Northeast Gas/Electric System Study

prepared for

Northeast Power Coordinating Council

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PUBLIC VERSION

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Foreword

This Northeast Gas/Electric System Study was initiated in late 2023 by the Northeast Power Coordinating Council. Levitan & Associates, Inc. conducted the study based on the best information available at the time and throughout 2024 in accord with the production milestones set forth by the Northeast Power Coordinating Council and other study participants. Most of the gas infrastructure and electric simulation modeling was conducted in first-half 2024 and therefore relies on then available sources.

To facilitate review of the highlights of the Public Version of the Northeast Gas/Electric System Study, stakeholders are directed to the following:

- Study goals can be found in the Introduction, page 2.
- Key findings and observations can be found in the Executive Summary, pages 4 through 8.
- Key Risk Factors and Conclusions can be found in the body of the report, pages 76 through 79.

The following Table of Contents provides directions to the requisite details underlying the study approach and findings.

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Glossary

AEO	Annual Energy Outlook
Bcf	Billion Cubic Feet
BES	Bulk Electric System
BTM	Behind the Meter
Btu	British Thermal Unit
CAF	Capacity Accreditation Factor
CAGR	Compound Annual Growth Rate
CAR	Capacity Auction Reforms
CARC	Capacity Accreditation Resource Classes
CC	Combined Cycle
CEII	Critical Energy/Electric Infrastructure Information
CELT	Capacity, Energy, Loads, and Transmission
CEMS	Continuous Emission Monitoring Systems
CI	Confidential Information
CNG	Compressed Natural Gas
Con Edison	Consolidated Edison Co. of New York
CONE	Cost of New Entry
CT	Combustion Turbine
DR	Demand Response
DOE	U.S. Department of Energy
DFO	Distillate Fuel Oil
DPU	Department of Public Utilities
Dth	Dekatherm
EBB	Electronic Bulletin Board
EDC	Electric Distribution Company
EEA	Energy Emergency Alert
EFORd	Equivalent Forced Outage Rate on Demand
EIA	Energy Information Administration
EIPC	Eastern Interconnection Planning Collaborative
EMT	Everett Marine Terminal
EPA	United States Environmental Protection Agency
EPRI	Electric Power Research Institute
EU	European Union
FCA	Forward Capacity Auction
FERC	Federal Energy Regulatory Commission
FES Study	Fuel and Energy Security Study
FSRU	Floating Storage Regasification Unit
FT	Firm Transportation
GFER	Generator Fuel and Emissions Reporting
GJ	Gigajoule
GT	Gas Turbines
HDD	Heating Degree Days
HQ	Hydro Quebec
IC	Internal Combustion (Engine)
ICAP	Installed Capacity
ICF	ICF International
ID	Intraday
IEP	Inventoried Energy Program
IRP	Integrated Resource Plan
ISO	Independent System Operator
ISO-NE	ISO New England
LBR	Land-Based Renewables
LDC	Local Distribution Company
LIPA	Long Island Power Authority
LNG	Liquefied Natural Gas
LPG	Liquid Propane Gas
M&N	Maritimes and Northeast Pipeline
MAPS	Multi-Area Production Simulation
MDQ	Maximum Daily Quantity
MI	S&P Market Intelligence
MISO	Mid-Continent Independent System Operator
MMBtu	Million British Thermal Units
MMcf	One Million Cubic Feet
MRI	Marginal Reliability Impact
MSQ	Maximum Seasonal Quantity
NAESB	North American Energy Standards Board
NE	New England
NECEC	New England Clean Energy Connect
NEPOOL	New England Power Pool
NFG	National Fuel Gas

NGrid	National Grid
NMP	Nine Mile Point Nuclear Station
NRC	Nuclear Regulatory Commission
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYSERDA	New York State Energy Research and Development Authority
OFO	Operational Flow Order
OP4	Operating Procedure No. 4
OSW	Offshore Wind
PAL	Park & Loan
PEAT	Probabilistic Energy Adequacy Tool
PJM	PJM Interconnection
PNGTS	Portland Natural Gas Transmission System
PPA	Power Purchase Agreement
PV	Photovoltaic
RCI	Residential/Commercial/Industrial
REST	Regional Energy Shortfall Threshold
RFO	Residual Fuel Oil
RFP	Request for Proposal
RNA	Reliability Needs Assessment
RNG	Renewable Natural Gas
RTM	Real Time Market
RTO	Regional Transmission Organization
scf	Standard Cubic Feet
SCGT	Simple Cycle Gas Turbine
SPP	Southwest Power Pool
ST	Steam Turbine
Tcf	Trillion Cubic Feet
TTF	Dutch Title Transfer Facility
ULSD	Ultra Low Sulfur Diesel

Note on Conversion Factors:

Natural gas is measured by volume or heating value. The standard measure of heating value in the English system of units is millions of British thermal units or "MMBtu." Dekatherms (Dth) are also a standard unit of measurement. One MMBtu equals one Dth. The standard measure of heating value in the metric system is gigajoule (GJ); one GJ is slightly smaller than one MMBtu (1 GJ = 0.948 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.

1 Mcf ≈ 1 MMBtu = 1 Dth ≈ 1 GJ

1 Bcf = 1,000 MMcf ≈ 10^6 MMBtu = 10^6 Dth ≈ 10^6 GJ = 1 PJ

1 MDth = 1,000 Dth

Acknowledgement

This study is based upon work supported by the Northeast Power Coordinating Council, the North American Electric Reliability Corporation, Independent System Operator – New England, the New York Independent System Operator and the Northeast Gas Association. Pipelines doing business in New York and New England provided Levitan & Associates, Inc. (LAI) with the critical information needed to enable all hydraulic analysis conducted by LAI. Con Edison Company of New York, Inc. and National Grid Company have been active study participants and have been responsible for the hydraulic analysis of the New York Facilities System.

Without the ongoing guidance, participation and contributions of these entities, the technical assessment presented in this study would not have been possible.

Introduction

In November 2023, the Northeast Power Coordinating Council (NPCC) announced the launch of the Northeast Gas/Electric System Study. Levitan & Associates (LAI) was selected to conduct the analysis. NPCC convened a Steering Committee to support and advise LAI, which includes NPCC, New York Independent System Operator (NYISO), ISO New England (ISO-NE), North American Electric Reliability Corporation (NERC), and the Northeast Gas Association. In this study, LAI examines the gas supply and pipeline constraints that may occur during extreme winter weather events during the peak heating season, December through February. The Study Region is defined as New York and New England. Three winters are examined: 2024/25, 2027/28 and 2032/33. These three winter periods are referred to as the short-term, medium-term and long-term forecast periods, respectively.

About ten years ago, under a US Department of Energy (DOE) grant, LAI conducted similar analyses on behalf of ISO-NE, NYISO, PJM Interconnection (PJM), the Midcontinent Independent System Operator (MISO), and other participating planning authorities in the Eastern Interconnection. Consistent with the modeling approach used previously for the Eastern Interconnection Planning Collaborative (EIPC), we have updated the gas and electric topology, including clean energy development in New England and New York. We have refined the technical assessment to capture discernible operational challenges that ISO-NE and NYISO are expected to face over the short-, medium- and long-term.

Over the last ten years, despite both ISO-NE's and NYISO's increased dependence on natural gas, pipeline expansions across the Study Region have been limited to small projects only. Frequent pipeline capacity bottlenecks during the winter have therefore persisted, causing many regional pipelines to routinely post critical notices governing the scheduling of natural gas. The customers holding firm transportation entitlements on the pipelines that serve New England and New York are primarily local distribution companies (LDCs). Generators do not typically hold firm transportation entitlements, relying instead on contracting for transportation with third parties who do hold firm rights or utilizing non-firm capacity that is available after firm customers' gas has been scheduled. Emphasis in this study is therefore placed on the impact of scheduling restrictions on the availability of gas for generation during the peak heating season when plausible disruptions in the gas supply chain are tested.

ISO-NE and NYISO have made well-documented strides in information sharing with pipelines and generators in the wake of the 2013/14 Polar Vortex and 2017/18 Arctic Event. ISO-NE and NYISO have continued to make incremental improvements based on lessons learned from Winter Storms Uri and Elliott. Several fuel and energy security studies have improved both ISO-NE's and NYISO's operational readiness during stressed system conditions. Winter Storm Elliott has provided additional insight into the reliability risks associated with cold weather combined with loss of upstream production to power generators in PJM and MISO. Though these production losses did not spur significant generator outages in New England or New York, future similar weather phenomena could have disruptive effects in the Study Region. In this study, LAI models conditions based on weather events experienced in 2004 and 2015 to quantify the physical capability of the consolidated network of gas pipeline and storage infrastructure to serve customer demands under baseline hydraulic modeling. In consultation with the Steering Committee, LAI has postulated a diverse array of gas contingencies, some of which reduce pressure and flow to the Study Region in a similar manner to supply disruptions experienced in Winter Storm Elliott. The analysis of these postulated gas-side contingencies informs ISO-NE's and NYISO's control room operators regarding how much time they have before adversely affected gas generation is likely to trip offline.

Renewable and energy efficiency technologies have gained a larger foothold in the Study Region power system mix. The resource mixes assumed in the array of scenarios reflect the anticipated accelerated clean energy transitions. Large-scale offshore wind project additions in New England and New York as well as widespread development of land-based wind and solar in New York State will support this accelerated transition in the long-term forecast period. Transportation and heating electrification is an integral part of the states' decarbonization plans, and will result in additional electric-sector demand. This additional demand would put continued upward pressure on winter season peak electric demand through 2032/33. In performing this analysis of pipeline capability to serve gas-fired generation over the planning horizon, LAI has incorporated many assumptions that are driven by the Study Region states' renewable energy goals.

As is common in most forecasting efforts, the long-term forecast period is subject to much more uncertainty than the near-term and mid-term forecast periods. To the extent the pace of renewable energy development slows over the study horizon, there may be additional stress on the consolidated network of pipeline infrastructure that has not been captured in this study. Conversely, the pace of electrification of transportation and heating end uses may slow. The buildout of renewables and electric storage is based on information available in the public domain in 2023 and the first half of 2024, and is subject to change based on state and federal policies and consumer preferences.

Both ISO-NE and NYISO remain dependent on natural gas for electric grid reliability over the study period. While gas-fired generation capacity factors may decrease as renewables are increasingly commercialized, the fleet of gas-only and dual fuel generation resources will be relied on to both ramp and cycle to ensure grid reliability.

In light of this background, the goals of this study are four-fold, as follows:

- First, to quantify the physical capability of the consolidated network of pipeline and natural gas storage infrastructure to serve gas-fired generation under cold weather conditions over the study horizon;
- Second, to assess the resilience of gas infrastructure to withstand postulated gas and electric contingencies while continuing to serve LDC customers and scheduled gas-fired generation under cold and milder weather conditions;
- Third, to assess mitigation potential ascribable to dual fuel generation, electric storage, and/or other dispatchable thermal units when contingencies occur; and,
- Fourth, to identify key uncertainty variables and risk factors affecting gas/electric interdependencies.

There are three main topics covered in this report. First, LAI inventories the key attributes of the gas and electric system in New England and New York. Second, LAI documents the key inputs to the gas and electric models as well as the approach used to calibrate gas-electric interdependencies under multiple scenarios and defined contingency events specific to New England or New York. Third, LAI presents the results of the hydraulic modeling under baseline conditions and following the contingencies that represent the complement of low, moderate and high impact perturbations to gas infrastructure. Whereas low impact contingencies constitute short-term disruptions to gas supply chain that do not endanger electric grid reliability, high impact contingencies have the potential to imperil electric grid reliability by constraining gas deliverability to a high concentration of gas-fired generators. LAI conducted "stress tests" to examine the degree to which gas-fired generation could respond to an electric-side contingency. Some gas-fired generators are better situated to respond to an electric contingency, but most are limited in their ability to source intraday (ID) gas to respond on short notice.

The Steering Committee received a comprehensive report replete with hydraulic and electric simulation detail to support the situational awareness of control operators under baseline conditions when all gas infrastructure is available during cold temperature conditions. In addition, technical insight into the responsiveness of the integrated network of pipeline and storage infrastructure when there are postulated supply chain disruptions has been provided. In this Public Version of same report, LAI has removed all Critical Energy/Electric Infrastructure Information (CEII) and Confidential Information (CI) consistent with LAI's non-disclosure obligations.

Executive Summary

Key findings and observations are:

- Most gas-fired generators operating in the Study Region do not hold firm transportation entitlements, thereby exposing the generators to gas supply curtailment or interruption when pipeline congestion materializes during the peak heating season. Maintaining dual fuel capability, coupled with liquid fuel storage and resupply arrangements, is a viable way to satisfy fuel assurance objectives for electric system reliability during the modeled hydraulic periods. The Liquefied Natural Gas (LNG) importers to New England represent an integral part of gas-fired generators' ability to satisfy fuel assurance objectives. Extreme cold conditions lasting longer than the three-day periods modeled in this study could add additional stress to the network of gas pipeline and storage and oil storage infrastructure in the Study Region, thereby heightening electric reliability challenges if oil inventory cannot be replenished on a timely basis. Oil inventory replenishment is not addressed within this study, as ISO-NE and NYISO are evaluating oil inventory and other fuel security needs over longer time horizons as part of their current energy adequacy studies.

- Quantification of pipeline and gas storage infrastructure reveals the constraint points and operating limitations underlying the consolidated network of gas infrastructure along discrete route segments serving gas-fired generation. Hydraulic modeling confirms that the Study Region's natural gas infrastructure is fully or near fully utilized during the modeled extreme cold weather period. In selected cases, there may be pockets of additional deliverability, but upstream constraints limit the ability of gas to reach these segments. Should any of the modeled gas-side contingencies occur, constraints on the system would be exacerbated, thereby increasing reliance on oil-fired generation to ensure electric grid reliability. Contingency events that result in the cessation of gas throughput, specifically line breaks, have a very low probability of occurrence, but would have immediate and high impact on downstream customers. Across the breadth of gas-side contingencies evaluated in this study, the hydraulic results show that electric system operators would have adequate time to safely shut a generating unit down, except for a line break immediately upstream of an online generator. Contingency events that limit the flow of gas supplies into the Study Region or cause a diminution of compression within the Study Region are rare, but more likely to occur than a line break.

- With few exceptions, the loss of strategically located compression could generally be mitigated through increased horsepower utilization or increased flows through interconnections with other pipelines. However, some locations with concentrated gas-fired generation downstream pose more risk. The pressure decay following a compressor station outage would not likely cause damage to downstream turbines, and would allow continued gas flow, giving plant operators sufficient time to ramp down gas intake for the avoidance of harm.

- In New England, operating flexibility throughout the peak heating season is supported by the scheduling of gas supplies from Repsol Saint John and/or Constellation Everett Marine Terminal (EMT), which bolster deliverability at the eastern end of the Tennessee and Algonquin pipelines through the displacement of conventional flows from west to east. These deliveries give pipeline operators valuable scheduling flexibility since they displace the need for conventional flows west-to-east into New England. About 1.2 Bcf/d of LNG is available on a coincident basis: two-thirds from Repsol Saint John (0.8 Bcf/d) and one-third from Constellation EMT (0.4 Bcf/d). This incremental gas supply can be used to fuel approximately 8,000 MW of gas-fired generation. Almost half of ISO-NE's gas capable generation is gas-only. Absent Constellation EMT, Repsol Saint John could be used to fuel about 5,400 MW of gas-fired generation. Absent Repsol Saint John, about 2,600 MW could be served by Constellation EMT, including gas-fired generation in southern New England.

- Removing Constellation EMT from the gas supply mix reduces the deliverability of the gas system by 400 MDth/d. Under extreme cold weather conditions, where Repsol Saint John is sending out approximately 800 MDth/d and the west-to-east pipeline segments are fully utilized, no additional supply can be sourced from either of these paths. As a result, if Constellation EMT is not available, generators will have to replace up to 400 MDth/d of gas generation with an equivalent amount of oil generation. With the scheduled retirements of oil plants and the absence of Constellation EMT in the modeled long-term scenario, capacity deficiency actions would be needed to maintain electric system reliability.
- If, for whatever reason, Constellation EMT is not available, gas sendout from Repsol Saint John would still be deliverable into the eastern ends of Algonquin and Tennessee. However, Repsol Saint John is an imperfect substitute for Constellation EMT. This is because it does not deliver gas into Algonquin and Tennessee at the same points. Constellation EMT is located on Algonquin's J System in Cambridge, MA, which is downstream of the constraint point at the lateral header. Repsol Saint John cannot deliver gas across this constraint point if flows from the Algonquin mainline are already at capacity. Constellation EMT's location is ideal because it provides pressure support where Repsol Saint John cannot.
- Deliverability benefits related to counterflow at the back end of the Tennessee and Algonquin systems are predicated on Repsol's ability to pack the Maritimes & Northeast pipeline during cold snaps, thereby ensuring instantaneous delivery each morning. Under less extreme weather conditions, when the need for linepack is not anticipated, it could be many hours before supplies from Repsol could be available on the Algonquin and Tennessee systems in the event of a gas contingency. In contrast, Constellation EMT's location would provide both pressure and flow benefits in an instant.

- ❑ The consolidated pipeline network in upstate New York is constrained during cold snaps, limiting the availability of gas for generation in the Hudson Valley and the Capital District.

- ❑ In the downstate market on the New York Facilities System, the existing gas infrastructure is unable to meet demand for most generators during a cold snap. Operating risk in New York City and Long Island is already mitigated because scheduled generation mostly operates on oil. A few plants have firm transportation entitlements, but they represent a small fraction of the total thermal nameplate. Other mitigation is realizable through the activation of generator auto-swap capability. Recent experience with Winter Storm Elliott reveals the fragility of the New York Facilities System when upstream supply is materially reduced.

- ❑ In both New England and New York, incremental renewable generation and electric storage capacity is assumed in the mid-term and long-term cases in accordance with the various states' environmental goals. Intermittent renewable resources require additional load-following from dispatchable resources such as electric storage and gas and oil-fired generation. During cold weather conditions where gas use is constrained, oil and gas-fired resources may share the ramping burden, but during milder weather gas-fired generators do more load-following.

- In New England, the buildout of renewables through 2032 leads to as much as 4.6 GW to 7.1 GW of gas-fired generation ramping required over two to eight hours, respectively.
- In New York, the buildout of renewables leads to as much as a 7.1 GW ramping need over two hours for gas-fired generation.
- Ramping of gas-fired generation during mild winter conditions has historically been far lower than revealed in the long-term electric sector modeling. Transient hydraulic modeling indicates that higher ramps in the long-term can generally be accommodated in both New England and New York.

❑ During more temperate weather conditions when more gas-fired generation is scheduled on the New York Facilities System, the loss of compression or mainline deliverability on any one pipeline serving Consolidated Edison Co. of New York (Con Edison) and/or National Grid would likely result in the loss of significant gas-fired generation. Under the most disruptive perturbations, about 3,600 MW of gas-fired generation in New York City and about 1,000 MW of gas-fired generation on Long Island would have gas service interrupted. Most of these generators are dual fuel capable. Generators on the New York Facilities System are almost always at risk of interruption in the event of large loss of supply due to the tight margins between demand and supply into the system. The New York State Reliability Council has local reliability rules in place to ensure that oil auto-swap capabilities or minimum oil burn is in place for baseload facilities to mitigate the impacts of a gas contingency on electric reliability.

❑ The constrained baseline operating conditions on the gas systems in New England and New York during cold weather mean that limited gas-fired generation options are expected to be available to respond to electric contingencies, which could take the form of a sudden nuclear plant or HVDC transmission outage. In milder conditions, more gas-fired generation may be part of the response to a contingency, though practical hurdles to procuring and scheduling gas in the intra-day market may preclude or hinder the availability of gas-fired generation on short notice.

❑ The most economical means for mitigating a specific gas-side constraint depends on pipeline hydraulics and the technology and location of the affected generator(s). For high frequency and/or long duration constraints, one of the most economic mitigation measures, in lieu of adding backup fuel capability, may be the installation of additional pipeline capability. Such mitigation may be infeasible in New England and New York, however. Relative to new pipeline, low technology improvements in the form of increased horsepower at existing compressor stations are more likely to be achieved. For low frequency, short duration constraints resulting in the non-scheduling or interruption of gas-fired generation in New England or New York, the most economic mitigation measure is the use of oil. Also generators seeking LNG use to improve fuel adequacy could contract directly with LNG importers.

- Integral to this assessment is LAI's consideration of uncertainty. There are a number of key risk factors and uncertainties that pertain to LAI's central focus on the physical capability of the network of resources across the Study Region:

  - First, LAI has not evaluated the structure of wholesale energy markets in regard to the financial and market incentives underlying a generator's willingness to pay for firm transportation entitlements, or firm gas supply contracts for either LNG or pipeline gas. LNG importers cannot be expected to tolerate scheduling and LNG procurement risk that they would need to bear in order to arbitrage price spreads between global LNG prices and gas and electric prices in New England. There is no reason to believe that the required advance timing and high cost of scheduling LNG cargoes will change over the forecast period. ISO-NE may therefore need to consider wholesale market design changes or refinements that send price signals to gas-fired generation regarding the need to make arrangements that will ensure performance when needed. For gas-fired generators to rely on LNG for deliverability during the peak heating season, expensive call options will be needed to ensure adequate compensation. What is physically possible and commercially reasonable are likely distinctly different.

  - Second, since most generators do not have firm transportation entitlements, the ability of pipelines to provide intra-day scheduling flexibility to accommodate the twice daily ramp during cold snaps should be questioned. LAI recognizes that intra-day flexibility is offered on a best efforts basis by the pipelines in light of tariff restrictions requiring ratable takes. The transient model indicates what may be physically possible, but does not offer certainty regarding the feasibility of the assumption-based solutions relative to the operating provisions approved by Federal Energy Regulatory Commission (FERC). The issue of gas grid resilience is challenging in New York in light of the larger renewable ramps in 2032/33 and the infeasibility of leveraging upstream LNG from New England via displacement into New York.

  - Third, additional retirements of oil-fired generation could further limit ISO-NE's and NYISO's options during cold weather or contingency events. Aging Residual Fuel Oil (RFO) steam turbines cannot respond quickly to contingencies when offline, but they have expansive liquid storage capability that provides secure fuel supply during cold weather conditions. Conversely, aging fast-start generation, particularly in downstate New York, represents the fossil resource best equipped to respond to large and unexpected losses in electric supply. Fast-start generation may also be necessary to replace gas-only plants that trip offline under a gas supply contingency.

  - Fourth, in performing the contingency analysis LAI's focus has been on the physical capability of the pipeline network to continue to deliver scheduled gas to generators after an adverse event. The contingency analysis performed in the hydraulic modeling suite does not contemplate the array of pipeline operator actions that could be implemented to reduce deliveries in order to protect system integrity and maximize the ability to meet contractual obligations. Based on physical capability as opposed to standard pipeline operating procedure, the time-to-trip intervals reported in this study may be significantly longer than the time a pipeline operator gives a generator to ramp down operation under duress. If there is likely imminent service denigration to firm entitlement holders, the pipeline operator would likely require generators to stop taking gas, on a timeline allowing for safe shutdown to the extent reasonably possible.

- Fifth, the pace of electrifying the heating and transportation sectors relative to decarbonizing electric supply will affect the operational stresses on the gas infrastructure available to serve gas-fired generation over the long term. Assumed load growth over the long term reflects aggressive heating and transportation electrification and that will cause winter peak demand to grow substantially by the long-term forecast period. The pace of heating and transportation electrification may be reduced relative to ISO-NE, NYISO, and their member states' expectations due to changes in federal and state policies as well as customer choices. Reduced electricity demand growth would lessen the burden that gas-fired generation places on gas infrastructure in the Study Region. On the other hand, renewable energy additions, in particular, offshore wind along the New England coastline and the New York Bight has the potential to materially lessen reliance on oil and gas during the peak heating season. Uncertainty about the pace, amount and inevitability of electrification of heating and transportation as well as offshore wind in the years ahead may intensify operational stresses on the gas infrastructure available to serve gas-fired generation over the medium- and long-term.

1 General Framework

In this study, LAI's approach is built on the same general approach as the EIPC Gas-Electric System Interface Study, but incorporates additional refinements that account for a decade's worth of change in the power and gas industries.[1] This study focuses exclusively on winter conditions and includes daily supply constraints on natural gas available for generation. This means that natural gas supply is initially constrained to reflect the overall limits on pipeline and LNG supply during cold weather conditions. LAI is focused on the physical capability of the integrated network of pipeline and gas storage facilities to serve electric demand after fulfilling all gas utility sector requirements. The array of market, commercial and regulatory factors affecting deliverability is not part of the quantitative analysis performed for NPCC and the other Study Participants.

The core of the gas-electric study is the hydraulic modeling conducted using two Gregg Engineering software programs, WinFlow and WinTran. The WinFlow model represents a steady-state operating condition with pressures and flows held constant, enabling identification of constraint points and operating limitations on the natural gas system in a temporal snapshot. The WinTran model adds intraday demand profiles and dynamically represents pressure and flow across a set time interval. In this study, the time series considered in the transient model is limited to a three-day period, compared to the multi-week time series that ISO-NE and NYISO study for energy adequacy. The WinTran model yields insights into the ability of the consolidated network of pipeline and gas storage infrastructure to accommodate variable demands from utility sector and power generation end users, and enables LAI to determine the time-to-trip interval for generators following a gas system contingency event that results in the decrement or loss of pressure and/or flow along a discrete route segment or key point.

Hydraulic model development requires exhaustive inventory of the gas infrastructure capabilities, as documented in pipelines' FERC filings. All interstate pipelines doing business in New England and New York provided LAI with the requisite confidential information to support model construction and validation efforts. It also requires meter level hourly estimates of utility sector customer and electric generator demand.[2]

Utility sector gas demand estimates, including LDCs and direct-connected industrial customers, were developed via a review of various LDCs' supply plans filed at state commissions in New England and New York and historical delivery data. Electric sector gas demands are generated via hourly dispatch modeling, which requires the development of various upstream input assumptions regarding demand, generation system mix, and other aspects of the power system.

Modeling was conducted for near-, mid-, and long-term study periods in winter 2024/25, 2027/28, and 2032/33, respectively. LAI generated hourly gas demand schedules that fit various case run parameters:

- **Forecast Year** represents the complement of base case load and resource assumptions that are adopted for a given future year.
- **Weather Event** represents the 21-day historical period modeled in electric simulations.

[1] The EIPC Gas-Electric Study documents are available here: https://eipconline.com/gas-electric-documents

[2] The New York Facilities System was modeled independently by Con Edison and National Grid, who operate the system, using their own internal hydraulic models. A broad array of model inputs has been supplied by LAI in alignment with study goals.

- **Hydraulic Period** represents the 3-day period sampled in hydraulic modeling.
- **Sensitivity** represents a deviation from base case assumptions that affect electric sector gas demand in a given forecast year. Sensitivities reflect uncertainty about future expectations for the electric system or LNG terminal sendout availability, but would be "known" going into the 21-day event.
- **Contingency** represents an adverse change to the electric or gas system that occurs with little or no notice.

These demand schedules were then integrated into the Gregg WinFlow and WinTran steady-state and transient hydraulic models. The consolidated utility sector and generator gas demands were examined under a number of cases to determine whether the scheduled gas volumes are physically deliverable. LAI's approach for the NYISO and ISO-NE modeling process are shown below.

Each model process shares a number of data inputs and end-stage hydraulic output. Electric system modeling (from Probabilistic Energy Adequacy Tool (PEAT) for ISO-NE and from Aurora for NYISO) is combined with utility sector demand forecasting to create gas demand profiles for input into the WinFlow and WinTran hydraulic models. The combined total gas demand, along with gas pipeline infrastructure, is input into hydraulic models for steady-state and transient simulations.

There are notable differences between the ISO-NE and NYISO modeling process flow. The PEAT model used for ISO-NE does not include specific fuel pricing but rather an assumed dispatch order by fuel. The PEAT model also relies on ICF International (ICF)'s forecasts for utility sector demand and peak-shaving operations, but those forecasts are informed by the same shared sources as LAI's utility sector forecasts that are used for hydraulic inputs. LNG terminal capability is also a large driver of gas availability in ISO-NE which is not present in NYISO. The Aurora model used for NYISO includes zonal transmission limits, but those limits rarely bind under the posited input assumptions.

Figure 1: ISO-NE Modeling Process Flow

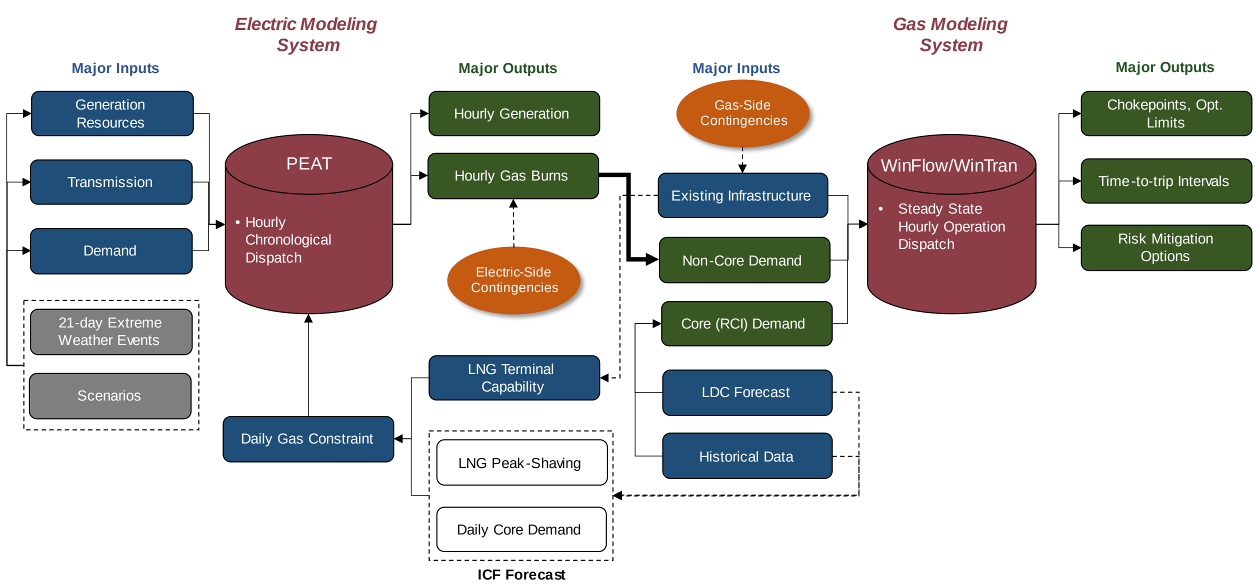
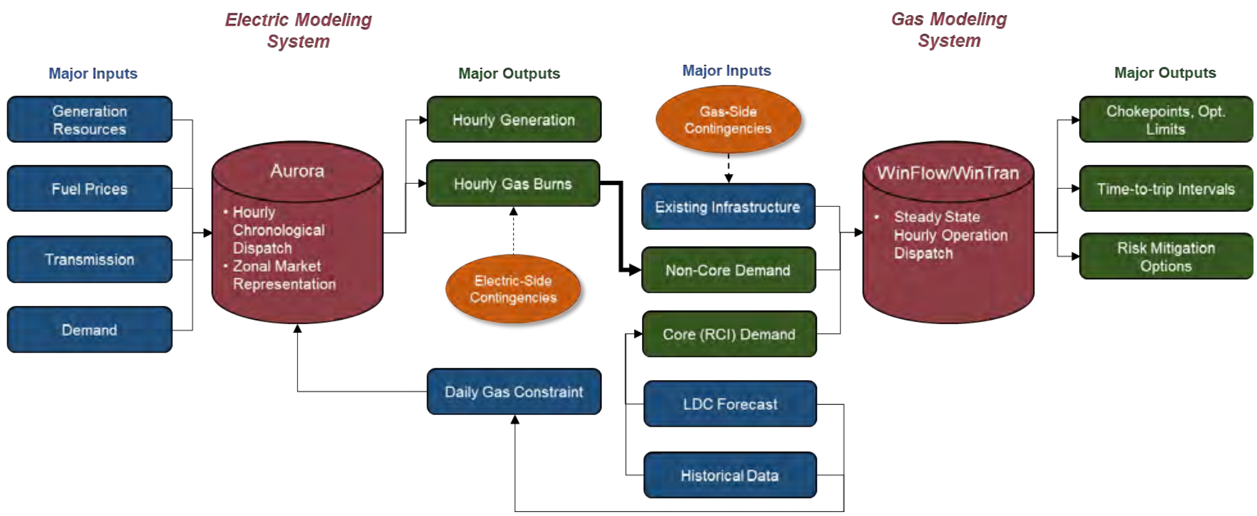


Figure 2: NYISO Modeling Process Flow



Many of the modeling inputs to the process flow, including gas and power demand and renewable generation profiles, are affected by the weather experienced during the selected historical event. Winter Storm Elliott, while a significant weather event for much of the U.S., had a more moderate impact on ISO-NE and NYISO compared to other regions. Although the storm caused over 100,000 power outages in New York and thousands of outages in New England, these were primarily due to damage to the electric distribution systems rather than major issues with the bulk electric system (BES). NYISO did not experience an energy emergency, and, in fact, was able to provide assistance to neighboring regions like PJM.[3] ISO-NE did briefly invoke Energy Emergency Alert (EEA) 1 due to unplanned generation outages and reduced power imports, but the situation was resolved in a few hours, with conditions stabilizing quickly.[4] Winter Storm Elliott also impacted the Con Edison LDC, affecting Manhattan, the Bronx, and parts of Queens and Westchester County. Pressure drops on the interstate natural gas pipelines supplying Con Edison prompted a Gas System Emergency, leading the company to activate its LNG regasification plant and implement emergency protocols, including Public Appeals to reduce gas demand.[5]

In contrast, and as shown in Figure 3, the cold wave in January 2004 brought more sustained and severe impacts to both ISO-NE and NYISO, making it a more appropriate event for testing cold-weather resilience. The January 2004 cold snap featured prolonged subzero temperatures, leading to record-breaking energy demand and significant stress on the grid's generation and transmission systems. This event placed the power system in New England and New York under far greater strain than Winter Storm Elliott, as the grid had to manage consistently high loads over several days.

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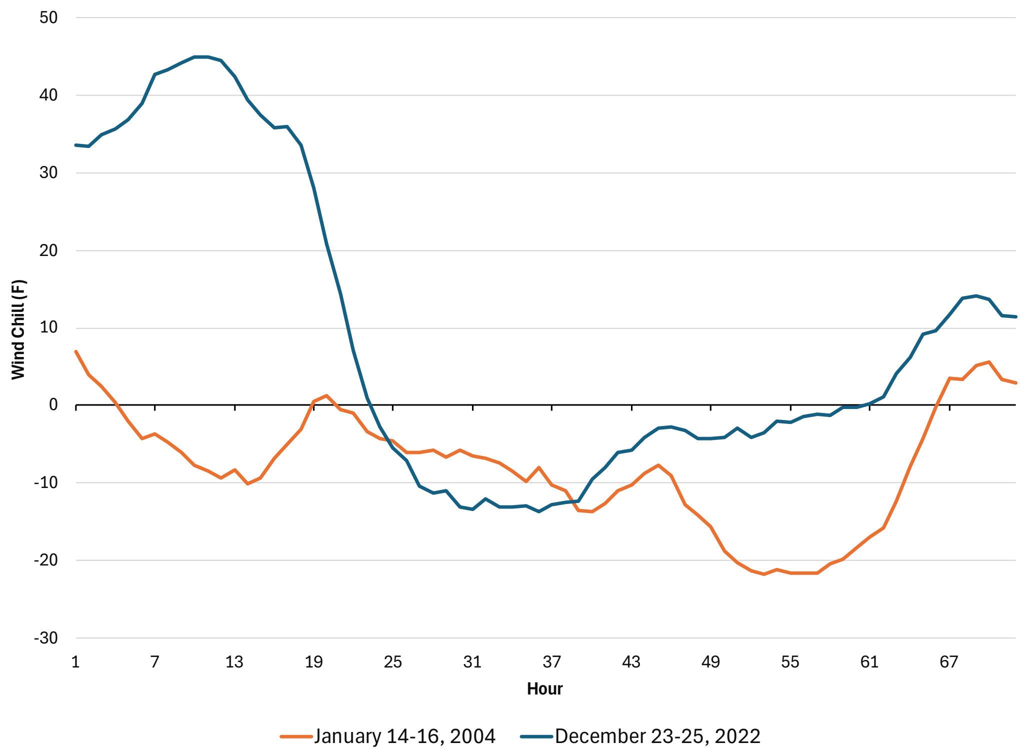
[3] Winter Storm Elliott caused PJM to employ various emergency operating measures, such as calling reserves, reducing exports, and calling for voluntary conservation. PJM barely avoided load shedding on December 23. See Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott, FERC, October 2023, Pages 64-72.
https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022

[4] *Id*, Page 72.

[5] *Id.,* Page 86-88

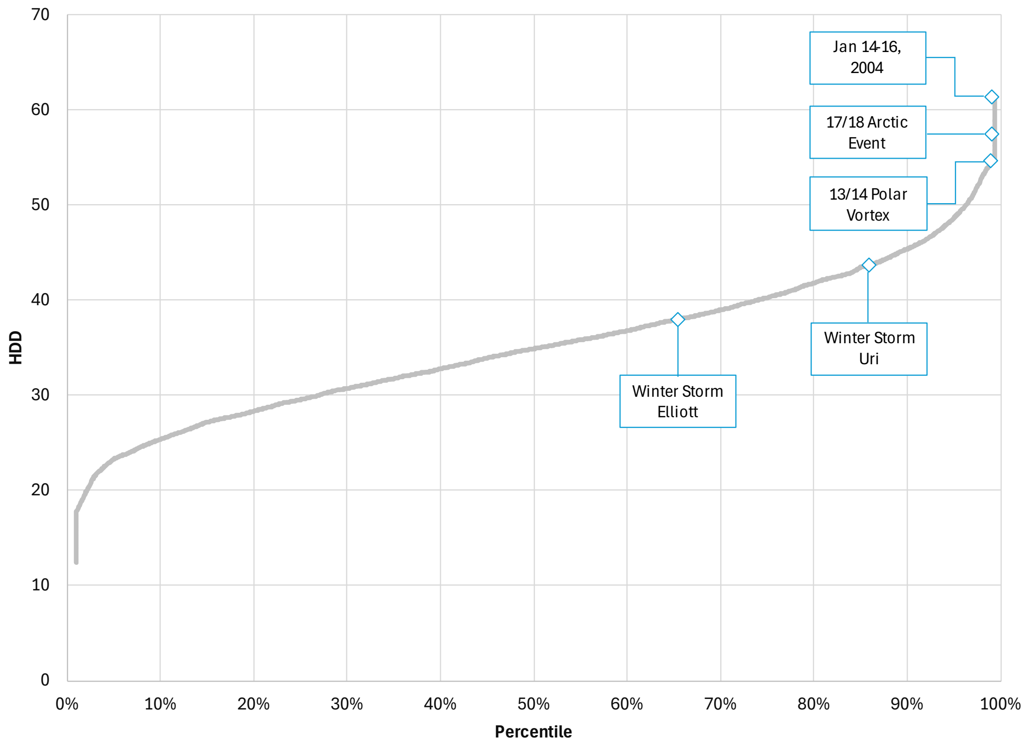
Figure 3: Wind Chill Comparison in New York – 2004 Cold Snap vs. 2022 Winter Storm Elliott



Winter Storm Elliott was particularly impactful to the gas and electric systems due to the loss of production in the Marcellus Shale, and therefore diminished fuel availability for gas-fired generation, and concurrent forced outages to many generators, including non-gas resources. While Winter Storm Elliott is not directly modeled, the use of the 2004 weather event, coupled with various gas-side contingencies, reflects stressed cold weather conditions in the modeled footprint.

Based on historical winter data for three-day periods from 2000 to 2022, as illustrated in Figure 4, the average Heating Degree Days (HDD) for selected hydraulic period (January 14–16, 2004) ranks within the top percentile. Cold weather of this duration and magnitude is very rare.

Figure 4: Three-Day Strip of Average HDD in Winter from 2000-2022 in New England[6]



Inputs to the hydraulic modeling suite reflect historical weather conditions, as follows:

1. Extreme cold when available gas for generation is limited by high demand from utility sector customers, sampled from the 2004 weather event, and
2. More temperate conditions when gas demand for power is less constrained but will experience large hourly swings due to loss of renewable supply as the sun sets and winds change, sampled from the 2015 weather event.

The weather events are drawn from periods of interest to both ISO-NE and NYISO that have been captured in their own fuel and energy security studies. Using historic weather conditions allowed LAI to mine various data sources to ensure coincident conditions across the power and gas system. The modeled conditions have happened before and therefore constitute a sensible starting point for purposes of testing gas and electric grid resilience over the study horizon.

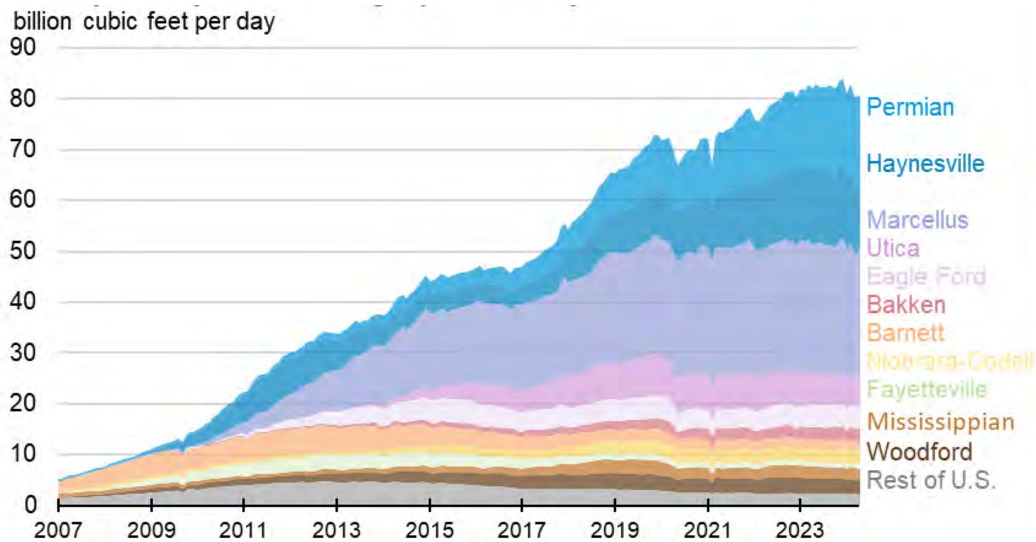
2 Natural Gas Facilities and Operations in the Study Region

Energizing North America with natural gas involves a complex supply chain from the wellhead to the burner-tip. The supply chain includes production, mid-stream, transmission, storage, and distribution facilities. Until the early 2000s, the majority of U.S. gas flows originated from traditional producing basins in Texas, the Gulf Coast, New Mexico, California, the Midcontinent region, the Rocky Mountains, and western Canada. Comparatively small amounts of natural gas were produced from other, mostly

[6] The three-day periods of interest for Winter Storm Elliott, Winter Storm Uri, the 2013/14 Polar Vortex, and the 2017/18 Arctic Event are December 23-25, 2022, February 12-14, 2021, January 2-4, 2014, and December 31, 2017-January 2, 2018, respectively.

conventional basins throughout the U.S., and then in the late 1990s from Atlantic Canada. Over the last two decades, the emergence and growth of shale gas has radically changed natural gas production and transportation dynamics throughout North America. In 2007, total annual shale gas production in the U.S. amounted to about 2.3 Tcf. By 2023, total annual U.S. shale gas production amounted to more than 38 Tcf.[7]

Figure 5: Monthly U.S. Dry Shale Gas Production by Formation[8]



The emergence of shale gas has also inspired major LNG export facilities in the Gulf Coast as hundreds of billions of dollars have been invested by global energy suppliers in liquefaction capability dedicated to the European Union (EU), Japan, and other Asian markets accessible through the Panama Canal.

In 2023, electric power generation accounted for 40% of the 89 billion cubic feet per day (Bcf/d) of U.S. natural gas consumption, while industrial and residential demand accounted for 26% and 14%, respectively.[9]

Despite the abundance of shale gas that has driven down both commodity prices for firm LDC entitlement holders and wholesale electric energy prices for electric generators, a lack of incremental pipeline capacity into New York and New England has kept the northeast reliant on oil and behind the citygate peaking resources, notably LNG in New England.[10] Imported LNG arrives into New England via three terminals: Constellation EMT in Massachusetts, Repsol Saint John in New Brunswick (which is vaporized in New Brunswick and then transported into New England via the Maritimes and Northeast Pipeline), and Excelerate Northeast Gateway, which is located offshore of Massachusetts. Northeast LDCs sign supply agreements with the Repsol and Constellation terminals to ensure that peaking supply will be available to

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[7] EIA FAQs: How much shale gas is produced in the United States? Accessed October 23, 2024. https://www.eia.gov/tools/faqs/faq.php?id=907&t=8

[8] EIA Short-Term Energy Outlook, Figure 43. Accessed October 23, 2024. https://www.eia.gov/outlooks/steo/images/Fig43.png

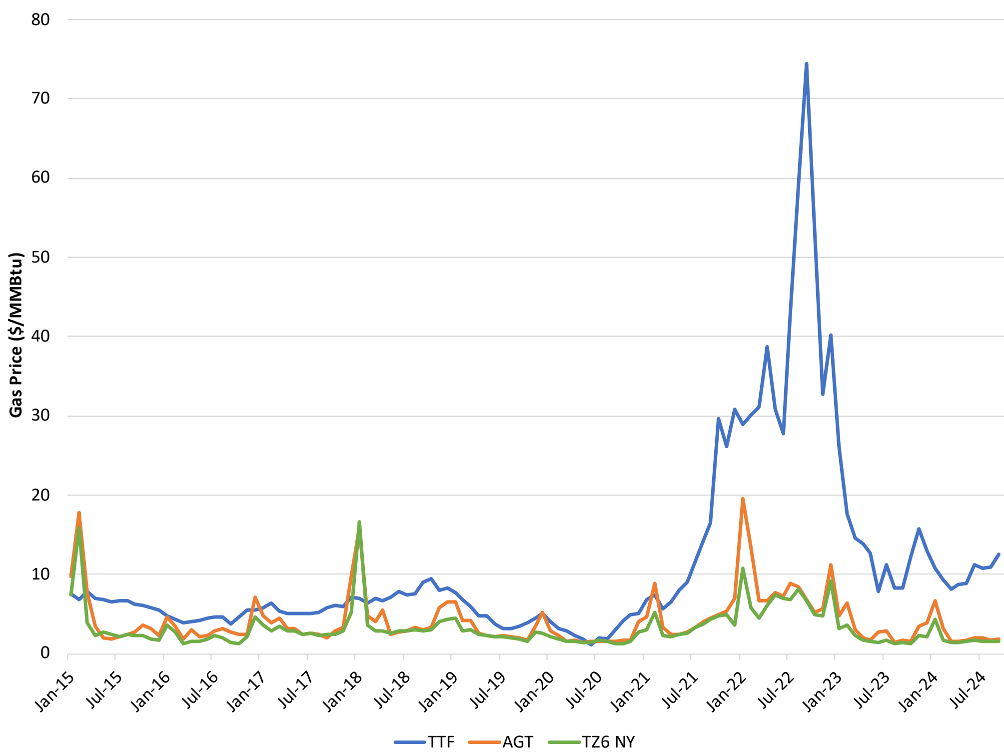
[9] U.S. Energy Information Administration Natural Gas Summary, accessed October 29, 2024. https://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm

[10] Offshore production in Atlantic Canada that was declining a decade ago when EIPC studies were conducted has since ceased, eliminating a potential supply pathway for dry gas production.

utility sector gas customers on the coldest winter days. The reliance on imported LNG causes New England's gas prices to be exposed to spikes in global LNG prices. The record high global LNG prices that peaked following the Russian invasion of Ukraine corresponded to record high winter futures of New England indices.

Figure 6 shows historical monthly averages of day-ahead delivered gas prices at Algonquin Citygates (the primary index of note in New England) and Transco Zone 6 New York (a pricing point of record in NYISO). These indices are compared to the Dutch Title Transfer Facility (TTF) futures price for the prompt month on the last traded date. There are several global markers for LNG, but TTF represents the closest, most liquid global price for LNG imports into New England.

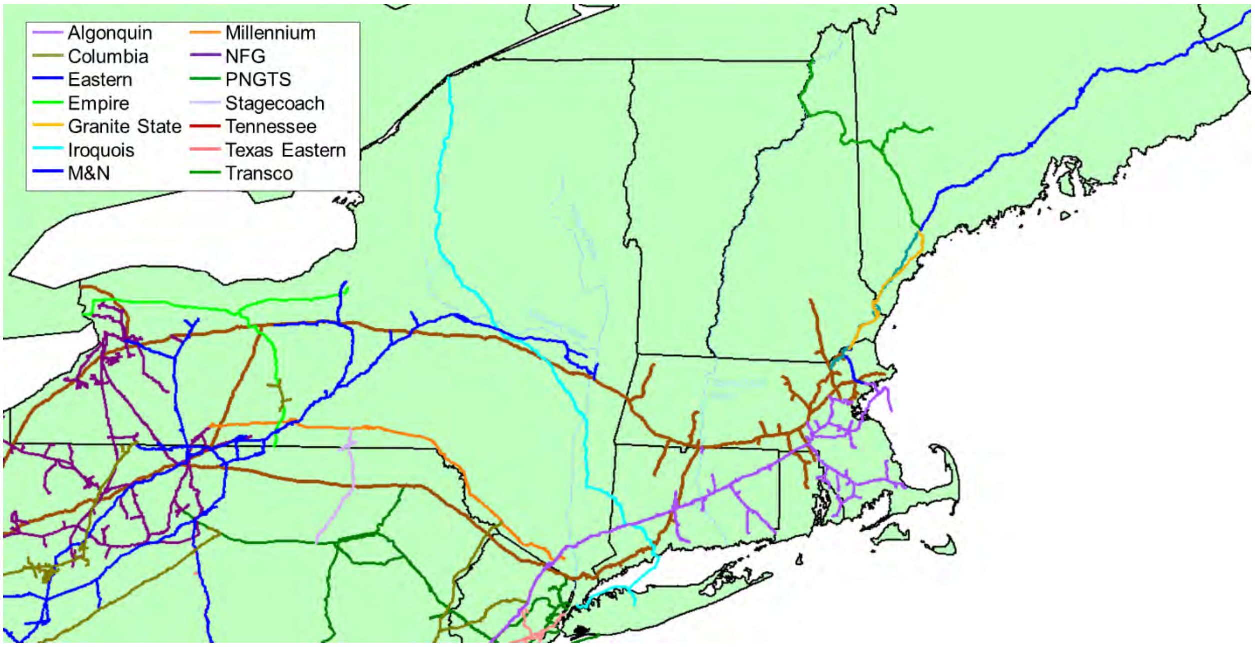
Figure 6: Natural Gas Price Comparison



2.1 Interstate Pipelines

The interstate pipelines operating in the Study Region are shown in Figure 7. There are fourteen interstate gas pipelines in the study area, eleven operate in New York and six operate in New England. Three pipelines – Algonquin, Tennessee, and Iroquois – operate in both New England and in New York.

Figure 7: Interstate Pipelines Operating in the Study Region



2.2 Underground Storage

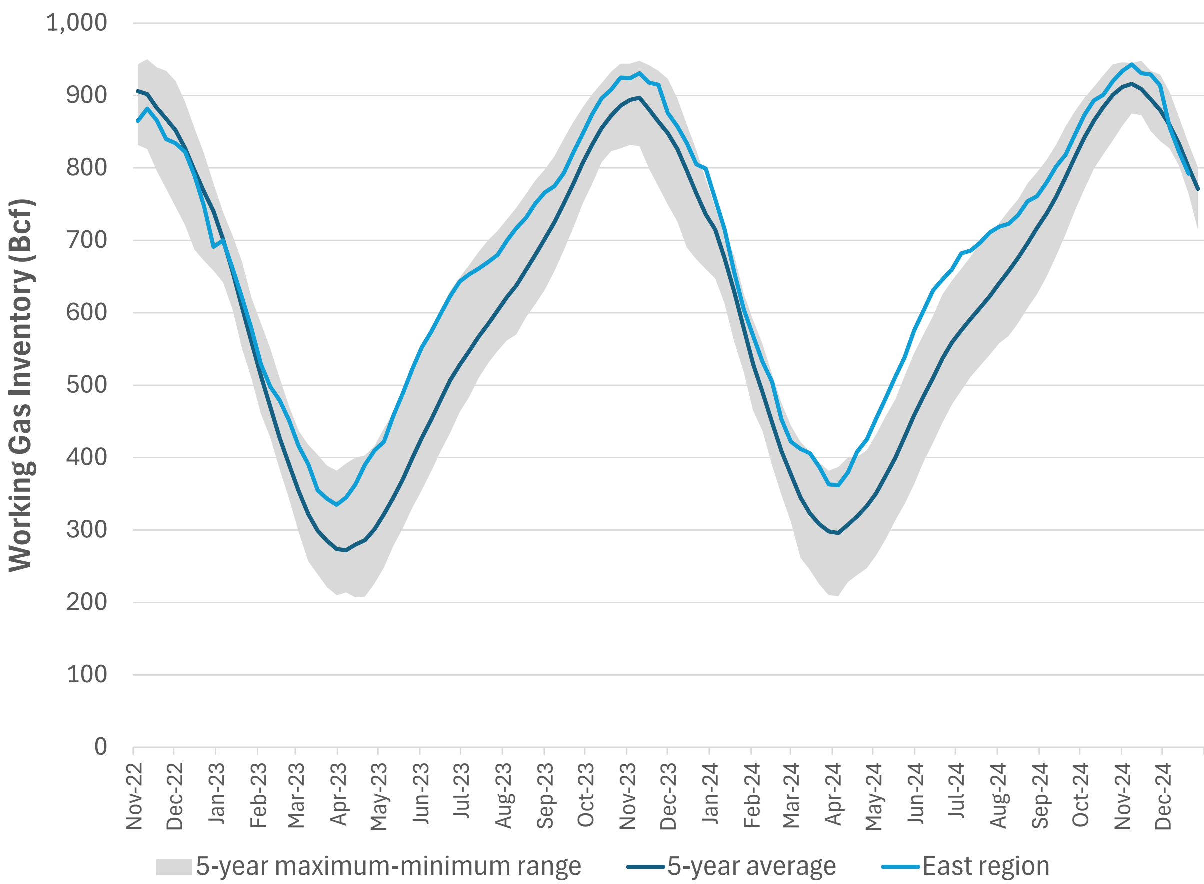
The majority of U.S. and Canadian natural gas storage is held in underground facilities which are located either near producing basins or close to major market centers.[11] Conventional underground storage is an integral part of the supply chain for New York and New England, although there is limited conventional underground storage in New York and none in New England. Reliance on gas storage capacity is central to LDCs' ability to serve customers throughout the heating season. Storage services are also available to generation companies, marketers, and gas producers who manage the injection and withdrawal of natural gas to supplement pipeline entitlements, manage pipeline imbalances, and mitigate daily or seasonal gas price volatility.

Figure 8 shows the East Region storage inventory over the last two years, as reported by the Energy Information Administration (EIA).[12] Entering the 2024/25 heating season, working gas inventory in the East Region for the week ending November 1st was 934 Bcf, 2.4% greater than the five-year average level of 912 Bcf. During recent weather events, including Winter Storm Elliott in 2022 and the 2017/18 Arctic Event, the East region experienced a four-week drawdown of 149 Bcf and 215 Bcf, respectively.

[11] Most underground storage is located in depleted oil/gas reservoirs, aquifers or salt caverns. Depleted reservoirs are the most common underground storage facility as they use existing oil or gas infrastructure with proven gas containment capability. The storage facilities in the Study Region are depleted gas/oil reservoirs. Although there are underground storage facilities in New York State (125 Bcf of working gas capacity), the storage facilities of particular relevance to New York and New England are located in Pennsylvania and southern Ontario, where there is greater working gas storage capacity (426 Bcf and 279 Bcf, respectively). Gas held in storage consists of working gas and base or cushion gas. Working gas is the gas that can be injected and withdrawn to meet market needs. Cushion gas represents the underlying inventory needed to provide the requisite pressure for working gas to be withdrawn.

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

Figure 8: East Region Storage Inventory[13]



Natural gas is typically injected into storage during the summer and fall seasons when there is slack pipeline delivery capacity and beneficial commodity prices relative to the heating season. Gas is withdrawn throughout the heating season, which usually spans early December to early March.

The underground storage capacity in the Study Region, all of which is located in New York, includes 24 facilities with working gas capacity of 125 Bcf and maximum withdrawal capability of 2,674 MMcf/d.

2.3 Liquefied Natural Gas

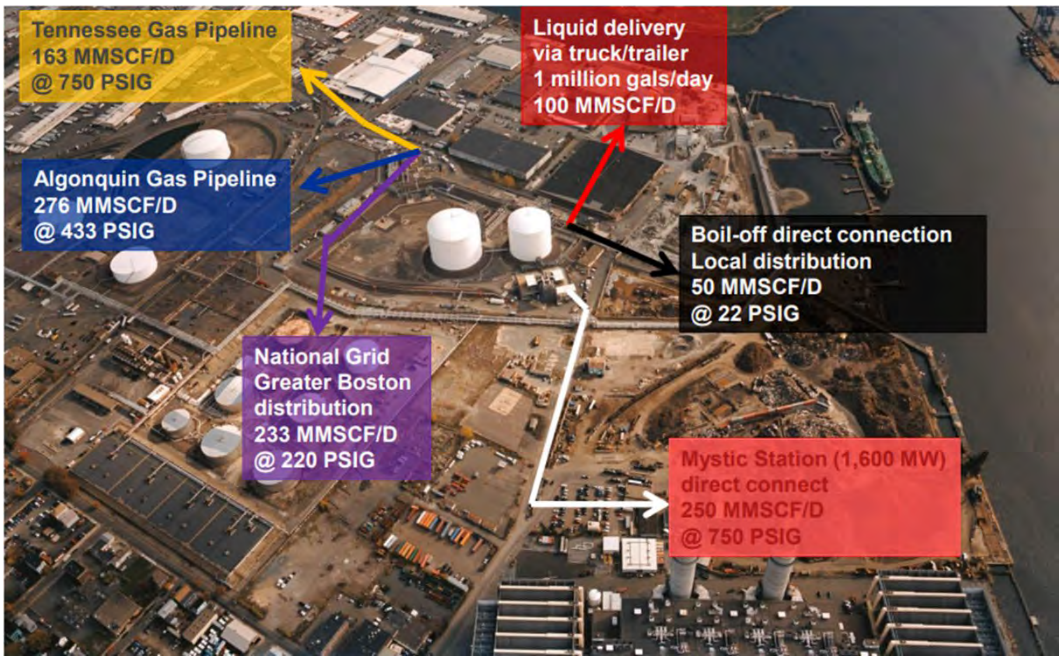
In addition to conventional underground storage facilities, natural gas can be stored above ground in liquefied form. There are three LNG import facilities in or near the Study Region. LDCs throughout New England and New York also have LNG storage tanks located behind the citygate to supplement pressure and flow during the peak heating season. While regasification of LNG from import terminals is used by gas-fired generators and LDCs in addition to, or in lieu of, pipeline-rendered supply, the regasification of LNG from satellite tanks is used to exclusively serve firm LDC customers. LNG from satellite tanks is used

[13] The East Region includes Connecticut, Delaware, District of Columbia, Florida, Georgia, Massachusetts, Maryland, Maine, New Hampshire, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Vermont, Virginia, and West Virginia.

to address operationally constrained parts of the gas distribution system, for meeting peak gas demand during extreme weather conditions, and to mitigate outage contingencies.

Constellation EMT in eastern Massachusetts has an on-site storage capacity of 3.4 Bcf.[14] Constellation EMT sends out gas to the Algonquin medium pressure system around Boston and the Tennessee high pressure system, as well as the NGrid low pressure system, the LDC serving the metropolitan Boston area. Constellation EMT previously served the Mystic 8 & 9 generating units and effectively provided them with firm gas throughout the year. Mystic 8 & 9 retired in May 2024, resulting in the loss of Constellation EMT's largest customer, thereby leaving the LDCs that rely on LNG supplies from the facility responsible for the full going-forward cost of service in order to keep the facility in operation.

Figure 9: Constellation EMT LNG Sendout Capability[15]



In addition to its pipeline connections, Constellation EMT also sends out LNG by truck to LDC satellite storage facilities in the greater Northeast. There are over forty LNG satellite tanks across New England that are integral in providing supplemental pressure and flow behind the citygate during cold snaps, when pipeline rendered supply is not sufficient to serve firm customers.[16] In 2023, New England's LDCs held roughly 15.5 Bcf of LNG storage capacity, not including the 3.4 Bcf storage capacity at the Everett LNG terminal or the 0.165 Bcf storage capacity at the new Northeast Energy Center.[17] Excluding Constellation

[14] The Constellation Everett LNG import facility is also referred to as the Everett Marine Terminal (EMT). It was previously referred to as Distrigas of Massachusetts. Such references are synonymous throughout this report.

[15] Comments of Constellation Energy Generation, LLC, filed November 7, 2022 in FERC Docket AD22-9. See page 8. https://elibrary.ferc.gov/eLibrary/filedownload?fileid=8B60D1EB-FAD9-C85B-9B7E-8453ACC00000

[16] Northeast Gas Association, "2021 Statistical Guide," p. 45, https://northeastgas.org/files/galleries/stat_guide_2021.pdf

[17] Northeast Energy Center LLC, Amended and Restated Petitions before the Massachusetts Energy Facilities Siting Board for Approval to Construct a Natural Gas Liquefaction, Storage, and Truck-loading Facility in Charlton, Massachusetts, https://northeastenergycenter.com/wp-content/uploads/2019/03/02282019_EFSB_Liberty-Energy03042019_Text-AppendixD.pdf.

EMT, the total daily vaporization and liquefaction capacity of the peak shaving facilities was approximately 1.54 Bcf and 0.06 Bcf, respectively.

Repsol Saint John, previously known as Canaport, received its first shipment in 2009. The facility has three LNG storage tanks which can each store 3.3 Bcf. Total storage capacity is 9.9 Bcf.[18] Repsol Saint John has a maximum sendout capacity of 1.2 Bcf.[19] Repsol Saint John has 0.73 Bcf/d of firm pipeline capacity on Maritimes and Northeast Pipeline (M&N) which allows sendout from Repsol Saint John to be delivered into Tennessee at Dracut, MA and into Algonquin at Beverly, MA.[20] This capacity currently has a monthly reservation rate of $12.78/Dth-month, which translates into an annual reservation charge of roughly $112 million for Repsol. Repsol Saint John's long-term firm transportation agreement with Maritimes & Northeast is scheduled to expire in 2034. M&N believes that Repsol will not pay this level of reservation charge in the future.[21] M&N total transportation capacity is 0.83 Bcf/d.[22]

New England's offshore LNG facility, Excelerate Northeast Gateway, is a submersible buoy system and therefore does not have on-site storage capacity. In 2003, Excelerate developed technology that would allow LNG to be regasified onboard an LNG carrier for direct injection into a high-pressure gas pipeline. This technology has been incorporated into the design of an LNG ship. It is commonly referred to as a Floating Storage Regasification Unit (FSRU). The purpose of an FSRU is to provide a platform to load LNG at a shore-side facility, transport the LNG to a market location and then regasify the LNG into a vapor to be transferred into a pipeline grid for consumer or industrial use.

Northeast Gateway differs fundamentally from Constellation EMT and Repsol Saint John as there is no storage capability unless an FSRU is connected. Excelerate Northeast Gateway is connected to Algonquin's Hubline by a 16-mile subsea lateral. The capacity of the lateral is 800 MDth/d, though scheduled sendout has never reached that quantity.[23] The facility entered service in December 2007. First sendout occurred in May 2008. Utilization can be characterized as extremely low.

The storage capacity associated with the FSRU is endogenous to the FSRU itself. Hence, the FSRU must remain on station at the buoy until the cargo is either fully delivered or a decision is made to deliver a portion of the cargo elsewhere. For example, during winter 2021/22, the Exemplar FSRU arrived at the buoy on January 4, 2022, sent out its first volumes on January 12, 2022, and delivered gas intermittently until February 28, 2022.[24] Northeast Gateway has not received a cargo since winter 2022. Northeast Gateway may not be an attractive delivery point for FSRUs, which can be utilized much more frequently in the global market. LAI has identified vessel scheduling risk as an impediment to harnessing the

[18] Id., *LNG Process*. https://www.saintjohnlng.com/lng-process

[19] Id., *About Saint John LNG.* https://www.saintjohnlng.com/about-saint-john-lng

[20] Enbridge, *Maritimes & Northeast Pipeline*.
https://infopost.enbridge.com/InfoPost/MNUSHome.asp?Pipe=MNUS

[21] Docket No. RP24-780-000. Prepared Direct Testimony of Michael J. Whalen on Behalf of Maritimes & Northeast Pipeline, L.L.C. See pages 25-26.

[22] Enbridge's Energy Infrastructure Assets, Enbridge, August 8, 2024, see page 80.
https://www.enbridge.com/~/media/Enb/Documents/Factsheets/FS_EnergyInfrastructureAssets.pdf?la=en

[23] Peak daily sendout per EBB scheduled flows data has been about 500 MDth. Given that FSRUs carry about 3,000 MDth, utilizing the full sendout capacity for the lateral would exhaust LNG supply at the FSRU in less than four days of operation.

[24] US Department of Energy, LNG Monthly 2022. See LNG Imports sheet.
https://www.energy.gov/sites/default/files/2023-03/LNG%20Monthly%20December%202022_3.xlsx

deliverability associated with Excelerate Northeast Gateway, particularly since Excelerate does not likely experience financial risk in scheduling its fleet to the EU.

Because sendout from Excelerate Northeast Gateway is injected into Algonquin's Hubline, it is hydraulically similar to sendout from Repsol Saint John, in that gas either flows south on Hubline into Algonquin or north on Hubline onto M&N and then can flow into Tennessee at Dracut or into northern New England. Excelerate Northeast Gateway could therefore act as a substitute for Repsol Saint John, or could be supplemental to Repsol Saint John, in which case gas from Excelerate Northeast Gateway would likely flow south onto Algonquin while deliveries of gas from Repsol Saint John into Dracut would likely increase. Incremental deliveries to Dracut would then be able to serve more gas-fired generation in northern New England and across Tennessee's Line 200 through New York and Massachusetts.

Sendout from Repsol Saint John or Excelerate Northeast Gateway is an imperfect substitute for Constellation EMT. This is because the gas from Repsol Saint John and Excelerate Gateway does not flow into Algonquin and Tennessee at the same points. For example, Constellation EMT is located on Algonquin's J System in Cambridge, Massachusetts, which is downstream of the constraint point at the lateral header. Gas delivered into Algonquin via Hubline cannot flow across this constraint point if flows from the Algonquin mainline are already at capacity. Constellation EMT's location is ideal because it provides pressure support where Repsol Saint John cannot.

Constellation EMT and Repsol Saint John have typically executed peaking option contracts with counterparties in New England, primarily LDCs. These contracts are executed in advance of the heating season, and sometimes span multiple delivery years with renewal provisions. Contracts are typically structured with a call payment on a Maximum Seasonal Quantity (MSQ), which is paid whether gas is called or not, which confers the option to purchase gas at a commodity rate, typically a formula-indexed to global LNG pricing or Henry Hub markers. Terminal operators must know their contract obligations before the heating season in order to ensure that they can manage LNG inventory via cargo deliveries. LNG cargoes can take several weeks of travel to get to import facilities, so Repsol and Constellation EMT must carefully plan the number and timing of LNG cargoes with suppliers to ensure that contract obligations can be met.[25] Spot cargo deliveries of an "ad hoc" nature are rare and have become more difficult given tight global markets.

Terminal operators are on record in this respect:

> Repsol does not purchase and store LNG on a speculative basis to meet some perceived future need of the market. The only quantity of LNG that should be considered deliverable is that which has been forward contracted by the market.[26]
>
> Specifically, Constellation does not buy LNG speculatively. Rather, we buy LNG to meet our LNG commitments. So as to minimize our exposure to sudden and potentially drastic LNG price swings, we seek to purchase the LNG we need to serve our customers quickly, typically

[25] Procurement and scheduling logistics are more complicated for Constellation EMT because of the vessel restrictions associated with refilling LNG inventory along the Mystic River.

[26] LNG's Vital Role, Karen Iampen presentation to the ISO-NE Markets Committee, January 14-15, 2020. https://www.iso-ne.com/static-assets/documents/2020/01/a5_d_i_repsol_presentation_lng_vital_role.pdf

> contemporaneous with our agreement to sell the LNG… LNG supply and transportation agreements of need to be negotiated and locked-in well in advance…[27]

Though contracts with generators are not in the public domain, ISO-NE's Inventoried Energy Program (IEP) indicates that only a small portion of LNG terminal sendout capability has been contracted under the IEP incentive structure.

ISO-NE's 2024 Winter Quarterly Markets Report states:

> Gas-fired generators qualified 345 GWh of inventoried energy, corresponding to about 4,800 MW of firm gas per hour. About 20% of the natural gas inventoried energy was backed by an LNG contract. The remaining gas contracts were backed by pipeline gas. The upper bound [of 560 GWh] estimated by the Analysis Group was based entirely on LNG supply.[28]

LNG eligibility for the IEP was capped at 560 GWh per maximum coincident historical sendout at LNG terminals, so LNG capability was not highly contracted by generators.

There are no LNG import terminals in New York. Satellite LNG storage facilities are located in Brooklyn, Queens, and eastern Long Island. Each of these satellite LNG facilities operated by Con Edison or National Grid liquifies natural gas on site, utilizing their existing liquefaction capability to produce the LNG held in inventory at the start of the peak heating season on December 1st. The satellite LNG facilities in New York City and Long Island cannot be refilled via truck. Hence, Con Edison and NGrid must aggressively manage the drawdown of LNG inventory to supplement local pressure in order to preserve the option of additional LNG regasification volumes in the event of a cold snap in late February or early March.

NGrid supplements their peaking sendout capability through compressed natural gas (CNG). While CNG is an integral part of gas-grid reliability during cold snaps, it is of no consequence for gas-fired generation on the New York Facilities System.

2.4 Intrastate Pipelines and Local Distribution Companies

Intrastate natural gas pipelines operate within state borders and link to local markets and to the interstate pipeline network. LDCs receive gas from interstate and intrastate pipelines for delivery to residential, commercial, and industrial customers located behind the citygate. A number of LDCs in the Study Region supply gas to generators behind the citygate, the greatest concentration of such generators is in downstate New York.

The New York Facilities System is supplied by four interstate pipelines: Transco, Texas Eastern, Tennessee, and Iroquois. Con Edison and NGrid coordinate planning, design, and operation under the terms of the New York Facilities Agreement. Con Edison and NGrid serve 13 GW of generation, the vast majority of which is served on a non-firm basis and may be interrupted during winter days as necessary in order to maintain system pressure for firm customers. LNG and CNG provide supplemental injections to the New

[27] Comments of Constellation Energy Generation, LLC, filed November 7, 2022 in FERC Docket AD22-9. See pages 23, 26.

[28] Winter 2024 Quarterly Markets Report By ISO New England's Internal Market Monitor, ISO New England Inc., May 31, 2024, page 26. The 560 GWh figure was added per Table 2-2. https://www.iso-ne.com/static-assets/documents/100011/2024-winter-quarterly-markets-report.pdf

York Facilities System to bolster pressures on peak days, but are reserved exclusively for gas utility sector demand.

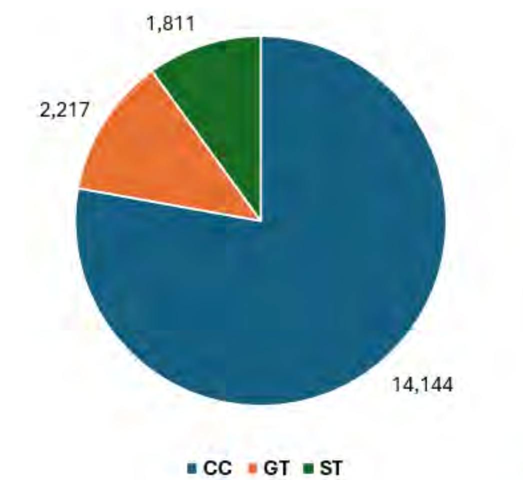
Utility sector gas demand on the New York Facilities System has increased significantly in recent years, largely due to incentives to switch from oil to gas heating systems. New York City's 2011 "Clean Heat Program" established a phase-out of the use of #4 and #6 fuel oil for heating. Per Con Edison's 2023 Long Term Plan: "Since NYC began phasing out the use of heavy heating oils in 2011 and the decade-long reduction in natural gas supply prices, which encouraged many customers to switch to firm natural gas service, Con Edison's firm peak demand has grown 41%."[29] The result of this growth is a much tighter margin between design day gas demand and available supply.

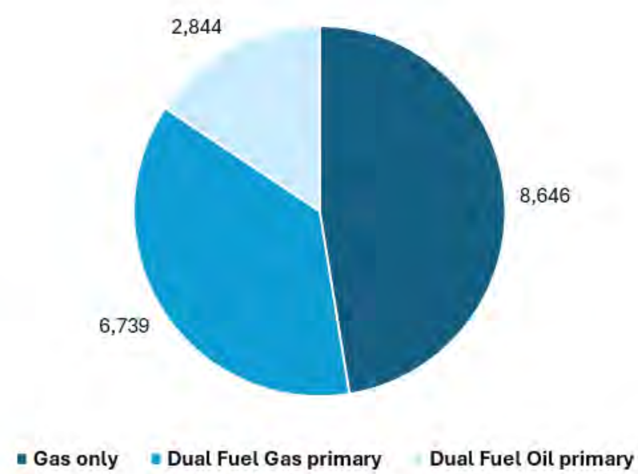
3 Gas-Fired Generation in the Study Region

In New England, gas-fired generators consist mainly of combined cycle, gas turbine, and steam turbine units. As shown in Figure 10, combined cycle units account for over 75% of the total capacity. Dual fuel units with gas as the primary fuel make up a much larger share than those with oil as primary. Over the long-term, a modest fleet retirement of around 690 MW is expected, mostly oil-primary dual fuel units.

As shown in Figure 11, the majority of gas-fired capacity in New York utilizes combined cycle technology. Oil-fired steam generation and combined cycle plants comprise 89% of the total thermal fleet. Similar to New England, dual fuel units represent a larger portion compared to the total gas-fired generation capacity. Over the long-term, approximately 1,255 MW of retirements are anticipated, including 795 MW from gas-only units and 460 MW from dual fuel units where natural gas is the primary fuel.

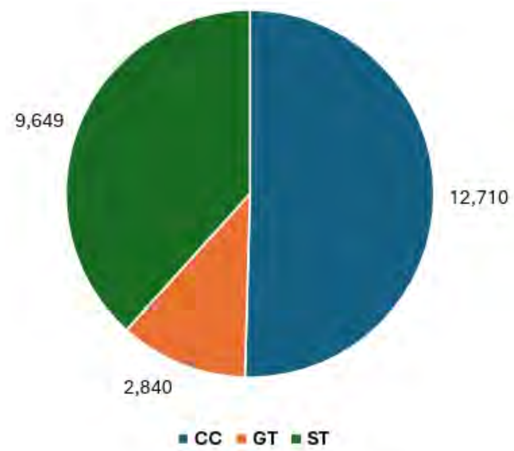
Figure 10: Current New England Gas-Fired Winter Capacity by Technology and Fuel Capability (MW)

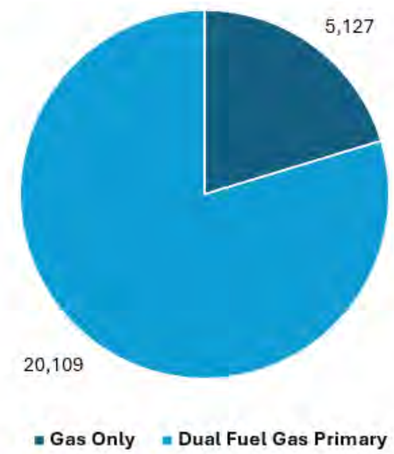




[29] See Consolidated Edison Company of New York, *"Gas System Long-Term Plan,"* 2023. Available at https://cdne-dcxprod-sitecore.azureedge.net/-/media/files/coned/documents/our-energy-future/our-energy-projects/gas-planning-process/final-long-term-plan.pdf

Figure 11: Current New York Gas-Fired Winter Capacity by Technology and Fuel Capability (MW)





3.1 Transportation Contracting

Interstate pipeline and storage companies offer two basic services: firm transportation and/or storage, and interruptible transportation and/or storage. Pipeline and storage infrastructure capacity is sized to meet the demand of firm customers, that is, those entitlement holders who pay the FERC-authorized cost of service rate to ensure guaranteed deliverability under all circumstances, except *force majeure*. *Force majeure* events are rare and include only the most severe or unusual operating conditions such as when mainline segments or compressor stations are not available, thereby reducing a pipeline's delivery capability. In December 2022, Winter Storm Elliott prompted *force majeures* across several interstate pipelines that serve New York and New England due to the loss of compressor stations and upstream supply. Loss of supply as a result of Winter Storm Elliott in December 2022 brought Con Edison to the brink of interrupting firm customers, which could have left over a million customers in Manhattan without heat for months in the winter.[30]

In exchange for this level of service reliability, firm customers pay a fixed monthly fee designed to reimburse the pipeline for its capital costs and fixed operating expenses. This fee is referred to as a reservation charge and is calculated to compensate the transporter for 100% of its fixed costs to render service irrespective of throughput levels. In contrast, interruptible service is available only when and if there is sufficient pipeline capacity after the needs of firm customers have been scheduled. Interruptible customers pay a variable rate proportional to actual usage. The volumetric rate paid by interruptible shippers for a lower quality of service in terms of delivery priority is negotiated by the pipeline and the shipper and varies by location across the Study Region.

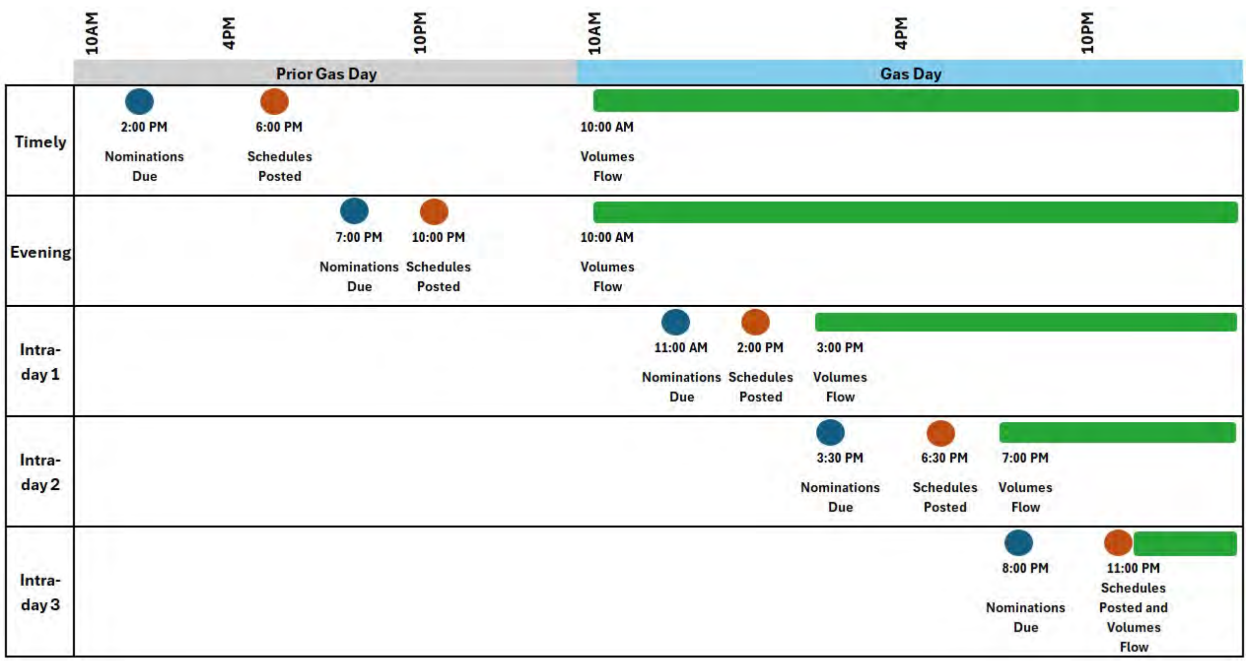
Within the broad categories of firm and interruptible transportation service, there is a range of service options offered by the different pipelines doing business in the Study Region. Shippers can also obtain capacity through the secondary capacity market. In the secondary capacity market, shippers holding unused primary firm capacity can release this capacity for sale to other shippers. Secondary firm capacity may have a priority of service lower than primary firm transportation service, but higher than interruptible service.

[30] See FERC, "FERC, NERC Release Final Report on Lessons from Winter Storm Elliott," (November 7, 2023). Available at https://www.ferc.gov/news-events/news/ferc-nerc-release-final-report-lessons-winter-storm-elliott

Natural gas is scheduled on a daily basis with the delivery period beginning and ending at 10:00 a.m. Eastern Time. Shippers communicate desired volumes, receipt points, delivery points, and relevant transportation contracts via nominations that are evaluated by the pipelines across five North American Energy Standards Board (NAESB) mandated daily deadlines. The "Timely" and "Evening" cycles are deadlines for gas nominated prior to the day of delivery. There are three "Intraday" cycles which shippers may nominate gas for delivery within the current day. The five NAESB cycles are detailed in Figure 12 below.

While pipelines are only required to administer the five NAESB nomination deadlines, some pipelines such as Algonquin and Tennessee provide additional cycles for greater scheduling flexibility. The additional scheduling flexibility offered by Algonquin and Tennessee provide the lion's share of the combined cycle and peaker fleet in New England with more opportunities to adjust intra-day gas scheduled volumes, thereby reducing a generator's adverse exposure to imbalance resolution costs.

Figure 12: Standard NAESB Nomination Cycles (Eastern Time)



Generators holding firm entitlements on pipelines serving New York and New England represent a small minority of total pipeline entitlements. Most primary firm entitlements are held directly by LDCs. The cost of holding such entitlements is recovered through state regulatory proceedings, which allows the LDC to recover the cost of pipeline entitlements regardless of utilization. Table 1 and Table 2 identify generators holding firm transportation back to a liquid supply point in New England and New York, respectively.[31]

[31] Summary only includes capacity that receipts at a liquid supply point. Firm transportation that only transports gas along a lateral to the generator is not included.

Table 1: New England Generators Holding Firm Transportation w/Receipt at Liquid Supply Points

Generator	Winter Capacity (MW)	Pipeline	Maximum Daily Quantity (Dth/d)	% of Winter Capacity covered by Contract's Maximum Daily Quantity
Lake Road	882	Algonquin	25,335	16%
Milford (Connecticut)	581	Iroquois	35,000	34%
Milford (Connecticut)	581	Tennessee	4,140	4%
Wallingford	349	Algonquin	10,000	11%

Table 2: New York Generators Holding Firm Transportation w/Receipts at Liquid Supply Points

Generator	Winter Capacity (MW)	Pipeline	Maximum Daily Quantity (Dth/d)	% of Winter Capacity covered by Contract's Maximum Daily Quantity
Sithe Independence	1,197	Empire	160,000	83%
Allegany Cogen	63	Eastern	6,100	51%
Brooklyn Navy Yard	295	Iroquois	25,548	61%
CPV Valley	740	Millennium	35,000	28%
Selkirk	442	Tennessee	11,000	13%

This tabulation is conservative with respect to the amount of firm delivery rights that generators have access to. Gas supply agreements where Firm Transportation (FT) entitlement remains in the hands of marketers, but generators receive firm supply, are not in the public domain.

3.2 Dual Fuel Capability

The majority of gas-fired generators operating in the Study Region do not have firm transportation entitlements on interstate pipelines, thereby exposing the generator to natural gas curtailments or interruptions when pipeline congestion materializes during the peak heating season: December, January, and February. Maintaining dual fuel capability, coupled with on-site liquid fuel storage and resupply arrangements, is a viable way to satisfy fuel assurance objectives for electric system reliability.

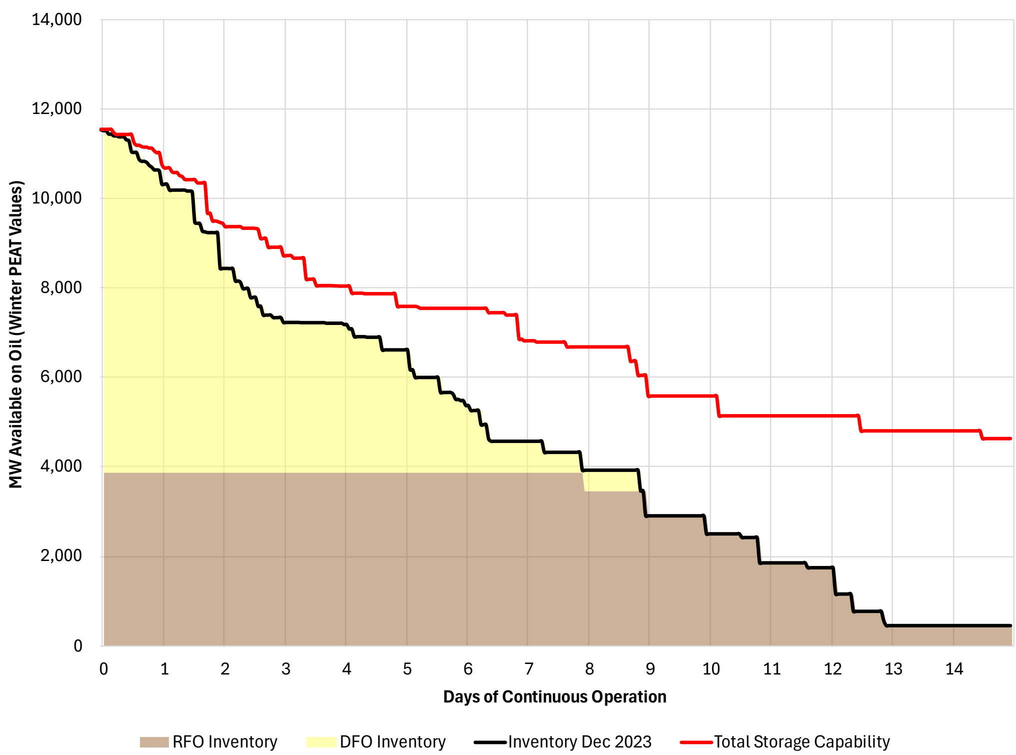
LAI developed a list of oil and dual fuel capable generators for the Study Region based on ISO planning materials. ISO-NE and NYISO also provided additional information on dual fuel capabilities, mostly sourced from operations surveys conducted on annual and weekly cycles. Most oil is delivered by barges and tank trucks, though some generators have pipeline connections to oil terminals. Trucks typically provide 7,500 to 10,500 gallons per delivery. Barge deliveries can amount to millions of gallons, depending on the local supply chain, receiving capability, and navigability of rivers and harbors.

3.2.1 ISO-NE

According to the near-term PEAT model database, there are about 9 GW of dual fuel capable units in ISO-NE. About one-third of this capacity is oil-primary that seldom runs on natural gas. In addition, ISO-NE has about 3,300 MW of oil-only generators. Large steam turbine units running on residual fuel oil make up about two-thirds of oil-only capacity. Gas turbine units make up the other third. RFO steam turbines comprise about 4 GW and have large tanks that allow for several weeks of continuous operation. Large RFO tankage capacity is an artifact of the steamers being initially designed in the 1960s and 1970s as intermediate cyclers, thereby requiring a ready source of fuel in inventory throughout the year. For well over twenty years, the RFO steamers throughout New England have been used sparingly, thereby idling or rendering obsolete a large portion of the existing RFO storage capacity as the carrying cost of storage inventory is prohibitively expensive for resources that have become *de facto* peakers.

This dynamic is illustrated via a reproduction of ISO-NE's oil depletion chart, which relies on OP-21 survey data.[32] The oil depletion chart represents a snapshot of oil inventory available at one point in time, and does not take into account that over time spent inventory may be replenished. Though inventory is plotted and measured in days of continuous operation for a level comparison, under typical operating conditions most generators do not run at full output over all hours of a day. Notably, both RFO and Distillate Fuel Oil (DFO) inventories have mostly been around 50% of aggregate storage capability heading into the heating season.[33]

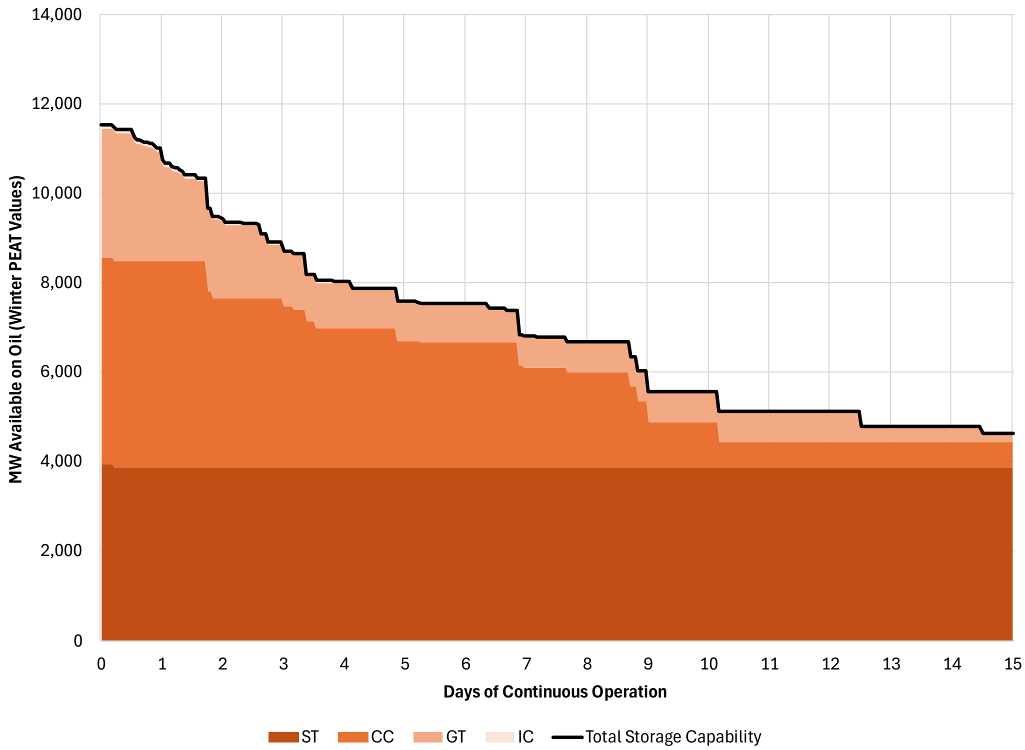
Figure 13: Oil Depletion Chart, ISO-NE Format



[32] See https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/oil-depletion-graphs

[33] Fuel Oil Charts, December 5, 2023, ISO-NE System Operations. See slides 4, 22, 23. https://www.iso-ne.com/static-assets/documents/100006/2023-12-05_oil_graphs.pdf

Figure 14: ISO-NE Oil Storage Depletion Chart by Technology, Near-Term Case



As shown in Figure 14, which provides a breakdown of total storage capacity by generator technology, most combined-cycle generators have enough storage capability to cover 3 days. About one-half can cover a full week. Gas Turbines (GTs) and Internal Combustion (ICs) have relatively small tanks – less than half can cover 3 days. ISO-NE's Cost of New Entry (CONE) reference unit has enough backup fuel to cover about 60 hours of continuous operation.[34] Most of the RFO steamers are located on New England's coastline and can therefore be replenished by barge. About half of ISO-NE's DFO storage capacity receives replenishment via pipeline or is supplied via pipeline by shared storage terminals "outside the fence." About one-fifth is resupplied via barge. The rest are supplied by truck. Larger combined-cycle plants (greater than 200 MW) have storage capacities that average about 6 million gallons and are typically restocked via pipeline or truck.[35] Some combined-cycle facilities have tanks with less than four days of storage, thereby requiring a near constant "train" of trucked oil replenishment to sustain operations during infrequent periods of extended operation.

By the mid and long-term forecast years, ISO-NE will lose some oil-fired capacity to attrition. About 1,300 MW of oil-fired generation (mostly RFO) is assumed to deactivate, 400 MW of which is dual fuel RFO steam turbine capacity. Figure 15 reports total storage capacity by generator technology taking into account these assumed deactivations.

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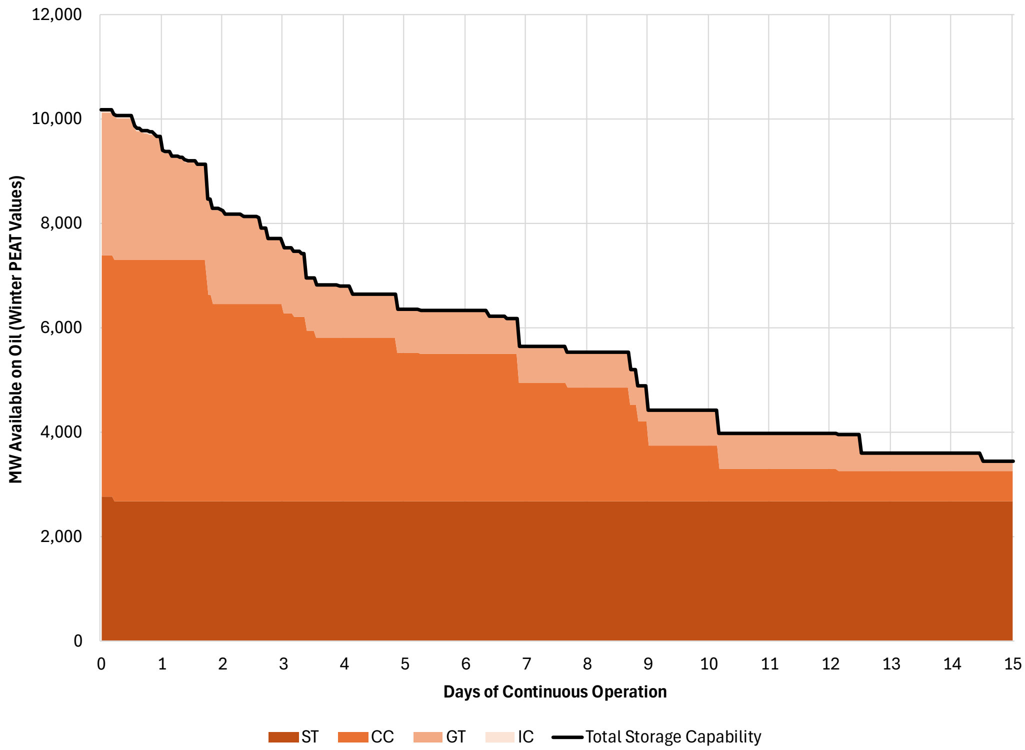
[34] CONE units are developed in engineering estimates to help set demand curve parameters for capacity auctions in ISO-NE and NYISO. They represent the cost of a new build resource that can provide new capacity to meet peak load.
[35] One combined-cycle facility is resupplied via barge.

Figure 15: ISO-NE Oil Storage Depletion Chart, Mid-Term Case



Most dual fuel generation in ISO-NE can “hot swap” from one fuel to another, meaning the dual fuel generation unit can continue operating and remain synced to the grid while switching fuels. Output for some units may fluctuate during switching, however. Additionally, RFO steam turbines and some combined-cycle turbines can co-fire fuel, though the exact tolerance of various fuel blends for sustained operation is unknown.

More than half of ISO-NE’s dual fuel fleet can switch from gas to oil within two hours, and most units can switch in four hours or less. Combined-cycle and RFO steam turbine plants tend to take longer to turn over. About 4,300 MW of ISO-NE’s dual fuel fleet, mostly made up of combined-cycle units, requires gas as the ignition fuel for start-up.

3.2.2 NYISO

NYISO has about 14.5 GW of dual fuel capacity per LAI’s review of the Aurora database, the Gold Book, and NYISO’s Generator Fuel and Emissions Reporting (GFER) survey data. All dual fuel capacity is listed as gas-primary in the Gold Book. There are also about 2,800 MW of oil-only capacity. In total, steam turbines comprise more than half of the 17.2 GW of oil-capable generation. Most of these steam turbines still run on RFO, though about 2,800 MW of in-city generation has switched or is about to switch to DFO per New York City legislation. Dual fuel requirements for generation served by the New York Facilities System also incent inventory top-ups prior to the winter season. Steam turbines tend to run more often in NYISO, particularly downstate, though they generally still act as peaking facilities.

Figure 16: NYISO Oil Depletion Chart

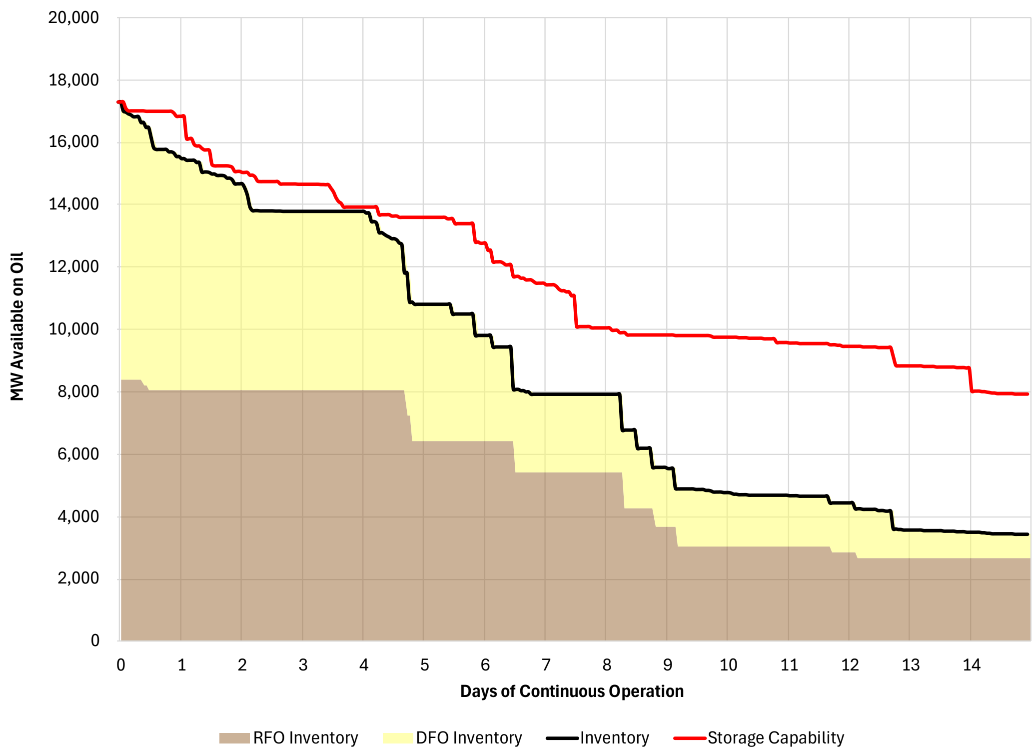
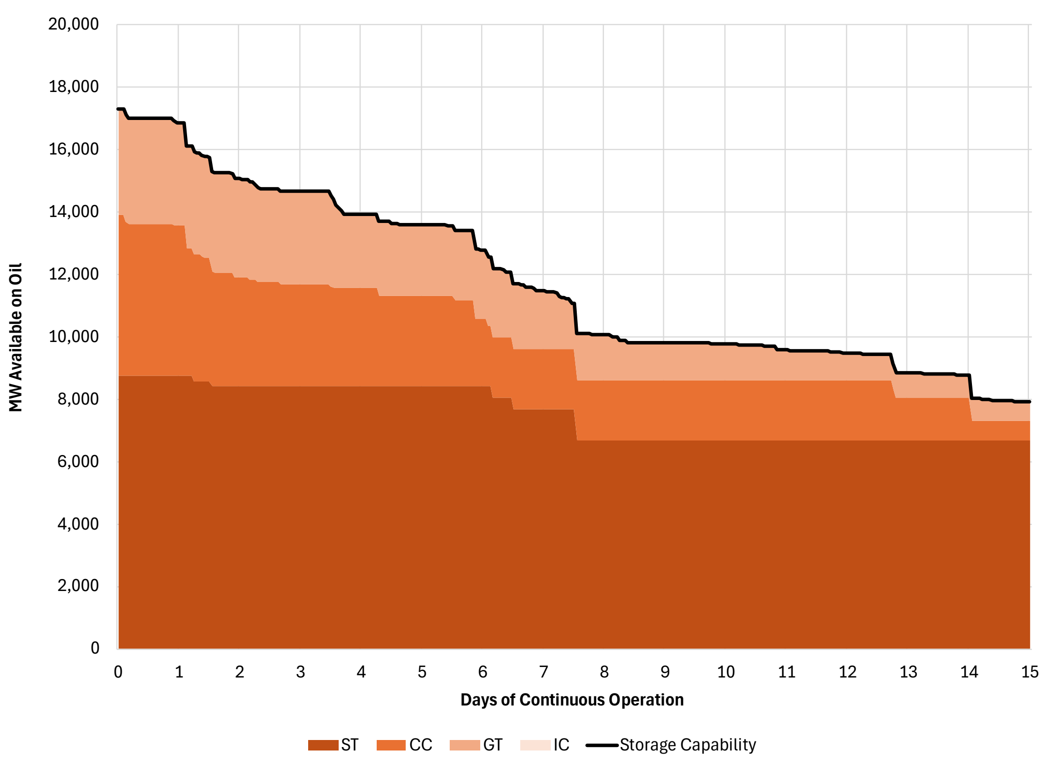
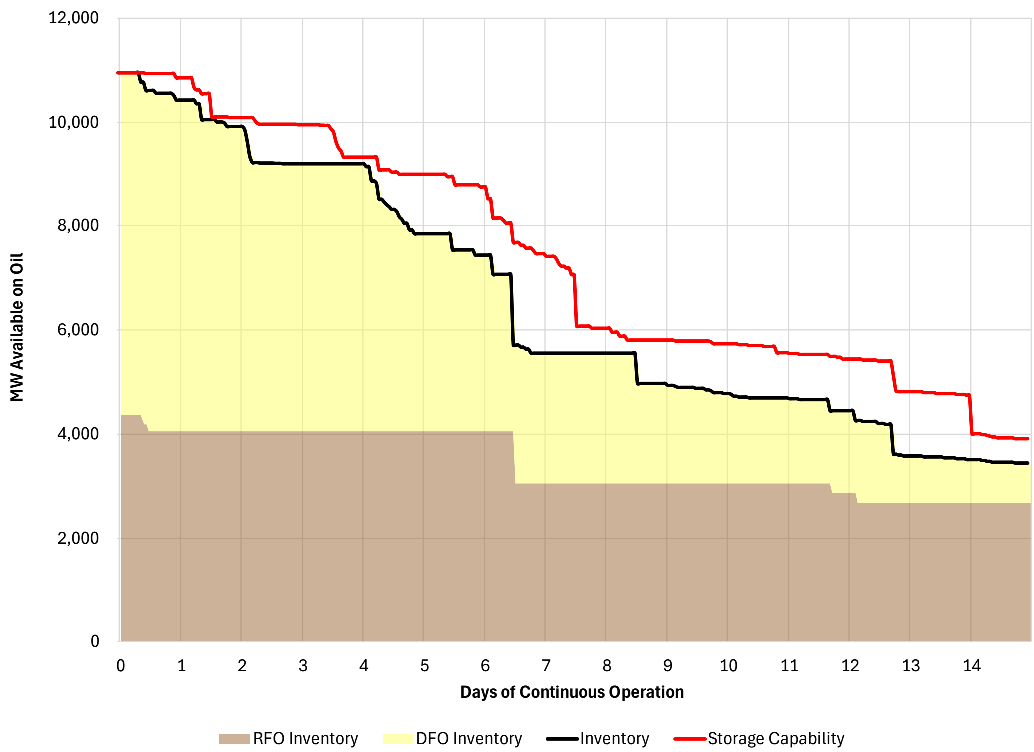


Figure 17: NYISO Oil Depletion Chart by Technology



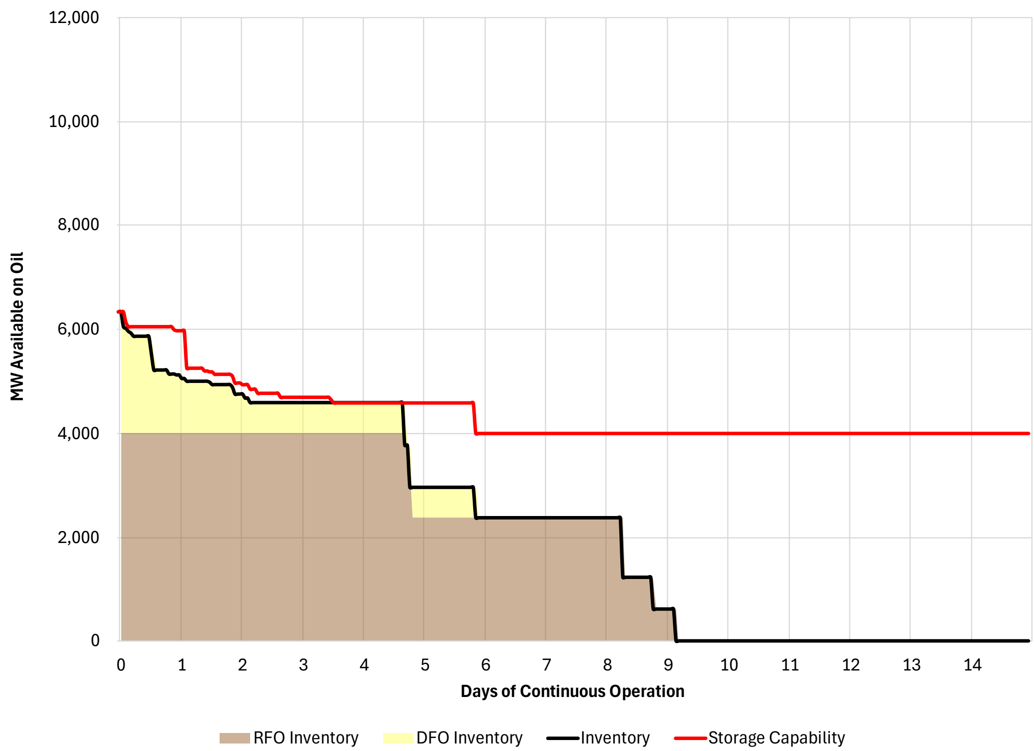
DFO units maintain a relatively high level of inventory, about 80% of stored fuel, mainly due to strong requirements for downstate inventory on the New York Facilities System. RFO units maintain about 50% of inventory heading into the winter. Most combined-cycle generators have storage capability to cover one or two days, and about half could cover a full week. GTs have relatively large tanks, more than half of NYISO's oil-capable GTs have storage for a week of operations. NYISO's CONE Study Simple Cycle Gas Turbine (SCGTs) are specified to have enough backup fuel to provide 96 hours of operation.[36] In the downstate region, almost all generation carries multiple days of liquid fuel. A large portion of the resources maintain storage inventory for seven days or more. Dual fuel generation upstate typically only carries about four days of inventory. The larger RFO resources upstate carry much less than their storage capacity. About 40% of the upstate RFO capacity only carries about four days of inventory, and the rest carry eight or nine days.

Figure 18: NYISO Downstate Oil Depletion Chart



[36] Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2025-2026 through 2028-2029 Capability Years, Analysis Group Inc. and 1898 & Co., October 2, 2024, page 34. https://www.nyiso.com/documents/20142/47366127/Analysis-Group-2025-2029-DCR-Final-Report-Updated.pdf

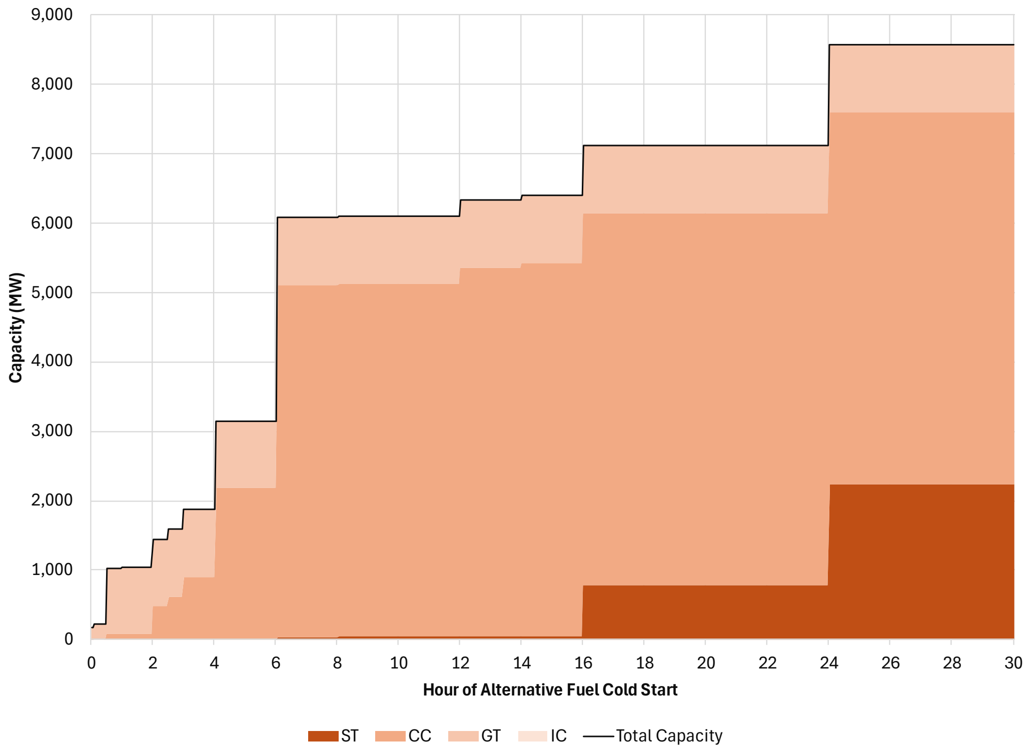
Figure 19: NYISO Upstate Oil Depletion Chart



About two-thirds of NYISO's oil-capable generation can be resupplied via barge. As with the balance of dual fuel and oil-fired capacity, the majority of this generation is on the New York Facilities System. One peaking facility on Long Island has an oil pipeline connection. The rest of NYISO's dual fuel generation is resupplied by truck. Like New England, several combined-cycle facilities can accommodate a sizeable "train" of trucks unloading over the day via multiple offload stations. However, several of these units note that they cannot replenish oil fast enough to support continuous operations.

GFER survey data for NYISO varies on the subject of dual fuel switching and hot-swapping. All dual fuel units represent that they can switch fuels in three hours or less. There is no differentiation between gas-to-oil and oil-to-gas switching in the posited survey question. Less than 1 GW of dual fuel capability must reduce generation to zero to switch fuels, but 4 GW must reduce generation to 10% of capacity or less during this interval. However, these resources are mostly combined-cycle generators that can complete a fuel switch in an hour or less. The majority of dual fuel generators can switch fuels at 80% or higher output. Steam turbines can co-fire oil and gas, and therefore often can stay online at a higher capability during a fuel switch. However, such units typically do not run on gas in the winter. About 4 GW of dual fuel capacity is auto-swap capable, with in-city generation (particularly combined-cycle units) making up more than half of this capacity.

Figure 20: NYISO Dual Fuel with Alternate Fuel Cold Start



About two-thirds of NYISO's dual fuel capacity can switch in an hour or less. Only steam turbines require more than two hours to switch. However, many of the units that take longer to switch can co-fire and therefore will reduce their gas demand during the switchover. Specific operational procedures are not available in the GFER survey data.

Many units in the NYISO fleet can start on oil. For larger combined cycle and steam turbine plants, however, that cold start process takes multiple hours and requires the better part of a day's notice for the older vintage steam turbines. Downstate IC peaking facilities can start on oil in an hour or less.

4 Gas Demand Forecast Development

As discussed in the General Framework, the hydraulic models must receive gas demand inputs at the meter level. This section describes how Residential/Commercial/Industrial (RCI) and electric sector gas demands were estimated for each forecast period.

4.1 Utility Sector Gas Demand Forecast

Meter-level gas demand forecasts for LDCs were derived from a combination of LDC design day demand forecasts, data from interstate pipeline FERC form 567 filings, and historical scheduled volume data. Regional LDC pipeline gas demand regression data were calculated from historical scheduled quantities on the interstate pipelines, and indexed to the total regional design day forecast (net on system injection capabilities such as LNG, Liquid Propane Gas (LPG), and CNG to account for demand growth. Daily estimates for regional utility sector demand for pipeline gas were calculated using weather assumptions and the regional demand regressions, and LDC-specific estimates were calculated based on the relative magnitudes of design day forecasts. The LDC demand estimates were then allocated across specific meters based on FERC form 567 coincident peak day throughputs provided by the interstate pipelines.[37]

4.1.1 Design Day Forecasts

Short-term (Winter 2024/25) and mid-term (Winter 2027/28) LDC design day forecasts were primarily driven by publicly available data in state filings. The majority of these design day forecasts include the short- and mid-term study periods (winters 2024/25 and 2027/28, respectively). Forecasts which did not extend through the mid-term study period were extrapolated through 2027/28 using the composite annual growth rate between 2024/25 and the latest available year. 2022/23 design day estimates for Maine LDCs (excluding Northern Utilities) and small municipal LDCs in Massachusetts and Connecticut, which do not file design day forecasts, were determined by their coincident peak day pipeline takes per the interstate pipelines' FERC form 567 throughput data. The design day estimates for these LDCs were then increased to winters 2024/25 and 2027/28 using the regional compound annual growth rate (CAGR) of utilities that did file design day forecasts. Long-Term (winter 2032/33) design day demand estimates were calculated relative to the mid-term estimates using the EIA's 2023 Annual Energy Outlook (AEO) for residential, commercial, and industrial growth rates for New England and the Mid-Atlantic from 2028 to 2033.[38] Table 3 details the total forecasted design day demand across the three study periods for New England and New York. Table 4 and Figure 21 describe the forecasted design day gas demand growth rates by region.

Table 3: LDC Total Design Day Demand in New England and New York

LDC Design Day Estimate (Bcf)		
Winter Period	**New England**	**New York**
2024/25	5.08	8.00
2027/28	5.24	8.16
2032/33	5.28	8.12

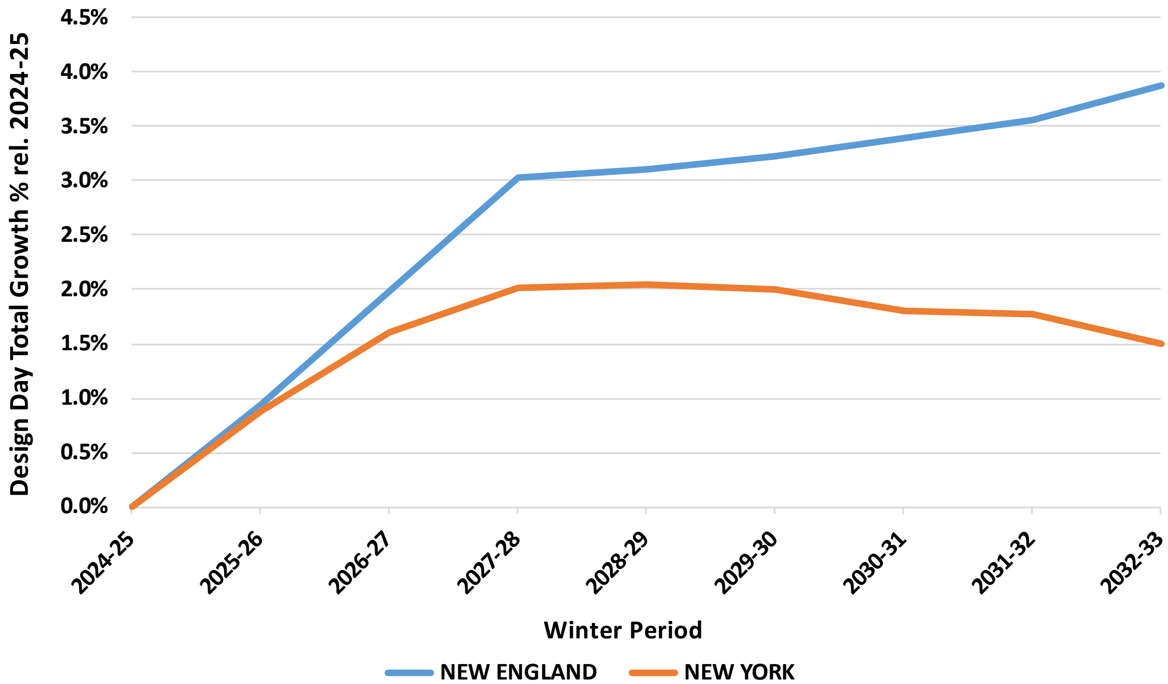
Table 4: LDC CAGRs by Region

	Winter 2024/25 to 2027/28 estimated LDC Design Day CAGR	Winter 2027/28 to 2032/33 estimated LDC Design Day CAGR
New England	1.00%	0.16%
Upstate New York	0.06%	0.10%
Downstate New York	1.04%	-0.22%

[37] Industrial customers who have a dedicated citygate were estimated based on their FERC 567 peak day throughput. No growth rate was assumed across the study periods for the large industrials. The demand from these industrial customers represent a very small percentage of peak day demand.

[38] Con Edison and Orange & Rockland shared their long-term design day forecast with LAI. Thus, the EIA AEO 2023 growth rate was not applied to these two LDCs.

Figure 21: LDC Design Day Demand Total Growth % rel. Winter 2024-25



4.1.2 Regional Utility Sector Demand Regressions

Regional regressions were calculated to estimate daily regional pipeline demand at a given HDD. The bases of these regressions were the historical scheduled quantities by meter for the period of 2014-2023 downloaded from the relevant interstate pipelines that deliver gas to LDCs in the Study Region. To separate LDC demand from scheduled quantities for generators on LDC distribution systems, generator data was downloaded for the corresponding period from the Environmental Protection Agency's (EPA's) Continuous Emission Monitoring Systems (CEMS). The hourly generator gas consumption was then converted into daily consumption (for gas days, not calendar days) and netted out of the scheduled quantities for the LDC that supplies the relevant generator.

The resulting scheduled quantities, net on-system generation, serve as a proxy for daily LDC pipeline gas demand. These quantities were summed by region and regressed against historical HDDs to create a formula for regional pipeline gas demand by HDD.[39] Due to a high penetration of on-system supply in New England, design day demand (net on-system injection capability) was used on especially cold modeled days.

4.1.3 Meter-Level Demand Estimation

The regional LDC pipeline gas demand estimates resulting from the regressions described in Section 4.1.2 were allocated to individual LDCs based on a given LDC's share of the total regional design day pipeline

[39] To account for demand growth and data gaps from certain pipelines, short-, medium-, and long-term multipliers were included such that design weather (as defined by the LDCs) resulted in the design day demand estimated in 4.1.1 (net any on-system supply used to meet design day demand).

demand. The resulting LDC-level estimates were then allocated to specific meters using percentages derived from the "coincident peak" meter throughput (net on-system generation) from the interstate pipelines' FERC Form 567s.

4.1.4 Intraday Gas Demand Profile

Lastly, daily meter-level LDC pipeline gas demand was converted to a series of hourly gas demands based on an intraday profile that was developed using typical meteorological year data sets prepared by the National Renewable Energy Laboratory for the Department of Energy's Office of Energy Efficiency and Renewable Energy, LAI's professional judgment and limited reporting of peak hour factors in LDC forecasts and other public sources.[40]

4.2 Electric Sector Gas Demand Forecast

LAI has actively coordinated with ISO-NE and NYISO to develop electric sector gas demand schedules. Given different modeling tools and milestone schedules, an integrated electric-side gas demand forecast was not produced. Nonetheless, LAI reviewed existing planning studies and modeling results to ensure that each Regional Transmission Organization (RTO) was not overly reliant on its neighbor to meet demand during stressed system conditions. In other words, interface flows between ISO-NE and NYISO were set so that imports shown in the electric sector modeling into ISO-NE from NYISO assumed in the ISO-NE modeling were consistent with exports from NYISO into ISO-NE in the NYISO modeling. Each forecast technique leans heavily on existing planning studies that have been shared with stakeholder committees. The analysis also leverages ISO-NE and NYISO's winter preparedness surveys.

Both ISO-NE and NYISO have developed strong energy adequacy and fuel security tools. This analysis is meant to supplement, not replace these tools. Fuel security and energy adequacy issues generally materialize over weeks, not days, as oil in New England, and LNG inventories are drawn. The electric sector demand forecast is not meant to replicate these studies, but rather to evaluate the ability of natural gas to serve load during peak hours and across the day, as firm LDC demand grows and the ramping needs from variable energy sources increase over the study period in general and 2032/33, in particular. Hence, LAI has remained focused on the ability of the pipelines serving gas-fired generation to "flex" during the morning and evening generator ramps. The hydraulic system modeling helps to augment the existing ISO-NE and NYISO energy adequacy tools by identifying how flexibly gas can be scheduled during varying operating conditions and system mixes. Consistent with study objectives, the hydraulic modeling also reveals system flexibility under various gas-side contingencies when disruptions or reductions in deliverability are postulated.

4.2.1 New England

For the purposes of this study ISO-NE provided output data from PEAT, which was recently developed for energy adequacy studies. LAI identified modifications to inputs used in prior energy adequacy studies in modeling requests for ISO-NE. PEAT is an extension of ISO-NE's 21-day Energy Assessment tool that is used as a part of ISO-NE's weekly operations reporting.[41] PEAT leverages the basics of the 21-day model,

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[40] The same intraday profile was applied to large industrial customers with dedicated citygates.

[41] More information on the 21-day Energy Assessment is found here: https://isonewswire.com/2022/12/19/iso-ne-rolls-out-enhancements-to-report-on-21-day-energy-supply-forecast/

but conducts probabilistic draws to examine different historical weather events and categorical branches of inputs affecting resource and energy availability, including:

- LNG inventory
- Oil inventory
- Price relationship between oil and gas (dispatch order)
- Levels of imports and generator forced outages

In ISO-NE's initial energy adequacy study, reported PEAT results reflected the distribution of outcomes for 720 simulations using various combinations of these inputs for each 21-day weather event and Constellation EMT/New England Clean Energy Connect (NECEC) scenario.[42] For purposes of the gas demand inputs for hydraulic modeling, a single simulation is used for each modeled event in order to provide a discrete gas burn schedule and control for variables that affect gas use, particularly the LNG inventory and dispatch order of oil and gas. ISO-NE's database included 3,744 events over 72 weather years (1950-2021) for selection. For ISO's initial energy adequacy studies using PEAT, only six winter events were selected for energy adequacy modeling in each forecast year.[43] In order to have stronger database options for load and renewable profiles available for parallel NYISO modeling as well as general ISO data sources, LAI focused on modeled events that occurred from 2000-2021. Therefore, the following 21-day events were used:

- **2004:** January 12, 2004 through February 2, 2004
- **2015:** February 14, 2015 through March 7, 2015

Outages and imports were also held constant at their average expected values, rather than subjecting outages and imports to probabilistic draws as was done in ISO-NE's energy adequacy modeling. Holding outages constant reduces potential arbitrary availability of large non-gas sources of energy (particularly nuclear power) and therefore avoids modeling a high-volatility swing in gas demand due to a single large outage. In terms of model functionality, PEAT's 21-day model has "perfect foresight" of what outages will be over the 21-day period. When a contingency that results in a large loss of supply happens in real time, control room operators rely on generation and other mitigation options that can perform with limited notice, which is not reflected in the 21-day model simulations. Therefore, for purposes of this study, each generator was derated at a constant unit-specific Equivalent Forced Outage Rate on Demand (EFORd) and imports were set at a constant value which varies by forecast year and hydraulic period.

PEAT's 21-day model includes limitations on natural gas burns. Reliability Committee materials note that "Available pipeline gas and LNG inventory are used to meet LDC consumption first… the LDC consumption forecast is determined by a temperature dependent function, developed by ICF".[44] ISO-NE utilizes

[42] Initial PEAT energy adequacy simulations were done for 2027 and 2032 winter and summer periods, with operations of large infrastructure such as Constellation EMT and New England Clean Energy Connect modeled as an input matrix of sensitivities. Additional information on the PEAT model is available here:
https://www.iso-ne.com/committees/key-projects/operational-impacts-of-extreme-weather-events
The final report for is available here:
https://www.iso-ne.com/static-assets/documents/100006/operational_impact_of_exteme_weather_events_final_report.pdf

[43] Some of the events selected for each forecast year overlap as well.

[44] See April 2023 presentation, slide 18.

temperature dependent functions from ICF to determine daily LDC demand and regas quantities from satellite facilities. The LDC demand is subtracted from pipeline sendout capability and LNG peak-shaving vaporization to determine residual gas made available for generation. Under colder weather, very little residual supply from pipelines is available for generators. Most gas available for generation in PEAT's 21-day model during cold weather comes from LNG terminals.

PEAT's 21-day model does have some modeling limitations worth noting. The model does not include intertemporal constraints on generator operations. There are no minimum operating periods, minimum loads, or efficiency penalties for running at part load. PEAT's 21-day model also faces limitations on how storage can be optimized to balance price taking energy with peak demand, and storage is instead set to a daily schedule. [45] Overall, these limitations generally balance against one another from an energy adequacy and dispatch simulation perspective, as some over-estimate the flexibility and efficiency of the ISO-NE fleet and others under-estimate those characteristics.

The following simulations were conducted using PEAT to populate the hydraulic model inputs:

Table 5: PEAT Modeling Runs Conducted

Run ID	Forecast Year	Weather Year	Sensitivity
1	Near-Term	2004	Base
2	Near-Term	2004	No EMT
3	Near-Term	2015	Base
4	Near-Term	2015	No EMT
5	Mid-Term	2004	Base
6	Mid-Term	2004	No EMT
7	Long-Term	2004	Base
8	Long-Term	2004	OSW Delay
9	Long-Term	2015	Base

Additional discussion of the forecast inputs is segmented by forecast year. A selection of modeling results is provided to identify overall trends and findings.

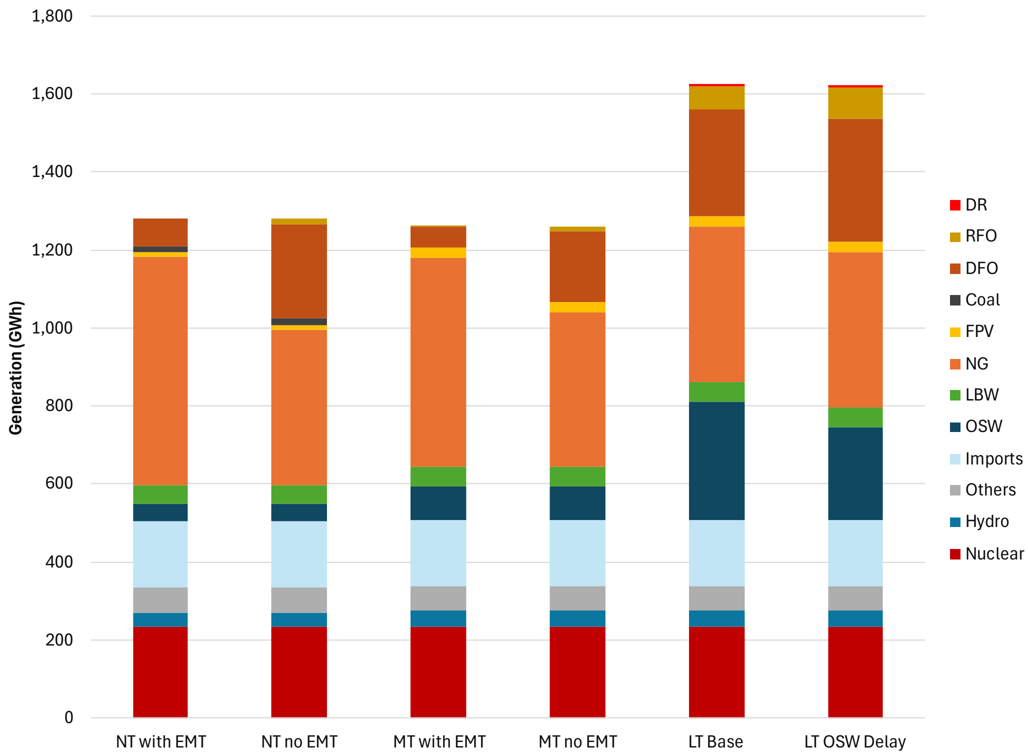
When Constellation EMT is available, it allows for incremental gas-fired generation to be scheduled to follow load during cold weather conditions. If Constellation EMT is not available, the 21-day model indicates that ISO-NE generators will lean more heavily on oil to meet electric load during cold weather conditions. In the near-term and mid-term cases in which Constellation EMT is assumed to be available, gas generation is about 600 GWh, accounting for approximately 45% of the total electric demand over the three-day period. In the near-term and mid-term cases without Constellation EMT, gas generation is reduced to about 400 GWh, accounting for approximately 31% of total electric demand over the three-day period, with the differential made up by incremental oil-fired generation. Similarly, in the long term, in which neither case includes Constellation EMT, gas generation is about 400 GWh, now amounting to 25% of total generation due to load growth.

Offshore wind generation increases significantly from the mid-term to the long-term, rising from about 90 GWh to 300 GWh. Oil generation operates less frequently in the near-term and medium-term when

[45] Future iterations of the model may redress some of these limitations.

Constellation EMT is assumed to be available, contributing around 5% of total generation, or about 70 GWh, and increases to about 400 GWh in the long-term to offset the loss in gas supply associated with the retirement of Constellation EMT. The total generation for three days rises from 1,260 GWh in the near-term and mid-term to 1,630 GWh in the long-term due to load growth, which is largely driven by electrification of heating and transportation.

Figure 22: ISO-NE Generation Mix During 3-Day Cold Period



About half of ISO-NE's gas-fired generating capacity, the lion's share of which are combined-cycle units, lack dual fuel capability. In the long-term modeled cases where only Repsol Saint John is available, the complement of gas-only generators cannot run at high load factors. While offshore wind partially mitigates this limitation, turbine cut-outs due to high wind speeds during the cold weather event reduce output during the evening of Day 1 and the morning of Day 2. Several large non-gas resources are assumed to retire by the mid-term and long-term forecast periods due to accepted de-list bids in the forward capacity auction. During the long-term modeled cases, ISO-NE can meet load but must resort to capacity deficiency actions, which are various measures that ISO-NE can take during emergency conditions to maintain the grid. Capacity deficiency actions are only taken during a few hours over the 3-day hydraulic period, as shown in Figure 26.

4.2.1.1 Near-Term Cases

LAI requested that ISO-NE use the currently operating resource mix for near-term case runs. Near-term cases utilize the load forecast from the 2022 Capacity, Energy, Loads, and Transmission (CELT) report, with behind-the-meter Photovoltaic (BTM PV) expectations sourced from the 2023 CELT forecast. While the 2022 CELT report is dated, the 2024 CELT report was not available when the near-term modeling request was fulfilled. Overall, the differences between the 2022, 2023, and 2024 CELT load forecasts with respect to the 2024/25 gross load winter peak are small.[46] Moreover, during the 2004 cold weather hydraulic period, gas burns fed into the hydraulic modeling are limited by LNG vaporization capacity and changes to demand are marginal. According to CELT 2024, New England (NE) gross winter peak is projected to grow from 21,984 MW in 2024/25 to 28,970 MW in 2033/34, with 94% of the increase driven by heating and transportation electrification.

The NECEC project is not assumed to be in service for Winter 2024/25.

A "with EMT" and "no EMT" nomenclature was originally used as a shorthand to describe daily LNG sendout capability with and without the Constellation EMT import facility. During the course of this analysis, the Massachusetts Department of Public Utilities approved long-term supply arrangements for Massachusetts LDCs that will likely keep Constellation EMT operating through another six heating seasons. In terms of availability of LNG infrastructure, the "with EMT" model runs have therefore effectively become the base case.[47] The cases, respectively, assume 1.2 Bcf/d or 0.8 Bcf/d of LNG that can be made available to generators, subject to additional constraints on LNG inventory enforced in the PEAT 21-day model.[48] The model does not consider any locational constraints on gas demand or supply within the regional pipeline system. Consequently, it makes no assumptions about which terminal infrastructure in New England is actually available. LAI's hydraulic model assigns LNG volumes to a specific terminal, e.g., all volumes are assigned to Repsol in the "no EMT" cases for delivery through Baileyville into M&N into Northern New England. In performing the sensitivity analysis, LAI has tested the substitutability of Repsol cargoes from New Brunswick for LNG cargoes from Constellation EMT. LAI's starting point is the coincident sendout of both Constellation EMT and Repsol Saint John, about 1.2 Bcf/d. In conducting this analysis, no incremental output from the Excelerate Northeast Gateway facility has been assumed.

Given that 2024/25 is the prompt winter, there is little uncertainty over other future resource additions or load changes that would be impactful. Therefore, no additional sensitivities were modeled.

As seen in Figure 23, in the near-term gas makes up a large share of baseload generation and load-following. Overall generation is higher than load when storage is charging. Storage discharge is shown below the load curve.[49] Gas constraints bind during all three days in the hydraulic period, with coal and oil resources making up the balance of energy needs not met by gas.

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[46] The 2024 Load Forecast estimated 22.4 GW of gross winter peak at 50/50 conditions and 23.2 GW at 90/10. The 2022 Load Forecast estimated 22.8 GW at 50/50 conditions and 23.5 GW at 90/10 conditions.

[47] MA DPU's approval of the four LDC contracts in Massachusetts does not obligate Constellation to maintain inventory for gas-fired generation. LAI notes that LNG cargoes are usually lined up many months before delivery, are usually not available on short notice through diversions or spot market cancellations, and may require tank inventory management action to make room for the next cargo.

[48] LAI does not make any assumptions about either generators' or marketers' willingness to enter into compensatory peak day call options to ensure that LNG will be scheduled and held in inventory to serve gas-fired generation. While the PEAT 21-day model does not specifically earmark gas supply from the pipeline, satellite peaking facilities, or LNG terminals to serve core demand or generators, the daily LNG terminal sendout was never less than the generator gas demand.

[49] Storage charging and discharging periods are set by a fixed schedule within PEAT. Storage cycling can be eliminated if the resultant energy loss causes a shortfall relative to load. Storage is also part of PEAT's reserves solution in many hours, as PEAT requires that generation that provides reserves has fuel available to back that commitment. In some cases, storage charging during the evening increases the work burden on fossil resources.

Figure 23: Hourly Generation and Load, 2004 Hydraulic Period, Near Term Base Case

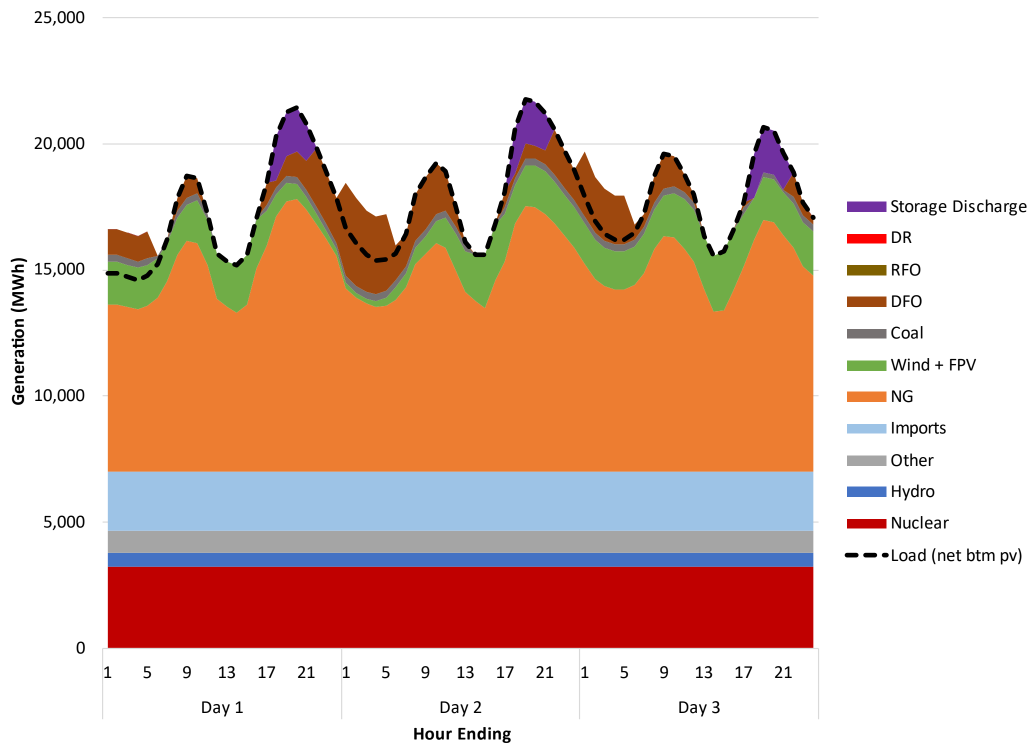
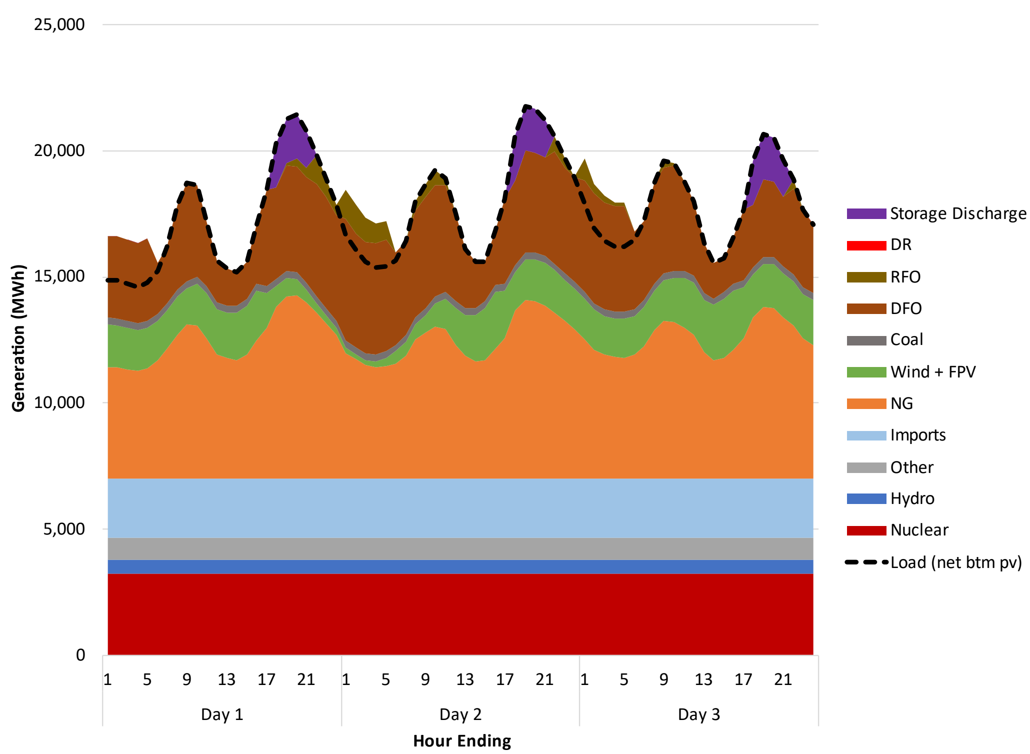


Figure 24: Hourly Generation and Load, 2004 Hydraulic Period, Near-Term No EMT Case



In the No EMT Case shown in Figure 24, less gas is available for power generation, and therefore more coal and oil resources are required to meet load. Coal and oil also take on more of the load-following burden as the gas profile becomes less variable.

4.2.1.2 Mid-Term Cases

ISO-NE completed two cases for mid-term modeling, a base case with EMT and a No EMT case under extreme 2004 weather.[50] LAI limited mid-term PEAT modeling to the 2004 weather event in order to prioritize review of both weather events in the long-term cases.

ISO-NE utilized the resource mix for Forward Capacity Auction (FCA) 18, which covers the resources cleared for the 2027/28 Capacity Commitment Period. Notable changes from the near-term include the addition of the Vineyard 1 and Revolution Wind projects, which represent about 1,500 MW of nameplate capacity, and about 1,800 MW of battery storage. FCA 18 market clearing also resulted in the retirement and de-listing of several coal and oil steam turbines. Mid-term cases utilize the load forecast from the 2022 CELT report, with BTM PV expectations sourced from the 2024 CELT forecast. As previously noted, the 2024 CELT forecast was completed prior to mid-term PEAT results furnished in May 2024 and the differences with respect to the mid-term load forecast are small.

The PEAT modeling ISO-NE conducted for its 2027/2032 study includes incremental imports from NECEC in the 21-day weather event. However, for purposes of this analysis imports are curtailed during stressed system conditions in the three-day hydraulic period. This assumption is consistent with the reliability considerations of ISO-NE's neighbors and the obligations that Hydro Quebec (HQ) has to Massachusetts and ISO-NE. NYISO does not assume that the Champlain Hudson Power Express will deliver power into New York in the Fuel and Energy Security Study.[51] In FCA 18, HQ only offered Summer Qualified Capacity. HQ's Power Purchase Agreement (PPAs) with the Massachusetts Electric Distribution Company (EDCs) do not indicate any obligation to provide capacity from NECEC.[52] In addition, Hydro Quebec is a winter-peaking system facing substantial increases in power demand that will require 8 GW to 9 GW of incremental capacity.[53] Even with ostensibly better conditions at present, HQ cut exports on Christmas Eve 2022, which contributed to a reserve shortage.[54]

[50] EMT had not yet received contract approval with modeling requests were made.

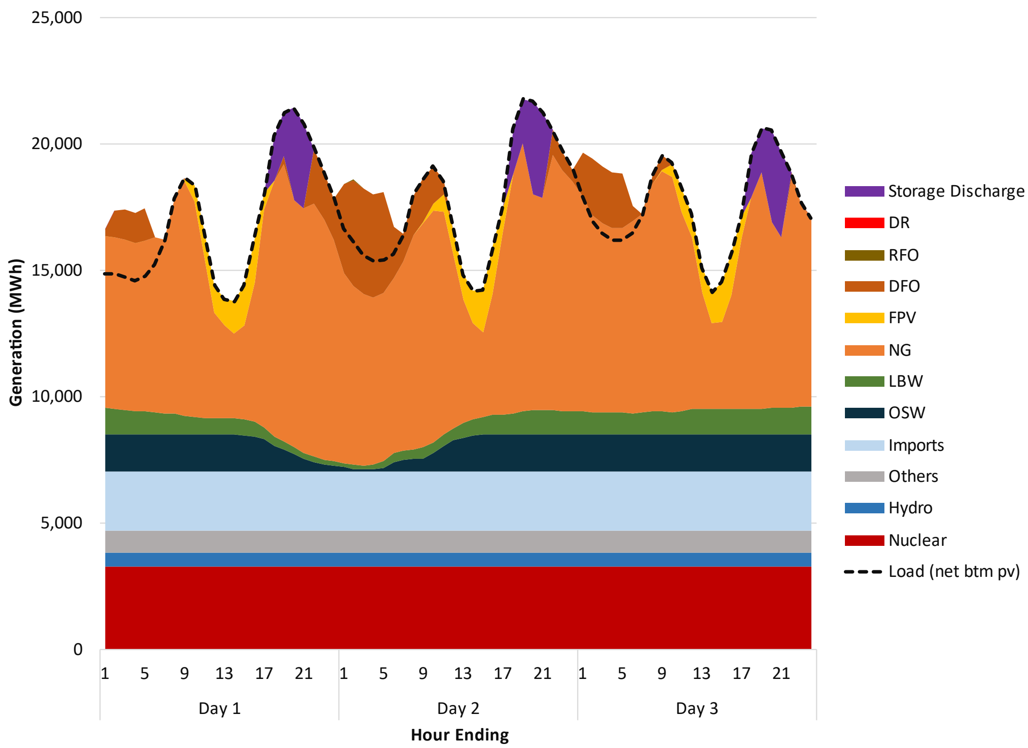
[51] Fuel and Energy Security In New York State: An Assessment of Winter Operational Risks for a Power System in Transition, Analysis Group, November 2023. See page 45: "The Champlain Hudson Power Express transmission project is not considered in the model; because Quebec is a winter peaking system we assume that no power would be delivered from Quebec during a cold winter period." https://www.nyiso.com/documents/20142/41258685/Analysis-Group-2023-Fuel-Security-Study-Final.pdf

[52] See section 7.5: "For the avoidance of doubt, but without limiting the condition set forth in Section 3.4(b)(ii), Seller shall have no obligation during the Services Term to pay for such Network Upgrades or to complete the Forward Capacity Auction qualification process."

[53] Towards a Decarbonized and Prosperous Québec: Action Plan 2035, Hydro Quebec, page 26. https://www.hydroquebec.com/data/a-propos/pdf/action-plan-2035.pdf

[54] ISO-NE maintains system reliability through generator outages, loss of imports on Christmas Eve, ISO NEWSWIRE, January 4, 2023. Accessed March 8, 2024. https://isonewswire.com/2023/01/04/iso-ne-maintains-system-reliability-through-generator-outages-loss-of-imports-on-christmas-eve/

Figure 25: Hourly Generation and Load, 2004 Cold Hydraulic Period, Mid Term Base Case



Notably, the three-day cold weather period includes high ramping needs from solar and wind cut-outs. Additional battery storage is available to meet the evening peak relative to the near-term case. Additional solar PV creates higher ramping need relative to the near-term cases.

4.2.1.3 Long-Term Cases

ISO-NE completed three modeling cases for the long-term forecast year:

- Base Case, 2004 weather event
- OSW Delay, 2004 weather event
- Base Case, 2015 weather event

Sendout capability from EMT is not part of the long-term case runs. The LDC contracts do not include a renewal mechanism as the Department of Public Utilities (DPU) placed emphasis on the LDCs finding alternatives to EMT once the contracts expire.[55] LAI requested that the resource mix use the FCA 18 cleared resource cohort as the starting point, with incremental adjustments for 4,000 MW of additional offshore wind and 1,500 MW of incremental battery storage. These adjustments reflect some offshore wind bids that were fielded under multiple states' Request for Proposal (RFPs) being in service by the

[55] LAI does not know how the LDCs will implement feasible alternatives to Constellation EMT when the peak day call option contracts expire in 2030. LAI has made the simplifying assumption that absent sufficient regulatory and commercial support, the import facility will not be available to serve LDCs after 2030, which means that the availability of nearby truck transported LNG to restock the satellite tanks will be lost. The feasibility of alternate trucking routes from Pennsylvania and Quebec is outside the scope of this inquiry. Substituting CNG for truck transported LNG appears infeasible in New England.

winter of 2032/33, and continued growth in battery storage due to states' goals and capacity needs. The 2024 CELT load forecast and CELT BTM solar forecast were used. ISO-NE agreed to model incremental 4-hour batteries with a different schedule than the existing pumped storage and 2-hour batteries from the mid-term model runs. This refinement scheduled charging during the afternoon when peak solar output occurs. Discharge remained set for the evening ramp. In the OSW Delay case, generic development of offshore wind was reduced from 4,000 MW to 2,800 MW, which better reflects procurement results that were not known at the time the modeling was requested.[56]

NECEC was treated the same way in the long-term modeling case as it was in the mid-term modeling cases, where imports were curtailed during the three-day cold weather hydraulic period.

Under the long-term results, load growth and the materially reduced daily LNG sendout capability due to the assumed closure of EMT create a tighter energy adequacy balance. While it may appear that ISO-NE has a generation shortfall relative to load in Figure 26, ISO-NE clarified that capacity deficiency procedures were necessary during the late night in Day 3 (January 14, 2004) and morning of Day 4 (January 15, 2004) of the modeled weather event. During this period, demand response (DR) resources are activated to help mitigate the event and storage cycling is reduced. In PEAT, capacity deficiency relief is modeled in two blocks of up to 500 MW each. One block represents relief from Operating Procedure No. 4 (OP4) actions 2-5 (net import relief)[57] and the other represents relief from OP4 actions 6-11 (voltage reduction, appeals for conservation).[58]

With these actions in place, there is no energy shortfall that occurs and ISO-NE can serve load. The loss of wind during this evening, as it contributes substantially to energy adequacy during the rest of the cold weather hydraulic period, is more impactful than in the mid-term cases. Gas-only capacity cannot respond to the shortfall event, and some oil-fired peaking resources with smaller tanks have presumably exhausted their inventory in previous hours. Gas generation over the event has a relatively flat profile, instead PEAT's 21-day model uses oil-fired generation to mitigate the loss of offshore wind.

Figure 27 shows the hourly load and generation during milder conditions in the 2015 hydraulic period. The gas ramping on day 2 is about 4.6 GW over 2 hours. Gas ramping needs are also somewhat mitigated from the introduction of 4-hour batteries scheduled to charge during the afternoon solar peak and discharge during the evening ramp. Wind cut-outs during the main ramping day increase the ramping need.

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[56] On September 6, 2024, Massachusetts and Rhode Island announced the selection of 2,878 MW of offshore wind. Massachusetts and Rhode Island Announce Largest Offshore Wind Selection in New England History, September 6, 2024 press release. Accessed September 9, 2024. https://www.mass.gov/news/massachusetts-and-rhode-island-announce-largest-offshore-wind-selection-in-new-england-history

Vineyard Wind 2 has since exited contract negotiations with Massachusetts, as Connecticut decided not to purchase a portion of the project output. This results in a loss of 800 MW from the September announcement.

Vineyard Offshore retreats from major wind project, Colin A. Young, State House News Service, December 20, 2024. https://www.wbur.org/news/2024/12/20/vineyard-offshore-retreats-from-major-wind-project

[57] Notably, the assumptions made about Canadian imports are lower than the capability of the ties between ISO-NE and Canada so therefore transmission headroom would be available to provide such relief.

[58] Establishment of the Regional Energy Shortfall Threshold (REST), Jinye Zhao and Mike Knowland, October 22, 2024 presentation to the New England Power Pool (NEPOOL) Reliability Committee. See slide 7. https://www.iso-ne.com/static-assets/documents/100016/regional_energy_shortfall_threshold_oct_rc.pdf

Figure 26: Hourly Generation and Load, 2004 Cold Hydraulic Period, Long-Term Offshore Wind Delay

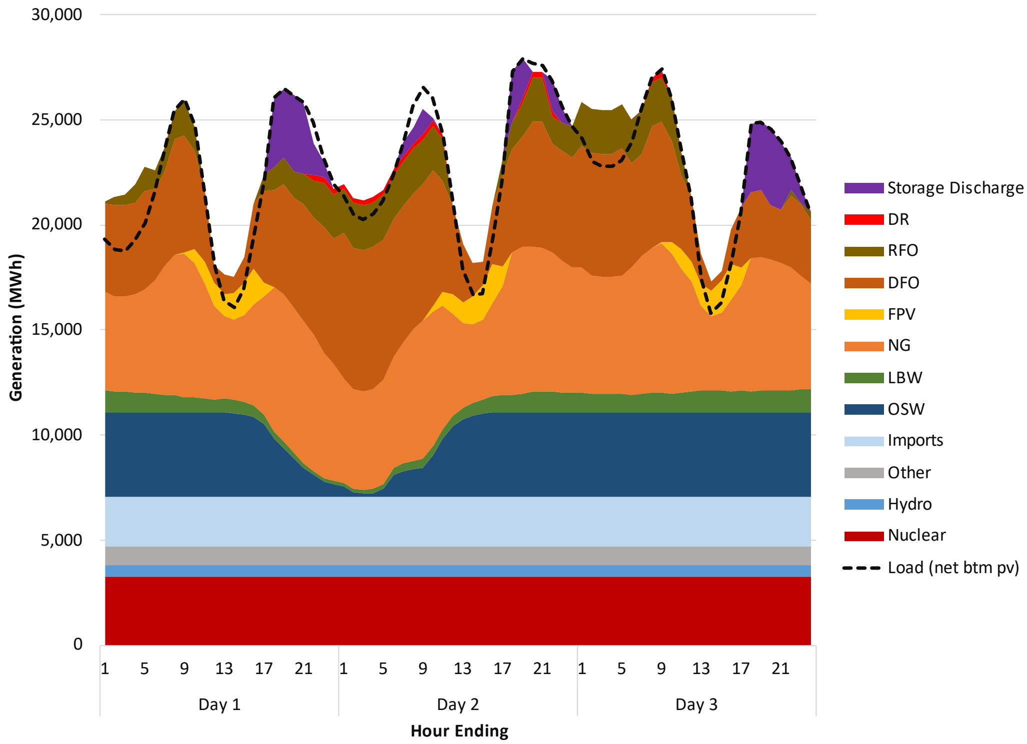
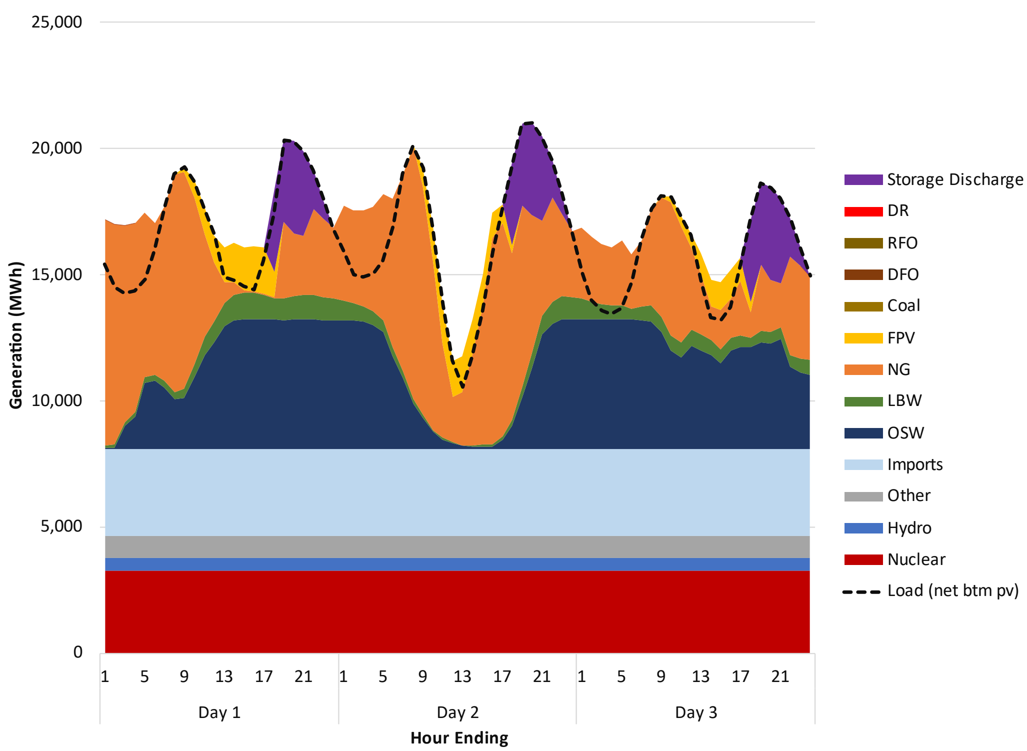


Figure 27: Hourly Generation and Load, 2015 Ramping Hydraulic Period, Long Term Base Case



4.2.2 New York

LAI conducted Aurora production cost modeling to develop hourly, unit-specific gas demand profiles. LAI used the default database provided by Energy Exemplar as a foundation. LAI augments Energy Exemplar's database with extensive customization based on public data sources, proprietary calculations, and professional judgment. The resource mix generally resembles the Contract Case from the 2023 System & Resource Outlook (2023 Outlook).[59] NYISO's modeling teams were occupied with the 2023 Outlook during NPCC study development and could not accommodate detailed modeling requests. However, NYISO materials released to the public over regular course of conduct for the stakeholder outreach over the Outlook, as well as focused requests from LAI, have augmented the study. NYISO staff provided ongoing input on shared global inputs as compared to NYISO's Outlook and daily gas constraints. The DNV GL renewable profile databases developed for the Outlook were particularly helpful to allow historical weather events to be modeled with weather coincident renewable output.[60] In particular, demand modeling has benefited from NYISO contributions of weather-normalized load and weather forecast data, as well as other NYISO sources for historical load that are available via the public web site.

Aurora represents an intermediate approach between the Multi-Area Production Simulation (MAPS) modeling conducted for the Outlook, and the model used as part of the Fuel and Energy Security Study (FES Study) that Analysis Group conducts on behalf of NYISO. The MAPS model that the NYISO maintains likely benefits from additional granularity of modeling inputs and NYISO's knowledge of system-wide generation and transmission, much of which is commercially sensitive. In contrast, the FES Study is a simplified dispatch model was created to evaluate energy adequacy over a multi-week period.[61] It is therefore like PEAT. MAPS modeling for the Outlook does not include any daily constraints on gas available for gas-fired generators after customers with firm transportation are served. The FES Study modeling specifies that "[t]he daily gas available for electrical generation is spread equally across all 24 hours in a day to produce an hourly amount of gas available to electric generators based on each day's average

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[59] The 2023 Outlook Report was published in July 2024. The report and many accompanying appendices are available here: https://www.nyiso.com/library#reports

[60] NYISO released zonal renewable output profiles as part of the Outlook data documentation on April 25, 2024. Materials were shared as part of the April 30, 2024 join Electric System Planning Working Group and Transmission Planning Advisory Subcommittee.
https://www.nyiso.com/documents/20142/44393357/04b_NYISO_Zonal_LBW_UPV_OSW_Shapes_2000-2023_For_Posting.xlsx
DNV also produced a set of offshore wind profiles for consolidated lease areas for the Installed Capacity (ICAP) Working Group in February 2023. Materials were posted February 2, 2023 for a February 7, 2023 meeting.
https://www.nyiso.com/documents/20142/36079056/4%20NYISO_OffshoreWind_Hourly_NetCapacityFactor.xlsx

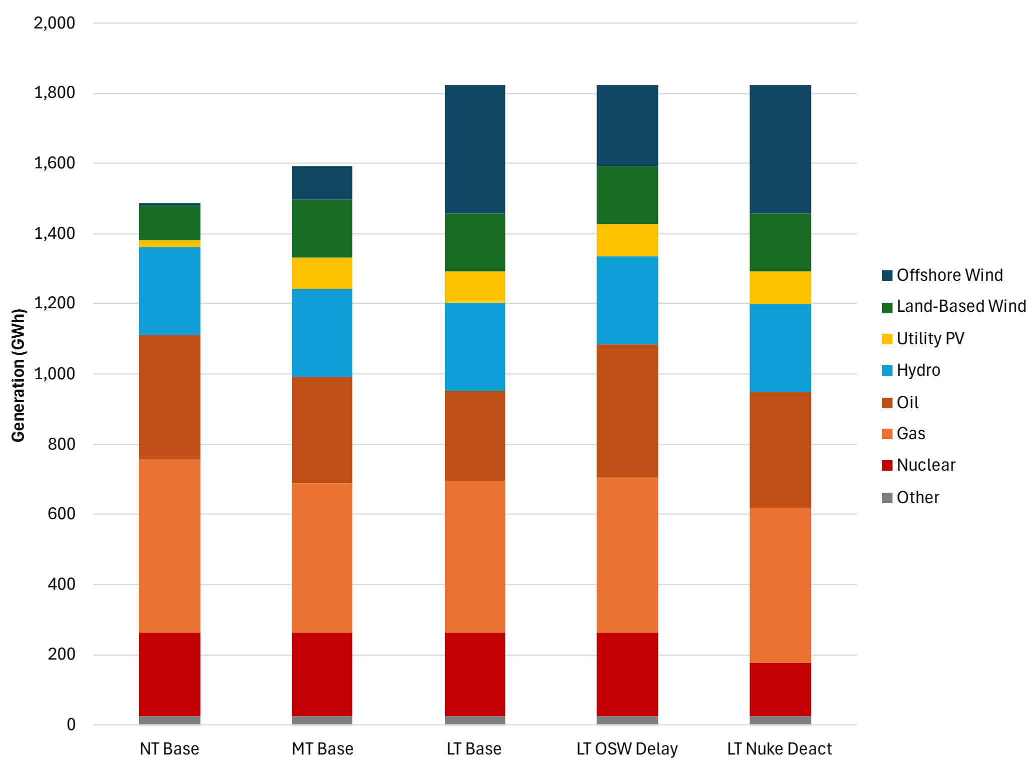
[61] Analysis Group notes that "The electric system model is designed to meet all load needs and reserve requirements using available resources given transmission and operational constraints." On the other hand, footnote states "Note, however, that the analysis is not a production cost model which takes prices into account for unit dispatch." Fuel and Energy Security In New York State: An Assessment of Winter Operational Risks for a Power System in Transition, Analysis Group November 2023. See page 47. https://www.nyiso.com/documents/20142/41258685/Analysis-Group-2023-Fuel-Security-Study-Final.pdf

temperature."[62] Aurora modeling conducted by LAI utilizes a similar daily gas constraint, but does not impose a uniform hourly constraint.[63]

In NYISO, some gas is available to electric generators during cold weather conditions but constraints on the New York Facilities System mean that gas-fired generation is further limited, particularly during the morning ramp for gas heating. Consistent with local reliability rules, typically only downstate units with automatic fuel swap capability or firm transport are operating on gas during cold weather. LAI's Aurora runs showed that load could be served by NYISO's generation fleet during cold weather conditions, but oil generation is required to follow load and supplant gas during cold weather.

As additional retirements occur and winter peak grows over the long term due to electrification, NYISO's fleet will have less capacity headroom to manage contingencies during cold weather conditions. On the other hand, renewable and electric storage build associated with New York State Energy Research and Development Authority (NYSERDA)'s various contracting initiatives helps to reduce reliance on fossil generation during cold weather. The buildout of renewables leads to as much as a 7.1 GW ramping need over two hours for gas-fired generation during milder system conditions.

Figure 28: NYISO Generation Mix During 3-Day Cold Period



[62] *Id*¸ page 39.

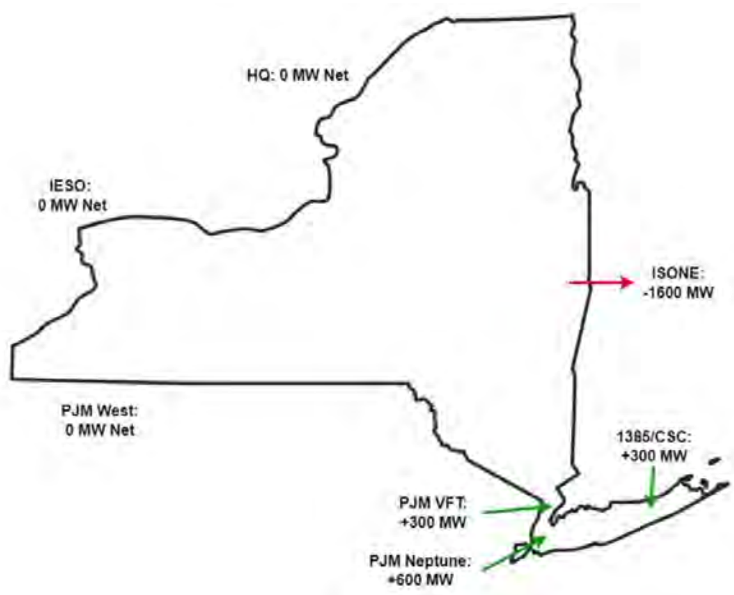
[63] Uniform daily constraints are referred to as "ratable takes" which hold the shipper's hourly takes to approximately 1/24th of the daily nominated quantity, or Maximum Daily Quantity (MDQ). Significant upward deviations from the ratable take exposes the generator to costly imbalance resolution penalties under each pipeline's tariff, the cost of which cannot usually be socialized under ISO-NE and NYISO's market rules.

LAI tested sensitivities that delayed onshore renewable buildout in the mid-term forecast period and offshore wind in the long-term forecast period. These sensitivities showed that NYISO would face a lower ramping burden if renewables are a less prominent part of the system mix. LAI also tested a nuclear deactivation case for the long-term forecast period, which causes oil to be even more leveraged in the modeling as gas-fired generation is already constrained during cold weather. Like ISO-NE, NYISO is reliant on aging steam turbines, many of which utilize RFO, during cold weather conditions. Most of these facilities have very low-capacity factors and require approximately 12 hours' notice to sync to the grid and be ready for dispatch. Additional discussion of model inputs and a survey of results is presented below.

4.2.2.1 Aurora Inputs

Aurora was utilized in a zonal configuration. Only the NYISO control area was modeled. Hence, imports from neighboring regions have been held constant, consistent with assumptions utilized in the 2023 Fuel and Energy Security Study. Using a zonal configuration in Aurora results in a loss in fidelity relative to the nodal MAPS solve utilized in the Outlook, but includes some additional granularity relative to the Fuel and Energy Security Study, which utilized an aggregated zonal transmission representation.[64] This zonal "pipe-and-bubble" configuration looks similar to the topologies utilized in the capacity expansion module of the Outlook.[65]

Figure 29: Fuel and Energy Security Study Interchange Assumptions[66]



[64] Fuel and Energy Security In New York State: An Assessment of Winter Operational Risks for a Power System in Transition, Analysis Group November 2023. See page 45, figure 13.
https://www.nyiso.com/documents/20142/41258685/Analysis-Group-2023-Fuel-Security-Study-Final.pdf

[65] 2023-2042 System & Resource Outlook Update, February 22, 2024 presentation to the NYISO Electric System Planning Working Group by Sarah Carkner, slide 23.
https://www.nyiso.com/documents/20142/43078666/03_02222024_2023-2042_System&Resource_Outlook_Update.pdf/4996d99f-7488-427a-59f5-9e5f1e6568cb

[66] *Id*, see page 46, figure 14.

The Aurora zonal topology includes all 11 NYISO zones (A-K). Limits are informed by various RTO studies, mainly the NYISO Outlook and Reliability Needs Assessment (RNA) studies. LAI received feedback from NYISO on appropriate transfer limit assumptions to use. Production cost modeling indicated that most of these interface limits do not bind often in the sampled period. Congestion is lower than shown in the Outlook or exhibited in recent history in large part due the assumption of zero net imports from Canada, which makes a number of exports to New York over the existing ties into the West (A) and North (D) transmission zones, which are upstream of the Central-East and UPNY-SENY interfaces.

LAI also includes the 1,300 MW Clean Path New York project in the transmission topology, consistent with the Contract Case of the Outlook.[67] The project is assumed to be in service by the mid-term case.

LAI utilized the 2024 Gold Book Baseline forecast as the starting point for baseline load, BTM solar nameplate, and other parameters.[68] NYISO has projected that the gross winter peak demand will increase from 24,739 MW in 2024/25 to 34,825 MW in 2033/34. This growth is primarily driven by heating and transportation electrification, which accounts for 71% of the increase. Large load projects contribute 19% to the growth, while econometric load growth represents 10% of the total increase. Additionally, NYISO provided historical hourly weather data (2004-2023) and 2024-2033 forecasts for weather and hourly zonal loads, including building electrification, behind-the-meter solar generation, and total demand. NYISO's base electric demand forecast is provided in a weather normalized format for a level comparison. Techniques were used to "de-normalize" NYISO's load forecast to reflect historical weather conditions. Hourly profiles for each zone were developed using NYISO's Integrated Real-Time Load as the base source.[69] The profiles were adjusted per estimated behind the meter output. The Mid-Term and Long-Term cases include a different load de-normalization technique to better capture the weather sensitivity of heating electrification.

Delivered fuel prices are forecasted for natural gas and oil. Weekly gas and oil prices for relevant indices were sourced from NYISO's Outlook forecast, which provides study years 2025, 2030, 2035, 2040, and 2042.[70] Years not provided in the Outlook were interpolated. Each gas-fueled generator was assigned a gas pricing index based on LAI mapping. Mapped indices which were not included in the Outlook were either assigned a locationally similar index that was included in the Outlook, or calculated using a scaling

[67] NYSERDA, and Clean Path NY terminated the project's REC contract. However, the project has not been cancelled and its future remains uncertain. See Utility Dive, "NYSERDA, Clean Path NY developers terminate contracts underpinning 175-mile transmission line," December 3, 2024, [NYSERDA, Clean Path NY developers terminate contracts underpinning 175-mile transmission line | Utility Dive]. The announcement of contract termination was made after the Aurora modeling was conducted, and given that transmission limits did not bind was unlikely to have a substantial effect on modeling.

[68] The Gold Book and associated data tables are available on NYISO's web site: https://www.nyiso.com/library#reports

[69] Notably, integrated real-time load coincident peak matched the 2004 coincident winter peak reported in the Gold Book.

[70] NYISO posted a draft data document on April 1, 2024 as part of materials for the April 4, 2024 joint Load Forecasting Task Force and Electric System Planning Group meeting. The forecast inputs, including fuel prices, are available here: https://www.nyiso.com/documents/20142/43890945/03a%20DRAFT%202023-2042%20System%20and%20Resource%20Outlook%20Data%20Document.xlsx

factor determined using S&P Market Intelligence (MI)/Amerex gas forward prices. LAI relied on the Outlook forecast for emissions allowance prices.

LAI estimated daily gas available to generators in NYISO in a similar manner as done in the FES Study.[71] LAI then estimated upstate and downstate LDC demand at a given temperature via analysis of daily scheduled gas data from interstate pipelines. LAI performed a quadratic regression on the scheduled gas data to create a formula for LDC gas demand as a function of temperature. Estimated LDC demand and exports to New England were netted out from imports from PJM and Ontario to approximate gas available to generators. The amount of gas available over time changes according to the LDCs' filed design day forecasts. The regressions used to estimate upstate and downstate LDC demand at a given HDD were estimated using daily scheduled gas quantity data from ten interstate pipelines that deliver natural gas in New York.[72] Zonal New York weather data was downloaded from NYISO's website.[73] Daily population-weighted HDD values for statewide New York, upstate New York, and downstate New York were calculated from the zonal NYISO data.

Each LDCs' daily demand was estimated by subtracting behind the citygate generator gas usage downloaded from the EPA's CEMS, similar to the adjustments conducted on the utility sector gas demand forecast. LDC daily demand was then aggregated into statewide, downstate, and upstate totals. LAI exercised professional judgment to exclude smaller utility gas usage where we observed significant data gaps on certain pipelines or scheduling patterns that did not make sense. In performing the regression analysis, LAI excluded about 16% of statewide design day pipeline demand, and later included a multiplier to add back omitted demand.

To evaluate accuracy, design day HDDs were input into the regression formulas to estimate statewide, downstate, and upstate design day LDC pipeline demand and compared to the LDCs' design day estimates. Design day HDDs and forecast demand were sourced from the LDCs' most recently available winter preparedness survey at the time of this analysis.[74] The HDDs were weighted proportionally to a given LDC's design day demand.[75]

[71] Fuel and Energy Security In New York State: An Assessment of Winter Operational Risks for a Power System in Transition, Analysis Group for NYISO, November 2023. See footnote 32, pg. 37.
https://www.nyiso.com/documents/20142/41258685/Analysis-Group-2023-Fuel-Security-Study-Final.pdf

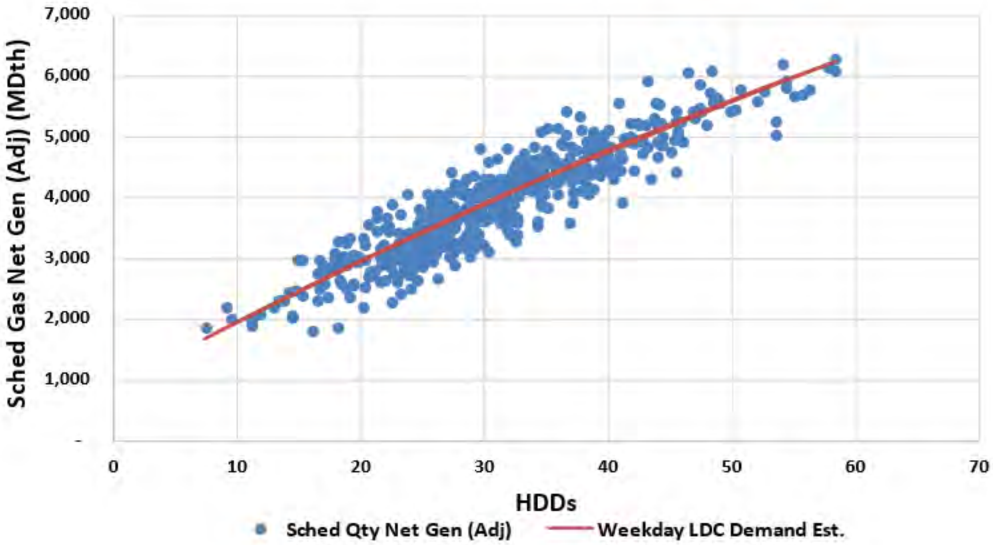
[72] The data was collected for winters 2017/18 through 2022/23. Scheduled quantities were downloaded using S&P's Capital IQ application for each meter for the ID3 cycle. For instances in which there was no data available for the ID3 cycle, ID2 data was used. This data source was also used by Analysis Group.

[73] Actual weather from NYISO's load forecast weather data was used. See https://www.nyiso.com/load-data

[74] See NY DPS Case 23-M-0230.

[75] This was done as a percentage of the total regional design day demand. The output from the regressions were compared to the LDCs' 2022/23 winter design day demand net any local gas injection capability (LNG, LPG, CNG, local Renewable Natural Gas (RNG), local landfill gas). The LDC design day estimates resulting from the regressions were adjusted up to account for the excluded LDCs.

Figure 30: New York Statewide Scheduled Gas Quantities Net Generation Regression



Some level of error is to be expected when using pipeline scheduled quantities as a proxy for LDC demand. On a given day, the sendout capability from a behind the citygate facility may differ from the nameplate capability. Scheduled flows do not yield visibility into on-system peaking sources of gas and some of these sources may be non-firm and not considered in design day. The usage of on-system resources may be informed by factors beyond daily temperature.[76]

To account for these uncertainties, the resulting design day estimates were trued up to the LDC design day forecast using an adjustment factor. When estimating LDC demand, a growth factor was applied consistent with the design day growth estimated by the LDCs in their winter preparedness filings.

[76] For example, an LDC may elect to use a dispatchable on-system resource to meet demand spikes on weekends with high weather variance (due to other supply options requiring ratable takes across weekend days). Additionally, scheduled quantities are only a proxy for actual metered flows, and LDCs over- or under-schedule deliveries for a variety of reasons throughout the winter. Lastly, the sample size for colder weather is very limited, and design weather is posited to represent extremely rare weather conditions as industry standard is often one in forty years.

Table 6: LDC Regression Parameters

Region	Total NY	DSNY	UPNY
Intercept (MDth)	745	541	428
HDD Coefficient (MDth)	93	77	9
HDD^2 Coefficient (MDth)	(0.27)	(0.33)	0.10
Design Day HDD	69	64	75
Excluded LDC Adj. Factor[77]	1.19	n/a	1.60
Estimated Design LDC Demand (MDth)	6,951	4,113	2,722
2022/23 LDC Filed Design Day Demand (Net On-Sys Gas) (MDth)	7,103	4,124	2,979
Design Day True-Up Adjustment Factor	1.020	1.002	1.095

Notably, the Analysis Group estimated that even on a design day, 263 to 537 MMcf would be available for electric generation.[78] LAI's design day availability estimates were slightly lower due to changes in the design day forecasts in more recent filings. As design day temperatures are very low, additional gas is available beyond these quantities in the modeled cases.

LAI did not make upward adjustments to the gas availability constraint to capture substitution of heating electrification for gas heating. As New York transitions to electrify heating end-uses, LAI expects oil heating and other non-gas fuels to be the most attractive options for replacement through 2032/33. Moreover, gas may still be needed as a supplemental heating source for many air source heat pump applications at very low temperatures.[79] NYISO has noted that the gas availability forecast may be somewhat aggressive with respect to the realities of the gas market. Available gas for generation may not be fungible across different pipeline locations, and given the relatively large requirements of some generators, quantities may not be able to be utilized in whole. Economics that promote fuel switching may also place oil in merit before the daily supply limitations of the gas system are reached.

LAI assumed that renewables and electric storage resources with an accepted class year interconnection cost allocation or a signed contract with NYSERDA will be commercialized. Given the evolution of NYSERDA's contracting efforts for offshore wind, the timing and resource-specific siting assumptions embedded in the Outlook, LAI Aurora inputs, and NYSERDA's current procurement status all differ. However, the overall energy contributions of renewables appear similar for the Aurora annualized results and 2023 Outlook Contract Case.

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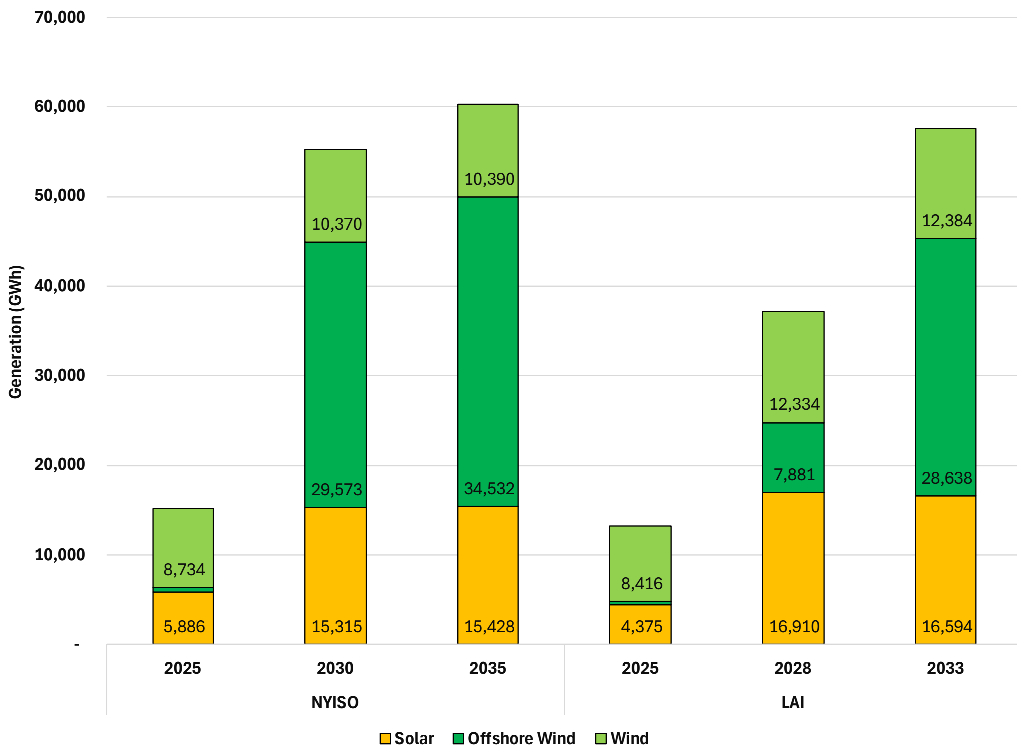
[77] This coefficient corrects for the faulty nomination data excluded from the regression calculation as discussed earlier in this section.

[78] See pages 96, 97.

[79] At low outdoor temperatures, air source heat pumps experience decreased efficiency and heating capacity, necessitating supplemental heating sources to maintain adequate indoor temperatures and meet heating loads. Heat Pump Assessment Study – an Electric Power Research Institute (EPRI) Report NYISO published December 19, 2022. See Page 4. https://www.nyiso.com/documents/20142/35104194/2022%20LFTF%20Dec%2019%20-%20EPRI%20Heat%20Pump%20Assessment%20Study.pdf/171575b4-3329-17b1-feb2-07dea7770092

Figure 31: Energy Comparison, Outlook Contract Case and LAI Aurora[80]



Notably, NYSERDA has identified substantial additional generation necessary to meet the 70% by 2030 Clean Energy Standard that would require extremely aggressive annual procurement quantities under a 30% attrition rate. Given the substantial attrition and delays to existing Tier 1 and offshore wind projects, LAI believes that maintaining a more modest buildout for the long-term cases is both realistic and preferable.

Retirements are sourced from NYISO deactivation notices and 2024 Gold Book. Consistent with the 2023 Outlook, nuclear units are not assumed to retire during the planning horizon. LAI assumes that the New York Power Authority's (NYPA's) small gas turbine phase-out will be effective at the end of 2030 for the units identified in NYISO's Comprehensive Reliability Plan.[81] Additionally, LAI assumed that a steam turbine unit would be retired by Long Island Power Authority (LIPA) pursuant to guidance in the 2023 Integrated Resource Plan (IRP) Summary Guide.[82]

LAI used the same weather events described for ISO-NE, which were available in the PEAT model. The 2004 event is present in the FES Study and includes a 14-day extreme weather event and the second

[80] NYISO values from Table G-6 of Appendix G: Production Cost Model Results: 2023-2042 System & Resource Outlook, NYISO published July 22, 2024.
https://www.nyiso.com/documents/20142/46037616/Appendix-G-Production-Cost-Model-Results.pdf

[81] 2023-2032 Comprehensive Reliability Plan, A Report from the New York Independent System Operator, November 28, 2023. See page 24.
https://www.nyiso.com/documents/20142/2248481/2023-2032-Comprehensive-Reliability-Plan.pdf

[82] Summary Guide: 2023 Integrated Resource Plan, Long Island Power Authority, updated March 2024. See pages 35-36. The Northport 3 unit was identified via NYISO feedback.
https://www.flipsnack.com/lipower/2023-irp-summary-guide/download-pdf.html

coldest three-day period in that study, which considered NYISO weather and hourly load data from 1993 to 2023. The FES study noted a 14-day event in February 2015 that had some overlap with ISO-NE's 21-day period. As in ISO-NE, LAI found that the 2004 weather event contains better hydraulic periods to sample for extreme cold weather, and the 2015 weather event contains better hydraulic periods to sample for milder conditions with large ramping needs in the projected gas schedule.

Table 7: Aurora Modeling Runs Conducted

Run ID	Forecast Year	Weather Year	Sensitivity
1	Near-Term	2004	Base
2	Mid-Term	2004	Base
3	Mid-Term	2015	Base
4	Mid-Term	2015	LBR Delay
5	Long-Term	2004	Base
6	Long-Term	2015	Base
7	Long-Term	2004	OSW Delay
8	Long-Term	2015	OSW Delay
9	Long-Term	2004	Nuke Outage
10	Long-Term	2015	Nuke Outage

Additional discussion of the forecast inputs and sensitivities is segmented by forecast period below.

4.2.2.2 Near-Term Case

There are limited ways that the current system mix can change in the prompt winter. Hence, no sensitivities were run. Ramping needs are less pronounced in the near-term relative to future years with solar and wind development, hence only the 2004 weather year was run.

Aurora inputs included differences in solar capacity, (about 1,900 MW as opposed to 300 MW), and battery storage capacity (430 MW compared to 20 MW), which are higher than the Gold Book values. Notably, the Outlook contract case had additional solar and battery development, even in the near-term, which somewhat narrows this gap. Many projects are in advanced stages of development in the interconnection queue.

During the 2004 Cold Weather Hydraulic Event, the daily gas constraint binds on all three days. Oil generation represents about 40% of fossil fueled output during the event. Hourly gas generation is relatively steady, though some large ebbs in output occur during the morning ramp for gas LDCs. Overall, gas is profiled across the day to respond to the evening peak, but does not ramp up during the smaller morning peak.

Figure 32: Hourly NYISO Generation by Fuel Type, Near-Term 2004 Cold Event

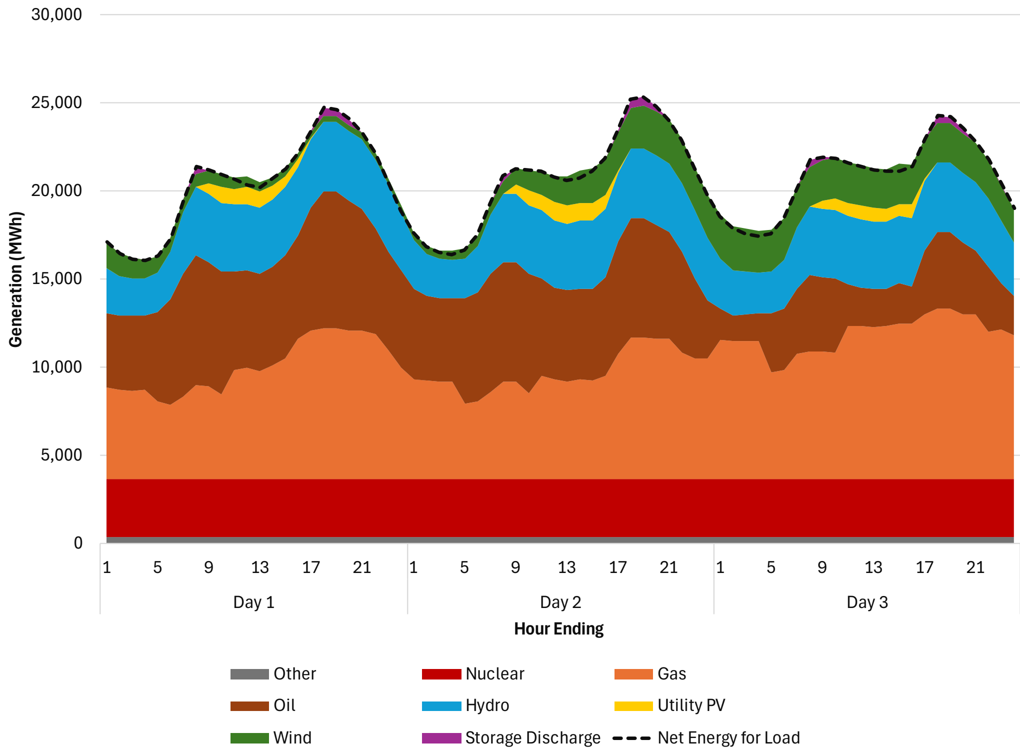
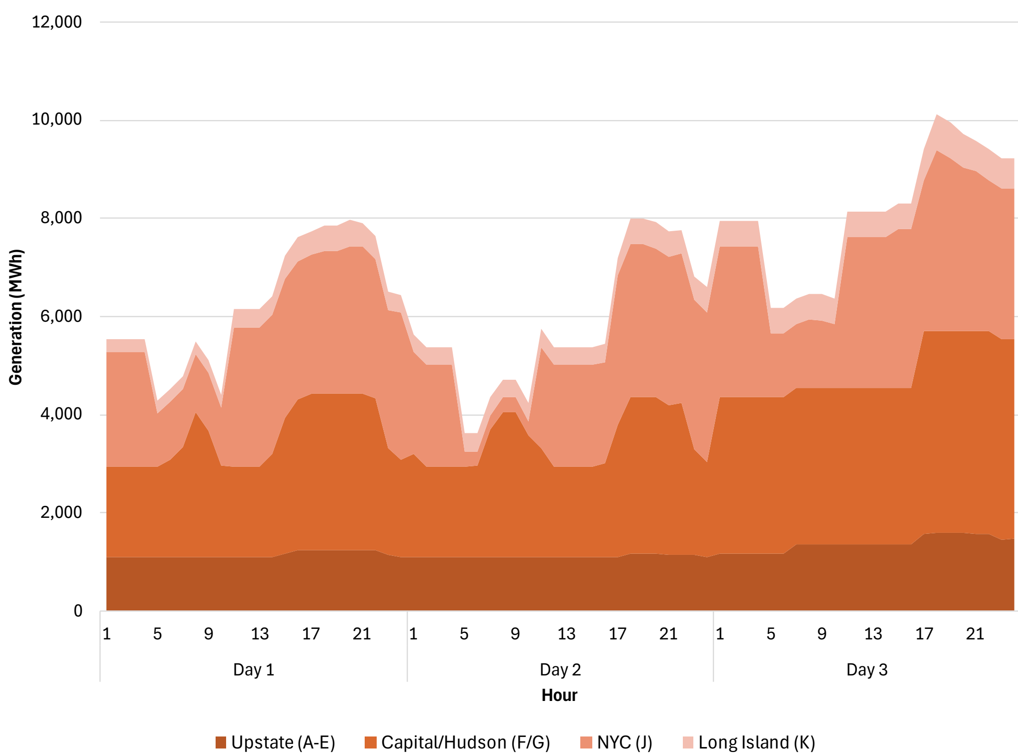


Figure 33: Hourly NYISO Gas Generation, Near-Term 2004 Cold Weather Event

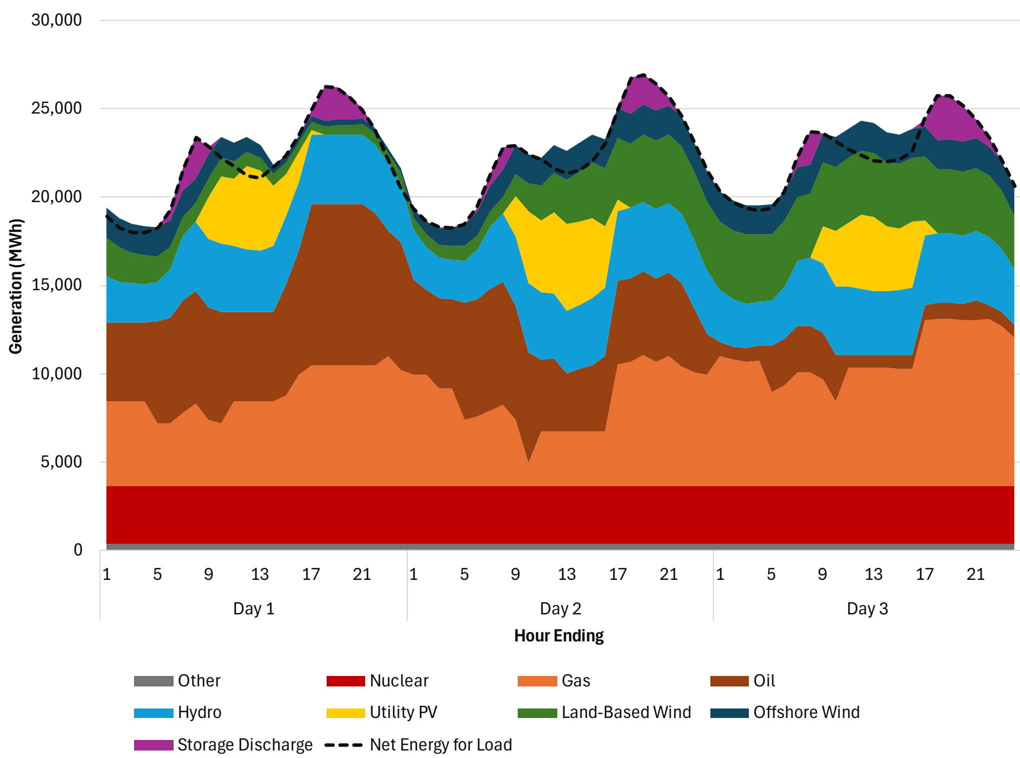


Combined-cycle generation makes up the lion's share of gas burn, though some peaking capacity is utilized in small quantities. Several combined-cycle generators in New York City are heavily utilized, but generators supplied by Con Edison under an interruptible service rate are curtailed at forecasted low temperatures during peak heating hours to ensure firm rate customer reliability. Oil burn is mostly comprised of steam turbines on residual fuel oil upstate and on Long Island along with combined-cycle plants running on backup fuel. As with gas, some peaking capacity is utilized in small quantities. Facilities in the Capital/Hudson region carry most of the load-following burden.

4.2.2.3 Mid-Term Cases

Wind, solar, and battery resources represent a larger portion of NYISO's capacity and generation mix in the mid-term case. Tier 1 land-based renewables (LBR) and the first of NYSERDA's contracted offshore wind developments make up the bulk of renewables added.[83] Conversely, fossil fuels make up a smaller portion of generation with more price-taking clean energy available. Battery storage helps mitigate peak demand; despite higher peaks, clean energy and fossil generation peaks around 25 GW as found in the near-term case runs. Notably, the January 14 day in the event shows more fossil burn than the peak day on January 15 due to high winds which cause offshore wind turbine generator cut-outs and low output during the afternoon and evening.

Figure 34: Hourly NYISO Generation by Fuel Type, Mid-Term 2004 Cold Event

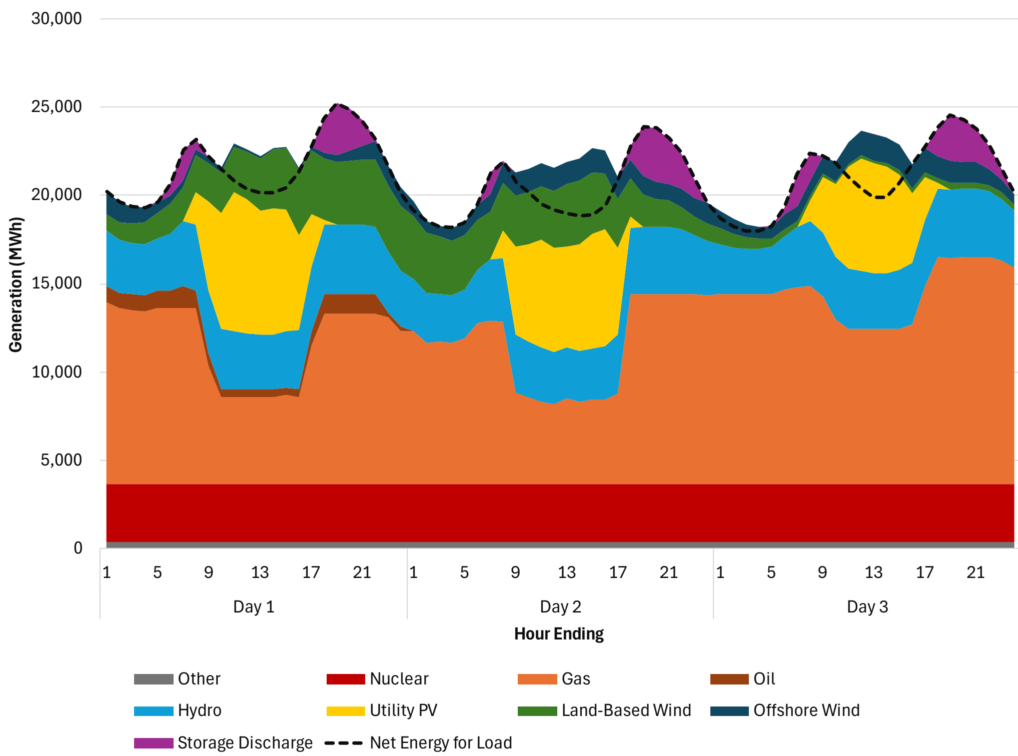


Given the large quantities of renewable energy penetration posited in the mid-term case, LAI also tested hydraulic events during milder conditions from the 2015 weather year. The 2015 weather year was utilized

[83] NYSERDA's 2023 solicitation resulted in the re-contracting of Empire Wind 1 and Sunrise Wind, which previously were awarded in 2019 under NYSERDA's first solicitation. Information on NYSERDA's offshore wind solicitations can be found here: https://www.nyserda.ny.gov/All-Programs/Offshore-Wind/Focus-Areas/Offshore-Wind-Solicitations

since it sampled February and March, where solar output is generally higher than in January. The steepest ramping events are found in that dispatch. During the ramping event, temperatures are milder so the daily gas constraint does not bind across two of three days, including the principal day of interest. The ramping event resulted in a 6.4 GW increase in gas generation over a two-hour period during a daily average temperature of 27°F in Day 2. Under these weather conditions, gas generators connected to the New York Facilities System could be subject to ratable take provisions under operational flow orders (OFOs) that clamp down on hourly excursions. However, in the modeled scenarios most of the ramping capability NYISO schedules is provided by direct connected gas-fired generators upstate, which are less likely to face these restrictions. The ramping need is largely due to increased penetration of solar power and the need for replacement generation as the sun sets. Historical data from EIA 930 indicates that winter gas ramping during the past six winters was lower than this projected level. On January 17, 2019, under similar weather conditions to the 2015 hydraulic period, gas ramping amounted to 2.6 GW over two hours to 3.8 GW over four hours. The forecasted ramping demand is effectively a doubling of ramping needs historically provided by oil and gas.

Figure 35: Hourly NYISO Generation by Fuel Type, Mid-Term 2015 Ramping Event



A land-based renewables delay sensitivity was also conducted. Given supply chain issues, contracting revisions with NYSERDA, and other development obstacles, large portions of Tier 1 projects under development are at risk of cancellation or delay. This sensitivity reduced the land-based wind and solar projects assumed to be in service in 2028 by about 5 GW. As a result, the ramping burden on gas plants is reduced by about 25%, though more fossil (and primarily gas) generation is needed to serve load overall. The renewables delay sensitivity was only conducted for the 2015 ramping period, as the gas constraint binds in the 2004 cold weather period and therefore gas demand and dispatch would be minimally affected.

4.2.2.4 *Long-Term Cases*

Load growth and offshore wind development represent the main differences between the mid-term case and the long-term case. Per the Gold Book, winter peak grows substantially with additional electrification. Offshore wind capacity is assumed to increase to about 7 GW by the 2032/33 winter.[84] Additionally, some retirements of the NYPA small gas fleet and one of four Northport steamers reduce the size of the fossil fuel fleet. Battery storage totals about 4.8 GW. While storage helps to smooth the diurnal winter peak, large fossil ramps are still necessary to manage offshore wind and solar variability.

Both the 2004 cold weather and 2015 ramping hydraulic periods were developed in Aurora for the long-term forecast year. Additionally, two sensitivities were conducted for both hydraulic periods. The offshore wind delay sensitivity assumed that about 2,650 MW, or roughly two large offshore wind projects, are delayed from the base case and therefore removed from the 2032/33 long-term forecast. The Nuclear Outage case assumes that two of the older nuclear facilities in New York are unavailable in the 2032/33 winter, which results in approximately 1,200 MW of price-taking non-gas capacity being offline. This sensitivity is similar to a disruption studied in the FES Study, but represents a lower outage quantity.[85] Both units have indicated intent to file for subsequent license extension with the Nuclear Regulatory Commission (NRC).[86] The reasons for an outage are not defined but one facility could retire and the other could be on an unplanned maintenance outage during the weather event.

In the 2004 cold weather period, fossil generation makes up a smaller portion of NYISO's generation mix. The profile for gas generation during the long-term cold weather period remains similar to the mid-term profile for the same weather event as the daily gas constraint binds at similar levels. Additional renewables mainly offset the need for oil. Oil switching is reduced on day 2 and nearly eliminated on day 3 with strong wind output. However, day 1 includes high winds above cut-out speeds that result in wind generation being reduced coincident with the normal solar ramp in the evening. This results in a fossil ramp of about 8.5 GW over four hours, with about 5.5 GW met by oil and 3 GW met by gas.

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[84] Following selection in NYSERDA's 2022 offshore wind solicitation, three projects totaling about 4 GW of offshore wind faced material modifications due to GE Vernova's decision to change turbine offerings. These same three projects have re-bid into the 2024 solicitation which is expected to make contingent awards.

[85] FES Study, see page 98. The Analysis Group described the Nuclear Station Outage disruption as "Probability *meaningfully less likely than* typical conditions used in system operational assessments" which supports LAI's approach of taking a lower total MW value (Nine Mile Point Nuclear (NMP) Unit 1 and 2 exceed 2,000 MW of combined capacity) and not narrowly tying the modeling input to a nuclear station outage.

[86] Status of Subsequent License Renewal Applications, United States Nuclear Regulatory Commission, accessed August 7, 2024. https://www.nrc.gov/reactors/operating/licensing/renewal/subsequent-license-renewal.html

Figure 36: Hourly NYISO Generation by Fuel Type, Long-Term 2004 Cold Event

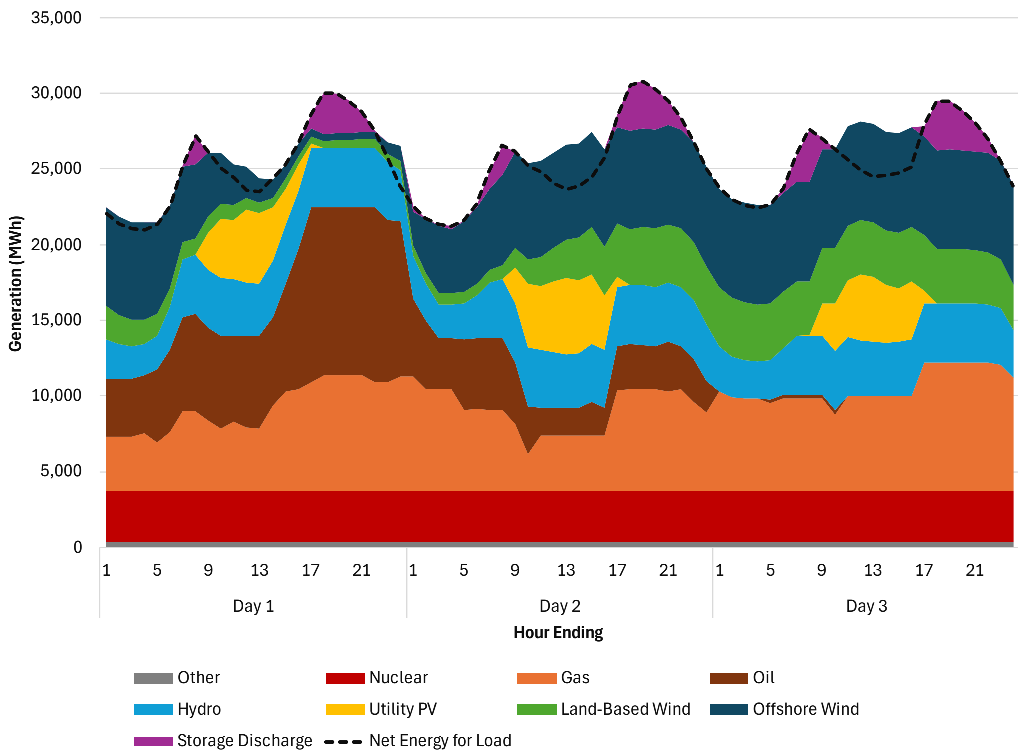
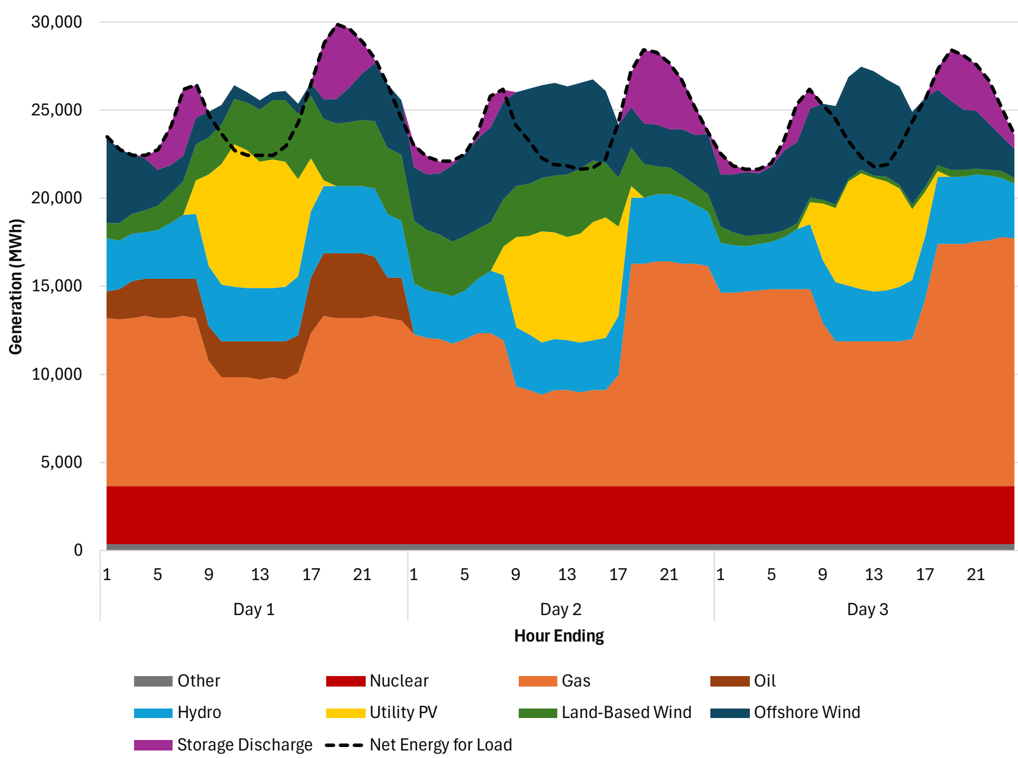


Figure 37: Hourly NYISO Generation by Fuel Type, Long-Term 2015 Ramping Event



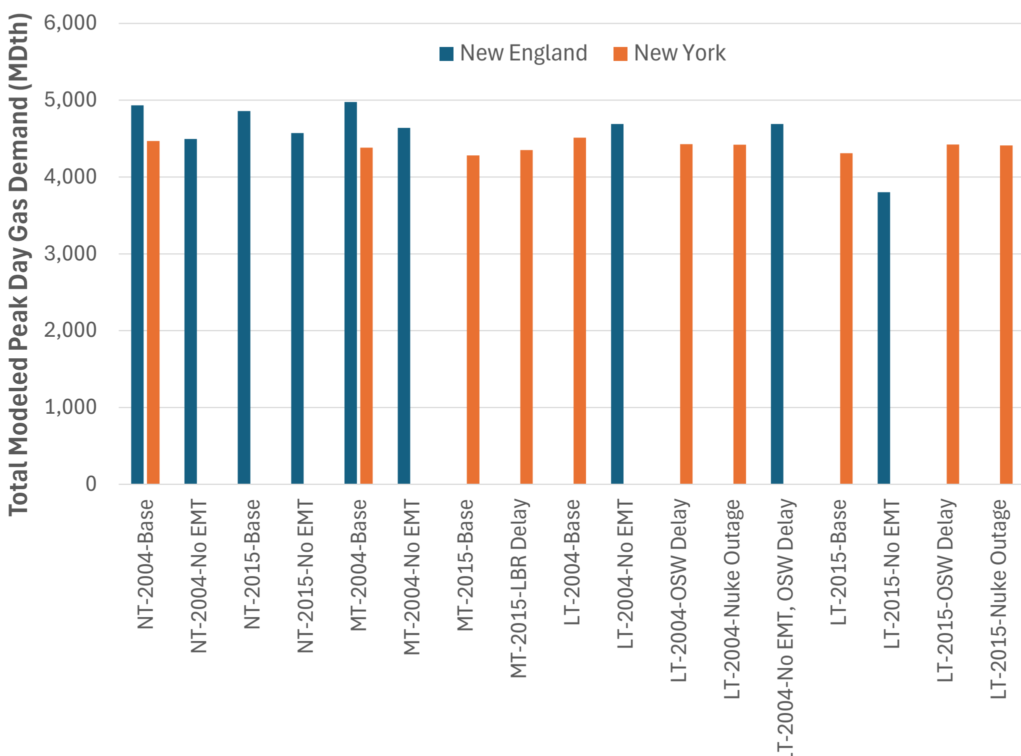
As gas burn is constrained in the 2004 hydraulic period, the profile of gas demand is relatively unchanged. However, additional oil-fired generation is necessary to meet load. The need for oil reduces the non-gas headroom available on the NYISO system to respond to contingencies. Ramping needs for gas in the 2015 ramping period are somewhat reduced by storage expansion, but increase to about 7.1 GW over two hours. Ramping behavior in the 2015 event remains about the same in the Nuclear Outage sensitivity, but overall reliance on gas generation increases.

4.3 Integrated Gas Demand Forecast

The peak seasonal electric sector and utility sector gas demands, as described in Sections 4.1 and 4.2, respectively, have been assumed to occur on a coincident basis. While utility sector demand is greater than electric generator demand in the winter, more detailed hourly load shape forecasts are available for electric load than for utility sector load. It was assumed that the maximum winter electric load occurs on a very cold day when utility sector load for heating is also highest.

Figure 38 shows the combined peak day gas demand forecast input into LAI's consolidated hydraulic model for each of the cases studied. Figure 39 and Figure 40 show the combined hourly profile of peak day gas demands by case for New England and New York, respectively.[87]

Figure 38: Total Peak Day Gas Demands by Case



[87] Texas Eastern and Transco are not included in the consolidated hydraulic model because their only delivery meters in the Study Region are to the New York Facilities System. Therefore, the gas demands that are served by these pipelines are not included in these figures.

Figure 39: Hourly Profile of Peak Day Gas Demands by Case: New England

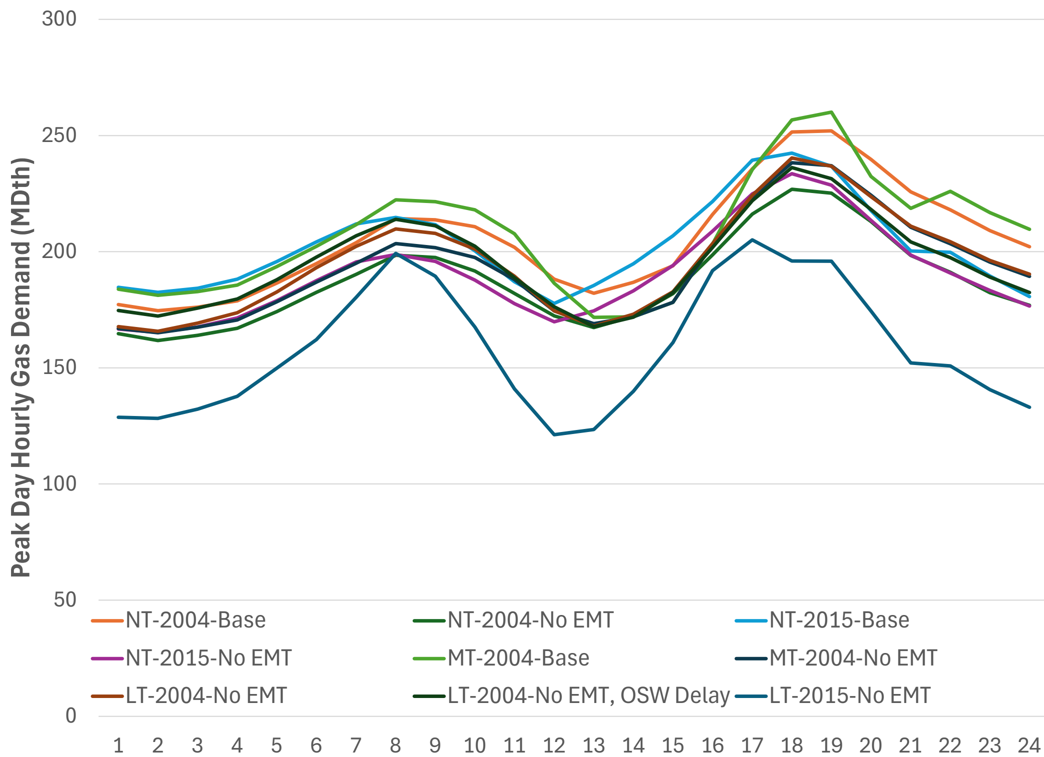
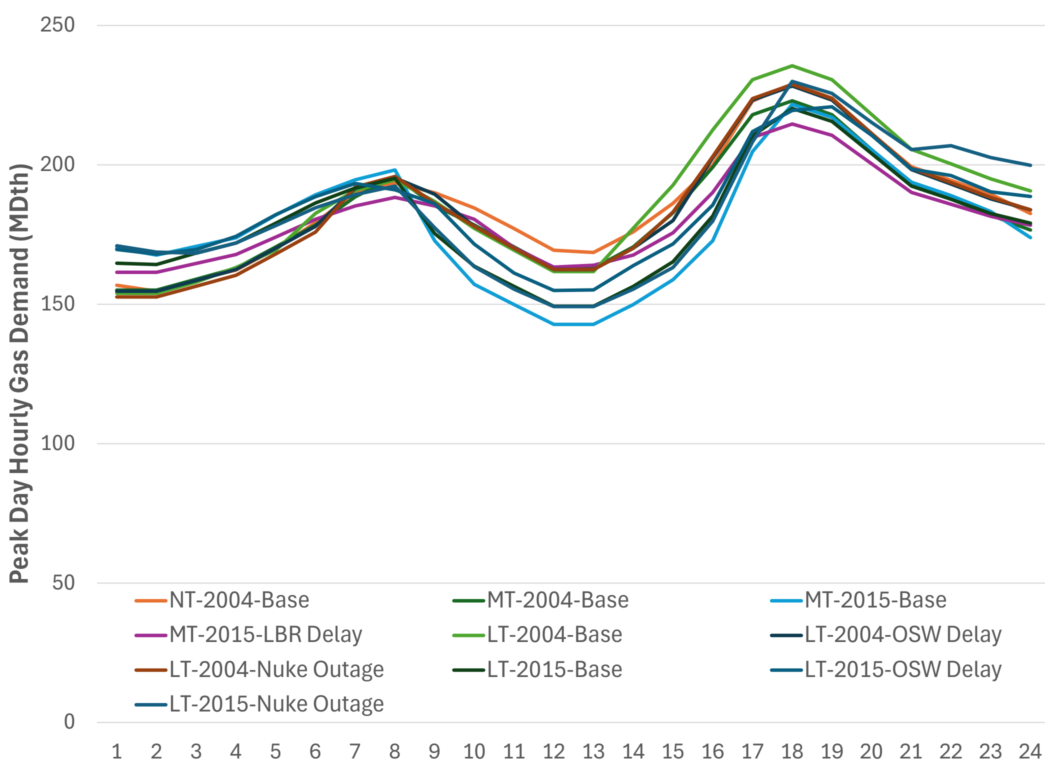


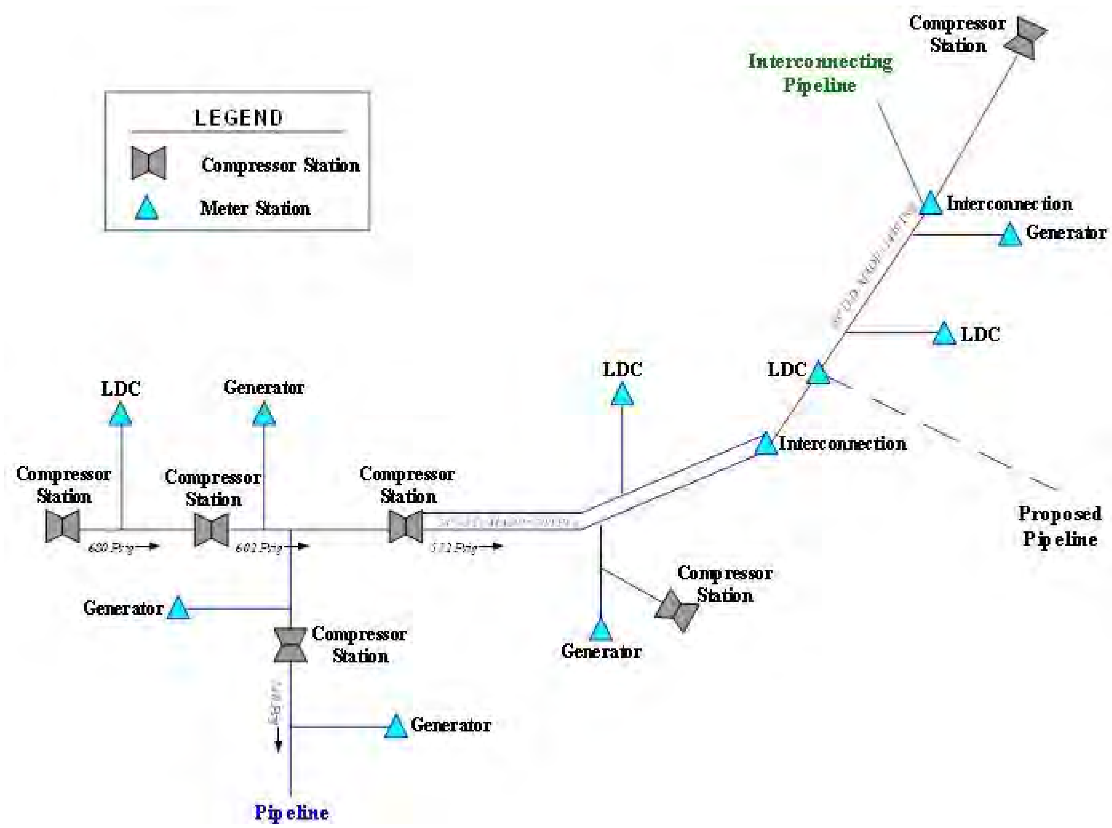
Figure 40: Hourly Profile of Peak Day Gas Demands by Case: New York



5 Baseline Hydraulic Modeling Analysis

The hydraulic modeling analysis requires the use of WinFlow, the steady state model, and WinTran, the transient flow model.[88] Using these modeling platforms and Confidential Energy Infrastructure Information (CEII) provided by the pipelines, including FERC Form 567 filings and Certificate of Public Convenience and Necessity Exhibit Gs, LAI has formulated hydraulic representations of the pipelines serving generation in ISO-NE and NYISO. 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 41, the models incorporate compressor stations, pipeline segments, interconnections, receipts from production and other supplies, storage injection / withdrawal points, and deliveries to utility and electric sector customers. Other model 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.

Figure 41: Example Hydraulic Model Schematic



LAI first reviewed the most recent available FERC Form 567 pipeline filings, filed in May 2023 for the year 2022. These filings were used to confirm the infrastructure parameters for each pipeline segment, and the coincident peak day flow volumes were used to validate model functionality. In many cases, modeled pipelines extend outside of the Study Region. In these cases, boundary flow limitations were assumed

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[88] The hydraulic models are licensed by Gregg Engineering, Inc. and are subject to non-disclosure provisions.

based on compressor station throughput capability and peak day design information posted on the respective pipeline Electronic Bulletin Board (EBBs) or stated in the FERC filings.

In addition to reviewing the FERC Form 567 filings, LAI reviewed the status of various pipeline certificate applications before FERC to identify incremental infrastructure that is likely to be in place before one or more of the studied time horizons. Pipeline infrastructure projects were identified for inclusion in the modeled footprint if the project's infrastructure has been defined and precedent agreements sufficient to support a project's construction were publicly known as of July 1, 2024. LAI also reviewed relevant FERC filings, open season notices, other pipeline announcements, and press releases. Consistent with industry conventions, LAI views the existence of precedent agreements as synonymous with need as such binding agreements commit shippers to a long-term financial commitment when FERC certificates an expansion of a pipeline's delivery capability. These agreements have been typically used to demonstrate market need to FERC, a prerequisite for regulatory approval.[89] The only project meeting these criteria is Iroquois' Enhancement by Compression Project (Docket No. CP20-48), which is expected to be placed in service in November 2027.[90]

Following construction and validation of the individual pipeline models, LAI consolidated contiguous pipelines into a working network flow model in order to account for interconnect flows and the associated impacts on pipeline operations. The consolidated hydraulic model includes the nine interstate pipelines that serve generation in the Study Region: Algonquin, Eastern, Empire, Iroquois, M&N, Millennium, National Fuel Gas (NFG), Portland Natural Gas Transmission System (PNGTS), and Tennessee.[91] In total, these systems encompass approximately 7,000 miles of pipe.

The validation of hydraulic model solutions requires the incorporation of pressure cutoff levels below which each generator either cannot operate at any output level or cannot operate at full power output.[92] The types of turbines in use by each generator and availability of on-site compression were determined based on public information where possible. Minimum pressure requirements based on the type of turbine used by each generator were assigned where such information was available. When available, LAI incorporated pressure cutoffs for NYISO generators based on GFER survey responses. Where information was not available to determine the minimum pressure requirements and availability of on-site compression for a specific generator, LAI incorporated a standardized minimum pressure requirement as

[89] The relevance of Precedent Agreements to support market need is presently under review by the U.S. District Court and FERC.

[90] Algonquin held an open season for Project Maple in 2023 and has indicated that discussions with potential shippers are underway. As of this publication date, not enough information has been made available to warrant inclusion of Project Maple in the consolidated model.

[91] Granite State is excluded from the hydraulic modeling as it serves only utility sector customers, and interconnections with other pipelines (M&N, PNGTS, and Tennessee) are instead modeled as deliveries from those pipelines. Texas Eastern and Transco 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 the New York Control Area or New England.

[92] While the same post-contingency pressure differentials affecting generation customers would also affect utility sector customers, these customers are not subject to the same delivery pressure triggers that are assumed to take generators offline. LAI has not sought to analyze the extent to which utility sector customers would be able to continue operation following contingency events.

the cutoff point to capture any impairment in operation based on whether or not a generator has on-site compression to boost the delivery pressure.

Sendout from the three LNG import terminals located in or supplying gas to the Study Region is used to parameterize specific cases. Sendout from Repsol Saint John is assumed to be 0.8 Bcf/d in all cases. Sendout from Excelerate Northeast Gateway is assumed to be 0 Bcf/d in all cases. Sendout from Constellation EMT is assumed to be either 0.4 Bcf/d or 0 Bcf/d in each case, depending on whether the facility is in-service. These assumptions are consistent with ISO-NE's LNG assumptions in PEAT.[93] Sendout from LNG storage facilities located behind the citygate is incorporated in development of the utility sector gas demand forecast and is not separately represented in the consolidated hydraulic model.

In addition to assumed LNG sendout, the key variable input across cases is gas demand by location, based on the integrated gas demand forecast, including the transient intra-day demand profiles for each meter. Implementing variable flows also results in variable intraday system pressures and compressor station utilization, among other factors that drive linepack dynamics. Applying intra-day demand profiles increases stress on the pipeline network during periods of increasing demand, as linepack is drawn down and system operating pressures are reduced.

In New England, all generator gas demand was determined to be deliverable.[94] In New York, the required minimum delivery pressures are not able to be maintained at selected behind the citygate plants when intraday demand profiles are applied, resulting in a small amount of undeliverable scheduled gas for generation in some cases. The identification of undeliverable gas demand does not indicate that there will be unserved load. Gas that cannot be delivered at one plant may be able to be delivered to another plant in a different location that is not subject to the same gas infrastructure constraint. Fuel-switching, at the same plant or ramping at another plant, can also be used to offset constraints on gas deliverability. These results therefore represent a conservative finding regarding gas deliverability to generation.

At the local level, analysis was conducted in consultation with the LDCs operating in downstate New York because there is a heavy concentration of gas-fired generation on the New York Facilities System.[95] Con Edison and National Grid (NGrid) performed the baseline and contingency assessment for their systems and the New York Facilities System at large using their updated 2024 models based on study design and model assumptions provided by LAI, including a "cold" scenario (average Central Park temperature of 12°F and a suite of "mild" scenarios (average Central Park temperature of 27°F). Using the temperatures and generation schedules postulated by LAI, NGrid and Con Edison reported that the New York Facilities

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[93] The deliverability of up to 1.2 Bcf/d from Constellation EMT and Repsol Saint John reflects physical capability on the pipelines linking this supply with generators in New England. Commercial considerations associated with generators' willingness to pay, as well as that same willingness among marketers serving the region, are outside the scope of this inquiry, but are nevertheless noted in qualitative terms. Whether Constellation and/or Repsol would be willing to tolerate scheduling and LNG procurement risk in order to arbitrage price spreads between global LNG prices and gas and electric prices in New England is not known with certainty.

[94] In New England, much of the scheduling flexibility to serve gas-fired generation that has been observed in the hydraulic modeling analysis is made possible by the displacement services attributable to LNG supplies flowing from the M&N/PNGTS Joint Facilities into Algonquin at Beverly and Tennessee at Dracut and directly from Everett LNG into Algonquin and Tennessee. In New England, the gas supply limitation embedded in PEAT limits the amount of scheduled generator gas demand, and thus the amount of undeliverable scheduled gas.

[95] No other hydraulic modeling of local system deliverability has been conducted elsewhere in New York or New England.

System can accommodate gas deliveries to heating customers and generators under non-contingency conditions.

5.1 Mitigation Measures to Alleviate Pipeline Constraints

The most economical means of mitigating a specific constraint depends on pipeline hydraulics and the location and technology characteristics of the affected generator. Constraint mitigation therefore involves one or more physical infrastructure improvements and/or leveraging existing dual fuel infrastructure during the peak heating season, December through February. While the baseline modeling results do not identify significant amounts of undeliverable scheduled gas to generation, the assumptions used to determine the gas demand for generation reflect the constrained nature of the gas infrastructure in the Study Region by limiting the available gas supply.

For high frequency and/or long duration constraints resulting in the limitations on the deliverability of gas to generators, one of the most economic mitigation measures, in lieu of adding backup fuel capability via oil storage, may be the installation of additional pipeline capacity. Decarbonization goals in New England and New York likely render such mitigation infeasible despite the anticipated relaxation in FERC pipeline certifications through the medium-term planning horizon. Low technology improvements associated with uprating compression at existing compressor stations may boost deliverability, thereby improving the delivery profile for both utility sector end-users and gas-fired generators. Since increased reliance on natural gas is contrary to state electrification goals in the Study Region, the prospect for implementing pipeline improvements is considered remote despite the permitability of low technology solutions at FERC.[96]

For low frequency, short duration constraints resulting in the non-scheduling or interruption of gas-fired generation in New York or New England, the most economic mitigation measure is the use of oil. The use of liquid fuels may be obtained from existing oil tanks coupled with contracting initiatives that promote increased oil inventory heading into the peak heating season starting on December 1st. In light of the various states' electrification and environmental goals, LAI does not believe that the permitting and construction of new oil tanks for generation is feasible. In addition to increased oil use, another mitigation approach that is practical in New England is contracting for service from Constellation EMT and Repsol Saint John. LNG can be delivered via displacement on pipelines in New England, thereby firming up the transportation during the peak heating season. Generators seeking LNG use to improve fuel adequacy could contract directly with Constellation and/or Repsol,[97] or obtain such displacement services indirectly under a third-party marketer arrangement.

The use of LNG to supply gas-fired generation is not feasible on the New York Facilities System because of a ban on LNG trucks and new LNG facilities in New York City. Notably, both the dispatch of existing oil-fired generation and LNG availability are captured in the electric system modeling, though the mechanisms that will promote fuel security are not strictly defined in this study.

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[96] To demonstrate market support for pipeline expansion, the applicant is typically required to file service agreements for firm transportation or firm storage as part of a Certificate of Public Convenience and Necessity application filing at FERC. This requirement is presently under review in light of the District Court's July 2024 decision to remand Transco's Reliability Energy Access Expansion Project, a recently completed 0.83 Bcf/d pipeline expansion to serve New Jersey, Philadelphia and Baltimore.

[97] Excelerate's Northeast Gateway submersible buoy system is also a potential source of LNG.

6 Contingency Modeling Analysis

Using the baseline transient models as a starting point, 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, this analysis focuses on an array of potentially moderate to severe gas- and electric-side contingencies in both New England and New York.

6.1 Gas-Side Contingencies

Gas-side contingencies were modeled in WinTran as disruptions in gas supply, storage, line breaks, or loss of horsepower at compressor stations located near gas-fired generators. LAI formulated the gas-side contingencies to be evaluated in both ISO-NE and NYISO in consultation with the Steering Committee.

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 contingencies, i.e., infrastructure outages. In order to evaluate the pressure trends at generators located downstream of a contingency event, the transient model was run for a 72-hour period, including at least 24 hours before the contingency event and at least 24 hours after the contingency event to measure relative delivery pressure trends at meters serving gas-fired generators.

Disruptions were applied to the transient models to simulate specific contingencies in order to examine the resulting gas pressure and flow trends following each contingency event. For each tested disruption, LAI evaluated the system impacts following the event, including the time interval before the first affected generator would be forced to stop operating on gas by decreasing delivery pressure and the total amount of scheduled generator gas demand that would be at-risk of being undeliverable.

LAI conducted this assessment based on the assumption that scheduled volumes would continue to be delivered to both utility sector customers and generators until minimum delivery pressures could not be maintained.[98] The purpose of this approach is to determine whether there would be sufficient time following each contingency for generation operators to safely ramp down affected plants before they would be directed by the pipeline to stop operating on gas. The analytic framework is designed to calibrate the responsiveness of the consolidated network of pipelines and gas storage infrastructure to continue to serve scheduled gas-fired generation under the postulated perturbations to the supply chain. LAI has not attempted to incorporate specific additional pipeline operator actions, which would include signaling generators to stop taking gas, beyond optimization of system capabilities within the model.

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 Diesel (ULSD), distillate oil, kerosene, or residual fuel oil following the postulated event. Model solutions

[98] Utility sector customers would experience the same post-contingency effects as generators. Following a postulated gas-side contingency, the normal curtailment priority would cut shipments to non-firm generators first and would adjust shipments to utility sector customers 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. Utility sector customers typically have lower minimum required delivery pressures than generators, but if delivery pressures drop low enough following a contingency, utility sector customers would eventually also be forced offline. Undeliverable scheduled gas to utility sector customers has not been assessed in this study.

in WinTran encompass the utilization and management of linepack as a possible short-term mitigation measure to sustain continued gas-fired generation when outage contingencies are tested. Other mitigation measures built into the reoptimization of natural gas flow following a postulated event include increased flows through pipeline interconnects, reversal-of-flow, and use of spare horsepower at compressor stations downstream of a postulated event.

With the exception of line breaks, which are the most extreme type of event studied in terms of immediate impacts, there would be adequate time for orderly shutdown or fuel switching, before generators would be forced offline by decaying system pressures. While pipeline operators would likely require generators to ramp down their gas deliveries following most contingencies sooner than indicated in the time-to-trip intervals derived by LAI, in most cases the ramp down process could accommodate fuel switching, if the generator is dual capable, or avoid damage to equipment during shutdown if the facility does not have dual fuel capability. In the case of line breaks, this interval can be much shorter, depending on the proximity to generation and whether the closest downstream generator is operating at the time of the event.

LAI worked with Con Edison and NGrid to evaluate local deliverability on the New York Facilities System following postulated gas and electric-side contingencies.

Results of the contingency analysis have been classified as CEII and are therefore not included in the public version of this report.

On a relative basis, New England experiences the most substantial gas-side contingency impacts, measured in terms of time-to-trip intervals and relative to total affected generation, due the more concentrated locations of generators. Affected generation in upstate New York is largely limited to isolated pockets of gas deliverability constraints following the postulated events, due to the broader distribution of generators across pipelines and locations.

6.2 Electric-Side Contingencies

Electric-side contingencies equivalent to the largest single source loss of supply (approximately 1,300 MW) were posited for NYISO to "stress test" the resilience of the gas system to allow additional gas-fired resources to make up an energy shortfall on short notice. During extreme cold weather modeled in the 2004 hydraulic period when daily gas use is already constrained, gas is unlikely to provide a full response. During cold weather conditions ISO-NE's PEAT model has fully allocated gas toward electricity production.[99] Similarly, the daily gas constraint in Aurora is binding for NYISO. In ISO-NE, there is some fast-start gas-fired generation, about 350 MW, that provides reserves and often responds to contingencies. There is firm transportation associated with this plant, but firm transportation holdings are not allocated to specific generators in the PEAT model.[100] In NYISO, almost all fast-start gas-fired

[99] There is some vaporization capability into NGrid's Boston Gas system from Constellation EMT which is not part of the modeled PEAT vaporization capability, which only considers direct sendout to the pipelines. Though NGrid has a claim to some of this vaporization capability via its long-term contract, some of this capability could be utilized as a vehicle to provide displacement services to gas-fired generators that are directly connected to Algonquin or Tennessee.

[100] LAI notes that the quick start capability enabled by firm transportation provides a Locational Forward Reserve Market benefit, thereby providing ISO-NE with a dependable source of generation on short notice when operating conditions warrant.

generation is located downstate on the New York Facilities System. During cold days, ratable take restrictions are often in place, and therefore a no-notice request for large quantities of non-ratable gas will not be accommodated.

Baseline hydraulic modeling further supports this conclusion, as deliverability to electric generators is strained in the cold weather hydraulic period tested in the steady-state. In these periods, both ISO-NE and NYISO must rely on non-gas solutions to balance the grid. Fast-start dual fuel units may instead be activated on oil due to either operational or economic drivers. Reservoir hydro and demand response resources may also be able to respond quickly. In NYISO, Aurora modeling suggests that pumped storage will likely be available to meet electric contingencies as its lower efficiency makes it more valuable as a reserve provider with stored fuel rather than being used for energy arbitrage.

However, during milder weather conditions gas may be a more attractive option to re-balance the system. However, there are practical limitations to sourcing gas on an intra-day basis that undermines a contingency response oriented around significant incremental gas burn. Even during comparatively milder winter days, pipelines may seal nominations at critical upstream pooling points, depending on nominated volumes relative to system capacity. Surely, generators, like both pipelines and primary entitlement holders, will be concerned about unauthorized gas use. While LNG terminal sendout represents one potential source of intraday gas, its relevance to NYISO is limited.

In NYISO gas generator headroom was identified during high-demand evening contingency hours and sourced from part-loaded and offline units. The incremental MW output is prioritized, first from part-loaded units, then from more efficient peaking units. There is no strict preference between gas-only and dual fuel units. So long as a dual fuel unit is not already running on oil, the most efficient gas-powered peaker is selected for gas headroom. In NYISO, many of the fast-start generators are located on the New York Facilities System.

LAI sent Con Edison and NGrid gas schedules corresponding to demand assuming an incremental contingency response. These schedules were evaluated using each company's New York Facilities System steady-state model for New York City and Long Island. As noted above, the gas schedules were set based on efficiency as a proxy for merit order. No attempt was made to maximize the amount of gas that could be delivered under the contingency response. Con Edison and NGrid found that their systems could only support a portion of the incremental gas burn that would be necessary to respond to a large single source of supply in the mid-term forecast period. Headroom for incremental gas is very limited in the long-term forecast period due to expected core LDC demand growth. NGrid indicated that during still milder conditions (approximately 35°F daily average temperature) the NGrid portion of the New York Facilities System could support far more demand than was estimated, including a contingency response, in the baseline model runs.[101]

Importantly, all hydraulic modeling of scheduling potential on the New York Facilities System is predicated on the simplifying assumption that the requisite gas is delivered to the New York Facilities System from one or more pipelines serving Con Edison and NGrid to support the control room's decision to start-up

[101] These values are general guidelines and do not account for hydraulic limitations that may impact the ability to deliver gas to a particular unit or combination of units. Actual limits on generation will vary with system conditions, time of day, and weather, and could be higher or lower.

gas-fired generation when there is a loss of electric infrastructure.[102] If, for whatever reason, such gas is not delivered to the New York Facilities System, both Con Edison and NGrid have reported the practical difficulty of accommodating the start-up of gas-fired generation that has not been previously scheduled, but that does not itself preclude best efforts on the part of one or both utilities provided there is no denigration to high priority, residential and commercial customers.

6.3 Contingency Mitigation Measures

6.3.1 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 upstream supply. 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.[103] Under FERC guidelines, a pipeline is permitted to exercise its reasonable judgment to determine whether or not the event warrants a declaration of *force majeure*. There is a well-established FERC policy regarding the nature of events that qualify as *force majeure* events.[104]

FERC has defined *force majeure* events as outages that are both unexpected and uncontrollable. Notification to affected shippers happens quickly on the pipeline's 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 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 linepack, 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 gas-fired generation following the postulated 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 constrained operating conditions, a pipeline would be likely to issue an OFO placing requirements and/or limitations on customer actions, if such a directive is not already in effect, or to make an OFO which is already in effect more restrictive. Depending on the severity of the event, non-firm shippers directly connected to the pipeline downstream of the event

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[102] The ability of generators or marketers serving generation in NYC or Long Island to arrange requisite supply effectively on a no-notice basis is outside the scope of this inquiry.

[103] 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 include: first, interruption or curtailment of interruptible shippers; second, interruption or curtailment of secondary firm shippers (out-of-path); third, interruption or curtailment of secondary firm shippers (in-path); and, fourth, curtailment of deliveries to firm customers on a *pro rata* basis.

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

may be notified that, effective immediately, the pipeline cannot offer continued service to shippers lacking firm entitlements.

When a pipeline needs to curtail scheduled deliveries, firm customers may be curtailed as well. Such extreme events would typically warrant declaration of a *force majeure.* In reviewing the array of mitigation opportunities following gas-side contingency events, pipeline operators can independently implement actions to optimize system operations, and can work with other market participants to make adjustments that protect system integrity.

In this section, the nature and type of mitigation measures that can be undertaken by pipeline operators independently and in cooperation with other market participants are reviewed to address the relative merit of different mitigation measures affecting electric system reliability. Importantly, in performing this study LAI notes that no formal outreach effort to individual pipeline operators has been conducted to explore how such measures would be implemented.

6.3.1.1 Mitigation Measures Implemented by Pipeline Operators

The WinTran model solutions capture pipeline system responsiveness to real-time operational factors following a postulated gas-side contingency. Therefore, many of the operator actions that would be implemented following a gas-side contingency are already incorporated within the WinTran solutions, including increased utilization of available compression, draw down of linepack, and increased interconnection flows into the pipeline or decreased interconnection flows out of the pipeline.[105] During the peak heating season, however, or during cold snaps in shoulder months, there may not be any spare compression or linepack available to mitigate adverse impacts to gas-fired generators. Moreover, an operator's decision to leverage linepack 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.[106] The feasibility of adjustments to interconnection flows, potentially leveraging upstream or downstream linepack on one or more contiguous pipelines would depend on whether such assistance could be offered without adversely affect deliverability to the connected pipeline's own customers, and therefore may be limited under peak day conditions. Inter-pipeline cooperation and mutual assistance are provided on a best-efforts basis as there is no mandate to provide mutual aid to mitigate the disruptive consequences following a gas-side contingency.

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.[107] Pipelines typically address contingency events

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[105] Allowing generators to draw down linepack by continuing to take gas following a contingency would enable sustained operation. Pipelines would not be obligated to allow non-firm customers to continue to receive gas following an adverse event. Therefore a generator's access to this mitigation measure would depend on both contractual character of service and a pipeline's ability to implement mitigation along a discrete route segment under duress.

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

[107] 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 can sign up to receive all pipeline critical day notices directly from the pipeline as soon as the notice is posted.

through actions that 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.

6.3.1.2 Mitigation Measures Involving Other Market Participants

The system responses revealed through the transient modeling do not incorporate the array of mitigation measures designed to limit disruptions following a postulated gas-side contingency that depend on market participants other than pipeline operators. These measures are RTO-specific and will require stakeholder commitments to implement region-wide for purposes of improving gas generator performance post-contingency.

The flow of information is an integral part of the operational, planning and policy engagement between the electric and gas systems. FERC has issued rulemakings that address gas-electric interdependence and coordination, in particular, communication and information-sharing between the natural gas and electric industries.[108] In response to the 2004 cold snap in New England, the Commission sought in order No. 698 to improve coordination between the gas and electric industries in order to improve communications about scheduling of gas-fired generators.[109] As part of an effort to continue addressing certain issues raised by FERC Order 698, ISO-NE issued a paper, "Addressing Gas Dependence," where enhancement solutions are defined. Currently, ISO-NE has Operating Procedure No. 21 in place.[110] ISO-NE periodically requires generators to complete a Generator Fuel and Emissions survey, which allows ISO-NE to collect data to monitor fuel inventory levels, fuel replenishment, and actual or anticipated environmental limitations. ISO-NE, in collaboration with MISO, PJM, and Southwest Power Pool (SPP), has published a joint position paper[111] outlining strategies to enhance gas-electric reliability through targeted recommendations for RTOs, gas producers, pipelines, and federal and state regulators. While allowing for regional flexibility, the recommendations emphasize the need for coordinated national efforts among regulators and stakeholders to address broader issues. ISO-NE collaborates routinely with interstate pipelines, conducts annual assessments of critical natural gas infrastructure, and shares forecasted generator dispatch data to enhance pipeline coordination.[112]

NYISO indicated that communication systems had been established to send Energy Emergency Alerts to the pipelines, such as public appeals to reduce demand, voltage reduction, demand side management, conservation measures, and interruption of non-firm loads. NYISO has implemented changes to the Open Access Transmission Tariff to incorporate the New York State Gas-Electric Coordination Protocol, thereby

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[108] 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. Available at https://www.ferc.gov/sites/default/files/2020-04/order-787_0.pdf

[109] *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. Available at https://www.ferc.gov/sites/default/files/2020-06/OrderNo.698.pdf

[110] Procedure No. 21 improves communication among pipelines and market participants, including LNG importers.

[111] ISO-NE, Strategies for Enhanced Gas-Electric Coordination: A Blueprint for National Progress, February 21, 2024 20240220_joint_rtos-gas-electric-coordination-white-paper.pdf

[112] ISO-NE, New England Winter Gas-Electric Forum, September 2, 2022
https://www.iso-ne.com/static-assets/documents/2022/09/ne_gas_electric_forum_presentations.pdf

strengthening communication pathways among market participants. Since 2012, NYISO has also conducted the NYISO Electric Gas Coordination Group to provide a forum for market participants and stakeholders to address the aforementioned issues and future developments.[113]

ISO-NE and NYISO are engaged in ongoing coordination with pipeline companies on an array of scheduling, including maintenance scheduling, penalty administration, and notification issues. ISO-NE and NYISO know which gas-fired generators are dual fuel capable and communicate on a regular basis with those units regarding liquid fuel inventory levels and the logistics of oil replenishment. Working in close consultation with generators and trade associations, both ISO-NE and NYISO control room operators may inform the pipeline of which generation unit(s) are needed most for electric grid security.

Pipelines can also potentially leverage operational relationships across the supply chain to shift customer deliveries between pipelines where a customer is supplied by multiple pipelines or to reduce deliveries. The avoidance of any degradation of service to utility sector customers may be enabled in the event of underutilized receipt point capacity into the local distribution system on another pipeline that can increase deliveries.[114] A pipeline operator may take additional steps through its LDC balancing agreement or through a formalized outreach procedure, to examine an LDC's ability and willingness to manage load. Depending on the spatial configuration of affected utility sector 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. [115]

A pipeline operator may be able to augment pipeline deliverability by working with suppliers to increase receipts through incremental intraday gas storage withdrawals. However, most pipelines do not have storage withdrawal rights. Typically, the rights are controlled by the storage customer, thus necessitating coordination with one or more storage entitlement holders. For pipelines that do not have 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 reschedule storage withdrawals.[116] In 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.

Like ancillary services from a pumped storage plant, incremental LNG sendout from the import terminals has the potential to mitigate disruptive events across ISO-NE. While there are dozens of above ground

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[113] See NYISO, Electric Gas Coordination Working Group, (February 3, 2012). Available at https://www.nyiso.com/documents/20142/1403569/NYISO_EGCWG_02032012.pdf/b2f17176-4022-2fe9-a486-8f86bb07dcec

[114] Many LDCs, Con Edison included, operate "grid-like" distribution systems where multiple gate stations served by several or many different pipelines allow for operating flexibility, thereby allowing for flow-day diversions and the more complete utilization of pipeline interconnect capability to mitigate an adverse event.

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

[116] On a Winter Peak Day, there may not be additional storage withdrawal capability to help restore pipeline integrity. Storage entitlements generally are location specific and rely on the storage facility capabilities as well as the available downstream pipeline capability. In order for storage or LNG to mitigate, 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 pipeline rendered supply.

satellite LNG tanks owned and operated by LDCs throughout the Study Region, back-end displacement of pipeline rendered supply through local area LNG sendout is deemed infeasible in the context of supporting electric grid objectives. Therefore LAI does not consider this to be a feasible mitigation measure.[117]

A pipeline operator may be able to improve deliverability by working with shippers to implement Park & Loan (PAL) transactions. On pipelines that offer PAL service, a customer can borrow gas at a certain time and pay it back at a later date consistent with the tariff repayment provisions.[118]

Other 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.

6.3.2 Electric-Side Contingency Mitigation

This section addresses the possible mitigation measures and actions that could be taken by NYISO, ISO-NE, pipelines, LDCs, and/or the gas-fired generators in response to the loss of either a baseload capacity resource or a high voltage transmission facility.

6.3.2.1 Mitigation Measures Implemented by ISO-NE and NYISO

Following an electric-side contingency, control room operators determine which generators are required by location to ensure electric reliability. Many of these generators should be able to start-up quickly on oil, particularly peakers and most other units on the New York Facilities System.

When either NYISO or ISO-NE 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 that were not scheduled in the day-ahead market may find it challenging to obtain sufficient fuel in the intra-day market. During cold weather events in New England and New York, the intra-day market is illiquid. There is not usually sufficient opportunity to line up incremental volumes on short notice to participate in the Real Time Market (RTM) using natural gas. There is a higher cost of intra-day supply related to pipeline transportation if the shipper violates an OFO, consumes too much of its daily confirm non-ratably, and the pipeline cannot accommodate hourly variances. During the peak heating season, 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 challenging the respective Market Monitors to review the reasonableness of full or partial cost reimbursement.[119] Additional costs for intra-day gas procured after the occurrence of an electric-side contingency event may include a substantial cost premium relative to daily mid-point index prices.

[117] Satellite LNG tanks are used to protect LDCs' firm 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.

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

[119] 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.

At this time, neither ISO-NE nor NYISO has a rule that gives generators the opportunity to change bids in the RTM to reflect ratable-take penalty charges, daily imbalance charges, and/or unauthorized use charges when mitigating electric-side contingencies. In both NYISO and ISO-NE, RTM rules restrict fuel cost adjustments once the market has closed, but adjustments are allowed for before the operating hour. NYISO requires fuel costs to be finalized 75 minutes before the operating hour, as outlined in its Reference Level Software User's Guide.[120] Notably, NYISO prohibits generators from recovering costs associated with unauthorized natural gas usage, such as during service interruptions or if use is penalized. However, NYISO permits adjustments to high-cost offers (over $1,000/MWh) provided these are submitted before the RTM closes.[121]

Another mitigation measure in the event of a pipeline *force majeure* declaration pertains to rescheduling generation to another generator that is located "electrically near" the postulated electric-side event to serve electric grid reliability objectives. Such a diversion would require communication between the generator and pipeline operator(s) based on information from either NYISO's or ISO-NE's control room. As LAI understands it, flow day diversions may be implemented by pipeline operators on an ad hoc basis.

6.3.2.2 Mitigation Measures Associated with Market Reforms

Potential mitigation measures include NYISO and ISO-NE market initiatives designed to strengthen the deliverability of natural gas to gas-fired generators. Administrative reforms oriented around daily scheduling flexibility are also part of this array.

With regard to scheduling, in response to continued FERC direction to better align the electric and gas day, industry stakeholders have been immersed in a continuing multi-year dialogue to standardize gas scheduling reforms that promote still more harmonization between the gas and electric days. In terms of electric reliability, modifications to the current NAESB gas schedule may constitute a step in the right direction regarding greater scheduling flexibility. NYISO has indicated support for increased flexibility in gas scheduling via the implementation of additional nomination cycles throughout the gas day.[122,123] Both NYISO and ISO-NE also support increased liquidity in gas markets over weekend and holiday periods.[124]

Regarding changes in wholesale electric market design, ISO-NE has implemented measures including the Energy Market Opportunity Cost Project which has helped optimize the use of limited fuel supplies for oil-fired and dual fuel generators during stressed conditions. Opportunity cost pricing principles reflect the potential net revenue loss if fuel supply is reduced linearly over a rolling seven-day period. If the fuel supply is insufficient for maximum output during all profitable periods, the opportunity cost is positive. If

[120] NYISO Reference Level Software User's Guide, Appendix B Fuel Cost Adjustment Functionality, https://www.nyiso.com/documents/20142/3625950/RLS_UG.pdf

[121] NYISO Market Services Tariff, Section 23, October 25, 2024 https://nyisoviewer.etariff.biz/viewerdoclibrary/mastertariffs/9fulltariffnyisomst.pdf

[122] Gas Electric Harmonization Forum Survey Results: Comment Submissions – February 27, 2023 – Compiled, page 325.

[123] 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 RTOs' ability to call on gas-fired generation in strategic locations following an electric-side contingency, or to mitigate other abnormal system conditions.

[124] Gas Electric Harmonization Forum Survey Results: Comment Submissions – February 27, 2023 – Compiled, page 328.

sufficient, the opportunity cost is zero.[125] ISO-NE's Day-Ahead Ancillary Services Initiative (DASI) incentivizes day-ahead reserve product participation and enforces penalties for non-performance, aligning day-ahead commitments with real-time reliability needs. This new market design is scheduled to take effect on March 1, 2025.[126]

Structural changes to capacity markets administered by ISO-NE and NYISO have the potential to improve gas/electric resilience during cold snaps. ISO-NE is proposing Capacity Auction Reforms (CAR) that would transform the region's Forward Capacity Market to a prompt and seasonal market with accreditation reforms. The CAR aim to enhance cost-effectiveness by ensuring that resource compensation is better aligned with contributions to maintaining resource adequacy and grid reliability. Under RCA, accreditation would be done via a Marginal Reliability Impact (MRI) calculation rather than using heuristics.[127] Resource modeling improvements led to ISO-NE identifying winter resource adequacy risk in impact analyses, rather than all risk being concentrated in the summer, largely due to modeling constraints on daily gas for non-firm generation and energy limitations for DFO storage. In turn, MRI values would consider unit-specific fuel security attributes and forced outage rates in accrediting gas and oil-fired resources. CAR reforms have the potential to provide price signals that support LNG contracts in New England in the medium- and long-term, particularly if accreditation values significantly reduce operating revenues from capacity sales during the winter season. In May 2024, ISO-NE received FERC approval to further delay FCA 19 until February 2028 to have time to develop a prompt and seasonal capacity market design and corresponding capacity accreditation reforms.[128]

NYISO has a longstanding practice of procuring reserves in its DAM, a process in place since the organization's inception. This approach ensures that sufficient reserves are scheduled ahead of time to maintain system reliability.

NYISO has implemented capacity accreditation reforms that, similarly to the ISO-NE RCA project, will reflect accreditation based on marginal reliability contribution rather than simply based on heuristics. Resources are sorted into Capacity Accreditation Resource Classes (CARCs) which are then assigned a Capacity Accreditation Factor (CAF) based on reliability modeling.[129] Currently, thermal generation CARC classifications that would apply different CAFs for different firm fuel classifications are not yet implemented. On July 23, 2024, FERC accepted tariff provisions proposed by the NYISO to include the modeling of natural gas constraints in capacity accreditation, subject to the condition that NYISO delay

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[125] Phase 1 was put into effect in November 2018 and provided market participants with an estimated daily opportunity cost to use in formulating energy market offers. Phase 2 went into effect in December 2019 and added a real-time market opportunity cost calculation.

[126] ISO-NE Day-Ahead Ancillary Services, accessed October 27, 2024 https://www.iso-ne.com/committees/key-projects/day-ahead-ancillary-services-initiative

[127] Resource Capacity Accreditation in the Forward Capacity Market: Overview of Key Concepts in Capacity Accreditation, June 7-8, 2022 presentation by Steven Otto to the NEPOOL Markets Committee, see slide 11. https://www.iso-ne.com/static-assets/documents/2022/06/a02_mc_2022_06_7-8_resource_capacity_accreditation_in_the_forward_capacity_market.pptx

[128] Letter order accepting ISO New England Inc.'s 04/05/2024 filing of proposed revisions to its Transmission, Markets and Services Tariff to delay the nineteenth Forward Capacity Auction until 02/2028, May 20, 2024, FERC Docket No. ER24-1710. https://www.iso-ne.com/static-assets/documents/100011/er24-1710-000.pdf

[129] Capacity Accreditation: Implementation Details, presentation by Maddy Mohrman to the Business Issues Committee, December 14, 2022. https://www.nyiso.com/documents/20142/34963268/4%20CA%20Capacity%20Accreditation%20pres.pdf

implementation until the 2026-2027 capability year.[130] Resources will need to demonstrate firm fuel capability to avoid receiving a non-firm CAF. NYISO is also examining the impacts of moving to a "more seasonally differentiated capacity market" in the Winter Reliability Capacity Enhancements Issue Discovery project.[131]

RTO programs that ensure that the control room has realistic operational options during cold snaps or outage contingencies also mitigate contingency risk. An example is ISO-NE's Winter Reliability Program, which ran from winter 2013/14 through 2017/18. The program provided economic incentives for oil and LNG storage and demand response. Another example is ISO-NE's Energy Market Offer Flexibility Project, which produced changes that allow generators to update supply offers in real-time (up to 30 minutes before the start of an hour) to reflect changes in the cost of fuel.[132] 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."[133]

The Inventoried Energy Program (IEP) in Appendix K of Section III of the ISO-NE Tariff is a voluntary interim program designed to provide incremental compensation to certain resources that maintain inventoried energy during cold periods when energy security is stressed. The program began in the winter of 2023/24 and is presently scheduled to end in February 2025. A dual fuel generator with dedicated oil can be compensated for the inventoried energy associated with the oil under the program. Natural gas associated with firm supply arrangements also qualifies under the IEP, and electric storage, demand response, and refuse facilities may offer inventoried energy.[134]

ISO-NE's Regional Energy Shortfall Threshold (REST) Initiative seeks to develop a reliability-based threshold that reflects the region's risk tolerance regarding energy shortfalls during extreme weather.[135] The REST metric is in effect an energy adequacy companion to the commonly held resource adequacy standard for one day in ten years' loss of load expectation. ISO-NE's PEAT will be used to quantify energy shortfall risk and measure it against REST metric thresholds.[136] ISO-NE and stakeholders may then identify solutions to mitigate energy shortfall risk if it exceeds REST metric thresholds.

Another specific NYISO program is NYISO's Comprehensive Shortage Pricing proposal, which increases reserve requirements in Southeast New York.[137] Coupled with NYISO's Comprehensive Scarcity Pricing

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[130] Order Accepting Tariff Revisions Subject to Condition, issued July 23, 2024, FERC Docket No. ER24-2096.

[131] Winter Reliability Capacity Enhancements, Micheal Swider to ICAP Working Group, August 13, 2024. https://www.nyiso.com/documents/20142/46346732/Winter_Reliability_Enhancements_Aug13_ICAPWG.pdf

[132] 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.

[133] "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

[134] Winter 2024 Quarterly Markets Report, ISO-NE Internal Market Monitor, May 31, 2024, page 26.

[135] See ISONE "Establishment of the Regional Energy Shortfall Threshold (REST)" presentation (8/2024): https://www.iso-ne.com/static-assets/documents/100014/a14_regional_energy_shortfall_threshold_aug_rc.pdf

[136] In this study, LAI has relied on PEAT forecasts. Once established, ISO-NE will evaluate if meeting the REST requires the development of specific regional solutions.

[137] On February 18, 2015, NYISO filed proposed changes to its Market Administration and Control Area Services Tariff to implement these provisions, Docket No. ER15-1061-000:
https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20150218-5152

changes, more generation capacity will be available, thereby providing NYISO control room operators with increased flexibility to respond to electric-side contingencies.[138]

Operating permits do not typically contain exemptions from seasonal or annual oil burn operation limits during a declared emergency event.[139] 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 authority. RTOs can request a waiver under Section 202(c) of the Federal Power Act in order to allow individual generators to run at maximum output levels to alleviate electricity shortages during emergencies. This measure often is used to waive emissions or environmental permitting restrictions for a short time.[140] PJM requested, and DoE granted, a 202(c) waiver during Winter Storm Elliott.[141]

7 Key Risk Factors

Consistent with the goals and objectives NPCC set forth for purposes of evaluating the physical capability of the consolidated network to withstand postulated disruptions in the gas supply chain during cold snaps, LAI has identified a number of risk factors. These risk factors have not been quantified but are summarized in this section in order to put in perspective the feasibility of the mitigation measures contemplated to preserve electric grid reliability under dynamic resource mix changes over the long-term.

Dual Fuel and Oil Retirements: PEAT modeling of the long-term forecast period shows that the electric system will be stressed from a daily capacity perspective during the modeled 2004 extreme cold weather conditions if Constellation EMT retires after the current long-term contracts with Massachusetts LDCs end. Additional dual fuel and/or oil generator retirements beyond those assumed in the PEAT modeling conducted for this study represent a risk to ISO-NE's ability to serve load on peak winter days. Given the limited DFO storage capability at many generating facilities, the region may want to consider solutions that mitigate replenishment risk.

Aurora modeling did not show similar stressors, but non-gas capacity will remain critical to meeting NYISO load. Dual fuel and oil retirements are also a risk factor in NYISO. Oil-fired generation makes up a substantial portion of the load-following energy in cold weather in the electric system modeling, even in the long-term forecast period where additional renewables are available.

LNG Availability: The ISO-NE PEAT results assumed that full LNG sendout capability from import terminals in Everett, MA and New Brunswick is available to provide gas for generators. The steady state and transient flow modelling does not consider the commercial realities of LNG procurement. Importers will

[138] Although NYISO allows generators to recover imbalance charges outside of OFO periods, bids reflecting imbalance charges can be mitigated. If imbalance charges are incurred, they are recoverable on mitigated bids subject to the approval of the Market Monitor.

[139] Some air permits require strict thresholds to be met for backup fuel to be engaged at all, such as the declaration of an energy emergency by the ISO.

[140] Energy Waivers Library, U.S. Department of Energy. Accessed January 13, 2025. https://www.energy.gov/ceser/energy-waivers-library

[141] Federal Power Act Section 202(c): PJM December 2022, U.S. Department of Energy. Accessed January 13, 2025. https://www.energy.gov/ceser/federal-power-act-section-202c-pjm-december-2022

require forward contracting ahead of the heating season to ensure that inventory is available for generators. Absent compensatory call options with generators or marketers that serve them, the LNG importers cannot be expected to dedicate existing inventory that is managed to support Constellation EMT's and Repsol Saint John's contract obligations during the peak heating season.

The substitutability of Repsol Saint John for Constellation EMT is predicated on the daily scheduling of Repsol's inventory for delivery in northern New England, which is largely contracted by LDC customers during the peak heating season. Repsol Saint John's ability to serve generators in New England cannot hinder its contractual obligations to LDCs in New England. Repsol Saint John manages its LNG inventory to ensure that forward obligations to core customers are met. Notably, Repsol Saint John's long-term firm transportation agreement with Maritimes & Northeast is scheduled to expire in 2034, one year after the long-term forecast period. It costs Repsol about $112 million per year to hold firm transportation on Maritimes & Northeast regardless of use. Because this contract obligation is deep in-the-red from the shipper's perspective, it is unclear what commercial considerations may govern the use of Maritimes & Northeast going forward. Absent compensatory arrangements between gas-fired generators or marketers and Repsol, gas-grid operating flexibility will likely be imperiled after the study period ends by the loss of most or all displacement services available to the thermal fleet in New England. While there may be other pathways to get gas into northern New England during a peak winter day, these would require new investments and/or regulatory approvals and the size and scope of such an addition is unknown. Hence, the potential for such mitigation has not been explored in this inquiry.

Pipeline Operations: The hydraulic modeling conducted considers only the physical capability of the consolidated pipeline network. However, contractual requirements, and not physical deliverability, often represent the binding constraint, based on the pipeline operators' need to preserve system reliability for firm customers. This limiting criterion is true for both the baseline condition and the array of actions taken post gas-side contingency. Insofar as nearly all gas-fired generators in New England and New York do not have firm transportation entitlements back to a liquid receipt point, gas nominations to support scheduled generation would be wholly subordinated post contingency. Gas-electric coordination protocols are in place that enable electric system operators and pipeline operators to be aware of such protocols in order to operationalize effective mitigation measures. Such gas-electric protocols should enable post-contingency responses to avoid damage to gas turbines attributable to the sudden cessation of gas supply. To the extent that pressure losses happen more quickly than pipeline operators can accommodate, the operator may need to resort to Automatic Flow Controls as the final measure to preserve gas grid integrity.

Renewables and Load Growth: In ISO-NE and NYISO, the integration of renewables and rising electrification-driven demand creates significant long-term challenges. Both regions are projected to experience aggressive demand growth, particularly in the winter, due to increased electrification of transportation and heating, and some large load integration in NYISO. Offshore wind is expected to be developed in the long-term forecast period; however, its intermittent nature and potential performance issues during extreme weather, such as high winds or frigid temperatures, highlight the need for enhanced grid flexibility through load-following conventional generation and electric storage.

8 Conclusions

The gas and electric system modeling confirms that the region's natural gas infrastructure is fully or near fully utilized during periods of extreme cold weather.[142] Though gas supplies are limited during cold weather and oil shares the load following burdens, during milder conditions the interstate gas pipeline system can accommodate larger hourly ramps that will be needed to balance the grid as more renewable resources come online. Given the constraints in the natural gas infrastructure during cold weather, and practical difficulties scheduling intraday gas to respond to electric-side contingencies such as the sudden loss of a nuclear unit or large transmission line, the availability of oil-fired generation is critical to ensure the reliability of the electric system in New England and New York, in particular, the New York Facilities System. Scheduling flexibility in both the gas and electric days is enhanced through use of LNG. Gas generators' use of LNG in New England from Constellation EMT and/or Repsol Saint John is an integral part of the region's gas infrastructure to serve both gas utilities and gas-fired generators under the harsh weather conditions evaluated in this study.

Scenarios that postulate gas- or electric-side contingencies would likely result in increased dependency on the region's oil generation fleet. In New England, the potential loss or retirement of Constellation EMT combined with the scheduled retirement of oil plants could necessitate capacity deficiency actions in a few peak hours in order to preserve electric system reliability in the long-term scenario. East-end injections via Repsol Saint John and Constellation EMT that otherwise displace conventional west-to-east flows on Algonquin and Tennessee, in particular, provide valuable benefits in the form of pressure support and enhanced scheduling flexibility. Repsol Saint John is an imperfect substitute for Constellation EMT. Nevertheless, Repsol Saint John provides substantially similar operational benefits to both gas utilities and gas-fired generators in New England, but certainly not all. There are LDC service issues, including a small amount of generation behind the citygate in Cambridge, MA, that can be mitigated or resolved through sendout from Constellation EMT. Moreover, Constellation EMT's location is ideal for the provision of instantaneous pressure and flow under both harsh weather conditions and milder weather when a need arises. Repsol Saint John is located further away and would take longer to meet an unanticipated need.

In regard to the deliverability and scheduling of LNG from one or both import terminals, LAI finds that what is physically possible and commercially practicable are distinctly different. LNG import facilities are not sufficiently incentivized to secure cargoes in excess of their contracted firm obligations executed well ahead of the heating season. Likewise, under the current wholesale market design New England's gas generators are not sufficiently incentivized to enter into such contracts in the form of call options with one or both LNG importers. This tension between buyer and seller is understandable since no one knows the timing and severity of extreme weather many months in advance. Structural reforms contemplated by ISO-NE and the region's stakeholders have the potential to make more effective wholesale price signals with an eye toward electric grid resilience during cold snaps.

In NYISO, dual fuel capable generation is more commonplace, particularly in downstate New York. Electric simulation modeling did not reveal the same level of stress in NYISO as observed in ISO-NE. During both the baseline weather conditions and the array of gas-side contingencies tested in this study, oil is heavily relied upon by NYISO to meet demand. Gas-fired generation is unlikely to respond in large measure to

[142] There are some pipeline route segments that are less than fully utilized and have limited additional deliverability during cold snaps in part due to upstream supply limitations. The aggregate amount of such additional headroom is insignificant in relation to consolidated deliverability across the Study Region.

electric contingencies, as much of the fast-start capable resources are supplied via the New York Facilities System, which lacks flexibility during harsh weather conditions to schedule dual fuel generators on natural gas in the first place.

In the long-term scenario, demand was assumed to increase substantially due to electrification of heating and transportation. Demand growth increases gas demand for power generation and further stresses the electric system. Uncertainty about renewable resource additions in New England and New York, in particular, offshore wind entry, has the potential to heighten performance requirements across the thermal fleet with the passage of time, especially if the states maintain the collective resolve to support aggressive heating and transportation electrification goals. Both ISO-NE and NYISO are likely to face complex tradeoffs about grid resilience, environmental decarbonization goals, and the preservation of both options and incentives placed on gas and dual fuel generators to sustain flexible operation.