)	HGDS S18 (MDth)	RGDS W23 (MDth)	RGDS S23 (MDth)
Algonquin	0	0	0	2	-	2
Dominion	72	229	208	396	445	396
Empire	138	140	151	142	132	138
Iroquois	56	300	56	401	95	389
Millennium	205	206	222	218	326	300
NFG	11	18	11	19	12	18
Tennessee	156	240	173	269	143	223
Total	637	1,133	820	1,446	1,153	1,465

[49] The Texas Eastern and Transco pipelines are not included in the New York consolidated hydraulic model. Therefore, the gas demands associated with downstate generators that are served by these pipelines are not included in this table.

Figure 10-21 and Table 10-10 show the deliverability of generator peak day gas demands and associated scheduled energy under baseline conditions.

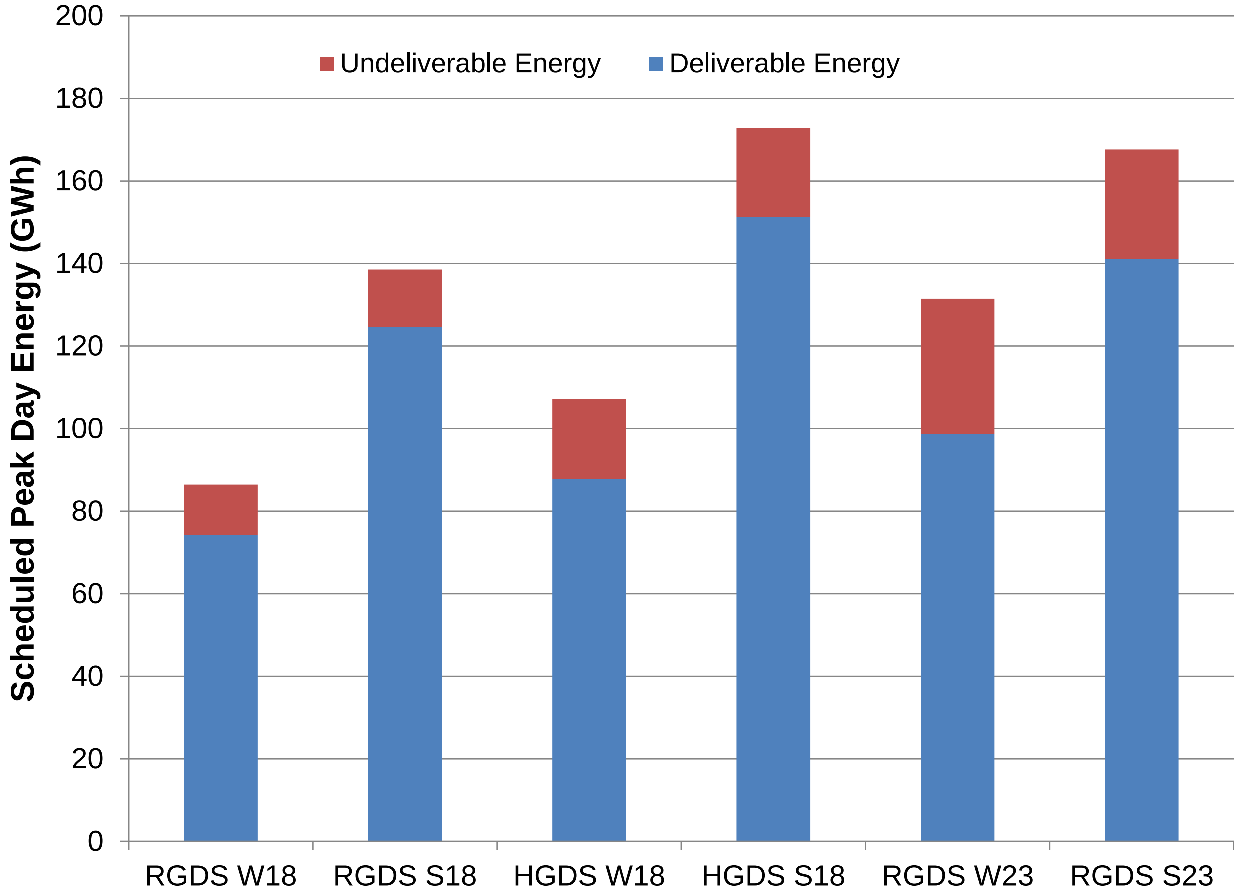

Figure 10-21. NYISO Baseline Energy Deliverability

Table 10-10. Summary of NYISO Baseline Results

Season	Scheduled Gas (MDth)	Scheduled Energy (MWh)	Scheduled Energy with Undeliverable Gas (MWh)	Scheduled Energy with Undeliverable Gas (%)
RGDS W18	637	86,428	5,238 (gas-only) 6,980 (dual-fuel)	14
RGDS S18	1,133	138,542	1 (gas-only) 13,999 (dual-fuel)	10
HGDS W18	820	107,207	9,508 (gas-only) 9,918 (dual-fuel)	18
HGDS S18	1,446	172,826	1,248 (gas-only) 20,347 (dual-fuel)	12
RGDS W23	1,153	131,465	10,924 (gas-only) 21,826 (dual-fuel)	25
RGDS S23	1,465	141,129	2 (gas-only) 26,516 (dual-fuel)	16

10.3.5 PJM

The pipelines included in the consolidated PJM hydraulic model are shown in the map and model diagram in Figure 10-22 and Figure 10-23, respectively. The model includes nine interstate pipelines that operate in eastern PJM: Algonquin, Columbia Gas, Dominion, Dominion Cove Point, Eastern Shore, Equitrans, NFG, Tennessee, Texas Eastern, and Transco. Other pipelines serving LDCs in the western part of PJM have been included in the LDC contingency analyses.[50,51] In total, these systems encompass approximately 17,630 miles of pipe, and are represented by 2,454 nodes and 3,351 legs. Gas flows both east and west out of the Marcellus and Utica producing basins in Pennsylvania, West Virginia, and Ohio to serve customers in PJM and neighboring PPAs.

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[50] See the Appendix of the CEII version of this report.

[51] The portions of ANR and NGPL serving the ComEd region of PJM are not included in the PJM consolidated model because they are not contiguous with the other pipelines modeled, and no interstate pipeline gas contingencies were modeled in the ComEd area.

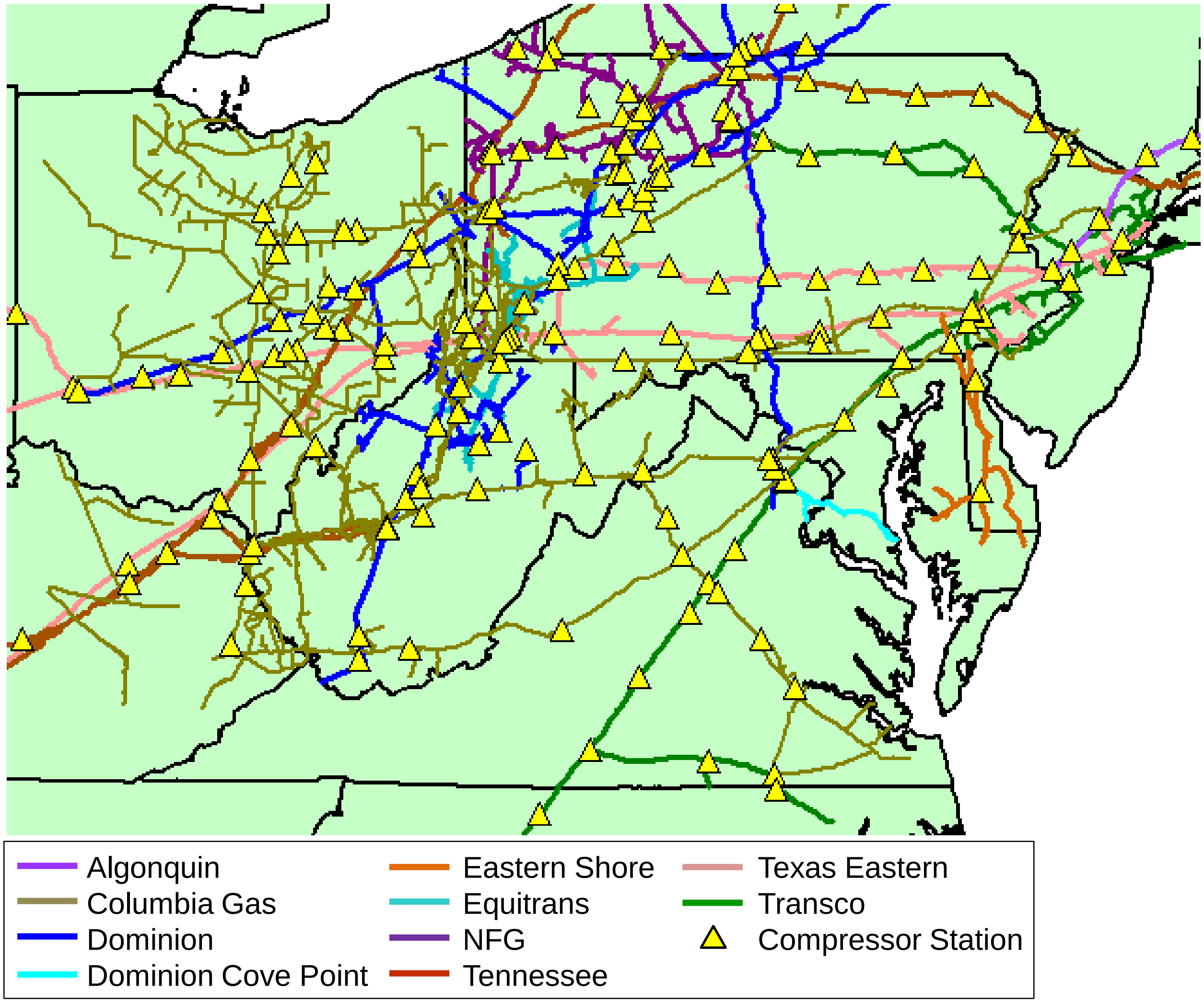

Figure 10-22. PJM Pipeline Map

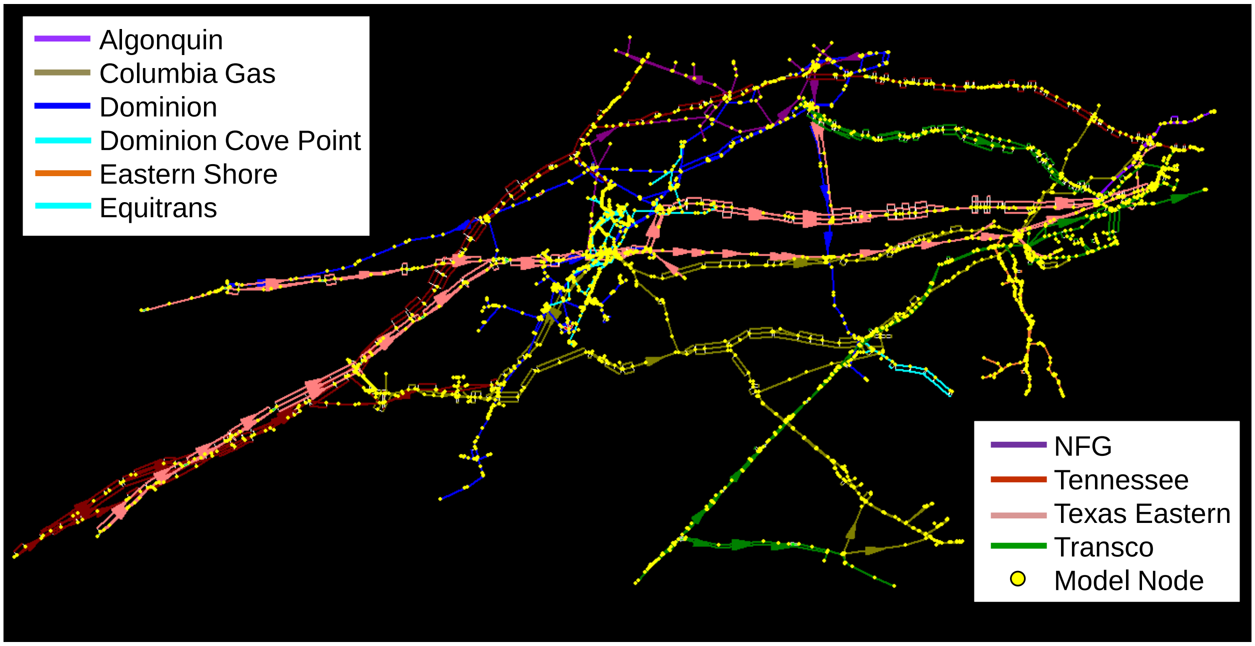

Figure 10-23. Consolidated PJM Model

Total seasonal peak day gas demand for electric generation by pipeline, including both directly connected and LDC-served loads, is shown in Table 10-11. Although electrically dedicated to New York City, the Bayonne Energy Center and Linden Cogen plants are located in New Jersey. Therefore, they are included in the PJM analysis. In addition, the Marcus Hook plant located in eastern Pennsylvania is electrically dedicated to PJM, and as such is included in the analysis. However, it is a capacity resource affecting the withdrawal of energy at Sayreville, New Jersey on the Neptune transmission line to Long Island.

Table 10-11. PJM Total Peak Day Gas Demand for Electric Generation by Pipeline

Pipeline	RGDS W18 (MDth)	RGDS S18 (MDth)	HGDS W18 (MDth)	HGDS S18 (MDth)	RGDS W23 (MDth)	RGDS S23 (MDth)
Columbia Gas	576	1,239	904	1,818	831	1,402
Dominion	515	591	2,126	2,408	1,271	1,217
Dominion Cove Point	27	553	38	691	24	562
Eastern Shore	30	241	88	284	80	256
Equitrans	0	36	58	61	73	73
NFG	3	18	7	34	54	48
Tennessee	265	739	966	860	785	837
Texas Eastern	784	1,826	1,664	2,458	1,186	2,199
Transco	407	2,583	915	3,162	411	2,582
Total	2,607	7,827	6,766	11,776	4,715	9,185

Figure 10-24 and Table 10-12 show the deliverability of generator peak day gas demands and associated scheduled energy under baseline conditions. While total PJM gas demand is lower in summer than winter, certain locations within PJM – specifically Eastern Shore's Delmarva Peninsula system and Texas Eastern's Philadelphia Lateral – have higher total gas demand on the

Summer Peak Day than on the Winter Peak Day due to high electric generator load that more than offsets the decrease in RCI demand between seasons. This results in lower gas pressures in those locations on the Summer Peak Day than the Winter Peak Day, and therefore more affected generation.

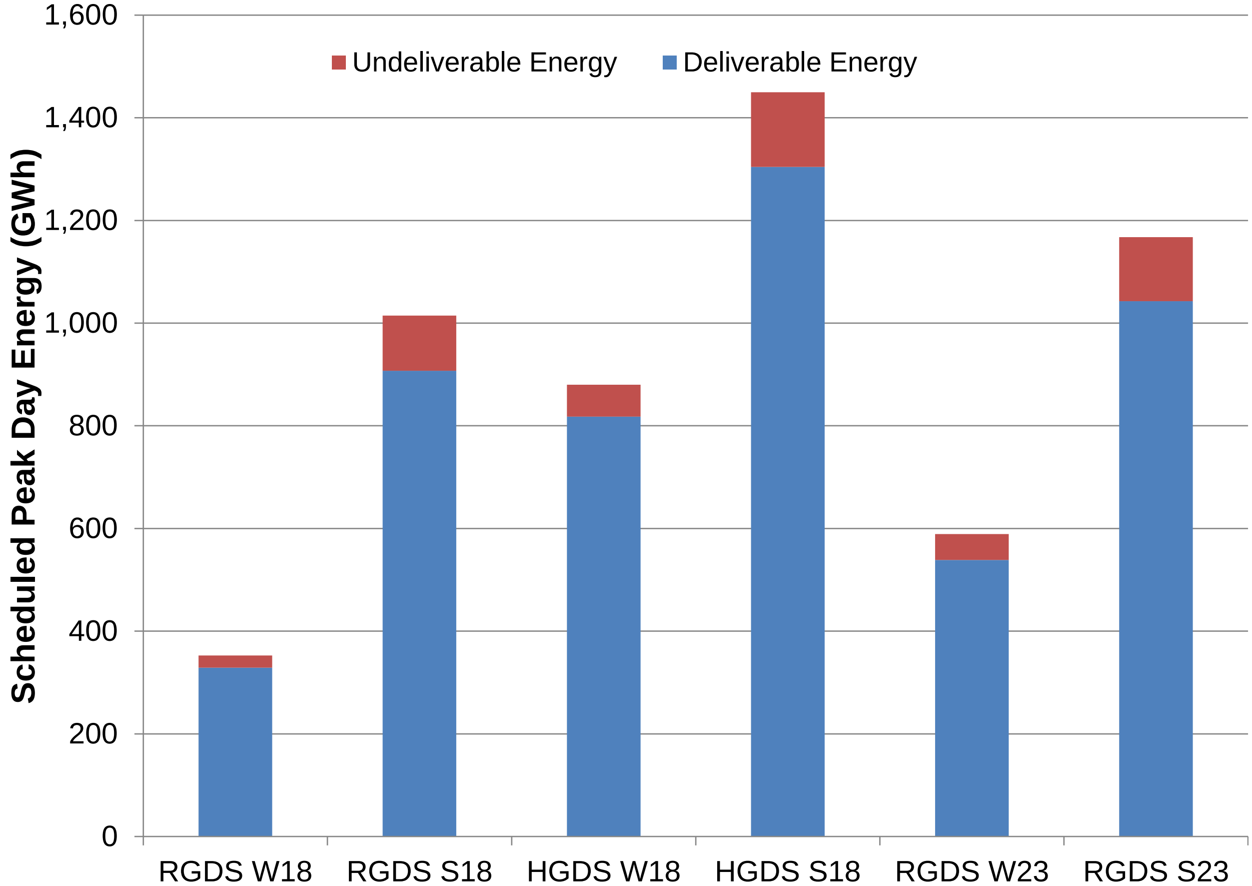

Figure 10-24. PJM Baseline Energy Deliverability

Table 10-12. Summary of PJM Baseline Results

Season	Scheduled Gas (MDth)	Scheduled Energy (MWh)	Scheduled Energy with Undeliverable Gas (MWh)	Scheduled Energy with Undeliverable Gas (%)
RGDS W18	2,607	352,687	10,707 (gas-only) 13,322 (dual-fuel)	7
RGDS S18	7,827	1,014,709	44,317 (gas-only) 63,070 (dual-fuel)	11
HGDS W18	6,766	880,010	39,010 (gas-only) 23,168 (dual-fuel)	7
HGDS S18	11,776	1,449,767	77,839 (gas-only) 67,427 (dual-fuel)	10
RGDS W23	4,715	588,968	22,400 (gas-only) 27,993 (dual-fuel)	9
RGDS S23	9,185	1,167,445	50,953 (gas-only) 73,633 (dual-fuel)	11

10.3.6 TVA

The consolidated TVA pipeline map and the corresponding hydraulic model are shown in Figure 10-25 and Figure 10-26, respectively. The hydraulic model includes the nine interstate pipelines that operate in TVA: AlaTenn, ANR, Columbia Gulf, East Tennessee, Midwestern, Tennessee, Texas Eastern, Texas Gas, and Trunkline. In total, these systems encompass approximately 8,000 miles of pipe, and are represented by 1,339 nodes and 1,778 legs. Gas generally flows across the PPA from south to north.

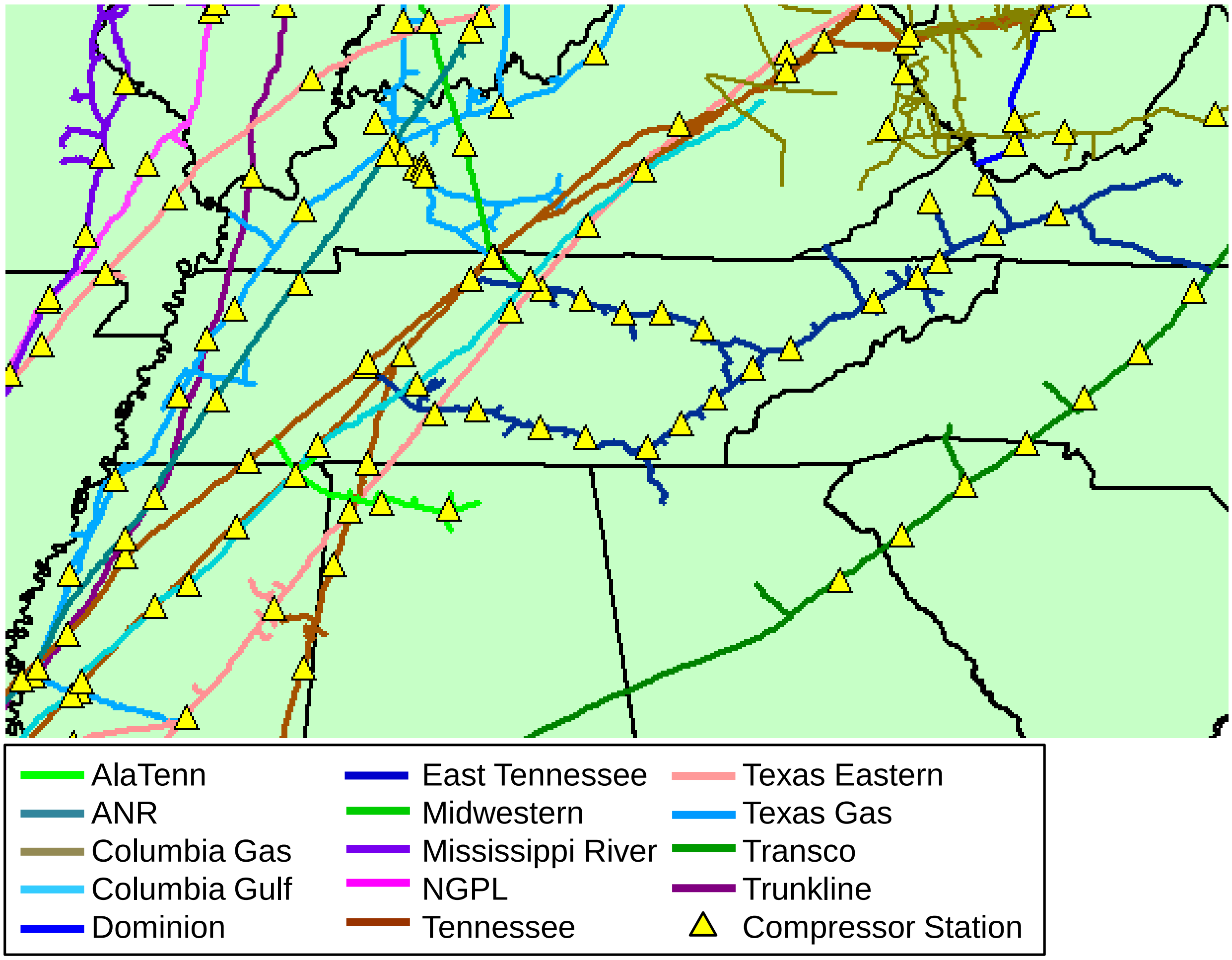

Figure 10-25. TVA Pipeline Map

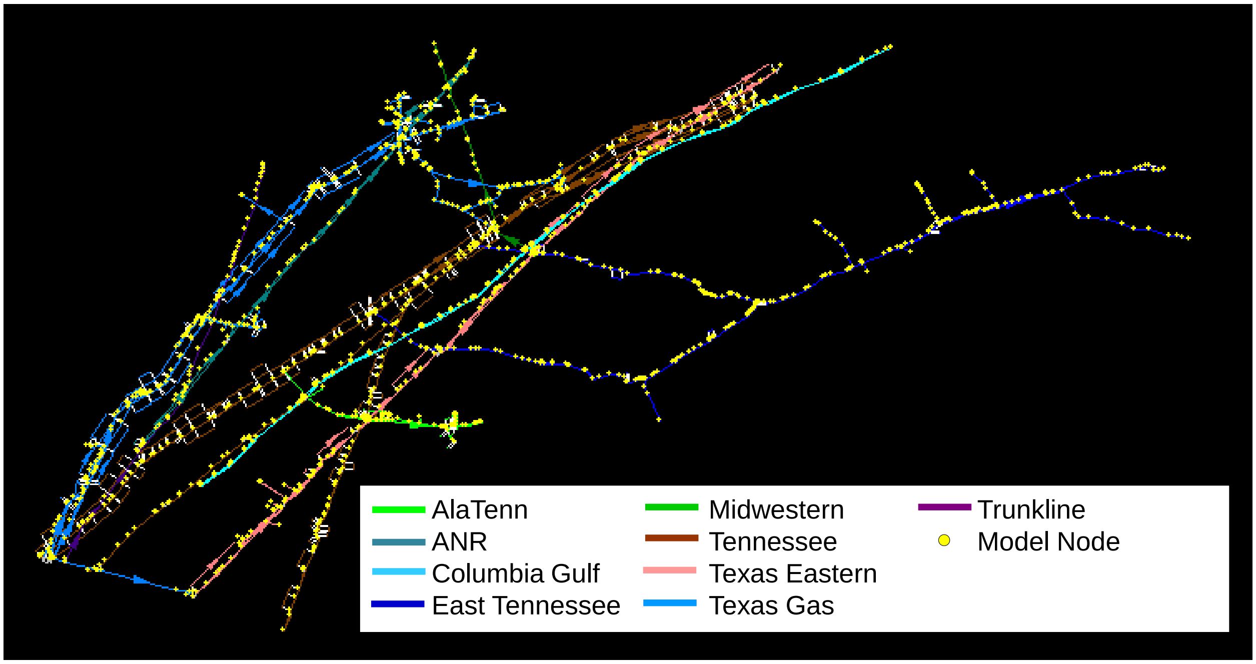

Figure 10-26. Consolidated TVA Model

Total seasonal peak day gas demand for electric generation by pipeline, including both directly connected and LDC-served loads, is shown in Table 10-13.

Table 10-13. TVA Total Peak Day Gas Demand for Electric Generation by Pipeline

Pipeline	RGDS W18 (MDth)	RGDS S18 (MDth)	HGDS W18 (MDth)	HGDS S18 (MDth)	RGDS W23 (MDth)	RGDS S23 (MDth)
AlaTenn	0	0	0	5	0	0
ANR	0	37	131	130	0	31
Columbia Gulf	0	0	27	24	0	0
East Tennessee	145	133	130	117	145	133
Tennessee	564	489	536	553	520	406
Texas Eastern	114	102	114	102	28	34
Texas Gas	300	313	308	470	300	340
Trunkline	64	73	283	256	3	52
Total	1,187	1,147	1,529	1,658	996	997

Figure 10-27 and Table 10-14 show the deliverability of generator peak day gas demands and associated scheduled energy under baseline conditions.

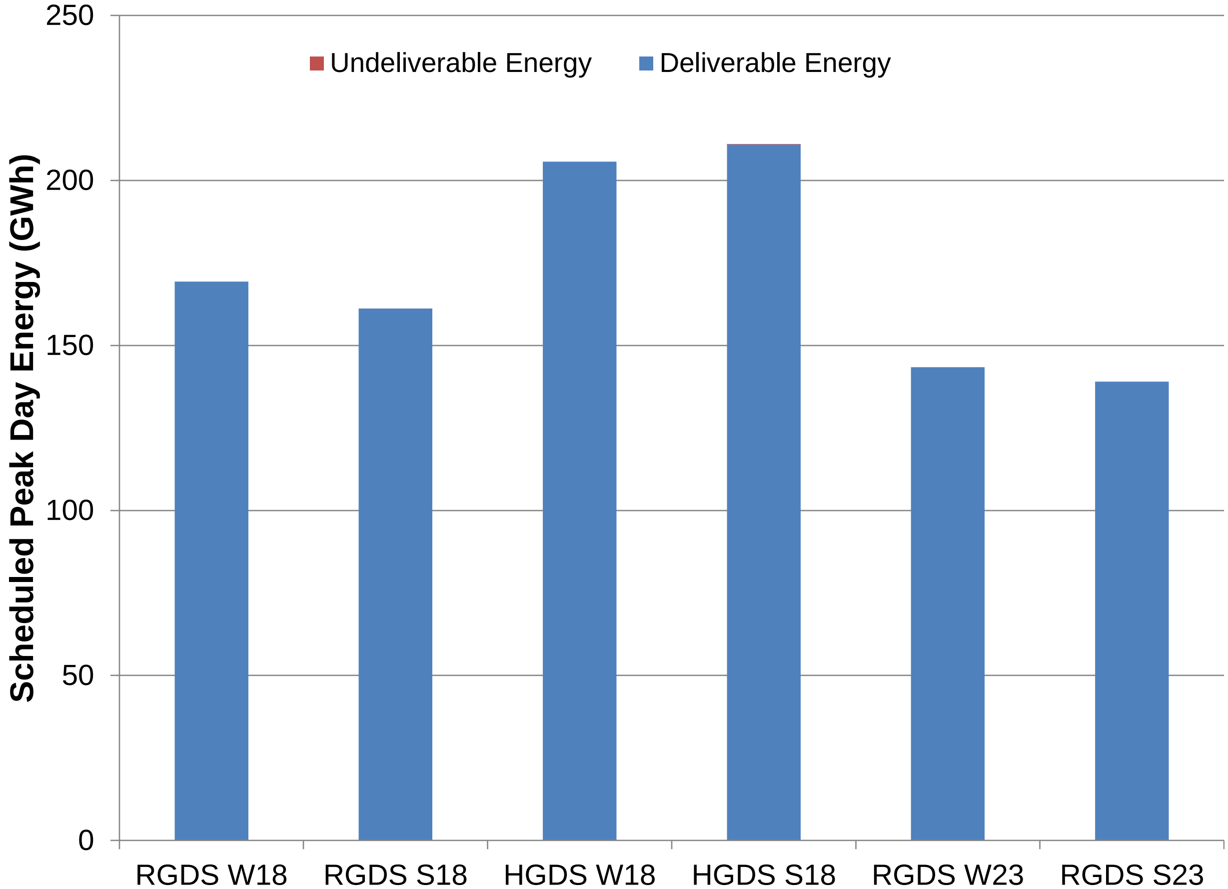

Figure 10-27. TVA Baseline Energy Deliverability

Table 10-14. Summary of TVA Baseline Results

Season	Scheduled Gas (MDth)	Scheduled Energy (MWh)	Scheduled Energy with Undeliverable Gas (MWh)	Scheduled Energy with Undeliverable Gas (%)
RGDS W18	1,187	169,348	0 (gas-only) 0 (dual-fuel)	0
RGDS S18	1,147	161,209	0 (gas-only) 0 (dual-fuel)	0
HGDS W18	1,529	205,713	0 (gas-only) 0 (dual-fuel)	0
HGDS S18	1,658	211,045	0 (gas-only) 162 (dual-fuel)	0
RGDS W23	996	143,453	0 (gas-only) 0 (dual-fuel)	0
RGDS S23	997	139,036	0 (gas-only) 0 (dual-fuel)	0

10.4 Severe Contingency Mitigation Measures

10.4.1 Gas-Side Contingency Mitigation

Mitigation measures are centered on improving the availability of gas capable generating resources following a severe gas side contingency. Across the Study Region, LAI has tested contingencies involving the loss of mainline capacity, loss of compression, or the loss of storage deliverability. Most, but not necessarily all postulated gas-side contingencies may warrant a pipeline's declaration of *force majeure*, the invocation of which typically permits pipelines to implement broad operating protocols, pursuant to their tariffs, to maintain system integrity.[52] Under FERC guidelines, a pipeline is permitted to exercise its reasonable judgment to determine whether or not the event warrants declaration of *force majeure*. There is a well-established FERC policy regarding the nature of events that qualify as *force majeure* events.[53]

FERC has defined *force majeure* events as outages that are both unexpected and uncontrollable. FERC has said that "routine, scheduled maintenance is not a *force majeure* event, even on 'pipelines with little excess capacity,' where such maintenance may require interruptions of primary firm service."[54] Notification to affected shippers happens quickly on the pipeline's electronic bulletin board (EBB), thereby informing all shippers of the event and the anticipated actions required to manage system integrity. To the extent the pipeline does not declare *force majeure*, but instead elects to issue an Operational Flow Order (OFO), Flow Day Alert, or a Strained or Critical Operating Condition, the transporter's corrective actions are typically prescribed within the pipeline's general tariff and conditions, thereby more narrowly defining the array and sequence of mitigation measures the operator may implement.

Since perturbations to a pipeline's steady state deliverability are buffered by line-pack, a time lag is typically observed between the occurrence of the event and the resulting changes in pressure and flow resulting in curtailment of scheduled of gas-fired generation following a postulated gas-side contingency. Depending on the duration of this lag, pipeline operators will implement a series of mitigation measures to maintain system integrity, including the continued delivery of scheduled volumes to gas-fired generators with firm transportation, and, to the extent possible, generators under secondary firm or interruptible transportation arrangements. To respond to

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[52] A pipeline's General Tariff and Conditions specifies curtailment priorities affecting the range of operator actions under normal and constrained operating conditions. Under constrained operating conditions, typical curtailment priorities for FERC jurisdictional entities include: first, interruption or curtailment of interruptible shippers; second, interruption or curtailment of secondary firm shippers (out-of-the-path); third, interruption or curtailment of secondary firm shippers (in-the-path); and, fourth, curtailment of deliveries to firm customers on a *pro rata* basis. When a transporter's ability to render service is impaired in a particular segment of the pipeline's system, then interruption or allocation is normally effectuated in accord with the above listed steps only in that segment of the transporter's system where service is impaired.

[53] FERC has since provided clarification on the nature of *force majeure v. non-force majeure* events.

[54] Gulf Crossing Pipeline Co., Docket No. RP12-814-002, October 7, 2013, p. 2.

critical operating conditions, a pipeline may issue an OFO, which may require customers to remain in contractual balance and adhere to ratable takes. OFOs are issued in extreme operating conditions.[55] Pipelines may need to limit all transactions in the affected area to shipments to primary firm transportation entitlement holders only. Depending on the severity of the event, non-firm shippers directly connected to the pipeline downstream of the event may be notified that effective immediately the pipeline cannot offer service to shippers that do not hold primary firm capacity.

Under extreme events, a pipeline may need to curtail scheduled volumes, as discussed above. Deliveries to firm customers may be curtailed as well, but such extreme events would typically warrant declaration of a *force majeure* event. In reviewing the array of operator actions in response to gas side contingency events, there are two general sets of operator actions: first, intrinsic mitigation measures, that is, changes to physical flows on a short duration basis designed to maintain scheduled flow to all or the majority of firm customers, and, subordinate to firm customers' requirements, whatever non-firm customers' scheduled flow can be accommodated in accord with the pipeline's scheduling protocols; and, second, extrinsic mitigation measures, that is, pipeline outreach efforts that are engineered on an *ad hoc* basis to limit adverse impacts to firm and non-firm customers in accord with the pipeline's curtailment protocols following a gas-side contingency. In this section, the nature and type of intrinsic and extrinsic mitigation measures are reviewed to address the relative (de)merit of different mitigation measures affecting electric system reliability.

10.4.1.1 Intrinsic Mitigation Measures

The time-to-trip intervals defined throughout the Target 3 report reflect the array of intrinsic mitigation measures available to gas system operators to limit disruptions following the postulated gas side contingency. As discussed in Section 10.2.1.2, the WinTran transient model solutions capture pipeline system responsiveness to equipment failures – both the loss of mainline capacity, compression, and (deliverability of) storage. Therefore, many of the operator actions that would be implemented following a gas-side contingency are already incorporated within the WinTran solutions. Transient model solutions reflect the consolidated network of pipelines and storage infrastructure across the Study Region. Therefore, this model assumes operating conditions and physical flow capability reflecting that all equipment is in service and available on the interconnected pipeline network to allow physical intrinsic mitigation measures to be implemented to mitigate the impact on potentially affected generation. For example, the portfolio of solution responses *may* include use of line pack and spare compressor horsepower, among other things.[56]

[55] Pipelines typically issue OFOs after issuing other levels of critical notices advising customers of operational conditions and the need for receipts to equal deliveries. In addition, a pipeline may issue a critical notice indicating that it may need to restrict service at certain points, and will not schedule gas, based on priority of service in order to preserve deliverability to primary firm customers.

[56] Allowing generators to draw down line pack by continuing to take gas following a contingency would enable sustained operation. Pipelines would not be obligated to allow non-

The loss of mainline capacity can be defined as the loss of one of several looped mainlines or a catastrophic pipe break. Loss of compression can be either the postulated loss of horsepower, but not the complete loss of all horsepower at a discrete, strategically located station (*e.g.*, for compressor stations with multiple compressors and/or drivers), or, instead, the complete loss of all compression at a station. Subject to operational tolerances, a pipeline operator would typically utilize line-pack to bolster deliverability following an event, but during the peak heating season, December, January, and February, or during cold snaps in shoulder months, there may not be any spare line-pack available to mitigate the impacts attributable to the disruption. Moreover, an operator's decision to leverage line-pack to mitigate the disruptive impact on gas-fired generators in the hours following an event may have additional adverse operational consequences during the next twelve to twenty-four hours that must also be weighed.[57] Operators would also contact their fraternity of pipeline, LDC and storage operators on short notice in the effort to increase interconnect flows to the maximum extent possible, thereby potentially leveraging upstream or downstream line-pack on one or more contiguous pipelines. Since interconnected pipelines lending operational assistance first must assure that such assistance will not adversely affect deliverability to their own customers, such assistance may not be available, particularly under peak day conditions.

In scheduling increased interconnect flows, pipeline operators would monitor intra-day flow variances that may exacerbate a low line-pack condition on one or more pipelines that participate in the pipeline work-around following an event. The increased loading of pipeline interconnects to mitigate the disruption is a normal operating protocol when a pipeline is operating in distress. However, in LAI's experience, exact operator actions are neither spelled out in FERC approved tariffs nor set forth in a preset "rule-book" governing operator assistance. The terms and conditions regarding scheduling and curtailment priorities under constrained or severe operating conditions are outlined in pipeline tariffs. Pipelines issue different levels of critical day notices (including a *force majeure* notice, which is the most restrictive notice) on pipeline EBBs as soon as practicable following an event. ISOs/RTOs can sign up to receive all pipeline critical day notices directly from the pipeline as soon as the notice is posted. Pipelines typically address contingency events through both formal and informal actions. Actions are implemented on an episodic basis and quickly through operational handshakes via telephone, e-mail and other pipeline electronic communication protocols. Depending on the circumstances, operators may also be able to reverse the directional flow downstream of the postulated event. Each of these operational responses to a severe gas side contingency is incorporated in the reoptimization of gas flows in the minutes and hours following an event. Hence, the portfolio of intrinsic mitigation measures that pipeline operators may use to minimize disruptive impacts following an event have already been incorporated in the results of the Target 3 transient analysis, although

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firm customers to continue to receive gas following an adverse event, therefore a generator's access to this mitigation measure would depend on their contractual character of service's position in the particular pipeline's tariff hierarchy.

[57] During the peak heating season or during cold snaps in shoulder months, replenishment of line-pack may not be achievable within the current gas day. Under certain circumstances, a pipeline may not be able to restore line-pack to the target operational level for several days. Replenishment of line pack is dependent on location, availability of supply, operating conditions and the nature of the postulated event.

the unique operating characteristics that differ by pipeline would allow operators to undertake additional situation-specific responses.

10.4.1.2 Extrinsic Mitigation Measures

The system responses revealed through the transient modeling in the Target 3 report do not incorporate the array of extrinsic mitigation measures available to system operators designed to limit disruptions following the postulated gas side contingency. Extrinsic mitigation measures are PPA-specific and will require stakeholder commitments to implement region-wide for purposes of improving gas generator performance and availability, both pre- and post-contingency.

The first subset of extrinsic mitigation measures pertains to information flow. The flow of information is an integral part of the operational, planning and policy initiatives that characterize gas/electric convergence initiatives undertaken by broad stakeholder groups over the last decade, in particular, pipelines and PPAs. In recent years, FERC has issued rulemakings that are designed to address gas-electric interdependence and coordination, in particular, communication and information-sharing between the natural gas and electric industries.[58] In response to the 2004 cold snap in New England, with FERC Order No. 698 the Commission sought to improve coordination between the gas and electric industries in order to improve communications about scheduling of gas-fired generators.[59] With Order No. 787 (Docket No. RM13-17-000) the Commission allowed transmission operators voluntarily to share information with each other that is necessary for the provision of and to maintain service reliability or near-term operational planning on electric and gas transmission systems.[60] Whether or not communication protocols and information sharing will continue to evolve is outside the scope of this Target 3 study.

In this Final Rule, FERC refers to pipelines and public utilities that operate gas or electric transmission facilities as "transmission operators." The Final Rule is designed to support the reliability and integrity of natural gas and electric transmission service by permitting transmission operators to share information that the operators deem necessary. In order to help manage system reliability during times of coincident peak loads, FERC will allow the communication of specific, non-public system related information. FERC has recognized that "{c}ommunication between interstate natural gas pipelines and electric transmission operators can be invaluable to help ensure that electric transmission operators maintain grid reliability and that interstate natural gas pipelines can meet contractual and operational obligations to all of their shippers."[61] FERC specified prohibitions, including a No-Conduit Rule, regarding the

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[58] See *Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators*, Docket No. RM13-17-000, Order No. 787, 18 CFR Parts 38 and 284.
[59] *Standards for Business Practices for Interstate Natural Gas Pipelines; Standards for Business Practices for Public Utilities;* Docket Nos. RM96-1-027 and RM05-5-001, Order No. 698, 18 CFR Parts 38 and 284,
[60] *Communication of Operational Information Between Natural Gas Pipelines and Transmission Operators*, Order No. 787, 78 Fed. Reg. 70163 (Nov. 22, 2013).
[61] *Ibid.*, pp. 7-8.

subsequent non-disclosure of information received under Order No. 787 to a third party or to the pipeline's employees that are affiliated with the pipeline's gathering facilities, marketing function or other interstate pipelines.[62] However, compliance with the Final Rule is voluntary, which impacts the extent of any consistency between the level and type of information sharing by different pipelines. The voluntary nature of Order No. 787 potentially gives rise to an inconsistency in information sharing.

Across the Eastern Interconnection, the PPAs have stepped up communication and coordination with pipeline companies on an array of scheduling, penalty administration, and notification issues.[63] The PPAs are cognizant of the contractual rights gas-fired generators have in regard to a pipeline's delivery capability, or lack thereof. Moreover, the PPAs know which gas-fired generators are dual-fuel capable and communicate on a regular basis with those dual-fuel units regarding liquid fuel inventory levels and the logistics of oil replenishment. Working in close consultation with their regional generators, the PPAs' electric control room operators may inform the pipeline of which generation unit(s) are currently most important (*i.e.*, must-run) for electric system reliability following a contingency event in an attempt to determine if the pipeline operators could implement best efforts mitigation measures that are simultaneously protective of RCI customers as well as the gas-fired generation units needed most for electric reliability, subject to a pipeline's contractual obligations.[64]

A second subset of extrinsic mitigation measures pertains to a pipeline's ability to leverage operational relationships across the supply chain. As discussed in the aforementioned section pertaining to intrinsic actions, following a severe gas-side contingency, a pipeline operator would take steps immediately or almost immediately to fully utilize available pipeline interconnect capacity to bolster both pressure and flow into the constrained region. Pipelines cooperate on a

[62] However, there is no equivalent communications order for communications between the PPAs and non-jurisdictional LDCs. The quality of service to a generator behind the citygate is generally governed by a negotiated agreement or tariff.

[63] See FERC Staff "Gas-Electric Coordination Quarterly Report to the Commission," December 18, 2014, Docket No. AD12-12-000 for an update on RTO/ISO coordination efforts.

[64] Control room authorization for a generator to obtain natural gas outside the North American Energy Standards Board (NAESB) approved nomination / confirmation cycle may trigger costs that the ISO/RTO may review for reasonableness. INGAA notes that pipeline tariffs permit a pipeline to assess a shipper or Operational Balancing Agreement (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 may be relatively small, the financial penalties assessed when OFOs are in effect much greater because they are intended to deter shipper misconduct that could harm a pipeline's operational integrity. The OFO typically requires customers to remain in contractual balance, *i.e.*, take ratably. Pipelines typically issue OFOs after issuing other levels of critical notices advising customers of restrictive operational conditions that necessitate receipts to equal deliveries. If a pipeline assesses a penalty to an offending shipper or point operator, FERC policy requires the pipeline to distribute all of the revenue from the penalty to non-offending shippers.

best-efforts basis during contingencies to meet service obligations. If time allows following those scheduling changes, and depending on the severity of the event, a pipeline operator may reach out to other pipeline operators to take additional steps to manage load by "backing off" the scheduled volumes at gate stations and meters across the neighboring pipeline's system. However, this coordinated multiple-operator response is contingent on shippers' willingness to reduce their scheduled volumes. Unlike for RTOs, while pipelines and LDCs in some regions have voluntarily entered into mutual assistance agreements, there is no mandate to provide mutual aid on the gas side. Under certain circumstances, deliveries to RCI customers may be backed down without denigrating service integrity at the local level. The avoidance of any degradation of service to RCI customers may happen as a result of underutilized receipt point capacity into the local distribution system. Across the Study Region, many LDCs operate "grid-like" distribution systems where multiple gate stations served by several or many different pipelines allow for operating flexibility at the local level, thereby allowing for flow-day diversions and the more complete utilization of pipeline interconnect capability to mitigate an adverse event at a specific point on a pipeline's system. An LDC's obligation to continue to serve a particular generator would depend on the terms of the character of service under which the generator is supplied, non-firm customers are generally served on an as-available basis, as discussed in the Target 1 report, and would therefore potentially or likely be curtailed following a contingency event affecting a pipeline's ability to deliver gas to the LDC, depending on the degree of service degradation.

Related to this extrinsic mitigation measure, a pipeline operator may take additional steps through its LDC OBA or through a formalized outreach procedure, to examine an LDC's ability and willingness to manage load.[65] Depending on the spatial configuration of affected RCI and generator gas demands following an event, the pipeline may reach out to more than one LDC to implement load management/conservation actions. Load management actions at the local level may include curtailment or interruption of non-firm LDC customers, typically industrial customers, and/or through changes to the intra-day scheduling of natural gas on other pipelines with gate stations on the LDC's system.[66] These extrinsic mitigation measures have the potential to trigger penalties for unauthorized gas use that exceeds a pipeline's approved tolerance level, daily imbalance charges, and other costs borne by a shipper to reconcile intra-day gas flow with scheduled nominations.[67] Certain of these costs pertain to a shipper's obligation to conform to the pipeline's FERC approved tariff, which may cause the shipper to incur significant additional costs to remain in balance within the gas day.

There are other extrinsic mitigation measures that pipeline operators may be able to implement to postpone curtailment or interruption of gas-fired generators following the postulated gas-side or electric-side contingencies. First, an operator may be able to bolster pipeline deliverability by scheduling intra-day gas storage withdrawals. However, most pipelines do not have storage withdrawal rights; usually, the rights are controlled by the storage customer, thus necessitating coordination with one or more storage entitlement holders. For pipelines that do not have

[65] For a more complete discussion of the use of OBAs, see Section 8.3.2.2.

[66] Reduction of firm deliveries to residential and commercial customers is not contemplated.

[67] A shipper's incurrence of these additional costs and how pipelines, generators, and LDCs allocate such costs are outside the Target 3 Scope of Work.

storage withdrawal rights, supplementing pressure and flow by scheduling storage withdrawals would require those pipelines to obtain storage withdrawal rights from other market participants or, alternatively, for one or more storage entitlement holders to schedule storage withdrawals to bolster deliverability following an event.[68] In Maryland and New England, there are LNG import terminals that may have idled regasification capacity coupled with working LNG inventory to supplement scheduled flows following an event.[69] Like ancillary services from an electric pumped storage plant, incremental LNG sendout from the GDF Suez Everett facility has the potential to mitigate disruptive events in the NEMA/Boston/SEMA zones in ISO-NE, as well as from the Repsol Canaport LNG facility in northern New England, depending on the location of the event. Likewise, incremental regasification from the Dominion Cove Point LNG terminal has the potential to mitigate disruptive events in the SWMAAC portion of PJM, as recently observed in January and February 2015. While there are dozens of above ground satellite LNG tanks owned and operated by LDCs throughout the Study Region, in particular in ISO-NE, NYISO, and PJM, back-end displacement of pipeline rendered supply through local area LNG sendout does not represent a routine extrinsic mitigation measure, but it may be viable in the short-term to support service to (must-run) gas-fired electric generators, depending on specific system conditions.[70]

Second, an operator may be able to bolster deliverability by using a Park & Loan (PAL) transaction. On pipelines that offer PAL service, a customer can borrow gas at a certain time and allow the storage holder to pay it back at a later date consistent with the repayment provision underlying a pipeline's PAL service authorized by FERC.[71] While PAL services may have a non-firm character of service, use of PAL service during the peak cooling season, in particular, may offer operators a dependable short-term solution to local area constraints. However, following an extreme event, the availability of PAL in a constrained region may not help sustain continued service to gas-fired generators without potential impairment to firm entitlement

[68] On a Winter Peak Day, there may not be additional storage withdrawal capability to use to help restore pipeline integrity following the event. Storage entitlements generally are location specific and rely not only on the storage facility capabilities, but also on the pipeline's transmission capability, which is designed and constructed to move gas from storage to a particular location. In order for storage or LNG to help mitigate a contingency event, the storage or LNG must be located downstream of the gas contingency and sufficiently proximate to the gas-fired generator so that the gas response time will mitigate the loss of gas from the pipeline.

[69] In RGDS S0, LAI assumed that the import facilities were not regasifying LNG on the Winter Peak Day or Summer Peak Day due to the absence of contractual commitments and anticipated value differences in Europe, the U.K. and Asia relative to the Study Region, excluding volumes for New Mystic.

[70] Satellite LNG tanks are used predominantly to protect RCI customers. The slow rate of re-liquefaction coupled with truck transportation delivery constraints render this mitigation measure almost always infeasible for purposes of sustaining gas-fired generation in downstate New York and in New England following a contingency, particularly during the heating season, November through March.

[71] During the heating season, limitations on the use of PAL to help sustain service to gas-fired generators following a contingency would be likely.

holders. Third, a gas control operator may have flexibility to be able to bolster deliverability by leveraging, to a limited extent, the use of no-notice service.[72] Many pipelines across the Study Region provide no-notice service. To the extent there is "spare" no-notice service built into the hourly profiles and levels of gas throughput on any given day, operators may be able to utilize such volumes in order to sustain service to gas-fired generators, particularly during the peak cooling season when LDC loads are typically a fraction of the LDC loads during the peak heating season.

The array of extrinsic mitigation measures are not formalized by pipeline companies, LDCs, and storage operators, and are not set forth in general in FERC approved tariff provisions. Instead, these measures represent LAI's understanding of the options available to pipeline operators and their respective shippers – both primary firm and non-firm customers alike – through standard operating protocols or generalized mutual assistance arrangements. The degree to which each extrinsic mitigation measure is useful in helping pipelines sustain service to gas-fired generators is highly dependent on the location and timing of the gas-side contingency, actual operating conditions on the day of the event, and the ability of contiguous pipelines to quickly implement actions to minimize consequent electric outages.

10.4.2 Electric-Side Contingency Mitigation

The array of electric-side contingencies tested in the WinTran transient model reveal the resiliency of the consolidated network of pipeline and storage infrastructure to provide additional natural gas to gas-fired generation plants following the loss of large generation or a major transmission facility. Like the intrinsic or extrinsic mitigation measures presented in Sections 10.4.1.1 and 10.4.1.2 covering gas-side contingencies, there are also intrinsic and extrinsic mitigation measures applicable to the electric-side as well. This section addresses the possible mitigation measures and actions that could be taken by the PPAs, pipelines, LDCs, and/or the gas-fired generation companies in response to the loss of either a baseload capacity resource or a high voltage transmission facility.

10.4.2.1 Intrinsic Mitigation Measures

When ISO/RTO control room operators give dispatch instructions to gas units to supplant lost generation from a large power plant or from a transmission contingency, gas-fired generators often scramble to obtain sufficient fuel to accommodate the unscheduled level and hourly profile of gas requirements following the event. There is a higher cost of intra-day supply related to pipeline transportation if the shipper violates an OFO, consumes too much of its gas non-ratably in violation of the tariff and the pipeline cannot accommodate such flexibility. Gas use to accommodate intra-day electric scheduling following the event has the potential to trigger ratable-take penalty charges, daily imbalance charges, and/or unauthorized use charges, thereby

[72] Whether or not a pipeline may draw on underutilized no-notice service to mitigate an adverse event depends on the pipeline, the location, the temperature condition, and the distribution of "shorts" and "longs" across the system.

requiring the ISO/RTO to review the reasonableness of full or partial cost reimbursement.[73] Additional costs for intra-day gas procured after the occurrence of an electric-side contingency event may include a substantial cost premium against the daily mid-point index price, penalties levied by the pipeline, LDC, or marketer, and daily imbalance charges. Also, generators covered under an Asset Management Agreement may be responsible for financial charges payable to the supplier associated with a *de facto* no-notice service. ISO/RTO market rules that provide the ability to change bids in the real time market (RTM) is an intrinsic mitigation measure that may help address these incremental fuel costs.

A second intrinsic mitigation measure in the event of a pipeline *force majeure* declaration pertains to diverting the flow of natural gas from a generator that has nominated and scheduled natural gas to another generator that is located "electrically near" the postulated electric-side event, that is needed for post-contingency system or sub-area reliability. The flow day diversion would require communication between the generator and the pipeline company based on information as to system conditions from the RTO/ISO control room and would need to be authorized under the applicable pipeline tariffs or contractual arrangements. Whether or not there is sufficient operational flexibility along the constrained pipeline segment or network of pipeline and storage facilities to accommodate the diversion on a Winter Peak Day or a Summer Peak Day is specific to the location and the range of operator actions that one or more pipelines may take following the event. Operational issues associated with the management of line-pack may also affect the feasibility of the flow day diversion. On a Summer Peak Day, flow day diversions are generally more easily implemented to accommodate the PPA's need for increased gas-fired generation at a specific location. Since the transaction happens in the RTM, when the gas day is nearing the end or has very limited liquidity to accommodate additional hourly nominations, market participants may incur additional transaction costs and/or penalties. In any event, a pipeline's or LDC's ability to take additional steps to ensure electric grid reliability would need to be reviewed transparently with, and authorized by, the applicable federal or, in the case of LDCs, state regulatory bodies.

A third intrinsic mitigation measure leverages the improved scheduling and coordination between the PPAs and pipelines doing business in the Study Region. The nature and extent of operational information readily available to an ISO/RTO on pipelines' EBBs varies from pipeline to pipeline. Pipelines must adhere to NAESB standards regarding pipeline operational and capacity posting information on their EBBs. Some pipelines exceed the NAESB standards and provide additional information. Following the electric-side contingency, control room operators determine which generators are required by location to ensure electric reliability. Depending on location, certain of these generators may be able to start-up quickly on oil. For various reasons, some gas-fired generators may not be able to start-up on oil. Pipeline operators are available 24/7 and may therefore be able to effectuate increased gas flow *and pressure* to start-up and sustain gas-fired generator performance, provided this information is available and communicated to ISOs/RTOs. Similar to the operator actions following gas-side contingencies, system responses can include the use of line-pack for one or more generators, increased

[73] Traditionally, most ISO/RTOs will typically reimburse a generator for additional costs associated with following or trying to follow a dispatch order from their Control Room operator. Nothing in this report speaks to the reimbursement of penalty costs.

horsepower at strategically located stations, point operator rescheduling of natural gas through interconnects, reversal-of-flow along key route segments to enable gas-fired generation, and deliveries via displacement with other gas-fired generators or LDCs. Under certain circumstances, LDCs may be willing to reduce receipts at specific gate stations while increasing receipts at others in order to facilitate delivery to designated gas-fired generator plant gates located near them. Also, coordination may be possible with one or more LDCs to utilize satellite LNG storage capacity to bolster local pressure to maintain service to gas-fired generators following a disruptive event.

Electric control room operators know which gas-fired generators are dual-fuel capable, their start-up times, and their ramp-up rates. However, among the group of dual-fuel capable units, control room operators do not always know what level of working oil inventory is available to enable start-up on oil, nor the relevant air permit restrictions on liquid fuel operation. These uncertainties may be applicable during the peak heating season as well as the peak cooling season. Moreover, during cold snaps, there may be constraints on oil instrumentation and auxiliary systems that render start-up on oil uncertain. Operator actions may therefore help divert natural gas scheduled to support a dual-fuel generator's daily profile to a gas-fired unit that is in the right location to help bolster electric system or local area reliability, but either does not have sufficient oil inventory or the ability to burn oil. This flow diversion is only possible if the original shipper agrees and it is operationally feasible for the pipeline to divert gas to the alternate plant.

Many of the same intrinsic mitigation measures discussed in Section 10.4.1.1 are also applicable in the context of electric-side mitigation measures.

10.4.2.2 Extrinsic Mitigation Measures

Extrinsic mitigation measures include PPA market and policy initiatives designed to strengthen the deliverability of natural gas to gas-fired generators across the Study Region. Administrative reforms oriented around daily scheduling flexibility are also part of the array of extrinsic mitigation measures of relevance to the PPAs. Extrinsic mitigation measures are PPA-specific and will require stakeholder commitments to implement region-wide for purposes of improving gas generator performance and availability, both pre- and post-contingency.

One extrinsic mitigation measure therefore relates to scheduling. In response to continued FERC direction to better align the electric and gas day, industry stakeholders have been immersed in a multi-year dialogue to standardize gas scheduling reforms that promote greater harmonization between the gas and electric days. In the way of background, the current gas nomination cycles are shown below in Figure 10-28 and discussed more fully in Section 8.3.1.

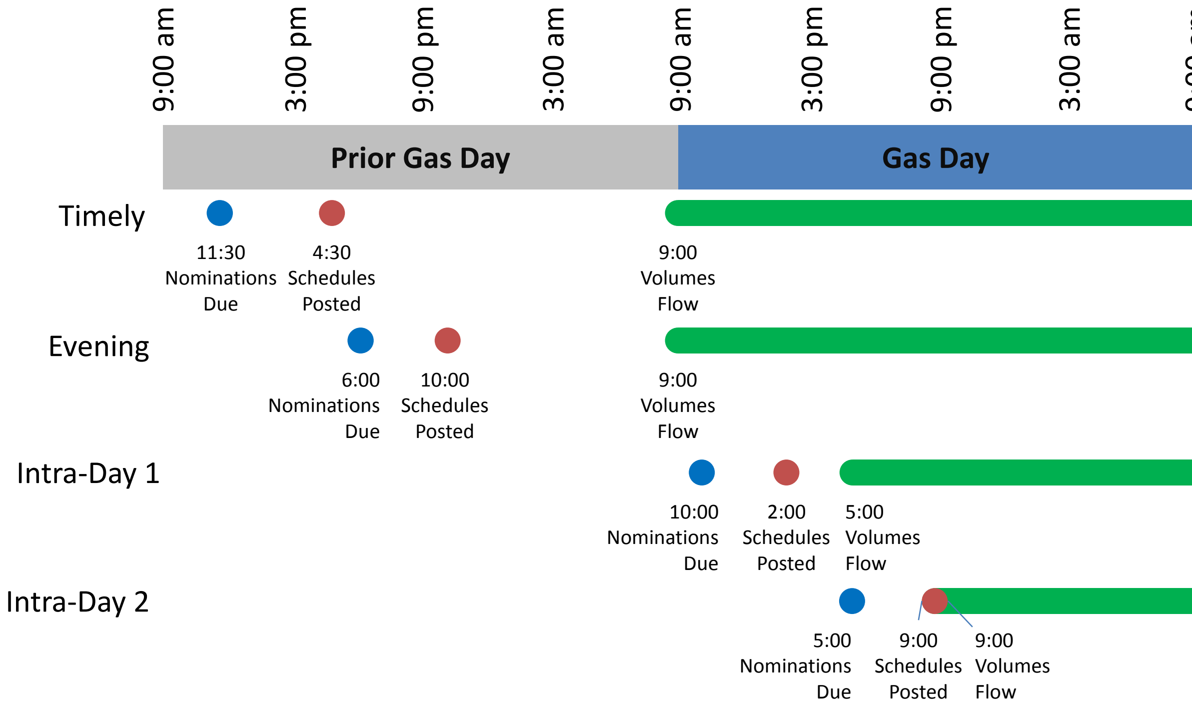

Figure 10-28. Standard NAESB Nomination Cycles (CCT)

Under the current NAESB nomination cycles, two main issues exist for gas-electric coordination: <u>first</u>, each gas day bridges two electric days and *vice versa;* and, <u>second</u>, gas-fired generators in several PPAs do not necessarily know if and when they have been scheduled to run before Timely Cycle nominations are due. 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.[74] The NOPR initiated a six-month NAESB process to attempt to develop an alternative to the FERC proposed gas nomination/confirmation cycles, clarify FERC policy on the bumping of interruptible nominations, and require all interstate pipelines to offer multi-party service agreements. Under the multi-party service agreement, multiple shippers can share the same pipeline capacity.

On September 29, 2014, following the aforementioned process, in which consensus could not be reached on an alternative to the FERC NOPR, NAESB filed a report notifying FERC of proposed changes to Wholesale Gas Quadrant (WGQ) standards modifying the nomination timeline. The report suggested some changes to nomination/confirmation deadlines and the

[74] On the same day, FERC issued an order initiating an investigation of the ISO and RTO scheduling practices. Specifically, the Commission established proceedings pursuant to Section 206 of the Federal Power Act to ensure that each ISO's and RTO's scheduling, particularly its day-ahead scheduling practices, correlate with any revisions to the natural gas scheduling practices ultimately adopted by the Commission in Docket No. RM14-2-000.

NAESB timeline, but does not propose adding an intraday 4 cycle as the NOPR proposal would.[75] The WGQ standards were proposed to be modified as follows (all times in CCT):

- Timely nominations would be due at 1:00 PM, with scheduled quantities posted at 5:00 PM the day prior to gas flow;
- Evening nominations would be due at 6:00 PM, with scheduled quantities posted at 9:00 PM on the day prior to gas flow;
- Intra-Day 1 nominations would be due at 10:00 AM, with scheduled quantities posted at1:00 PM of the current gas day;
- Intra-Day 2 nominations would be due at 2:30 PM, with scheduled quantities posted at 5:30 PM of the current gas day
- New Intra-Day 3 cycle is introduced. Nominations would be due at 7:00 PM, with scheduled quantities posted at 10:00 PM;
- The nomination cycle timeline is not dependent on the gas day start time.[76]

FERC also issued data requests to ISO-NE, NYISO, PJM, MISO, Southwest Power Pool, and California ISO regarding the scheduling of natural gas during the morning electric ramp and the consequent impact on electric reliability in order to further evaluate the competing proposals. In terms of electric reliability the WGQ standard modifications constitute a step in the right direction regarding greater scheduling flexibility. Nonetheless, the PPAs may choose to pursue continued refinement of WGQ standards while promoting the implementation of broad-based, hourly scheduling protocols throughout the gas day. Implementation of hourly scheduling procedures would likely strengthen a gas-fired generator's ability to obtain natural gas in the intra-day market, while supporting the PPAs' ability to call on gas-fired generation in strategic locations following an electric-side contingency, or to mitigate other abnormal system conditions. While hourly nominations provide greater opportunities for shippers to schedule gas intra-day, hourly nominations do not create additional capacity on a capacity constrained pipeline, but may allow for more efficient use of existing capacity.

A second extrinsic mitigation measure pertains to changes in wholesale electric market design. Structural changes to capacity markets administered by the PPAs have the potential to "harden" the supply chain from liquid sourcing points to generator plant gates, thereby supporting generator plant availability during cold snaps and contingencies. ISO-NE, PJM, NYISO, and MISO each have capacity markets where the PPA or, in some instances, the Load Serving Entity, procures generation capacity to meet the reserve margin target. PPAs have recently discovered that generation resources have not performed as designed when needed most due to pipeline delivery restrictions, commodity supply constraints, or perceived economic risks which deter procurement, among other physical and economic reasons. Such constraints were particularly evident during the Polar Vortex that occurred in January 2014. There have been other instances of generator non-performance in various PPAs due to various fuel-related constraints. ISO-NE

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[75] Gas-Electric Coordination Quarterly Report. FERC Staff, December 18, 2014. http://www.ferc.gov/legal/staff-reports/2014/12-18-14-gas-electric-cord-quarterly.pdf

[76] Comment of NAESB under RM14-2. http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13646032

has made recent changes to future wholesale market rules to provide economic incentives for increased resource performance.[77] PJM has also filed changes at FERC.[78] NYISO is considering making changes.[79] MISO is not currently proposing any changes to its capacity market to bolster resource performance. As discussed in Sections 8.4.5 and 8.4.6 of the Target 1 Report, gas-fired generation performance has not been problematic in TVA and IESO primarily because the

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[77] ISO-NE has changed the Forward Capacity Market to add performance incentives, *i.e.*, "Pay-for-Performance." ISO-NE filed its proposal, along with a New England Power Pool alternative as required by the tariff, on January 17, 2014. FERC issued an order which largely accepted ISO-NE's proposal on May 30, 2014. ISO-NE's Pay-for-Performance proposal implements a two-settlement process: a capacity resource's total capacity revenue is made up of a Capacity Base Payment and a Capacity Performance Payment. The Capacity Base Payment is determined via the clearing price in the Forward Capacity Auction. The Capacity Performance Payment is based on the capacity resource's performance during Capacity Scarcity Conditions, which are met whenever the real-time energy price includes a Reserve Constraint Penalty Factor. If a capacity resource provides more than its share of energy and reserves, it will receive a positive Capacity Performance Payment. If it underperforms, it will receive a negative Capacity Performance Payment. ISO-NE proposed limited exemptions to penalties for non-performance. Generators may decide to invest in physical and/or contractual improvements to ensure plant performance during scarcity conditions.

[78] Following the Polar Vortex in January 2014, PJM has sought to restructure its Reliability Pricing Model (RPM) to improve resource performance. PJM released a final proposal on October 7, 2014, which was presented to the PJM Board with comments from stakeholders. The PJM Board acted on December 3, 2014 and filed a modified version of the proposal as tariff changes on December 12, 2014. PJM will create a new capacity product, *i.e.*, "Capacity Performance." A multi-year transition period is planned. Capacity Performance resources would have a Performance Obligation to deliver a defined share of scheduled or dispatched energy to meet system requirements during Compliance Hours. Compliance Hours take place when PJM implements any emergency procedure requiring implementation of demand response (DR) or the loading of emergency capacity. If a resource delivers less than its share of capacity/energy when scheduled or dispatched, it would pay a Performance Payment determined by the MW shortfall and Net CONE. The collected Performance Payments would then be allocated to over-performing resources on a *pro rata* basis. There would be limited exemptions for non-performance. Generators are expected to price performance risk and investments needed to perform during critical hours into their RPM offers.

[79] NYISO has recognized a need for "mechanisms that provide incentives for generation to be available to reliably meet the real-time needs of the New York Control Area – especially on days when there is a high risk of a reduction in real-time resource availability due to factors including high demand from neighboring Control Areas and fuel supply uncertainty" (Dr. Nicole Bouchez, "Fuel Assurance Initiative: Fuel and Performance Incentives", December 18, 2014 Joint Market Issues Working Group / Installed Capacity Working Group meeting). NYISO is exploring a Fuel Assurance Initiative that may include changes to its capacity market. NYISO has considered performance incentives similar to ISO-NE's Pay-for-Performance, which would be in place during Critical Operating Days as designated by NYISO. Penalties paid by under-performing units may be allocated to over-performing units.

majority of gas-fired generation has obtained firm transportation entitlements for all or the majority of the gas-fired generator's fuel needs.

From a policy perspective, the capacity market structural changes promulgated by ISO-NE and PJM have the potential to enhance gas deliverability to gas-fired generators throughout the year, including during the peak heating season, thereby increasing ISO-NE's and PJM's ability to mobilize gas-fired generators on short notice following an extreme event.

A third extrinsic mitigation measure designed to improve resource performance following an electric-side contingency pertains to information flow. The PPAs have made compliance filings at FERC in accordance with FERC Order No. 787, which "{p}rovide[s] 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 utilities' or pipelines' system."[80] Information sharing through Order No. 787 has the potential to allow both gas and electric system operators to better address contingency events, although issues with the voluntary nature of Order No. 787 were noted previously.

A fourth extrinsic mitigation measure designed to improve resource performance pertains to specific PPA programs that ensure that the control room has bankable options during cold snaps or outage contingencies. An example is ISO-NE's Winter Reliability Program. In its first two seasons in 2013 - 2015, the program procured additional DR resources, provided incentives to oil-fired generators to increase fuel oil inventory, made payments to dual-fuel units for testing their switching capacity, and instituted market monitoring changes aimed at increasing the flexibility of dual-fuel units. The Winter Reliability Program has evolved from the first to the second year, and now includes possible compensation for unused oil inventory and LNG contract volumes, among other things.[81] Another example is ISO-NE's Energy Market Offer Flexibility Project, which produced changes to ISO-NE's Emergency Management System software that allow generators to change both price and supply offers hourly, reflecting the changing cost of fuel.[82] NYISO has also incorporated this capability. Allowing generators to revise their offers "reduces price risk for generators" and "ensures more accurate pricing in the wholesale energy market."[83] As discussed in the Target 4 report, establishment of market rules that provide

[80] FERC Order 787-A, Issued June 19, 2014. On February 18, 2015, the NYISO filed a post-technical conference report on its fuel assurance initiatives, FERC Docket Nos. AD13-7 and AD14-8.

[81] FERC Order Accepting Tariff Revisions, September 9, 2014. Docket ER14-2407.

[82] The new system allows resource owners to submit up to 24 separate offers to supply power for each hour of the following day, and to update their respective offers during the operating day. These offers specify the quantity of power and the price at which a resource is willing to supply the power. The prior offer period allowed for resource owners to submit one offer for all hours of the following day, with one opportunity to revise the offer before the operating day with no opportunity to modify offers during the operating day.

[83] "ISO New England Implements Major Enhancements to Wholesale energy Market". ISO-NE Press Release. December 18, 2014. http://www.iso-ne.com/static-assets/documents/2014/12/emof_final_12182014.pdf

generators with reasonable assurance of cost recovery for variable costs borne to test dual-fuel capability, including switching on-the-fly, would likely improve capacity performance during cold snaps or outage or supply contingencies.[84]

Another specific PPA program is NYISO's Comprehensive Shortage Pricing proposal, which will increase reserve requirements in Southeast New York and the New York Control Area.[85] Coupled with NYISO's Comprehensive Scarcity Pricing changes, more generation capacity will be available, thereby providing NYISO control room operators with increased flexibility to respond to electric-side contingencies.[86] Another specific PPA program is PJM's proposed increase in the energy market offer cap to $1,800/MWh for the winter 2014/15.[87] Another specific PPA program is MISO's Market Timeline proposal, which would adjust the electric scheduling periods in response to the NAESB gas scheduling reforms.[88]

As discussed in Section 11.2.4, operating permits do not typically contain exemptions from oil burn operation limits during a declared emergency event. While generators may seek emergency waivers from state regulators, an expedited process would need to be in place for this to be an effective mitigation measure that does not expose dual-fuel generators to permit violations or penalties. State regulations could be modified and transparent communications protocols established to allow air or water permit exemptions under certain emergency conditions declared by a state, federal, or ISO/RTO authority.

A fifth extrinsic mitigation measure relates to innovative services formulated by interstate pipelines that are designed to reduce scheduling risks posed by balancing charges and ratable take restrictions. For any service, including these enhanced pipeline services, a shipper would likely be required to enter into firm transportation contract in order for the pipeline to have sufficient capacity to support such service and, if necessary, build incremental infrastructure to support the service. One example of an innovative service formulated by an interstate pipeline is

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[84] In NYISO the large amount of dual-fuel generation is largely a consequence of LDC tariff requirements to preserve fuel assurance throughout the year, supplemented by the rules that are established by the New York State Reliability Council to maintain electric reliability in the event of the loss of gas during periods of peak electricity demand in New York City or on Long Island.

[85] On February 18, 2015, NYISO filed proposed changes to its Market Administration and Control Area Services Tariff to implement these provisions:

http://www.nyiso.com/ViewerDocuments/Filing/Filing977/Attachments/Filing_977.zip

[86] Although NYISO allows generators to recover imbalance charges outside of OFO periods, bids reflecting imbalance charges can be mitigated but should the imbalance charges be incurred, they are recoverable on mitigated bids.

[87] In response to the unprecedented spike in delivered gas costs in January 2014 and the failure of certain generators to perform due to uncertainty about fuel cost recovery, bids accepted below the cap can set the LMP. Cost-based offers above the cap that are accepted may recover their costs through uplift.

[88] The MISO proposal is currently at the "straw man" stage in the stakeholder process. It would move the DAM bidding period up two hours to 9 AM (three hours to 8 AM during DST) and shorten the rebid period from 1 hour to 30 minutes.

Enable Gas Transmission Co.'s Enhanced First Transportation (EFT-3) Services tariff.[89] Enable serves LDCs and gas-fired generators in MISO South. Under the EFT-3 tariff, shippers request a Maximum Hourly Delivery Obligation (MHDO) coupled with a Swing Ratio that contractually permits non-ratable takes for a specified number of hours.[90] Under the tariff, the Swing Ratio has to be consecutive, and the shipper is limited to a Swing Ratio at the primary delivery point each day. Enable's EFT-3 rate represents another novel pipeline service for generators. Under its terms, customers submit Day-Ahead nominations and "burn sheets." Customers negotiate a Swing Ratio in their service contracts, and may take non-ratably up to the lesser of their Maximum Hourly Quantity or their ratable hourly nomination multiplied by the Swing Ratio. This calculated number is the MHDO. Overrun charges apply to any non-ratable takes above this quantity. Customers also may face daily overrun charges.

Enable's EFT-3 service has four rate tranches based on the desired Swing Ratio. Customers pay higher rates to maintain a higher Swing Ratio. This rate provides bandwidth for customers to take non-ratably, but nevertheless depends on gas-fired generators receiving adequate notice from the ISO/RTO to determine the appropriate quantities to schedule. As such, Enable's EFT-3 tariff is a daily-scheduled service that is negotiated by the pipeline and the shipper. Enable retains the right to limit takes above the scheduled/contract quantities, but provides the shipper with the assurance of intra-day scheduling flexibility in accord with the negotiated Swing Ratio. Establishment of a contract right at the primary delivery point that allows for non-ratable takes consistent with the EFT tariff provisions helps shield gas-fired generators from unauthorized overrun charges and related penalty charges.

Another example of an innovative rate design is on the El Paso Natural Gas Pipeline Co. (El Paso), a Kinder Morgan company. Given the heavy concentration of LDC load and gas-fired generation in and around Phoenix, AZ served by El Paso, the pipeline has offered shippers an Hourly Firm Transportation Service (FT-H) service. Although outside the Study Region, El Paso's FT-H may also represent a workable and innovative rate design that if implemented in the Study Region, could ultimately provide PPA control room operators with increased confidence about the availability of gas-fired generation during a cold snap or outage or supply contingencies. There are several FT-H service options designed to confer intra-day scheduling flexibility based on risk considerations. FT-H service offers additional flexibility for gas-fired generators by conferring the right to take gas non-ratably without incurring penalties or jeopardizing gas system reliability. El Paso also offers additional premium services such as hourly no-notice transportation service (see Rate Schedule NNTH). Like Enable's EFT service, such contract rights can provide electric control room operators with greater confidence about the availability and flexibility of gas-fired generation during cold snaps or outage or supply contingencies. Importantly, the aforementioned discussion of El Paso's and Enable's innovative rate design are examples of innovation and do not represent an all-inclusive list.

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[89] See Enable Gas Transmission Rate Schedule EFT, FERC Gas Tariff Ninth Revised Volume No. 1, issued August 8, 2013.

[90] The FERC approved tariff includes a rate design change that replaces the prior Accelerated Consumption Election with the Swing Ratio.

Another example of an innovative service option is Spectra Energy, Eversource Energy and NGrid's announced Access Northeast Project. Under the proposed service option capacity, resources would be eligible for Electric Reliability Service (ERS).[91] While the Access Northeast Project has not been reviewed by FERC, ERS is intended as a firm, no-notice service option for electric generators. Other pipeline tariff innovations across the Study Region are underway that have the potential to improve control room operator access to gas-fired generation following an electric-side contingency event.

[91] This is a proposed transportation service option and has not been reviewed or approved by FERC.