2025-2034 Comprehensive Reliability Plan

A Report from the
New York Independent
System Operator

Draft 1
For Sept 25, 2025 ESPWG/TPAS

DRAFT – For Discussion Purposes Only

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Background

This *2025-2034 Comprehensive Reliability Plan* (CRP) completes the 2024-2025 cycle of the NYISO's Reliability Planning Process. The 2024 Reliability Needs Assessment (RNA), approved by the NYISO Board of Directors in November 2024, was the first step of the current cycle. This CRP follows the 2024 RNA and provides the regional transmission plan, incorporating findings and solutions from the quarterly Short-Term Reliability Process, as available, to maintain reliability over the ten-year planning horizon.

This section provides an overview of the current state of New York's electric grid, recent operational events, and findings from short-term reliability planning studies. Together, these elements offer context for understanding the system's evolving reliability landscape and inform the longer-term outlook presented in the CRP.

State of the Grid

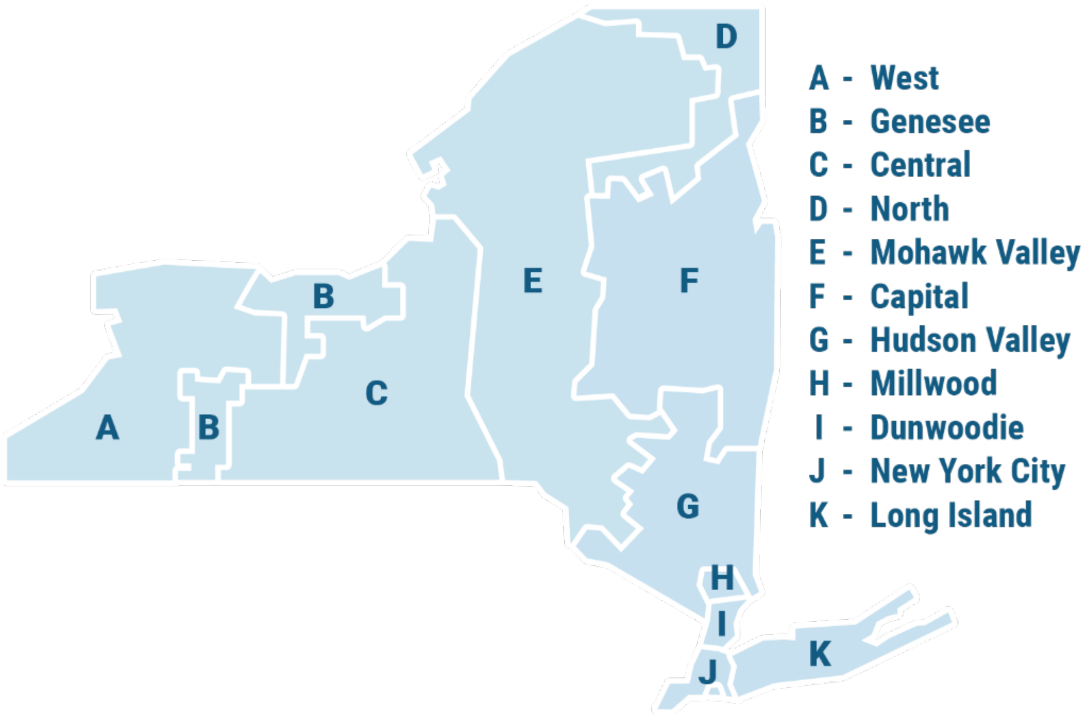
New York's power grid is dramatically changing how it serves consumers and is evolving to meet the state's clean energy objectives. The NYISO offers two annual publications—the *Load & Capacity Data Report*[1] (Gold Book) and *Power Trends*[2]—that provide independent sources of information and analysis on New York's electric system.

The New York Control Area (NYCA) is comprised of 11 geographical zones from western New York (Zone A) through Long Island (Zone K). At various points, this CRP refers to these zones to provide locational details regarding system demand, projected resource mixes, and anticipated transmission constraints. A map of the NYCA zones is shown in Figure 1.

[1] 2024 Load & Capacity Data Report (Gold Book)

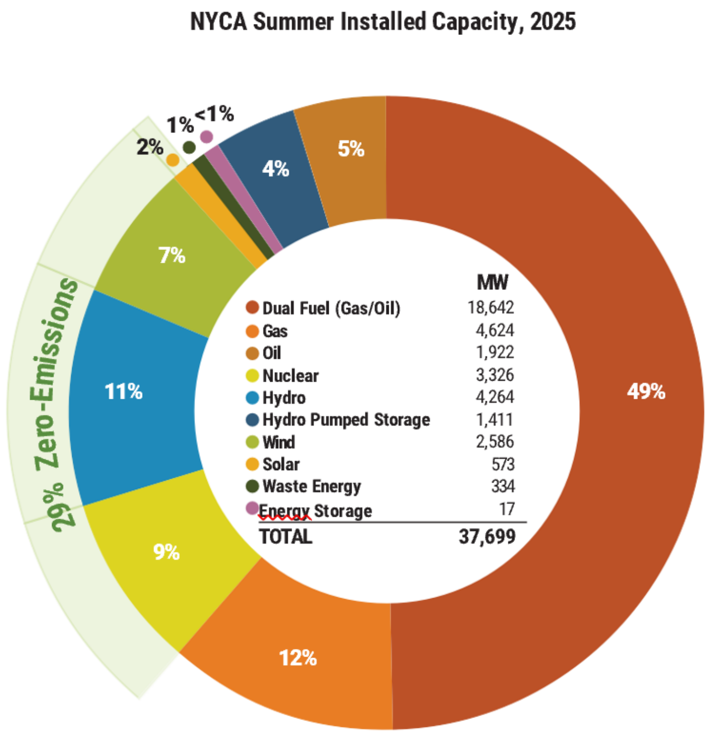
[2] 2024 Power Trends

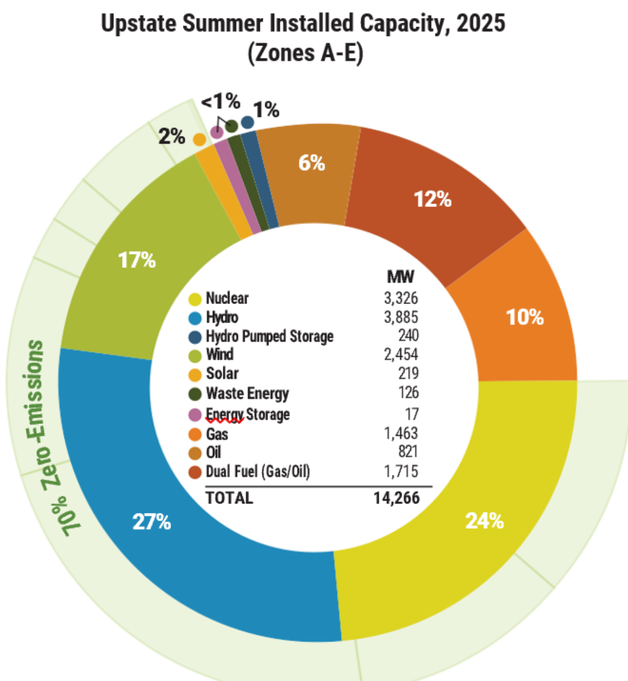
Figure 1: NYCA Load Zones



A summary of the current system resources is provided below. Figure 2 depicts the projected mix of resource capacity that was expected to be available for the 2025 summer capability period, and Figure 3 provides the energy production by fuel sources in 2024.

Figure 2: Summer Installed Capacity (MW) by Fuel Source – Statewide, Upstate, & Downstate New York: 2025





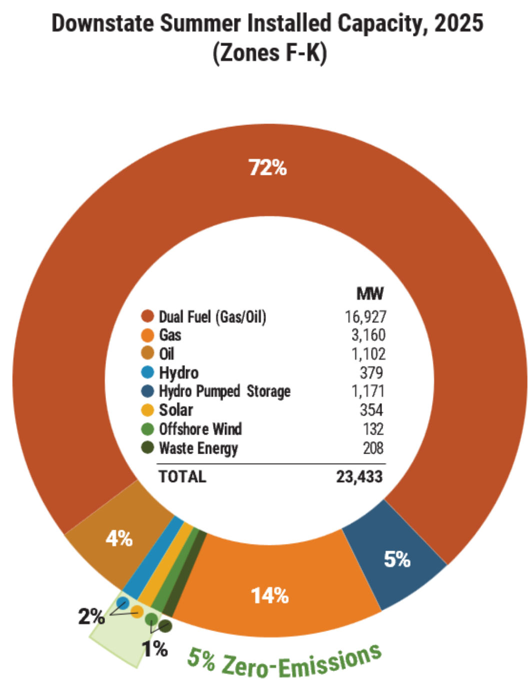
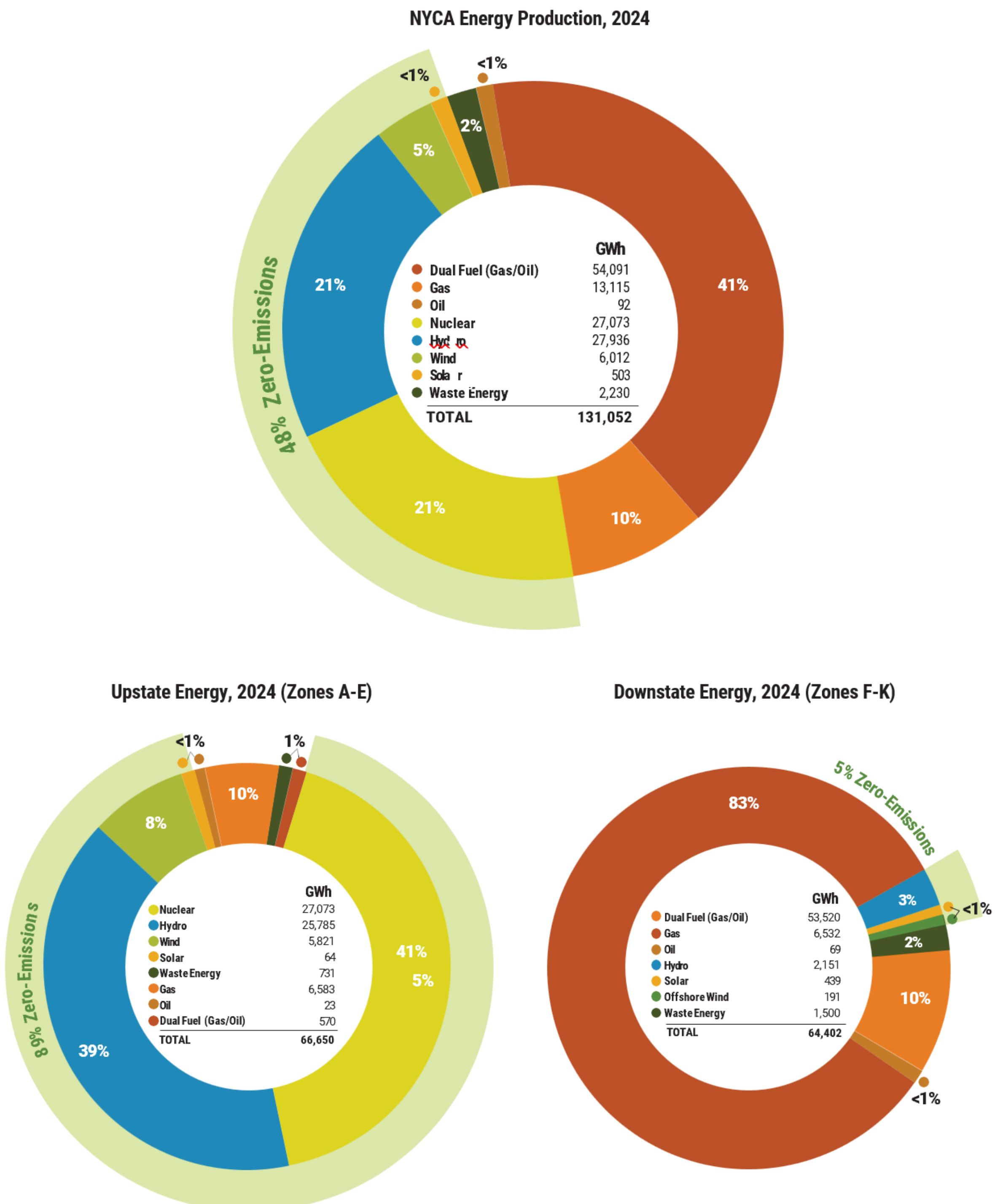


Figure 3: Energy Production by Fuel Source (GWh) – Statewide, Upstate, & Downstate New York: 2024



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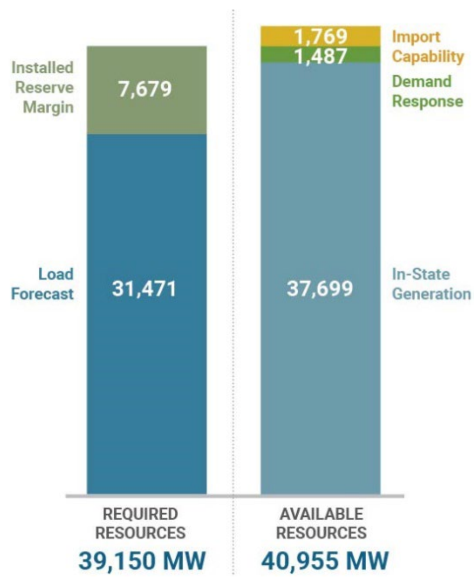
The total resource capability in the NYCA for the summer of 2025 was projected to be 40,910 MW, which includes 37,654 MW of generating capability, 1,487 MW of demand response, and 1,769 MW of net long-term purchases and sales with neighboring control areas.

The New York system's minimum Installed Reliability Margin (IRM) is established every year by the New York State Reliability Committee (NYSRC). The IRM represents the minimum level of capacity, beyond the forecasted peak demand, which must be procured to serve consumers. The IRM is established every year for each following capability year (May 1 through April 30) and is used to quantify the minimum capacity required to meet the Northeast Power Coordinating Council (NPCC) and NYSRC resource adequacy rules. The NYISO, in assisting NYSRC, analyzes forecasted demand, supplier performance, transmission capability, and factors such as extreme weather, to measure the grid's ability to meet reliability requirements. NYSRC has noted in several of its annual *Installed Capacity Requirement Technical Study* reports[3] that the inclusion of intermittent resources to the grid is a leading factor in establishing higher IRM requirements. The IRM for the May 1, 2025 - April 30, 2026 capability year is 24.4% of the forecasted NYCA peak load, representing an increase from the 22% established last year.

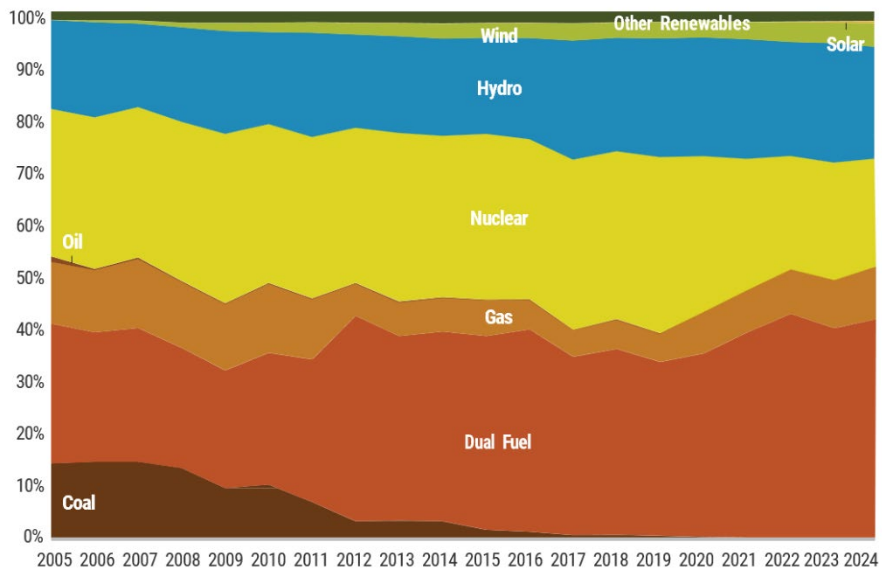
Figure 4: Statewide Resource Availability: Summer 2025



The historical generating capacity fuel mix in New York State from 2000 through 2023 is depicted in the Figure 5 below.

[3] NYSRC's IRM Reports: https://www.nysrc.org/NYSRC_NYCA_ICR_Reports.html.

Figure 5: Historical Generating Capacity Fuel Mix in New York State: 2005-2023

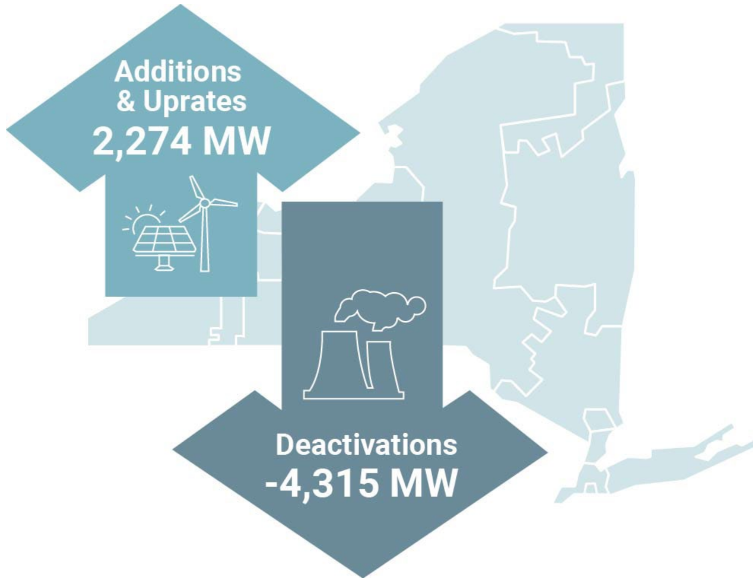


Regulatory Policies Affecting the Grid

Increasingly ambitious environmental and energy policies, evolving market rules, technological advancements, and economic factors impact the decisions by market participants and are accelerating the transition in the state's resource supply mix. During this transition, the pace of both the addition of new resource additions and the retirement of older, higher-emitting resources are projected to exceed historical levels. Changes to demand patterns and the generation fleet driven by federal, state, and local government regulatory programs may impact the operation and reliability of New York's bulk power system. Compliance with federal and state regulatory initiatives and environmental and permitting requirements may require investment by the owners of New York's existing thermal power plants in order to continue operation. If the owners of those plants must make significant investments to comply, the increased cost to continue operating could lead to the retirement of these resources needed to maintain the reliability of New York's bulk power system and, therefore, could necessitate replacement.

Balancing the grid throughout this transition not only requires maintaining sufficient capacity to meet demand but also requires that new resources entering service comparably replace the capabilities and attributes of the resources leaving the system (*e.g.,* fast starting/ramping and dispatchable both up and down, available when and for as long as needed, providing essential reliability services such as voltage and frequency control, support system's stability during disturbances). Continued dialogue and engagement among Market Participants, policymakers, and the NYISO will be essential to support the planning processes in order to identify the needs and services required to maintain a reliable system during and after this transition period.

Figure 6 : Additions and Deactivations Since 2019

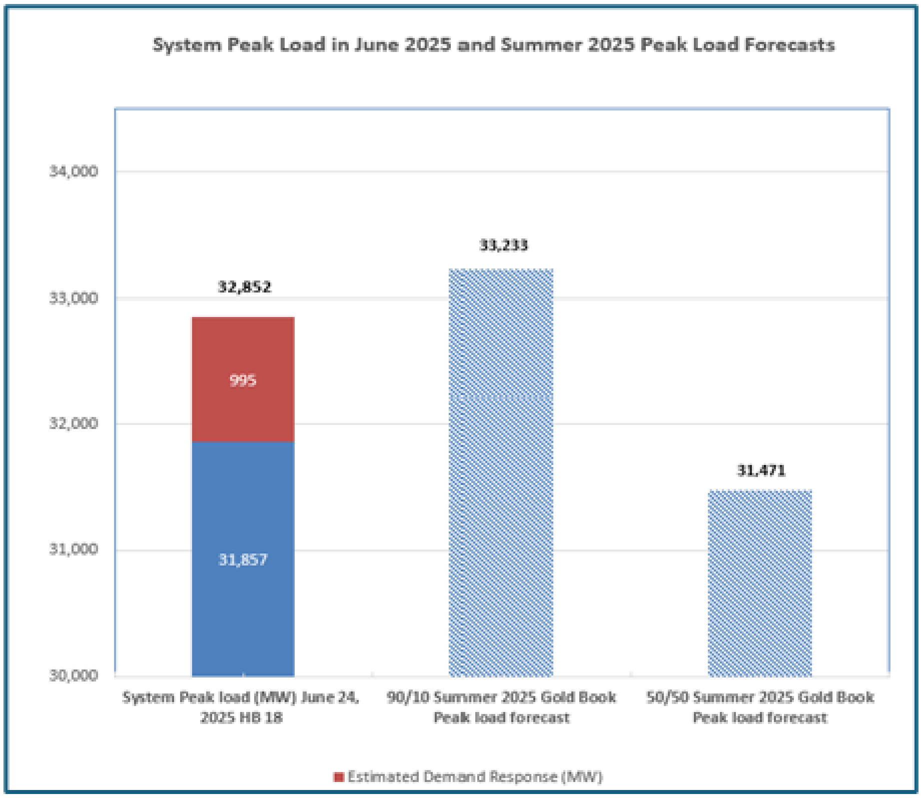


June 2025 Heatwave

Between June 23 and 25, 2025, the NYISO experienced one of the most challenging operating conditions in recent years as New York and much of the Eastern Interconnect experienced a heat wave. This section provides details of system conditions, operational actions, and resource performance during the event, offering context for understanding the reliability risks and planning implications in the CRP.

On June 24, 2025, peak net load reached 31,857 MW during the hour beginning 18:00 (HB18), after reductions of 995 MW of demand response. Without demand response reductions, the load would have been just 381 MW below the 90/10 forecast. 33,233 MW. The gross load for HB16 on June 24th was 34,491 MW and actually higher than HB18, but 2,675 MW of BTM solar and 1,096 MW of demand response reduced the net load, delaying the system peak load hour by two hours due to the solar and demand response contributions.

Figure 7: June Heatwave Load Comparison to Load Forecast



The NYISO declared a "Major Emergency" for a little over an hour and half on the evening of June 24th due to operating reserve deficiencies based on the following:

- Approximately 7,000 MW of capacity was unavailable at the peak load hour;
- Approximately 2,000 MW of external imports were curtailed from PJM, ISO-NE, and IESO limited import capability. The NYISO curtailed exports to ISO-NE and PJM;
- The NYISO procured 1,960 MW of emergency energy from neighbors; and
- Voltage reduction measures were counted as operating reserve, and demand response programs (EDRP/SCR) were activated across all zones.

Short-Term Reliability

The NYISO's Short-Term Reliability Process works in parallel with the longer-term Reliability Planning Process, providing updates and assessments that occur more frequently than the two-year reliability planning cycle. Findings from quarterly Short-Term Assessments of Reliability are incorporated into the CRP to ensure that recent developments are reflected in the longer-term outlook and planning assumptions.

The *Short-Term Assessment of Reliability: 2023 Quarter 2* ("*2023 Q2 STAR*")[4] and the *Short-Term Assessment of Reliability: 2025 Quarter 2* (*"2025 Quarter 2 STAR")*[5] are particularly noteworthy because they identify and address specific reliability impacts and expected changes to future demand forecasts.

In 2019, the New York State Department of Environmental Conservation (DEC) enacted regulations to limit Nitrogen Oxide (NOx) emissions, which has become known as the "Peaker Rule." This resulted in 1,027 MW of affected fossil-fired generators being deactivated or limited as of May 1, 2023 and an additional 590 MW becoming unavailable by May of 2025, unless a fossil-fired generator is identified as necessary to ensure the reliability of the system.

The *2023 Q2 STAR*, issued on July 14, 2023, identified a Short-Term Reliability Process Need due to a deficiency of up to 446 MW within New York City, resulting in violations of transmission security criteria, beginning in summer 2025. The need was driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City affected by the "Peaker Rule."

In accordance with the Short-Term Reliability Process, the NYISO issued a solicitation for solutions seeking solutions to resolve the reliability need. The NYISO determined that the Gowanus 2 & 3 and Narrows 1 & 2 generation units, which have a combined capacity of 508 MW, were necessary to continue to operate in order to satisfy the transmission security margin and maintain reliability of the system. As a result, the NYISO's designated these generation plants as necessary for reliability, which allowed their continued operation beyond May 2025, consistent with provisions in the "Peaker Rule." The NYISO described the continued operation of the Gowanus and Narrows units in the STAR as a temporary solution until the CHPE transmission project enters service and fully addresses the need for the remainder of the STAR's five-year study period.

After the conclusion of the 2023 Q2 STAR, the NYISO continued to evaluate the reliability of the system in each subsequent quarterly STAR and continued to confirm whether system changes mitigate the New York City deficiency or it was necessary for the NYISO to extend the identification of the Gowanus 2 & 3 and Narrows 1 & 2 as necessary to maintain the reliability of the system for an additional two-year period beyond 2027 to allow a permanent solution to enter service, as permitted by the "Peaker Rule."

[4] Short-Term Assessment of Reliability: 2023 Quarter 2, *available at* https://www.nyiso.com/documents/20142/39103148/2023-Q2-STAR-Report-Final.pdf.

[5] Short-Term Assessment of Reliability: 2025 Quarter 2, *available at* https://www.nyiso.com/documents/20142/39103148/2025-Q2-STAR-Report.pdf/.

2025-2034 Comprehensive Reliability Plan

The Comprehensive Reliability Plan to reliably serve New York demand for the 2025-2034 timeframe requires forecasting the balance between demand, generation, and transmission and managing growing uncertainty. This CRP is outlined in the following sections:

- **Comprehensive Reliability Plan (this section):** This section summarizes the findings of the 2024 RNA and describes the resolution of the identified Reliability Need in New York City. It also presents key future projects and planning assumptions that form the baseline conditions for the CRP. These baseline assumptions serve as reference points for scenario analyses conducted throughout the remainder of the plan, which explore uncertainties and associated reliability risks.
- **Planning for Uncertainty**: To better understand the range of possible futures, the CRP examines the uncertainty around key system factors—i.e., aging generation, demand, weather variability, imports, project delays, demand response, and additional resources—and their individual influence on system performance. The CRP then further examines combinations of these uncertainties and highlights how different plausible configurations can impact system reliability margins. This section uses statewide system margin calculations to quantify the relative and combined impacts of the different uncertainties.
- **Potential Pathways to a Reliable Grid**: The CRP explores certain combinations of demand and aging generation risks to gauge when, and under what conditions, Reliability Needs could be identified in the future. If scenarios are found to violate criteria, different scenarios of resource additions are modeled to demonstrate potential solution sets.
- **Aligning Reliability Planning with Operational Reliability**: The CRP examines (a) lessons learned from the June 2025 heatwave, (b) resource planning for normal conditions, and (c) comprehensive need for system voltage support. Together, these observations point to the need for a planning framework that better reflects operational realities and anticipates emerging reliability risks.

2024 RNA and Resolution of the 2033 New York City Reliability Need

The 2024 RNA evaluated the reliability of the New York bulk electric grid from 2028 through 2034, considering forecasts of peak power demand, planned upgrades to the transmission system, and changes to the generation mix. The RNA assesses a “base case” set of assumptions to identify actionable Reliability Needs if there is a violation of applicable Reliability Criteria. Based on the base case assumptions, the 2024 RNA identified a Reliability Need beginning in summer 2033 within New York City primarily driven by a combination of forecasted increases in peak demand, limited additional supply, the assumed retirement of the NYPA small gas plants based on state legislation, and the assumed unavailability of generators impacted by the DEC Peaker Rule. Accounting for these factors, the RNA initially found that the Bulk Power

Transmission Facilities (BPTF) will not be able to securely and reliability serve the forecasted demand in New York City. When accounting for forecasted economic growth and policy-driven increases in demand, the 2024 RNA found that New York City (Zone J) will be deficient starting in summer 2033 by as much as 17 MW for 1 hour and increasing to 97 MW for 3 hours in summer 2034 on the peak day during expected weather conditions.

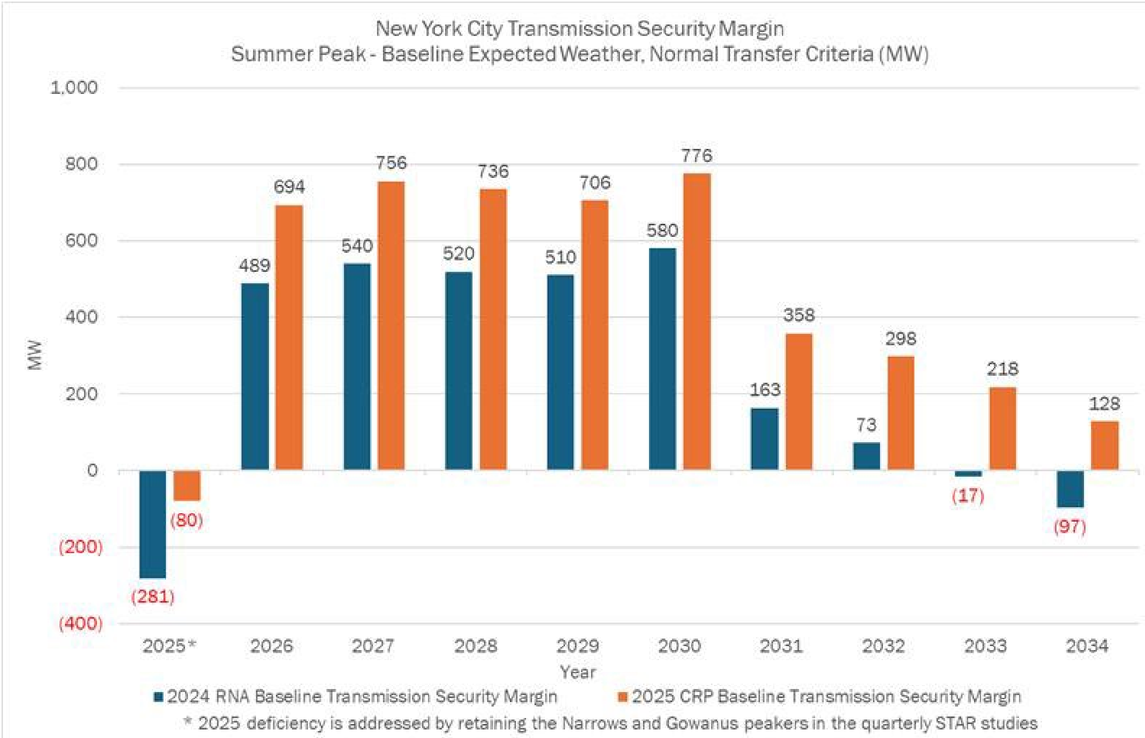
After the completion of the 2024 RNA, the NYISO considered relevant updates to Local Transmission Owner Plans (LTPs) and other system updates to determine if the Reliability Need is reduced or eliminated in accordance with its procedures. Following the release of the 2024 RNA, the 2025 Load & Capacity Report ("Gold Book") included the latest forecast and generation Dependable Maximum Net Capacity. The updated New York City peak demand forecast was roughly 200 MW lower each of the next ten years over the 10-year planning horizon compared to the 2024 Gold Book's forecasts used in determining the New York City Reliability Need.

Figure 8: New York City Forecast Comparison

Comparison of 2024 Zone J Goldbook Forecast and 2025 Preliminary Zone J Forecast										
Item	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Zone J Baseline Demand Forecast (2024 Goldbook) (MW)	10,960	10,990	11,020	11,040	11,050	11,080	11,130	11,220	11,310	11,390
Zone J Baseline Demand Forecast (Preliminary 2025 Goldbook) (MW)	10,764	10,790	10,820	10,840	10,860	10,880	10,930	11,010	11,080	11,170
Impact (MW)	*196*	*200*	*200*	*200*	*190*	*200*	*200*	*210*	*230*	*220*
Item	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Zone J High Demand Forecast (2024 Goldbook) (MW)	11,140	11,270	11,400	11,530	11,660	11,800	11,940	12,100	12,260	12,430
Zone J High Demand Forecast (Preliminary 2025 Goldbook) (MW)	10,800	10,920	11,040	11,170	11,330	11,510	11,650	11,800	11,960	12,130
Impact (MW)	*340*	*350*	*360*	*360*	*330*	*290*	*290*	*300*	*300*	*300*

Taking into account these system updates, the analysis showed that the revised system margin through 2034 would be positive and the Reliability Need identified in the 2024 RNA was eliminated. As a result, the NYISO notified stakeholders that a solicitation for solutions was not required to address the Reliability Need identified in the 2024 RNA in May 2025. Figure 9 below shows how the New York City transmission security margin deficiency identified in the 2024 RNA is addressed by the system updates.

Figure 9: New York City Margin Comparison



Future Projects and Assumptions in the CRP

The analysis in the CRP was performed using the 2025 reliability planning model. This model is similar to that used in the 2024 RNA and has been updated with the 2025 Gold Book demand forecasts and other updates consistent with the *2025 Q3 STAR*.[6] This section summarizes the key future projects and assumptions that have been included as part of this CRP.

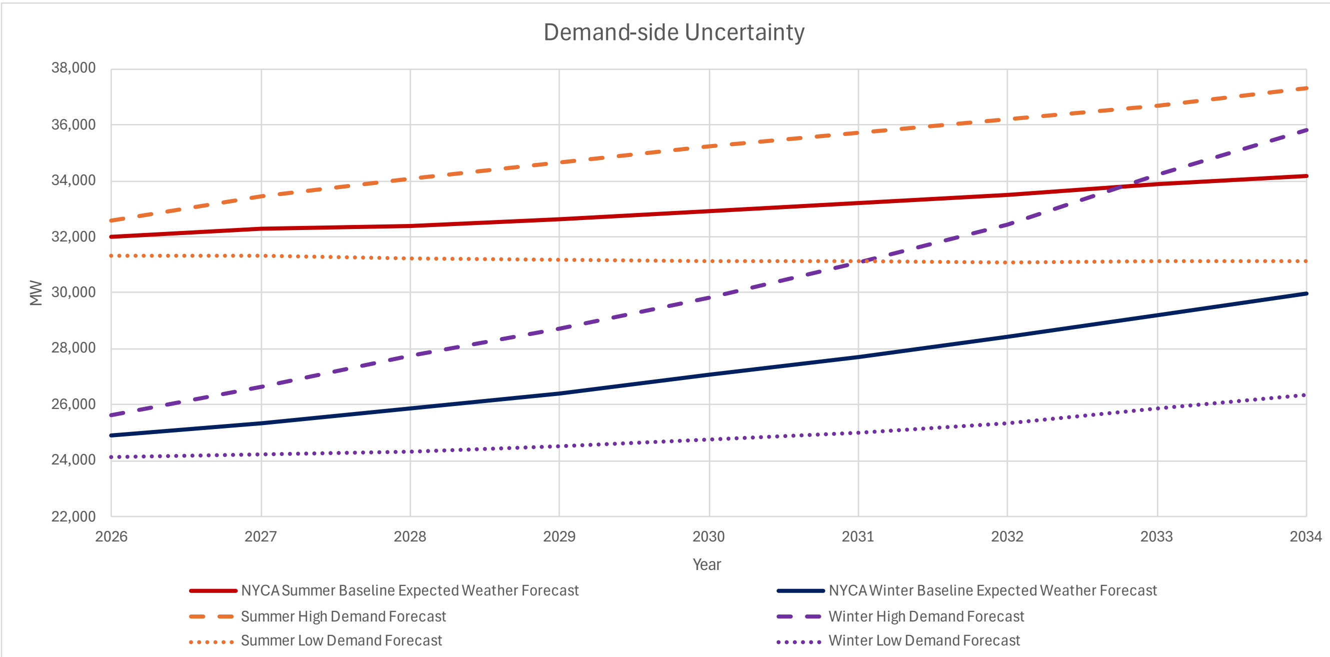
Demand Forecast

The 2025 Gold Book provides an in-depth review of the load forecast and changing resource mix. Baseline energy and coincident peak demand increases significantly throughout the 30-year forecast period in the Gold Book, driven largely by large load project growth in the early forecast years and electrification of space heating, non-weather sensitive appliances, and electric vehicle charging in the outer forecast years. As discussed further in the CRP, there is uncertainty in the demand forecast driven by uncertainties in key assumptions, such as population and economic growth, energy efficiency, the installation of behind-the-meter renewable energy resources, and electric vehicle adoption and charging patterns. These risks to the baseline demand forecast are seen through the incorporation of the lower and

[6] Short-Term Assessment of Reliability: 2025 Quarter 2, *available at* [to be added].

higher demand forecast, which provide a bounding to the range of forecasted conditions during expected weather.

Figure 10 2026-2034 Demand Forecasts



Planned Generation

Figure 11 provides a graphical representation of generation capability that is included in the CRP. Figure 12 highlights the planned future generation projects and deactivations. A new generation resource is included in reliability studies when the project has reached a key milestone in the NYISO interconnection process and is making significant progress in construction, project financing, and/or regulatory approvals. The additional generation modeled in this CRP includes a total of 656 MW of land-based wind generation, 1,740 MW of offshore wind generation, 1,993 MW of solar generation, and 35 MW of battery storage planned to be in service by summer 2028. The NYISO continues to track numerous additional generation projects active in the interconnection process.

For deactivations, the CRP assumes approximately 1,615 MW of generation removed because the generator is (1) in a deactivation state, (2) operationally impacted by the DEC Peaker Rule, or (3) a NYPA small gas plant that is assumed retired at the end of 2030 based on state legislation.

Figure 11: Planned Statewide Generation Mix

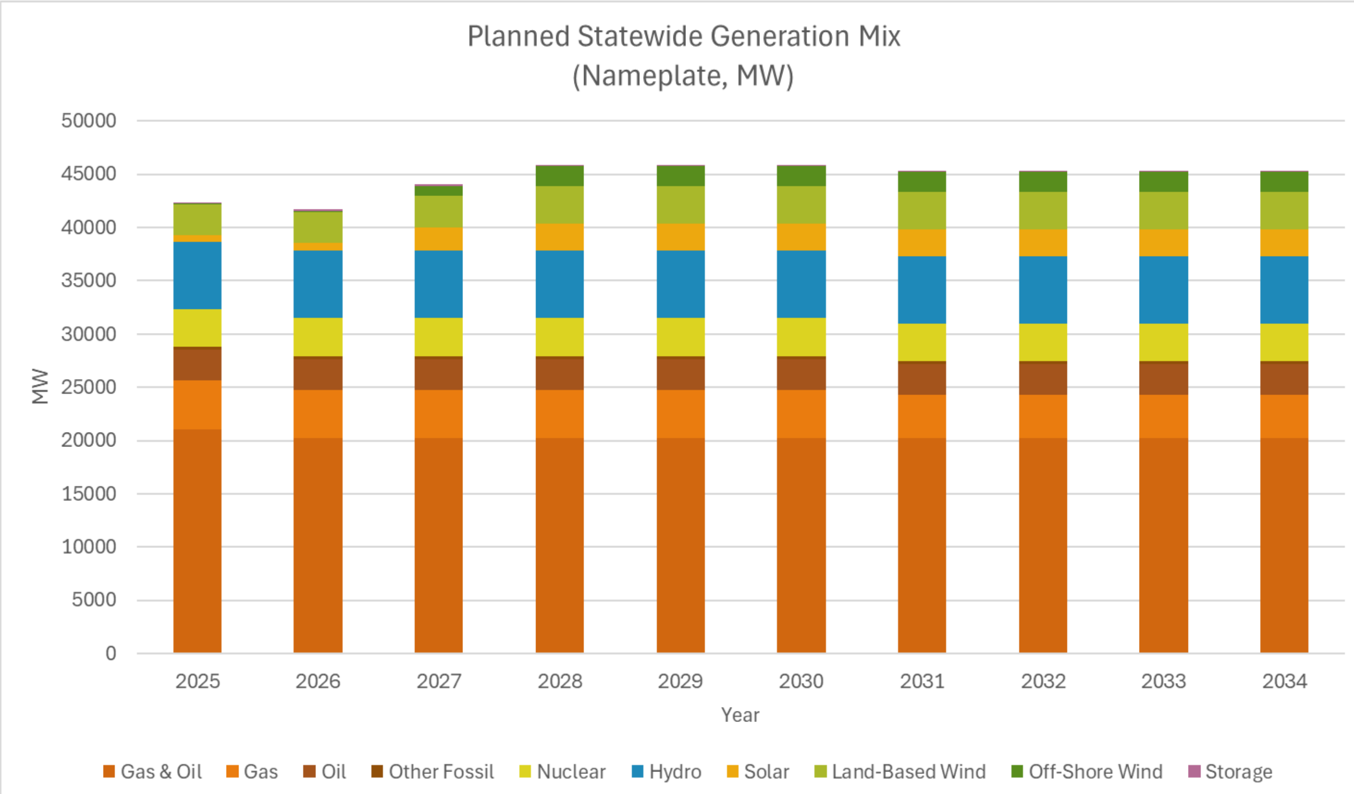
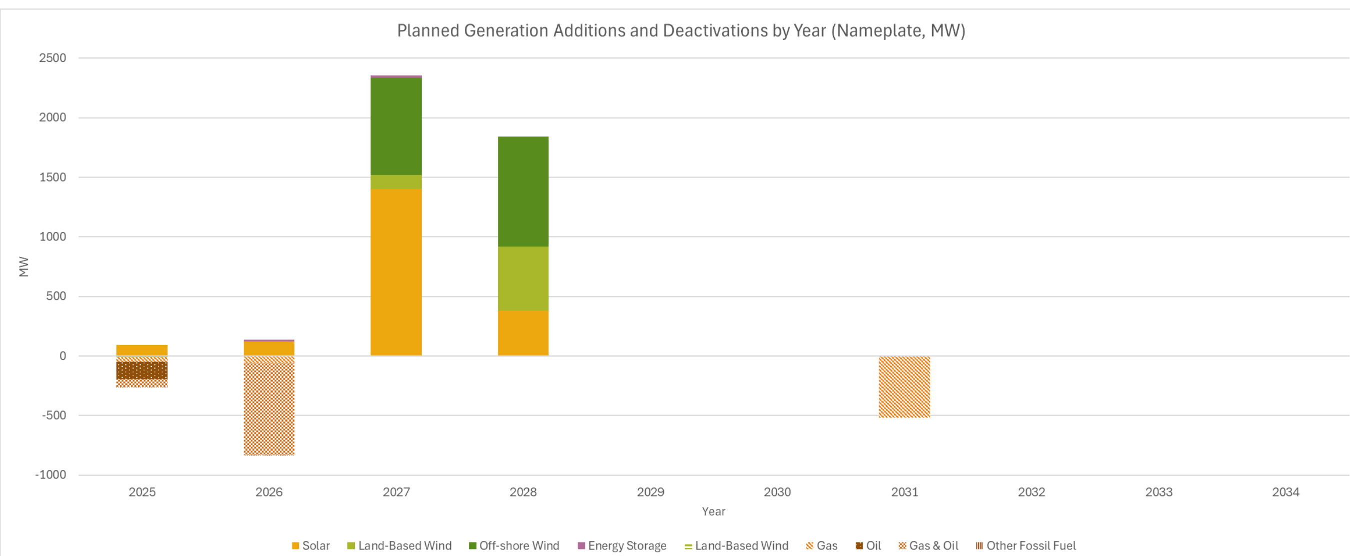


Figure 12: Planned Generation Additions and Deactivations by Year



Consistent with the 2024 RNA and NYSRC reliability rules, approximately 6,400 MW of generation with non-firm gas contracts, primarily in eastern New York, is assumed to be unavailable under expected winter weather peak demand conditions.

Planned Transmission

The major additions to the New York transmission system assumed in the CRP include the following:

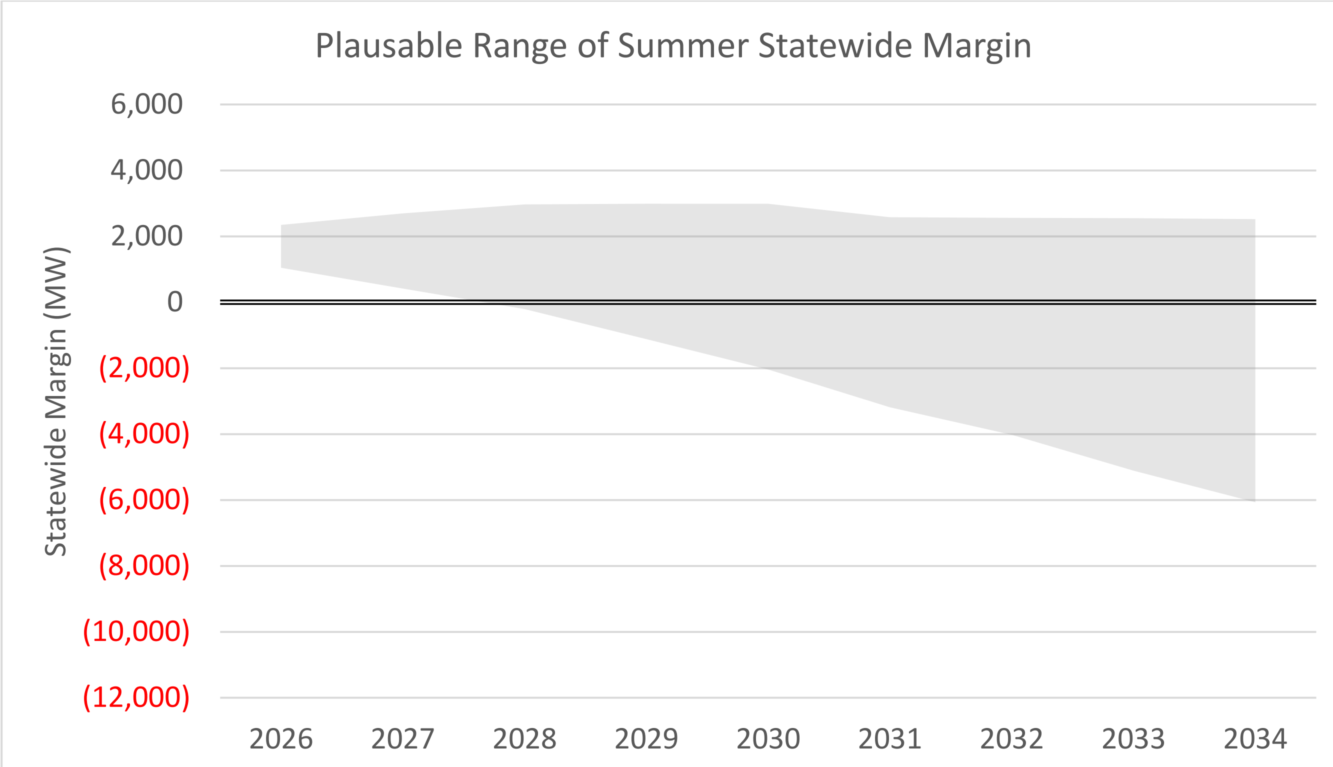
- **December 2025: Smart Path Connect** NYPA/National Grid's Northern New York Priority Transmission Project proposed under the New York State Accelerated Renewable Energy Growth and Community Benefit Act December 2025
- **May 2026: Champlain Hudson Power Express (CHPE)** 1,250 MW HVDC project from Quebec to Astoria Annex 345 kV in New York City (Zone J), awarded under NYSERDA's Tier 4 REC program. The facility is expected to provide capacity in the summer but not in the winter. The planned in-service date is spring 2026.
- **May 2030: Propel NY T051 Energy Solution** proposed jointly by NYPA and New York Transco, LLC through the NYISO's Public Policy Transmission Planning Process. The project adds three new AC tie lines between Long Island and the rest of New York and a 345 kV backbone across western/central Long Island.

Planning for Uncertainty

Reliability planning must account for how uncertainties in key system trends may interact and compound over time; it is not enough to study each risk in isolation. The NYISO identified numerous risk factors that could adversely affect the implementation of the CRP and hence system reliability over the planning horizon. These risk factors may arise due to uncertainty in, among other things, weather and climate, economic development, or federal and state regulatory and policy adoptions. While each of these factors presents its own set of risks, their combined effects can be far more consequential. A single uncertainty may reduce reliability margins but multiple uncertainties occurring together—such as higher demand coinciding with delayed transmission projects or overreliance on aging generation—can result in critical supply shortfalls.

To better understand the range of possible futures, the CRP uses scenarios to first examine the uncertainty around each individual key system factor—i.e., aging generation, demand, weather variability, imports, project delays, demand response, and additional resources—to assess its specific influence on system performance. The CRP then further examines combinations of these uncertainties and highlights the magnitude of the impact that different plausible configurations can have on system reliability margins. These examinations—both the individual and combinations—provide insight into the level and range of system reliability. Figure 13 below provides a high-level summary of the plausible range of statewide margins based on these examinations. The following sections detail the NYISO's examination and findings related the uncertainty from individual system factors and the combinations of those uncertainties.

Figure 13: Range of Statewide Margins [To be revised to include Winter]

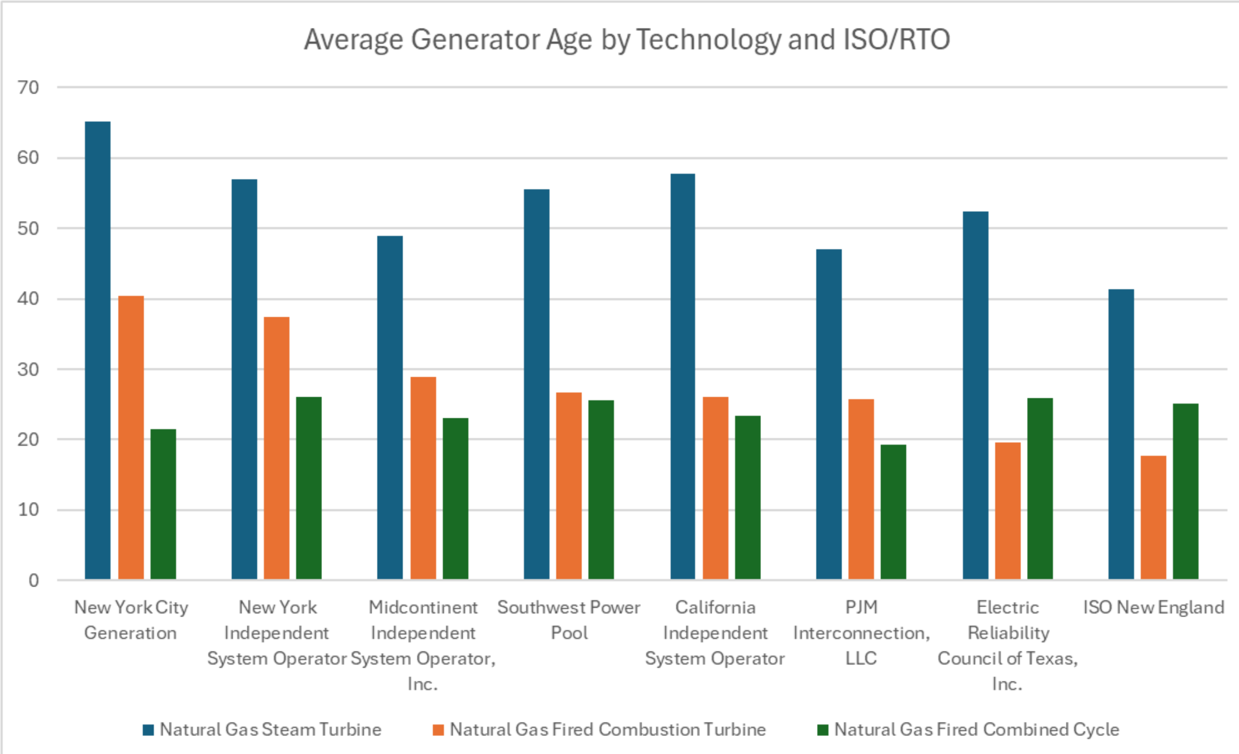


Aging Generation

New York's generation fleet is among the oldest in the country. Compared to other generation in other Independent System Operator (ISO)/Regional Transmission Operator (RTO) regions in the United States,[7] NYCA generation ranks among the oldest or second oldest in each of the natural gas steam turbine, combustion turbine, and combined cycle technology types. This is particularly apparent in New York City where the average age of a steam turbine is 65 years.

[7] U.S. Energy Information Administration, Form EIA-860 Detailed Data, *available at* https://www.eia.gov/electricity/data/eia860/.

Figure 14: National Average Generator Age



As they age, fossil-fuel thermal generators tend to experience more frequent and longer outages. For instance, owners will have greater difficulties in maintaining and finding replacement parts for older equipment. In New York, owners are also faced with these maintenance difficulties while considering the impact of policies to restrict or eliminate emissions. These factors may drive aging generators to deactivate or be more susceptible to catastrophic failure and, in turn, may exacerbate the NYISO's trend of declining reliability margins. Reliability concerns associated with the age and condition of New York's fossil-fuel generation fleet were underscored this past winter by the units entering ICAP Ineligible Forced Outages.[8]

To account for the risks of the NYCA's reliance on aging generation in reliability planning studies, the NYISO developed a statistical retirement risk model. This method, described in detail in Appendix [*], uses a data-driven approach to represent the risk of end-of-life failures for generating units as they advance in age. The method begins with retirement information for existing and retired generating units from the U.S. Energy Information Administration's EIA-860 data form.[9] Observed retirement behavior is transformed into survival (or retirement) curves for different generator types—e.g., natural gas steam turbines, combined cycle, etc. At the point in which a NYCA generator reaches the age at which 95% of peer units

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[8] Generator Status Updates, https://www.nyiso.com/ny-power-system-information-outlook.

[9] *See generally,* U.S. Energy Information Administration, Form EIA-860 Detailed Data, *available at* https://www.eia.gov/electricity/data/eia860/.

would have retired, a derate is applied to account for that generator's increasing retirement or failure risk with age. This derate is applied only to fossil-fuel thermal generators as nuclear, hydro, and renewables have failure and retirement risks that are not as correlated to age. Figure 15 shows how the risk, calculated in unavailable MW, grows in time as the fleet ages during the course of the planning horizon.

Figure 15: Aging Generation Risk Projection

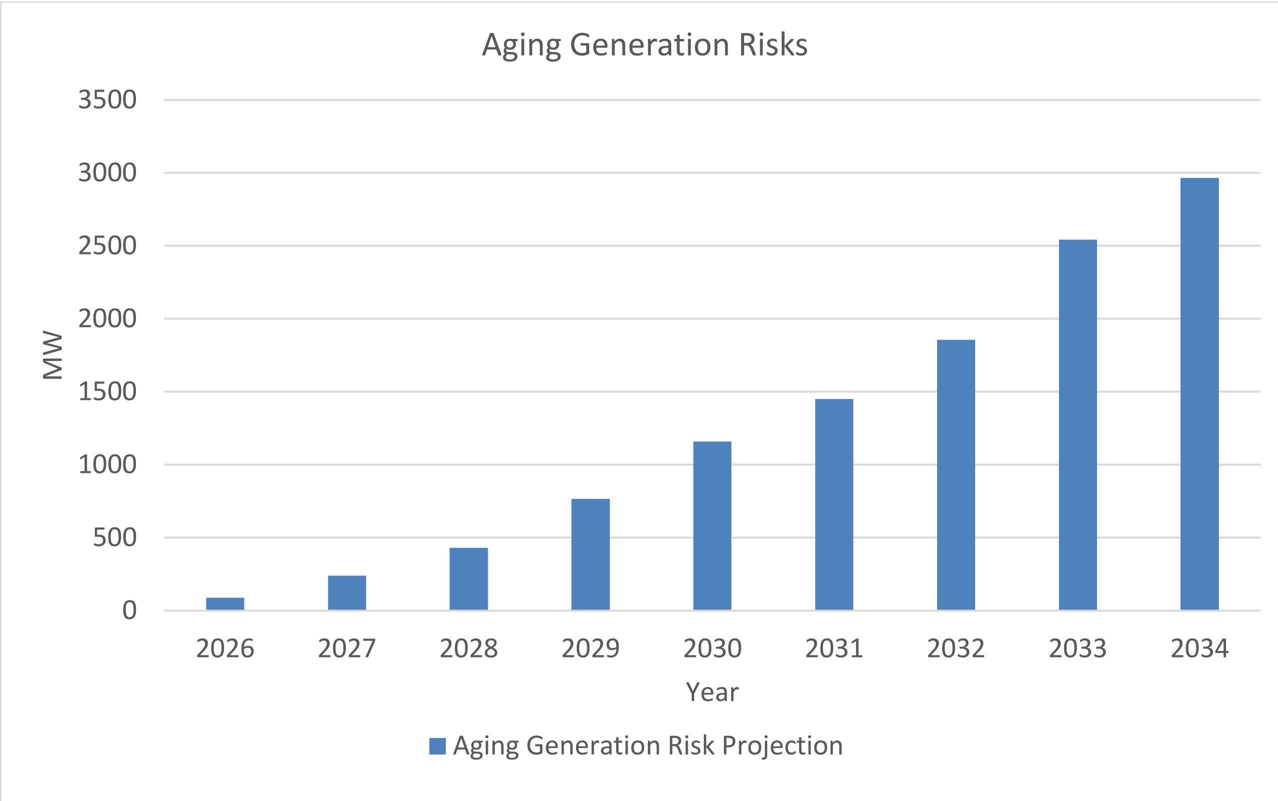
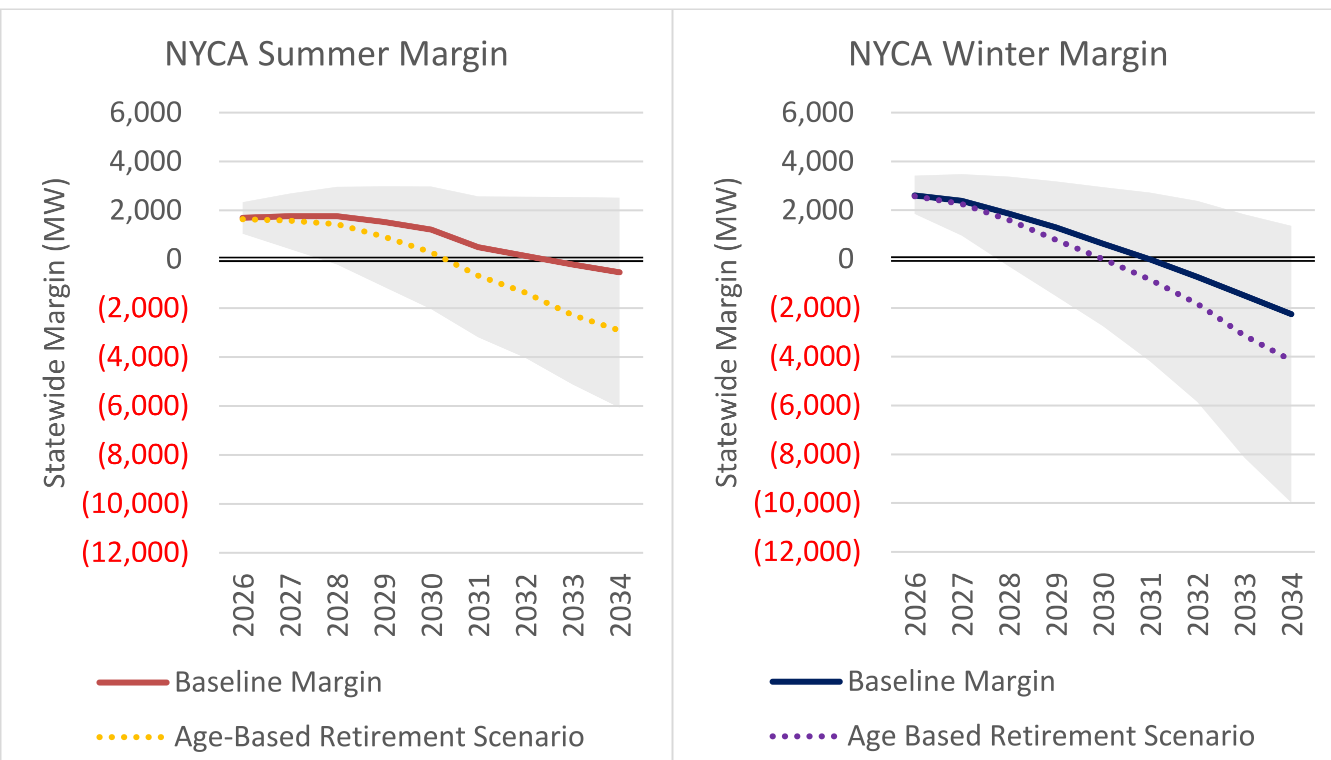


Figure 16: Statewide Margin Impact of Aging Generation



Demand-Side Uncertainty

The 2025 Gold Book includes three demand forecasts: Lower Demand, Baseline, and Higher Demand. Each of these forecasts contain differing inputs on economic, electrification, and large load assumptions. The behind-the-meter (BTM) Solar, BTM distributed generation, and energy storage forecasts are consistent across all scenarios. Further details of the Higher Demand and Lower Demand forecasts are summarized as follows:

- **Higher Demand –** The Higher Demand forecast is developed to broadly reflect levels of heating electrification and EV adoption commensurate with the achievement of New York's policy targets. However, the Higher Demand forecast does not include the full potential of peak-mitigating factors, such as managed EV charging and other flexible load and efficiency measures. The Higher Demand forecast assumes additional large load growth beyond that included in the baseline forecast. The Higher Demand econometric and EV and building electrification forecasts assume an increasing population and number of households over the duration of the forecast horizon, and stronger than expected economic growth.
- **Lower Demand –** The Lower Demand forecast assumes a slower EV adoption rate with a greater share of managed charging and a lower saturation of electric heating than the baseline forecast. Lower Demand forecast assumes reduced large load growth and weaker than expected economic growth relative to the baseline forecast.

The result of the differences in the forecasts is that the Higher Demand and Lower Demand forecasts produce lower and upper bounds around the Baseline forecast. Figure 17 provides a visual depiction of the three forecasts. Figure 18 shows the difference in the summer and winter statewide margin for each of the three forecasts.

Figure 17: Demand-Side Uncertainty

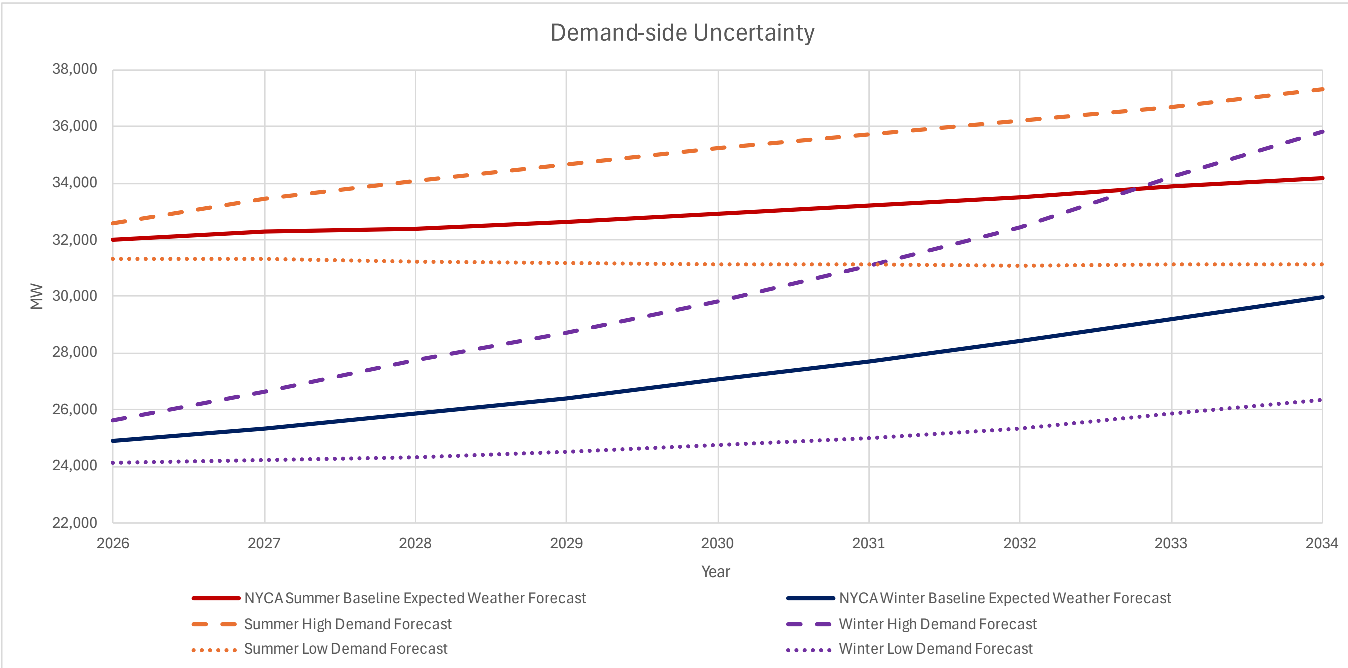
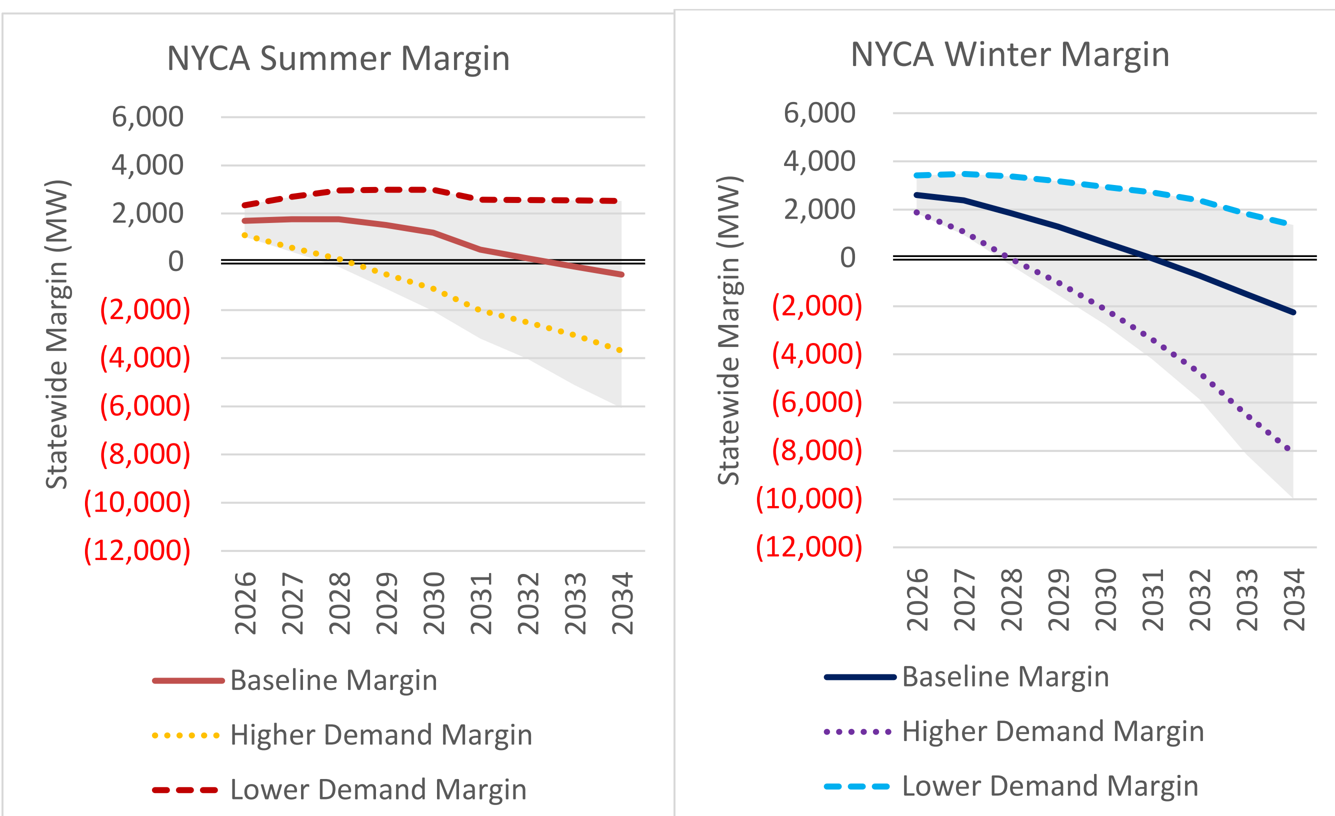


Figure 18: Statewide Margin Impact of Demand-Side Uncertainty



Large Loads

The recent increase of interconnection requests for large load projects poses a risk to reliability as the magnitude and speed of these requests are far exceeding that of additional resources that would be needed to serve them. Given the NYISO's approach in developing the demand forecasts and how that aligns with the progress of the large load interconnection requests, the forecasts do not account for all of the large load projects seeking to interconnect to the system. As of early September 2025, there are over 8,000 MW of additional requested large load interconnection projects in the NYISO interconnection queue compared to the loads projects included in the Baseline forecast for the 2024 RNA. Figure 19, below, summarizes the load interconnection projects that are in service and have pending interconnection requests in the NYISO's queue compared to the large load interconnection projects included in the Baseline forecast.

Similar to interconnection requests for resources, not all of the load interconnection projects will timely move forward. This CRP, therefore, examines different assumptions for the large load interconnection requests to better understand the uncertainty to the reliability of the system.

- **No New Large Load In Service** – Assumes that no large loads go into service over the planning horizon, including the future load projects accounted for in the Baseline forecast.
- **No Large Load Flexibility** – Consistent with the 2024 RNA, the NYISO assumed in the baseline analyses that cryptocurrency mining and hydrogen production large loads will be flexible during both summer and winter system peak demand conditions. That assumption was based on communications with load project developers and recent operating experience. The values presented for this impact assume that all large loads, regardless of their end-use, are inflexible and would draw power from the grid under all system conditions.
- **All Proposed Large Load In Service** – Assumes that all proposed large load interconnection requests as of September 5, 2025 are in service and operating at their full requested loads.

Figure 20 details the impact of each of the above changes in the assumptions for the large load projects on the statewide margin in both the summer and winter periods.

Figure 19: Large Load Interconnection Projects

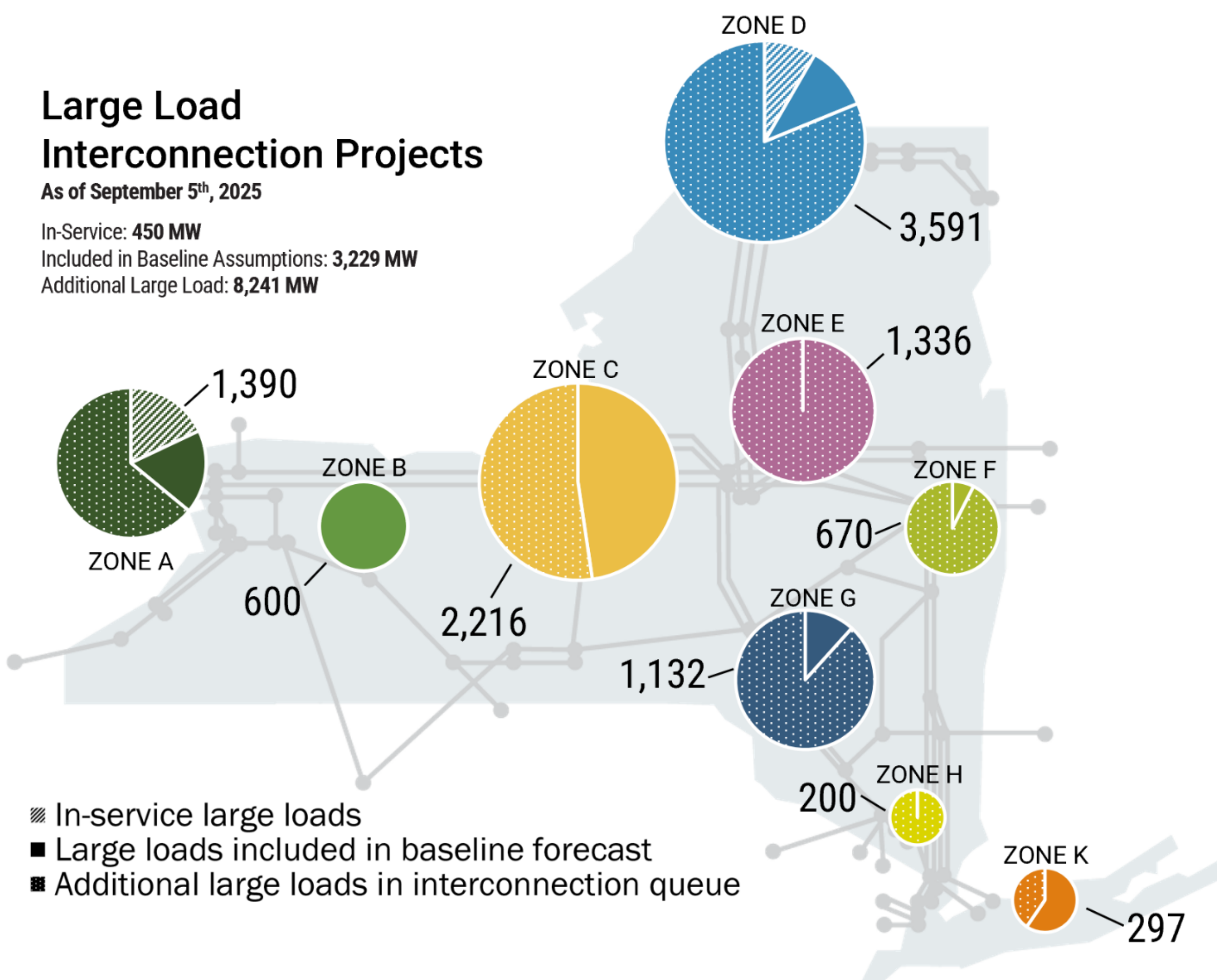
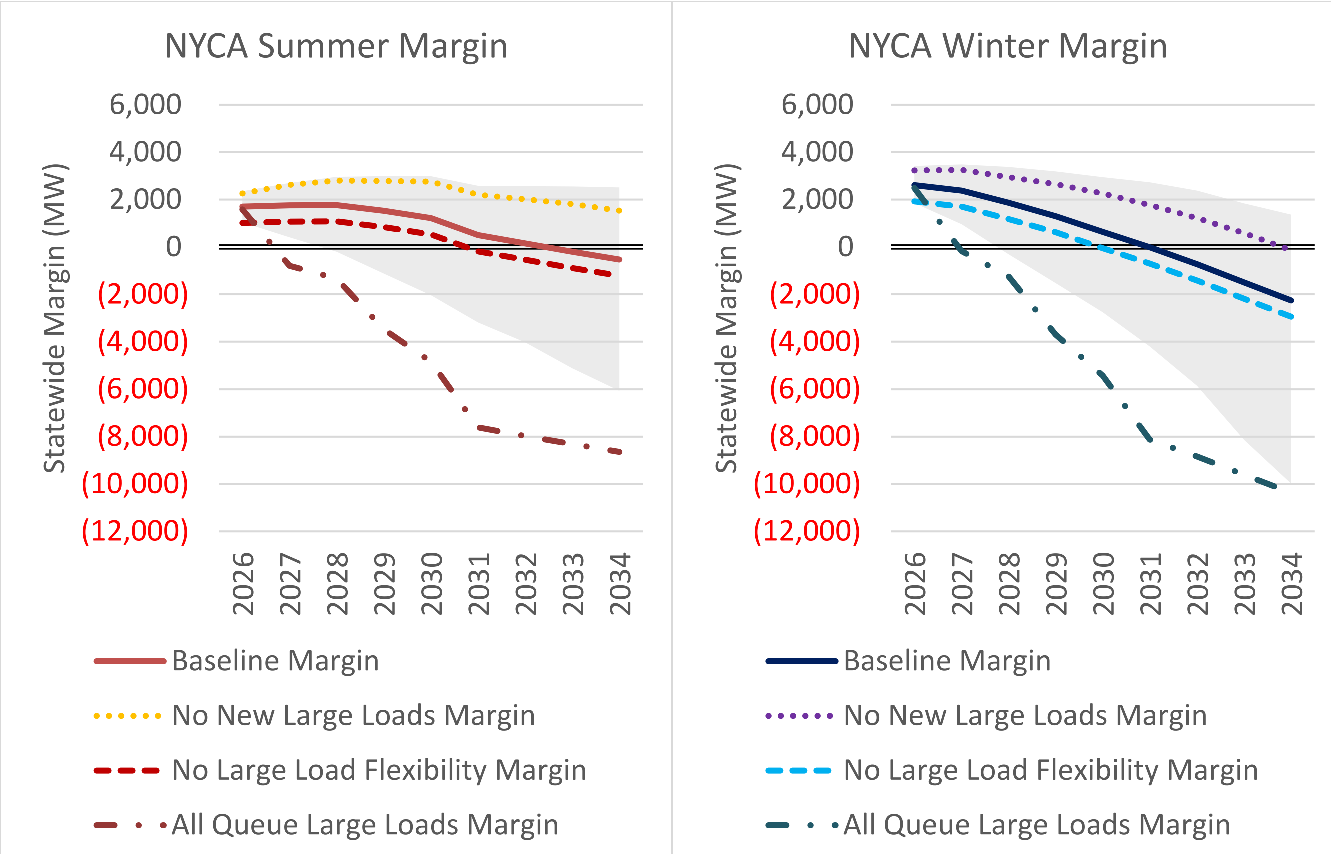


Figure 20: Statewide Margin Impact of Large Load Interconnection Projects



Weather Variability

Weather is a separate variable in forecasting demand from the policy and economic development considerations mentioned in the previous sections. The design condition of the baseline peak forecasts, as published each year in the NYISO Gold Book, are designed by the Transmission Owners at 67th percentile weather conditions for the Con Edison and Orange and Rockland service territories, and at the 50th percentile in the remaining transmission districts. The baseline forecasts are representative of expected weather for a given period. The baseline summer peak day daily maximum temperature is 92 degrees, and the baseline winter daily minimum temperature is 8 degrees.

- **Heatwave (90/10) -** The 90th percentile summer peak forecast represents a warmer than expected summer peak day with the daily maximum temperature being 95 degrees.
- **Coldsnap (90/10) -** The 90th percentile winter peak forecast represents a colder than expected winter peak day with the daily minimum temperature being 0 degrees.
- **Mild Summer (10/90) -** The 10th percentile summer peak forecast represents a milder than expected seasonal peak day, with cooler weather during the summer peak and a daily maximum temperature of 87 degrees.
- **Mild Winter (10/90) -** The 10th percentile winter peak forecast represents a milder than expected seasonal peak day, with warmer weather during the winter peak and a daily maximum temperature of 19 degrees.

The design condition serves as a balanced benchmark used in planning studies. However, the NYISO still needs to operate the system reliably throughout the various weather variations and, therefore, the actual peaks will vary from the baseline peak forecast. As a reference point, the actual peak during the cold snap that occurred between January 18 and January 23, 2025 was approximately 99th percentile (99/1) of the winter 2024/2025 baseline forecast, and the mid-June 2025 heat wave that occurred between June 23 and June 25 approached the summer 90th percentile (90/10) forecast.

Figure 21, below, summarizes the variability of the forecasts based on the variability of the weather compared to the summer and winter baseline expected weather forecast for the NYCA. Figure 22 then shows the impact of the 90/10 and 10/90 weather forecasts on the statewide margin for summer and winter periods.

Figure 21: Weather Variability

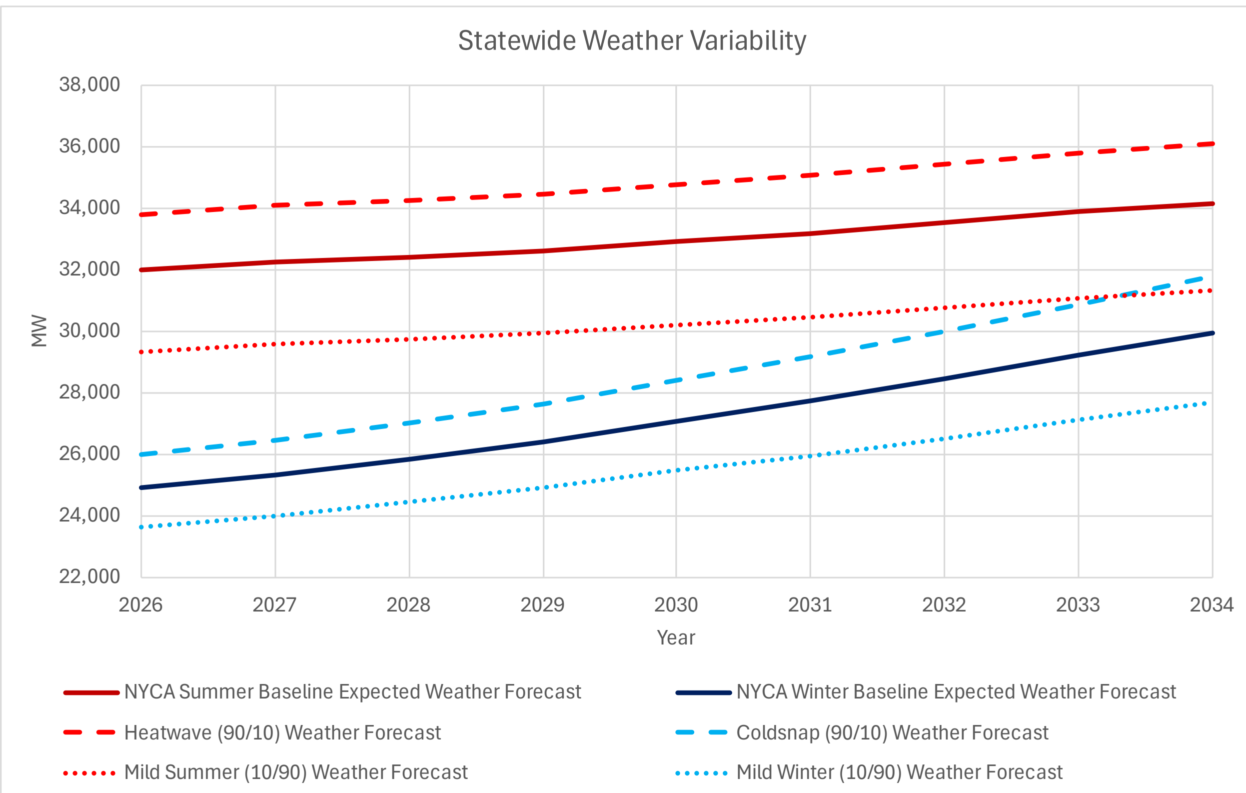
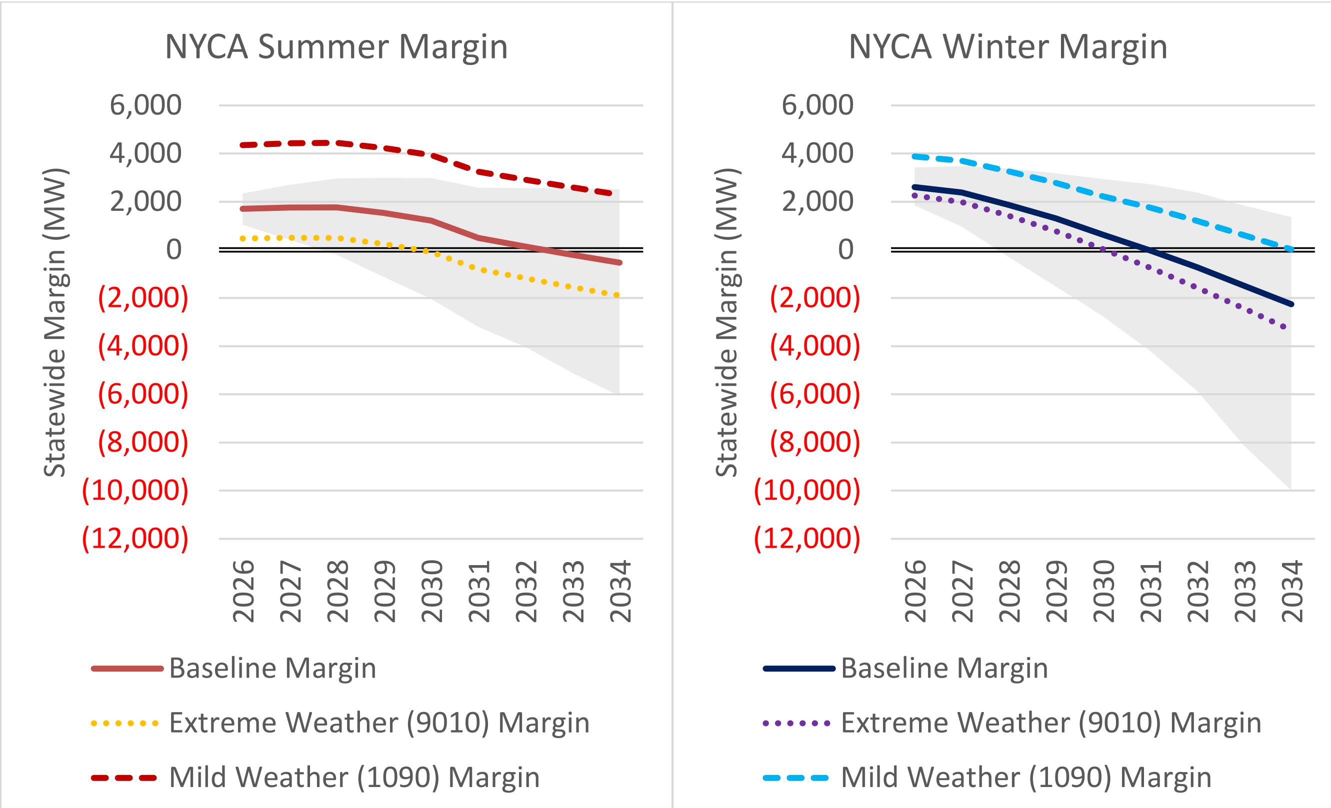


Figure 22: Statewide Margin Impact of Weather Variability



Reliance on Imports

The baseline statewide margin calculation assumes that all firm scheduled imports from neighboring systems, as determined by the Eastern Interconnection Reliability Assessment Group's annual processes, are available. Figure 23 summarizes the assumed interface flows used for the transmission security margin calculations. In summer peak conditions, the NYISO is expected to receive a net total of 3,094 MW from neighboring systems—of which 734 MW is assumed to be delivered to NYCA during winter peak conditions. However, during peak conditions when the New York system is stressed, neighboring systems may not be able to deliver power to New York due to their own system needs.

To assess uncertainty from neighboring systems being unable to deliver power to New York, this CRP assessed different scenarios of import limitation:

- The unavailability of imports Hydro Quebec over CHPE
- The unavailability of imports from PJM over Neptune
- The unavailability imports from PJM over Linden VFT
- The unavailability of all firm imports into the NYCA

Figure 24 summarizes the impacts to the statewide margin in both summer and winter. Figures 25 and 26 summarize the impacts to specifics zones within the NYCA for the unavailability of imports over CHPE and Linden VFT and Neptune.

Figure 23: Imports from Neighbors

Statewide Reliance on Imports							
From Area to NYCA	New England	HQ (CHPE)	HQ (Other)	PJM (Neptune)	PJM (Other)	Ontario	Total
Summer Imports	-83	1,250	1,100	660	157	0	3,084
Winter Imports	-83	0	0	660	157	0	734

Figure 24: Statewide Margin Impact of Imports

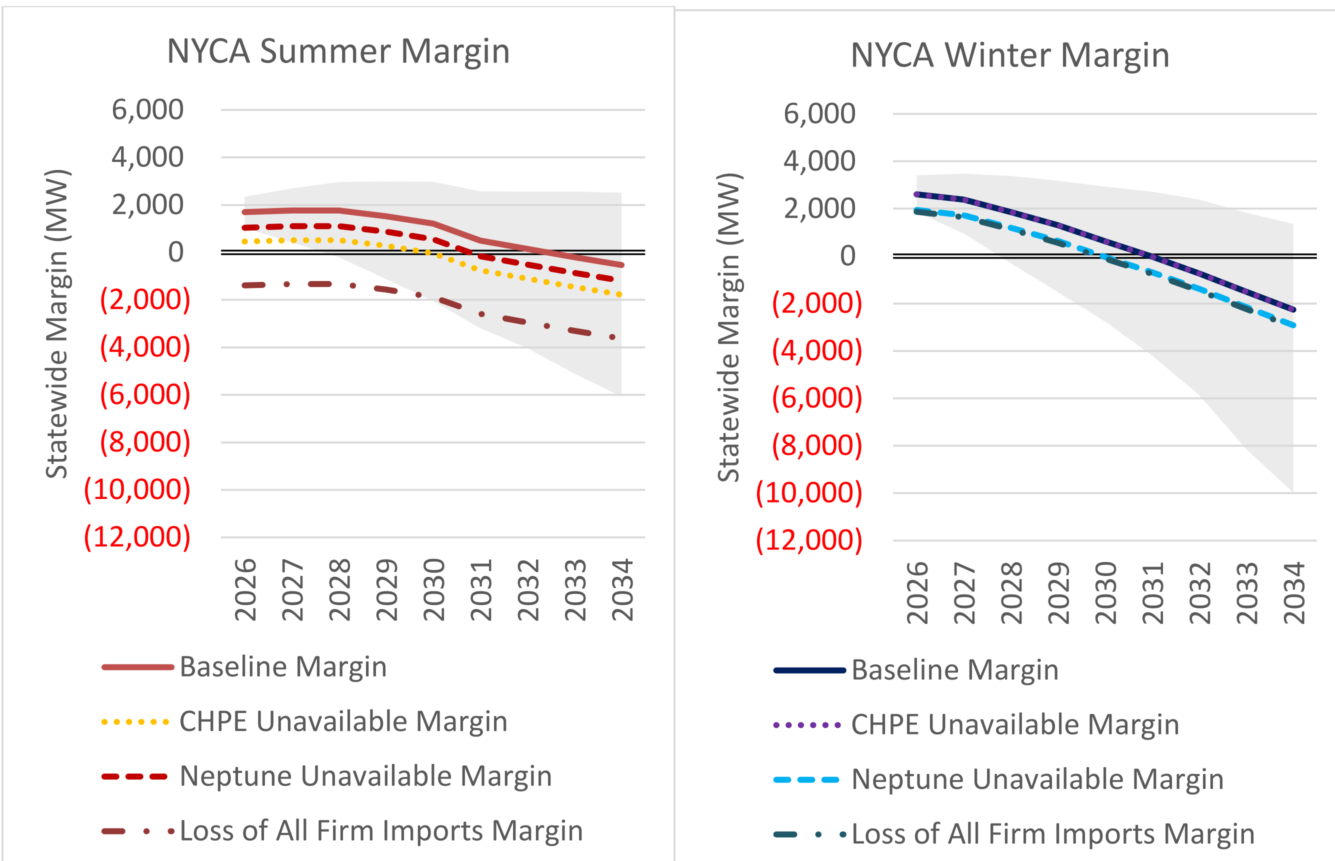


Figure 25: Zone J Transmission Security Margin with Impact of Imports

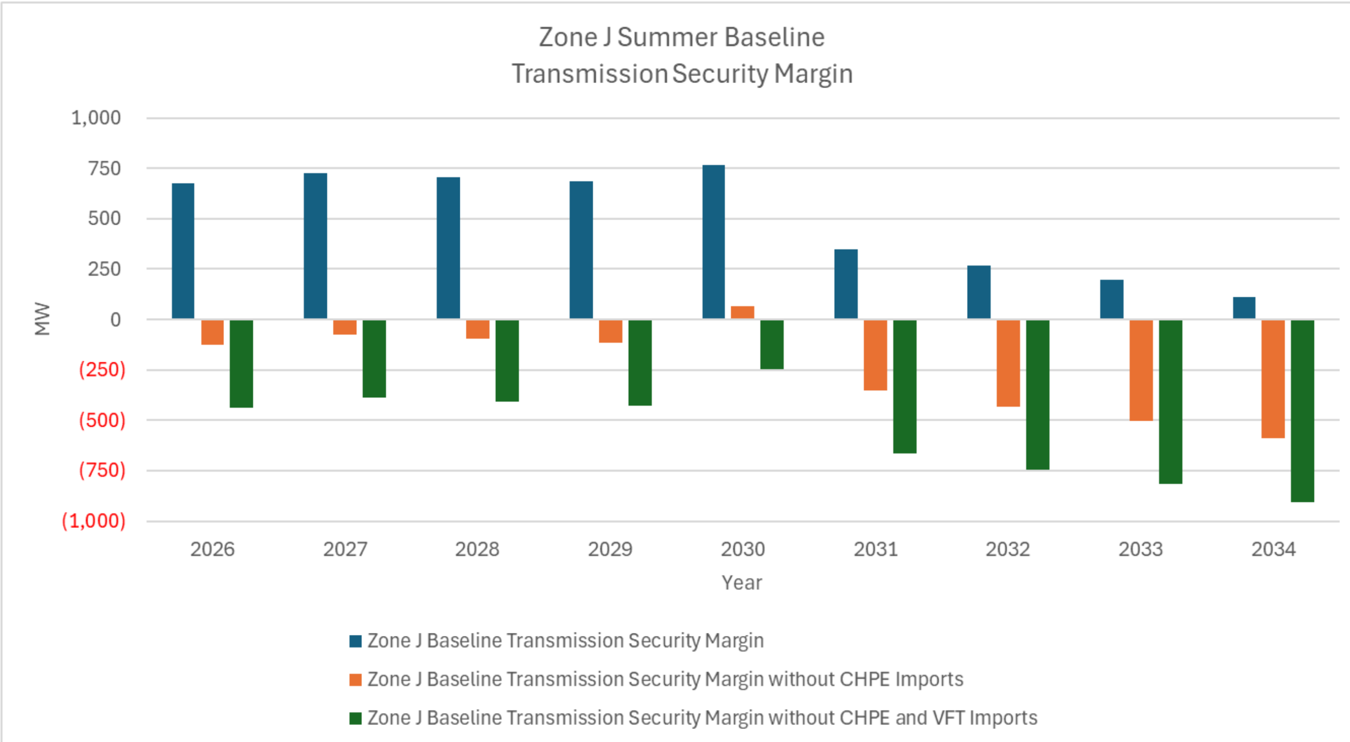
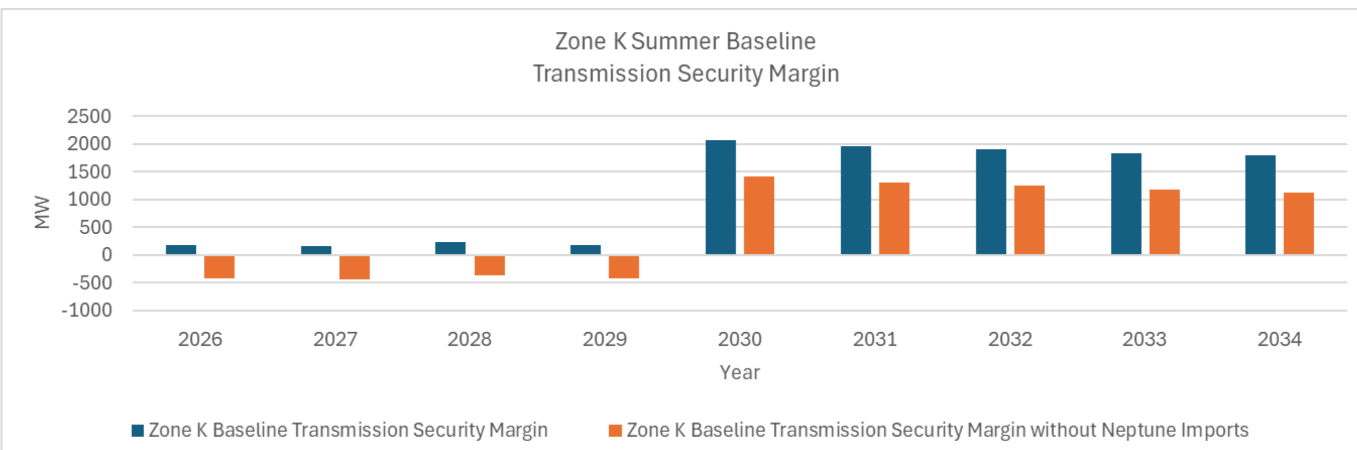


Figure 26: Zone K Transmission Security Margin with Impact of Imports



Demand Response

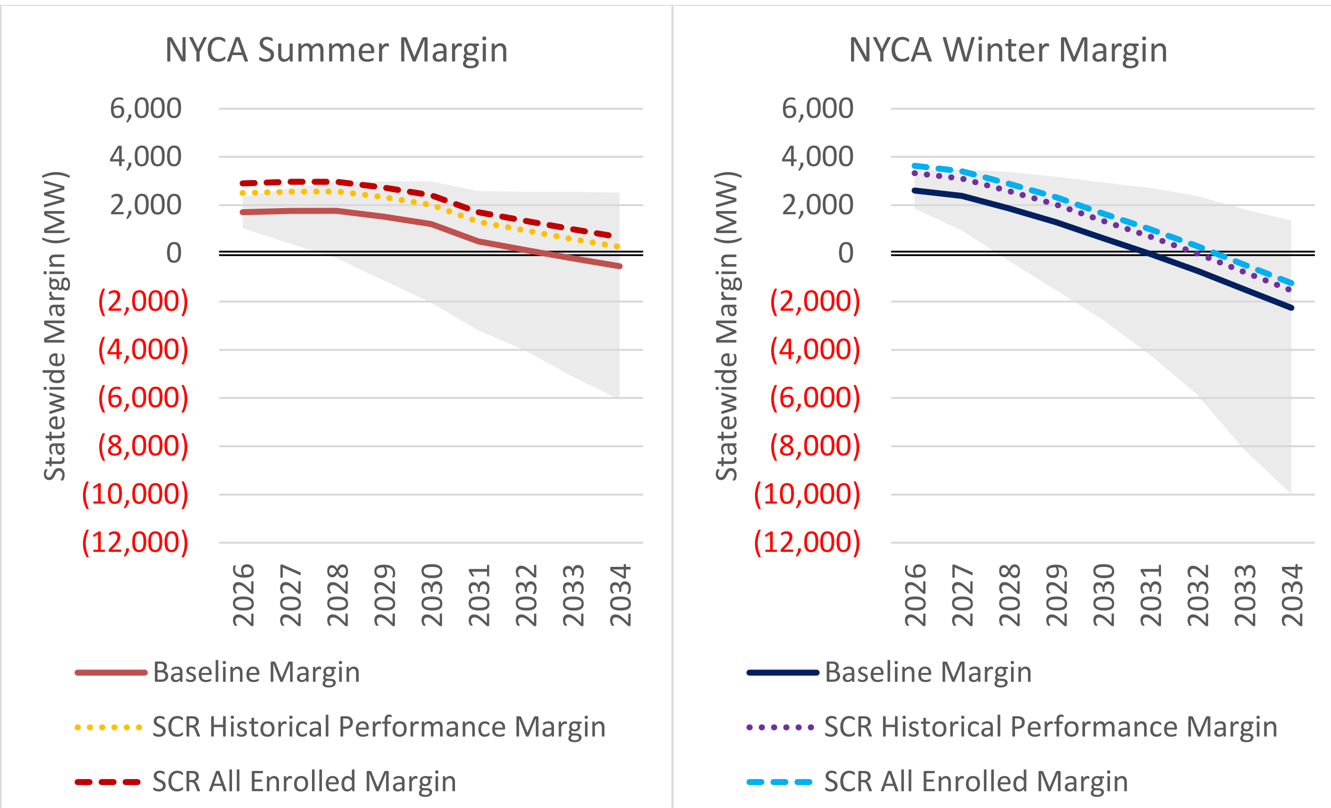
Demand response includes Special Case Resources (SCRs) for which the load is capable of being interrupted at the direction of the NYISO or have a Local Generator that can be operated to reduce load from the New York State Transmission System or the distribution system at the direction of the NYISO. In the NYISO's reliability planning studies, SCRs are not applied for transmission security analysis of normal operations but are included for emergency operations.

Figure 29 shows the SCR enrollment and derated values based on historic performance that assumed in the CRP.

Figure 27: Special Case Resources

Special Case Resources	
Summer Elections	
SCR Enrollments	1,205
SCR with performance based derate	804
Winter Elections	
SCR Enrollments	1,026
SCR with performance based derate	721

Figure 28: Statewide Margin Impact of Special Case Resources



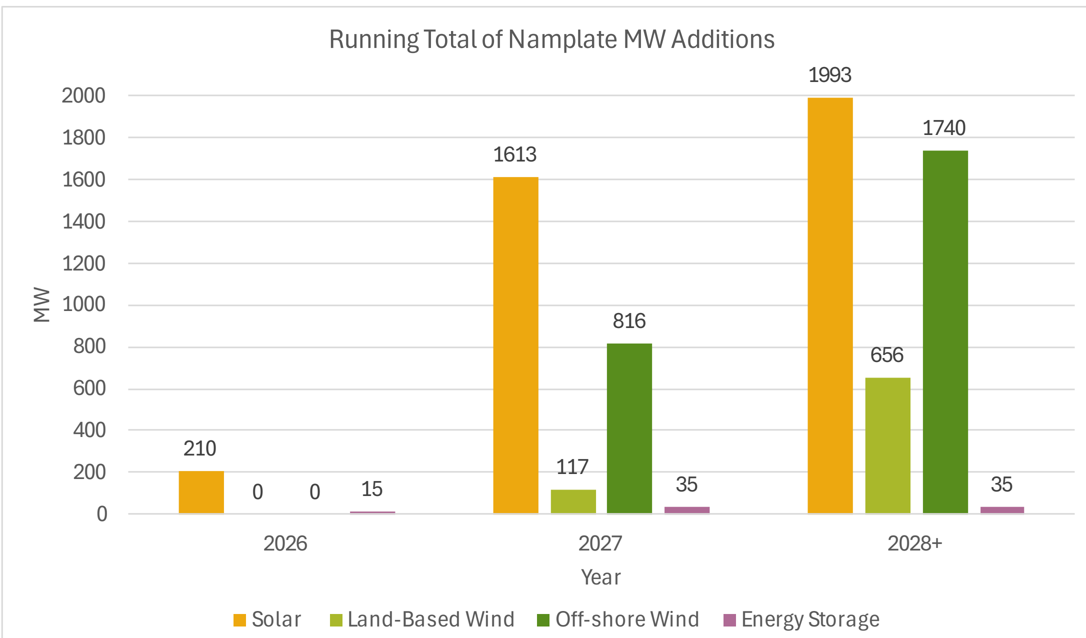
Potential Transmission and Generation Project Delays

Recently, supply chain issues have led to long lead times for the delivery of equipment needed to construct energy infrastructure. Additionally, delays in acquiring the permits that are required to build projects add additional risk for planned projects to meet their proposed in-service dates. This includes the potential for delay of key transmission projects like CHPE and Propel NY Alternate Solution 5, which are expected to have, among other things, a positive impact on overall system reliability. Transmission Owner

Local Transmission Plans ("LTPs") and additional resources planned through the NYISO interconnection process may also be postponed.

Currently, the Reliability Planning Process base cases assume over 4,400 MW of planned additional resources will be in service by the end of 2028. Recent actions taken by the federal government have drastically impacted the prospects for the development and construction of offshore wind and other renewable resources. The delay or cancellation of these resources coming into service will have adverse effects on system reliability. The total of nameplate additions assumed by fuel type are summarized in Figure 29.

Figure 29: Resource Additions



- **CHPE Unavailable –** Assumes the unavailability or delay of CHPE entering service past summer 2026. The CHPE connection from Quebec, Canada to New York City is currently scheduled to enter service in spring 2026 and is assumed to provide 1,250 MW to New York City in summer but 0 MW in winter.
- **Propel NY Alternate Solution 5 Project Delay –** Assumes the delay of the Propel NY Alternate Solution 5 project, which in-service date is currently identified as May 2030. The transmission infrastructure from this project will increase the import capability into Long Island from upstate by about 1,300 MW.
- **Status Quo –** Assumes that transmission and generation projects that are currently planned for in the Reliability Planning base cases but not currently in service (3,600 MW generation projects, as described above) do not enter service during the planning horizon, while maintaining the assumption that demand grows as forecasted, including large load development.

Figure 26 shows the statewide impact of Status Quo and CHPE Unavailable scenarios, while Figure 31 and Figure 28 show the significant impact of CHPE or Propel NY to the New York City and Long Island transmission security margines, respectively.

Figure 30: Statewide Margin Impact of Project Delays

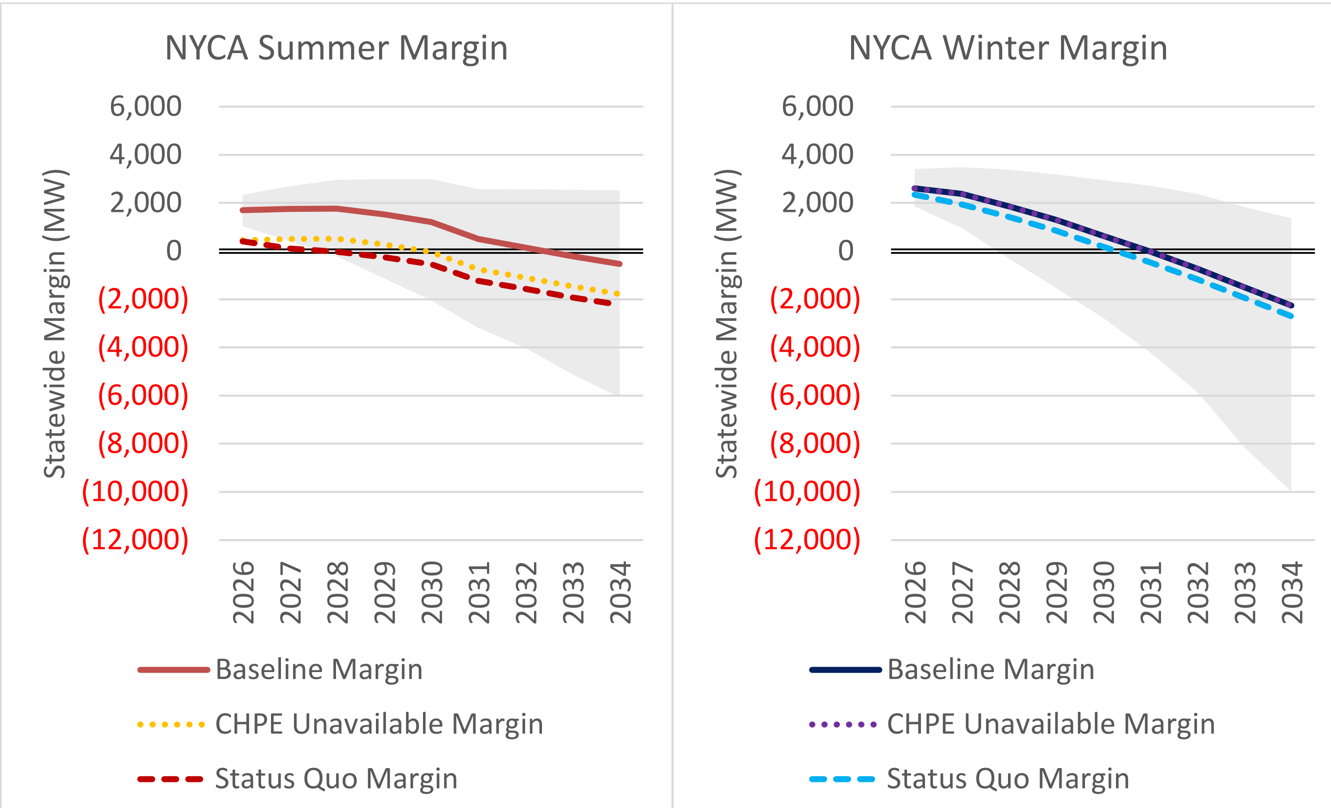


Figure 31: Zone J Transmission Security Margin with Impact of Project Delays

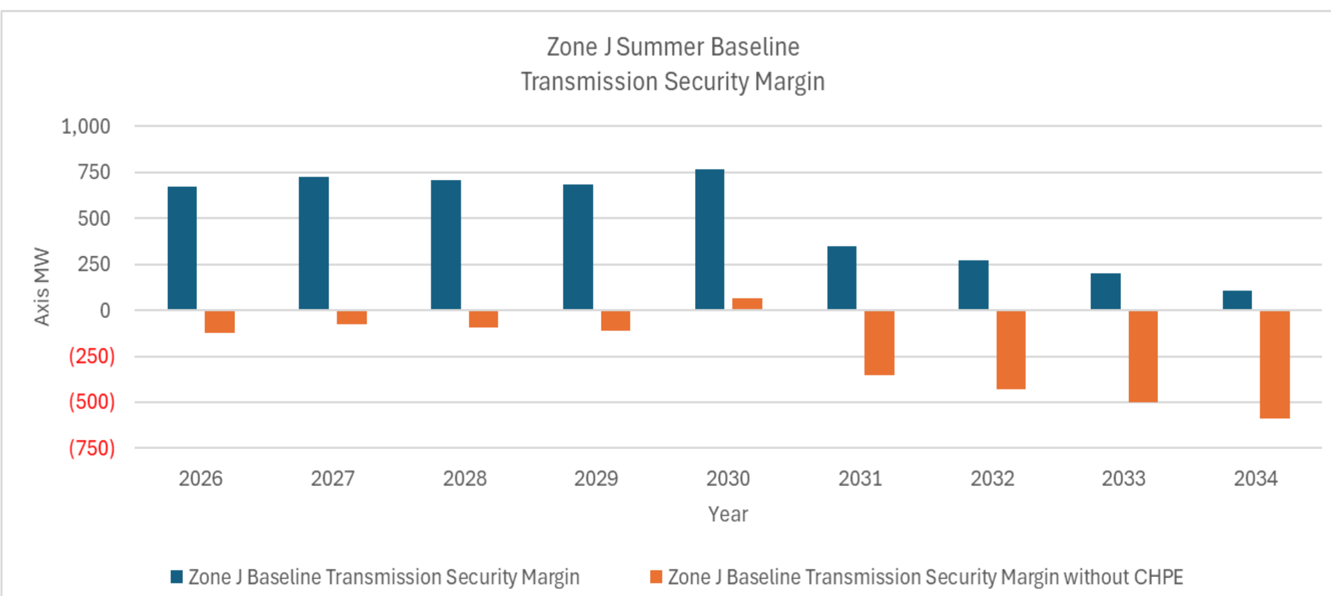
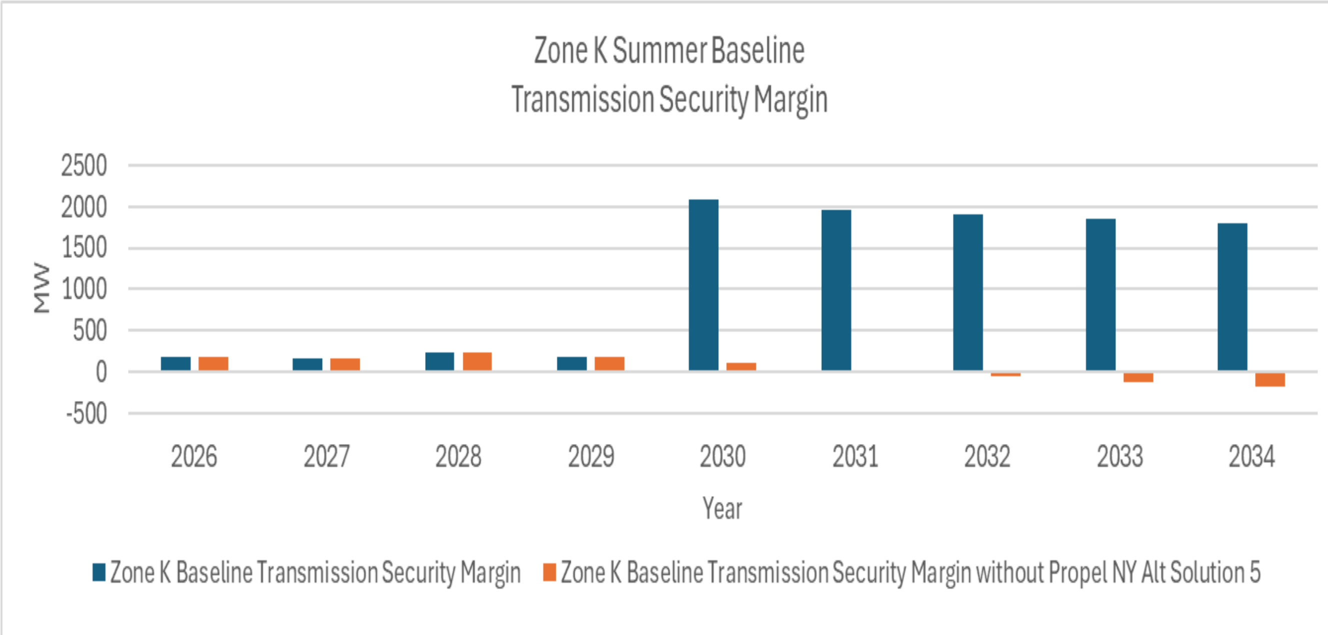


Figure 32: Zone K Transmission Security Margin with Impact of Project Delays



Additional Resources

Narrowing statewide reliability margins are observed in the baseline statewide system margin results, indicating that no surplus power would remain by 2034 without further resource development. As discussed above, the calculation of the baseline statewide margin in this CRP only assumes a subset of the total resources in the NYISO's interconnection queue. The narrowing reliability margins could be positively impacted by the advancement of projects that have completed the NYISO interconnection process, as well as the retention or replacement of existing generators. This assessment of additional resources evaluates:

- **Cluster Baseline Assessment (CBA) Case** – The generation projects summarized in Figure 33 have previously accepted cost allocation through the NYISO interconnection process, but do not yet meet other requirements of the reliability planning base case inclusion rules. Two scenarios, storage on and off, consider the impact if the energy storage projects have sufficient stage of charge to deliver power during the duration of the peak demand periods.

Figure 33: Additional Resources from CBA Case

Additional Resources	Land-Based Wind	Off-Shore Wind	Solar	Energy Storage
CBA Namplate MW Additions	1,158	0	4,219	2,519

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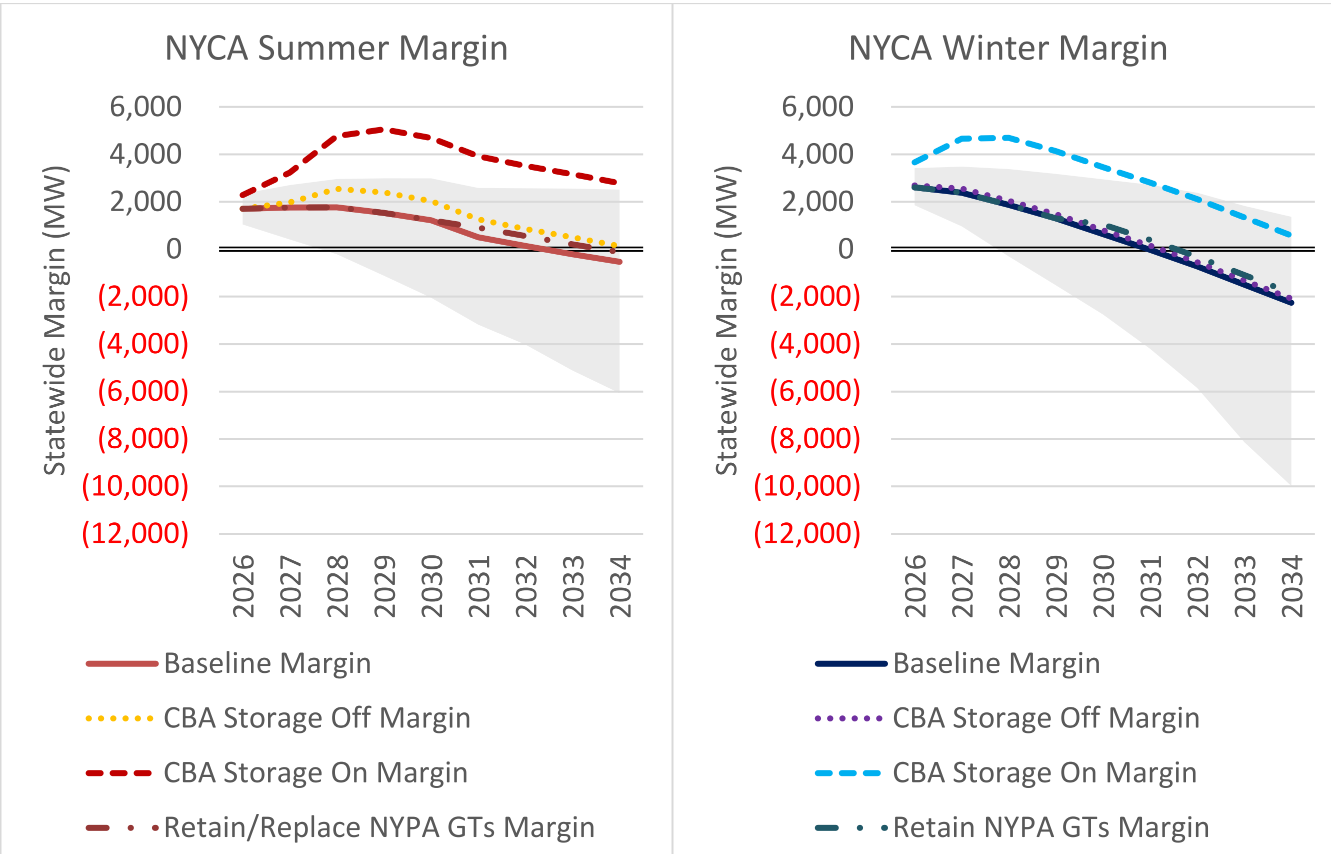
Additionally, this assessment considers the impact of retaining or replacing existing units with functionally equivalent resources. For example, the impact of the potential retirement or replacement of the NYPA small natural gas power plants is shown.

- **NYPA Small Gas Plants** – The baseline analysis assumes NYPA's seven small natural gas power plants (simple-cycle combustion turbines) in New York City and Long Island are removed by 2031, despite having a relatively young age of 27 years. This scenario looks at the impact if the 517 MW plants are either retained or replaced by functionally equivalent generation.

Figure 34: Statewide Margin Impact of Additional Resources



[New York City charts to be added in a future draft]

Plausible Combinations of System Risks

In addition to the assessment of the uncertainty around each individual key system factor discussed above, this CRP takes the additional step to examine combinations of these uncertainties to understand and highlight how different plausible configurations can benefit or harm system reliability margins beyond the assumed "baseline" condition. Figure 35 and Figure 36 show that, in most of the combinations assessed, which are more fully described herein, the statewide system margins during summer and winter peak conditions decrease over time. Most of the combinations of scenarios show decreasing margins through 2034 with the range of future margins growing over time. The most optimistic scenario combinations show positive margins by 2034 that are roughly equivalent to today's margins in the positive 2,000 MW range. On the other hand, the most pessimistic scenario combinations show deficiencies of up to 10,000 MW by 2034. While a negative statewide system margin is not, on its own, a violation of a Reliability Criterion, it is a leading indicator of the inability to securely meet system load under applicable normal system conditions.

Figure 35: Summer Statewide Margin Risks

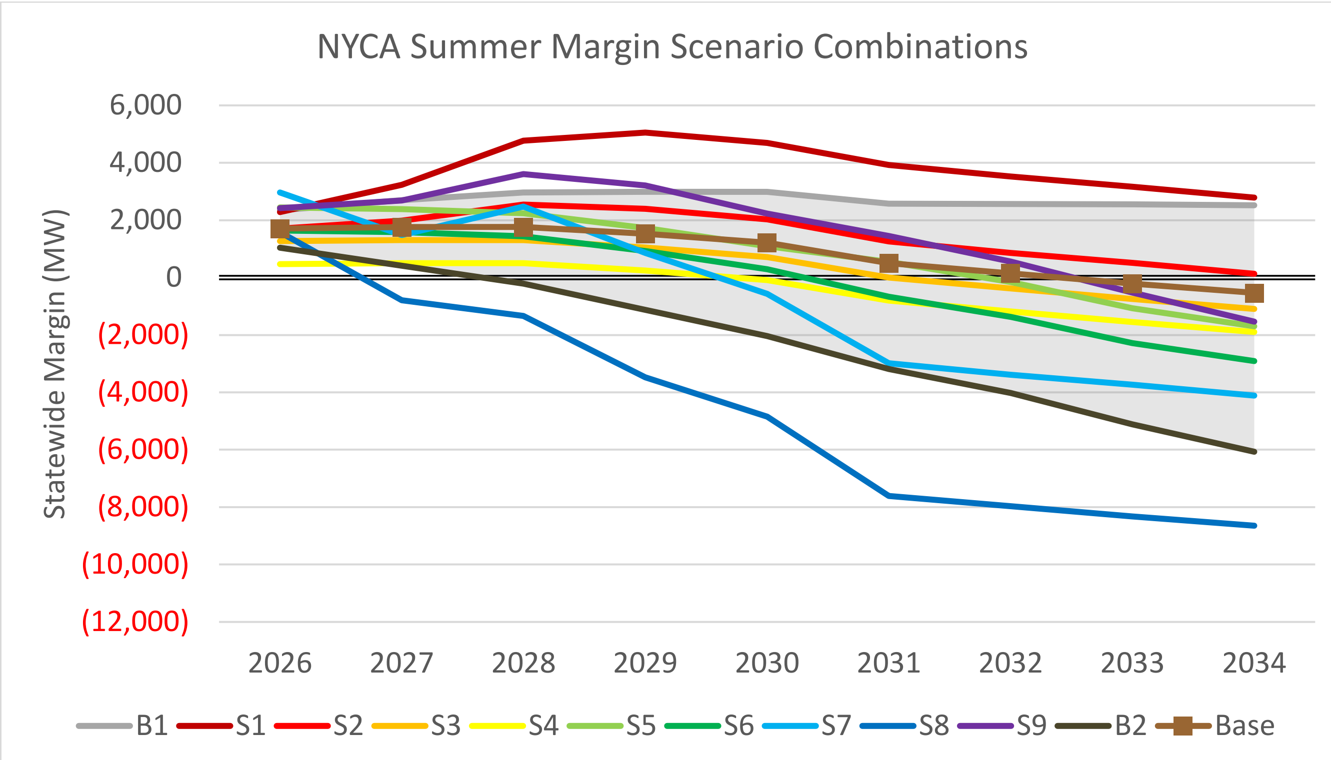
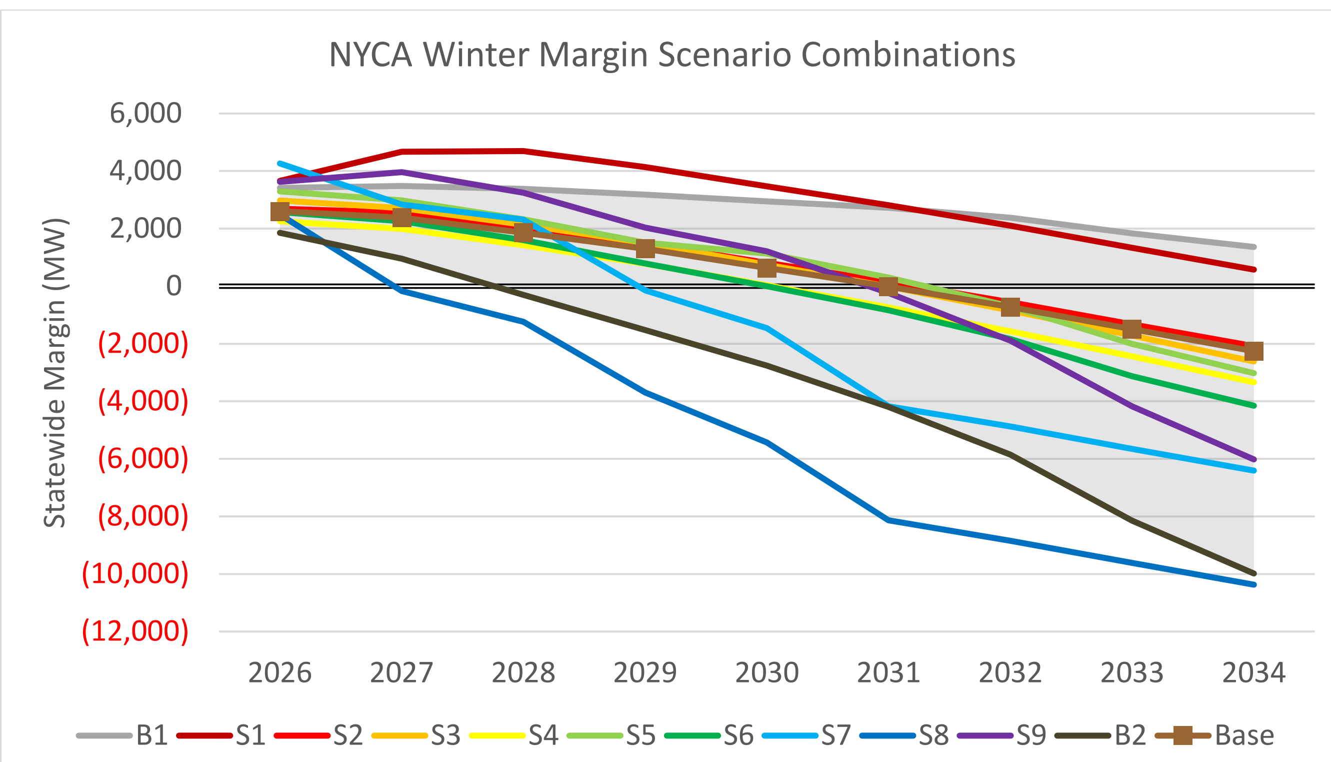


Figure 36: Winter Statewide Margin Risks



Short summaries are given below to describe how each scenario combination differs from the baseline statewide transmission security margin assessed in this CRP. Some factors describe long-term trends, such as generation construction and retirements, while others describe load or generation behavior on the peak hour, such as battery storage discharging or use of SCRs. Two combination scenarios (i.e., B1 – Boundary Scenario 1 and B2 – Boundary Scenario 2, as detailed below) are designated as boundary scenarios because between them, they capture a realistic range of statewide transmission security margins. The grey shaded area between boundary scenario margins is used as a reference for the statewide margin charts in the rest of the CRP.

- **Baseline**
    - Assumed System Conditions: Conditions on the peak hour align with baseline statewide transmission security margin assumptions for load, weather, conventional generation availability, solar and wind generation levels, and import availability.
    - Expected Statewide Margin in 2034: Summer is **deficient** by approximately 500 MW; winter is **deficient** by approximately 2,300 MW.
- **B1 – Boundary Scenario 1**
    - Assumed System Conditions: Demand growth follows the Lower Demand forecast from the 2025 Gold Book.
    - Expected Statewide Margin in 2034: Summer is **sufficient** by approximately 2,500 MW; winter is **sufficient** by approximately 800 WM.
- **S1 – Scenario Combination 1**
    - Assumed System Conditions: All generation in the queue is constructed on schedule, and battery storage is discharging at maximum output during the peak hour.
    - Expected Statewide Margin in 2034: Summer is **sufficient** by approximately 2,800 MW; winter is **sufficient** by approximately 600 MW.
- **S2 – Scenario Combination 2**
    - Assumed System Conditions: All generation in the queue is constructed on schedule, and no battery storage is discharging during the peak hour.
    - Expected Statewide Margin in 2034: Summer is **sufficient** by approximately 100 WM, winter is **deficient** by approximately 2,100 MW.
- **S3 – Scenario Combination 3**
    - Assumed System Conditions: A summer heatwave occurs, and SCRs are called and respond in line with historical performance.
    - Expected Statewide Margin in 2034: Summer is **deficient** by approximately 100 MW, winter is **deficient** by approximately 2,600 MW.
- **S4 – Scenario Combination 4**
    - Assumed System Conditions: A summer heatwave occurs.
    - Expected Statewide Margin in 2034: Summer is **deficient** by approximately 1,900 MW, winter is **deficient** by approximately 3,300 MW.

- **S5 – Scenario Combination 5**
  - Assumed System Conditions: Aging generation retires in line with NYISO's preliminary forecasting method; SCRs are called and respond in line with historical performance; and NYPA small plants are retained or replaced with functional equivalents.
  - Expected Statewide Margin in 2034: Summer is **deficient** by approximately 1,700 MW, winter is **deficient** by approximately 3,000 MW.
- **S6 – Scenario Combination 6**
  - Assumed System Conditions: Aging generation retires in line with NYISO's preliminary forecasting method.
  - Expected Statewide Margin in 2034: Summer is **deficient** by approximately 2,900 MW, winter is **deficient** by approximately 4,100 MW.
- **S7 – Scenario Combination 7**
  - Assumed System Conditions: All large loads currently in the interconnection process connect to the NYCA; SCRs are called and respond in line with historical performance, NYPA small plants are retained or replaced with functional equivalents; all generation in the queue is constructed on schedule; and all battery storage is discharging at maximum output during the peak hour.
  - Expected Statewide Margin in 2034: Summer is **deficient** by approximately 4,100 MW, winter is **deficient** by approximately 6,400 MW.
- **S8 – Scenario Combination 8**
  - Assumed System Conditions: All large loads currently in the interconnection process connect to the NYCA.
  - Expected Statewide Margin in 2034: Summer is **deficient** by approximately 8,600 MW, winter is **deficient** by approximately 10,300 MW.
- **S9 – Scenario Combination 9**
  - Assumed System Conditions: Demand growth follows the Higher Demand forecast, aging generation retires in line with NYISO's preliminary forecasting method; SCRs are called and respond in line with historical performance; NYPA small plants are retained or replaced with functional equivalents; all generation in the queue is constructed on schedule; and all battery storage is discharging at maximum output during the peak hour.
  - Expected Statewide Margin in 2034: Summer is **deficient** by approximately 1,500 MW, winter is **deficient** by approximately 6,000 MW.
- **B2 – Boundary Scenario 2**
  - Assumed System Conditions: Demand growth follows the Higher Demand forecast and aging generation retires in line with NYISO's preliminary forecasting method.
  - Expected Statewide Margin in 2034: Summer is **deficient** by approximately 6,100 MW, winter is **deficient** by approximately 10,000 MW.

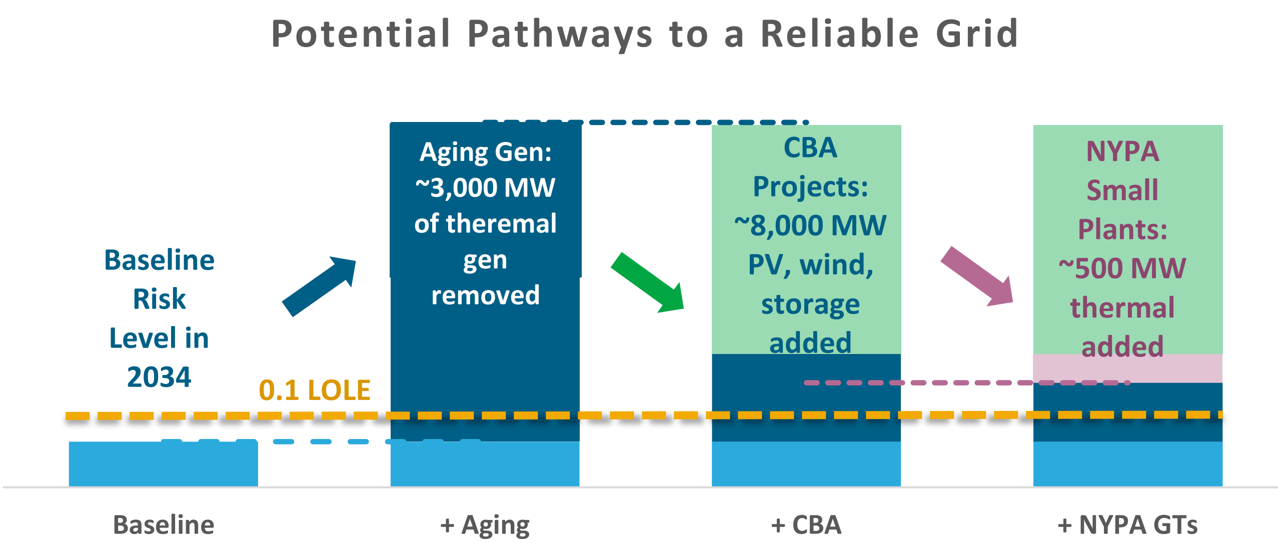
Potential Pathways to a Reliable Grid

The 2022 RNA and 2024 RNA show a clear trend toward narrowing reliability margins, which are only compounded by the risks and uncertainties highlighted earlier in the CRP. The two biggest uncertainties that affect the future reliability of the New York system are demand growth (including large loads) and the reliance on the aging thermal generation fleet. The CRP explored the interaction of these two key factors and potential pathways to maintain reliability for different scenarios. The CRP takes it a step further by using certain combination scenarios and assessing the system for violation of resource adequacy that would result in the identification of Reliability Needs and necessitate solutions, as follows:

- Resource adequacy was assessed over the 2026-2034 period;
- The Lower Demand, Baseline, and Higher Demand forecasts are assessed to evaluate reliability over the range of demand uncertainty;
- Effects of aging generation are modeled in each of the three demand forecasts using the statistical retirement risk model described in Appendix [*]; and
- If any of the scenarios exceed the 0.1 event-days/year LOLE criterion, different generalized scenarios are modeled to try to address the resource deficiency:
    - CBA: Generation and storage projects are added that have accepted cost allocation in the generator interconnection process, but do not yet meet reliability base case inclusion rules. This scenario adds 4,219 MW of solar, 1,158 MW of wind, and 2,519 MW of storage.
    - CBA + NYPA Small Plants: The NYPA small gas plants, totaling 517 MW in Zones J and K, are modeled as in-service past 2031 to represent either retention or inclusion of a comparable replacement. This scenario is intended to highlight the beneficial contribution to reliability from the power and operating characteristics of the NYPA small gas plants after 2030. This scenario is not intended to assess or reflect NYPA's May 2025 plan, which includes assessments that would conduct detailed evaluations of emissions impacts from deactivating its small gas plants and would evaluate impacts and retirements on a plant-by-plant basis, including the reuse of these sites for battery energy storage.[10]
    - CBA + NYPA Small Plants + Additional Generation: Compensatory MW in the form of perfect capacity additions are added statewide to indicate the remaining resources that would have to be procured to bring the system within LOLE criterion.

The figure below illustrates the sequence of analysis.

[10] NY Power Authority, Small Natural Gas Power Plants, https://www.nypa.gov/small-natural-gas-power-plants (last visited September 19, 2025).



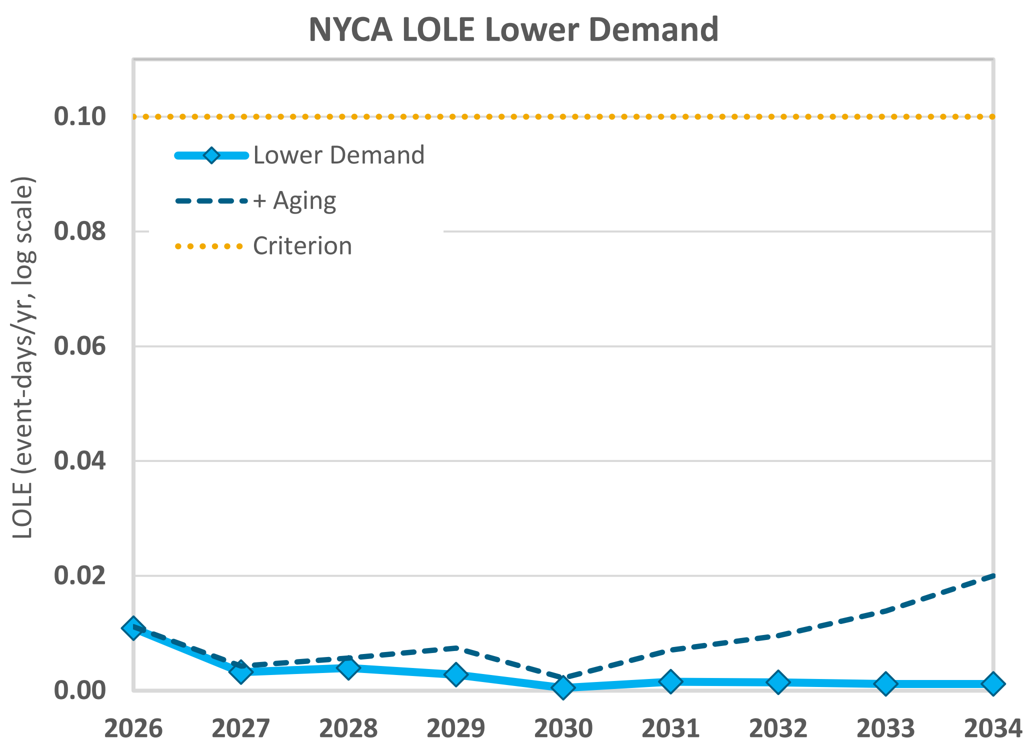
Lower Demand Forecast

Figure 37 below compares the annual, summer, and winter NYCA LOLE of the Lower Demand forecast with and without the effect of aging generation risks. As expected, aging generation increased the LOLE from the analysis with solely the Lower Demand forecast; however, the NYCA LOLE is still below the 0.1 event-days/year criterion, with the Lower Demand forecast.

Figure 37: NYCA LOLE with Lower Demand Forecast Table

NYCA LOLE (event-days/yr)										
Case	Season	2026	2027	2028	2029	2030	2031	2032	2033	2034
Lower Demand	**Annual**	**0.011**	**0.003**	**0.004**	**0.003**	**0.000**	**0.002**	**0.001**	**0.001**	**0.001**
	Summer	0.011	0.003	0.004	0.003	0.000	0.002	0.001	0.001	0.001
	Winter	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
+ Aging	**Annual**	**0.011**	**0.004**	**0.006**	**0.007**	**0.002**	**0.007**	**0.010**	**0.014**	**0.020**
	Summer	0.011	0.004	0.006	0.007	0.002	0.007	0.010	0.013	0.019
	Winter	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001

Figure 38: NYCA LOLE with Lower Demand Forecast Graph



Baseline Demand Forecast

Figure 39 below compares the annual, summer, and winter NYC LOLE of the Baseline demand forecast with and without the effect of aging generation risks. As expected, the Baseline demand forecast with the aging generation increased the LOLE compared to the LOLE for the Baseline demand forecast with violations of the criterion starting in 2033.

The following additional scenarios were performed to further characterize the nature of the criterion violations and identify the impact of possible solutions:

- **Baseline Demand Forecast + Aging Generation + CBA Scenario**: The CBA scenario of adding roughly 8,000 MW of proposed renewable and storage projects addressed the NYCA LOLE violations in 2033 and lowered the LOLE in 2024, but not below its criterion of 0.1 event-days/year.
- **Baseline Demand Forecast + Aging Generation + CBA + NYPA Small Plants Scenario**: To further address the remaining violation in year 2034, the NYPA small plants were modeled as in-service starting in 2031. This further lowers the NYCA LOLE; however, it is still not below

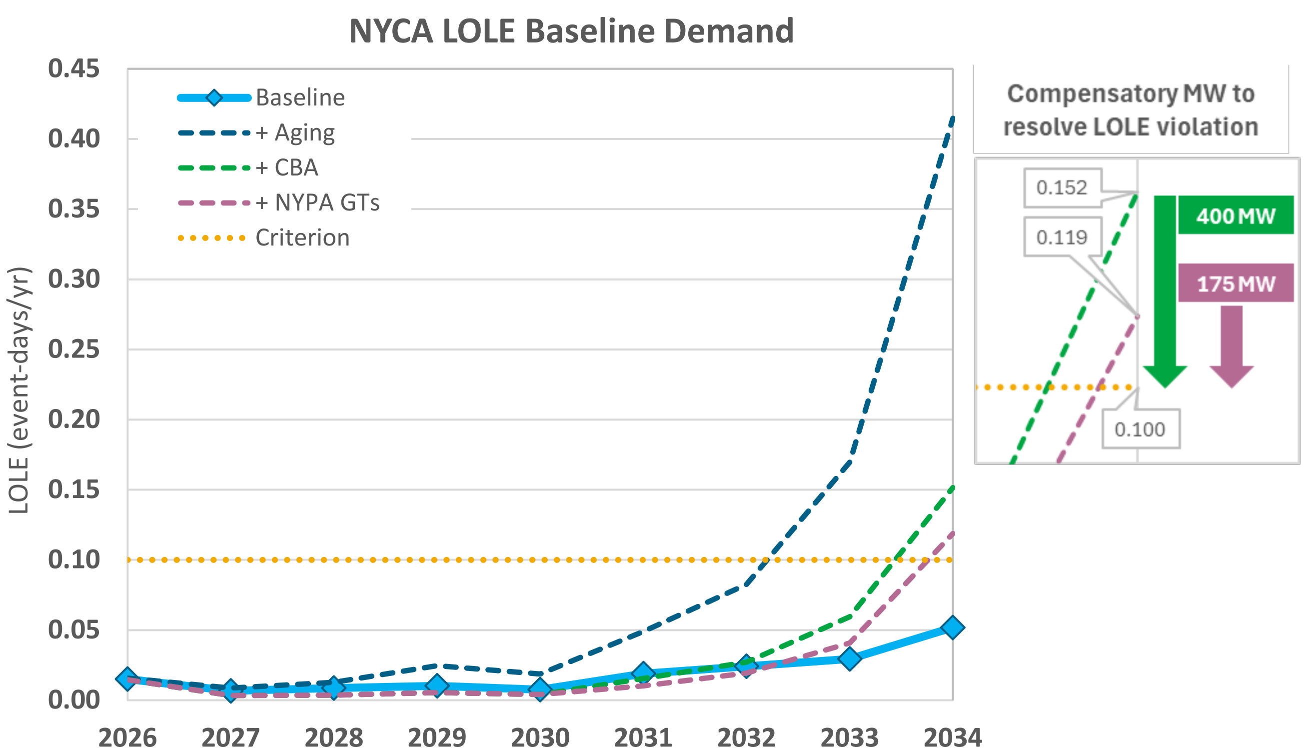
its criterion.

These additional scenario analyses identified that roughly 400 MW of additional "perfect capacity" is needed in the scenario with the addition of the CBA assumption to remain within criterion through 2033 and about 175 MW with the addition of both the CBA and NYPA Small Plants assumptions to remain within criterion out to 2034.

Figure 39: NYCA LOLE with Baseline Forecast Table

NYCA LOLE (event-days/yr)										
Case	Season	2026	2027	2028	2029	2030	2031	2032	2033	2034
Baseline	**Annual**	**0.015**	**0.007**	**0.009**	**0.010**	**0.008**	**0.019**	**0.024**	**0.029**	**0.052**
	Summer	0.015	0.007	0.008	0.010	0.008	0.019	0.024	0.026	0.031
	Winter	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.004	0.021
+ Aging	**Annual**	**0.016**	**0.009**	**0.013**	**0.025**	**0.019**	**0.049**	**0.083**	**0.170**	**0.415**
	Summer	0.016	0.009	0.013	0.025	0.019	0.049	0.081	0.142	0.244
	Winter	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.028	0.171
+ CBA	**Annual**	**0.014**	**0.003**	**0.004**	**0.005**	**0.004**	**0.015**	**0.027**	**0.060**	**0.152**
	Summer	0.014	0.003	0.004	0.005	0.004	0.015	0.027	0.051	0.086
	Winter	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.009	0.066
Compensatory MW (LOLE = 0.1 event-days/yr), Load Ratio										**400**
+ NYPA GTs	**Annual**	**0.014**	**0.003**	**0.004**	**0.005**	**0.004**	**0.010**	**0.019**	**0.041**	**0.119**
	Summer	0.014	0.003	0.004	0.005	0.004	0.010	0.019	0.032	0.053
	Winter	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.009	0.066
Compensatory MW (LOLE = 0.1 event-days/yr), Load Ratio										**175**

Figure 40: NYCA LOLE with Baseline Forecast Graph



The figure below visually depicts three reliability indices by summer versus winter and shows summer has more risk than winter within the 10-year study period.

Figure 41: Resource Adequacy Reliability Indices

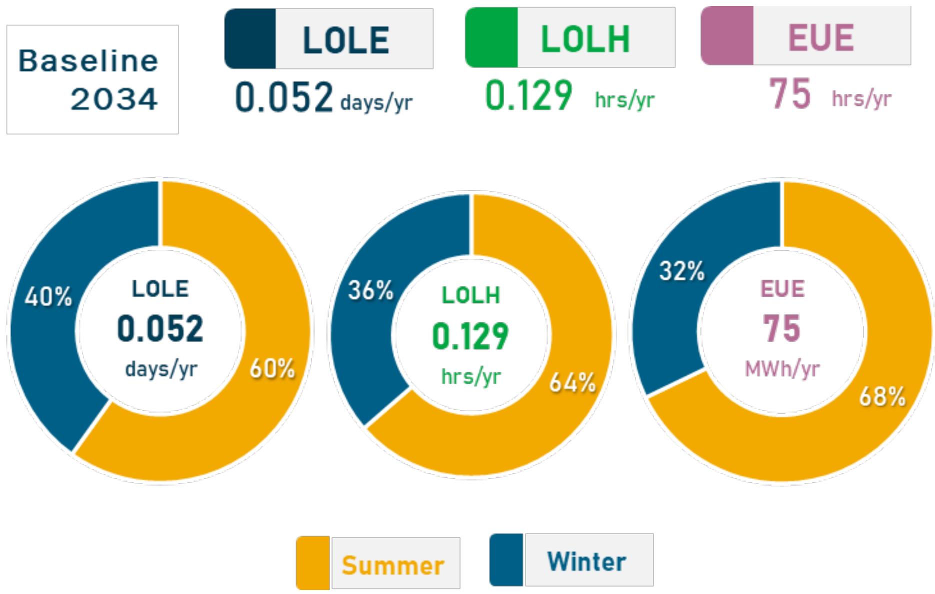
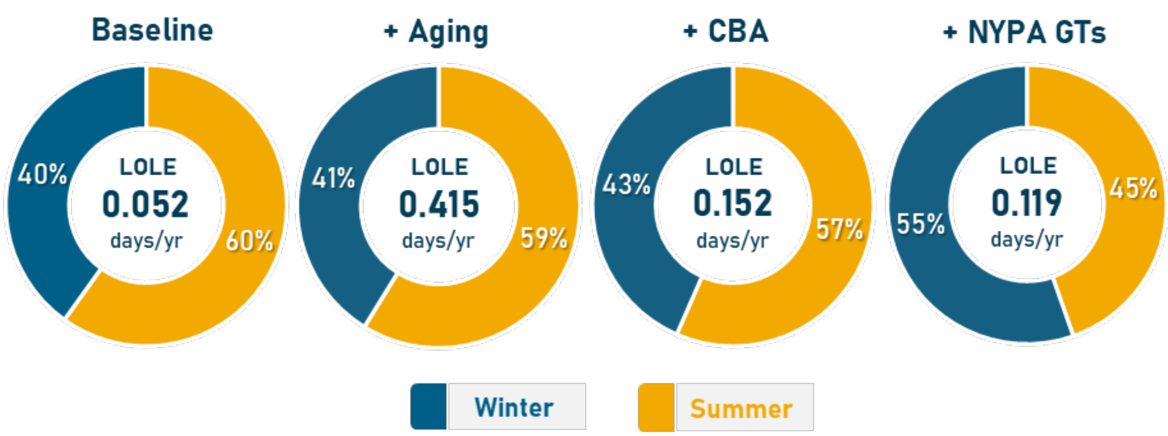


Figure 42: 2034 LOLE Results with Impacts of Uncertainty



Higher Demand Forecast

Figure 43 below compares the annual, summer, and winter NYCA LOLE of the Higher Demand forecast with and without the effect of aging generation risks. With solely the Higher Demand forecast, the NYCA LOLE is above its criterion starting in year 2031. The addition of the aging generation assumption further increased the NYCA LOLE across all years studied; however, it advanced the first year that the LOLE exceeded criterion to be year 2030. Notably, with the aging generation assumption, the LOLE is at criterion beginning in 2029.

Based on the foregoing, the CRP conducted additional scenarios to further characterize the nature of the criterion violations and to identify the impact of possible solutions.

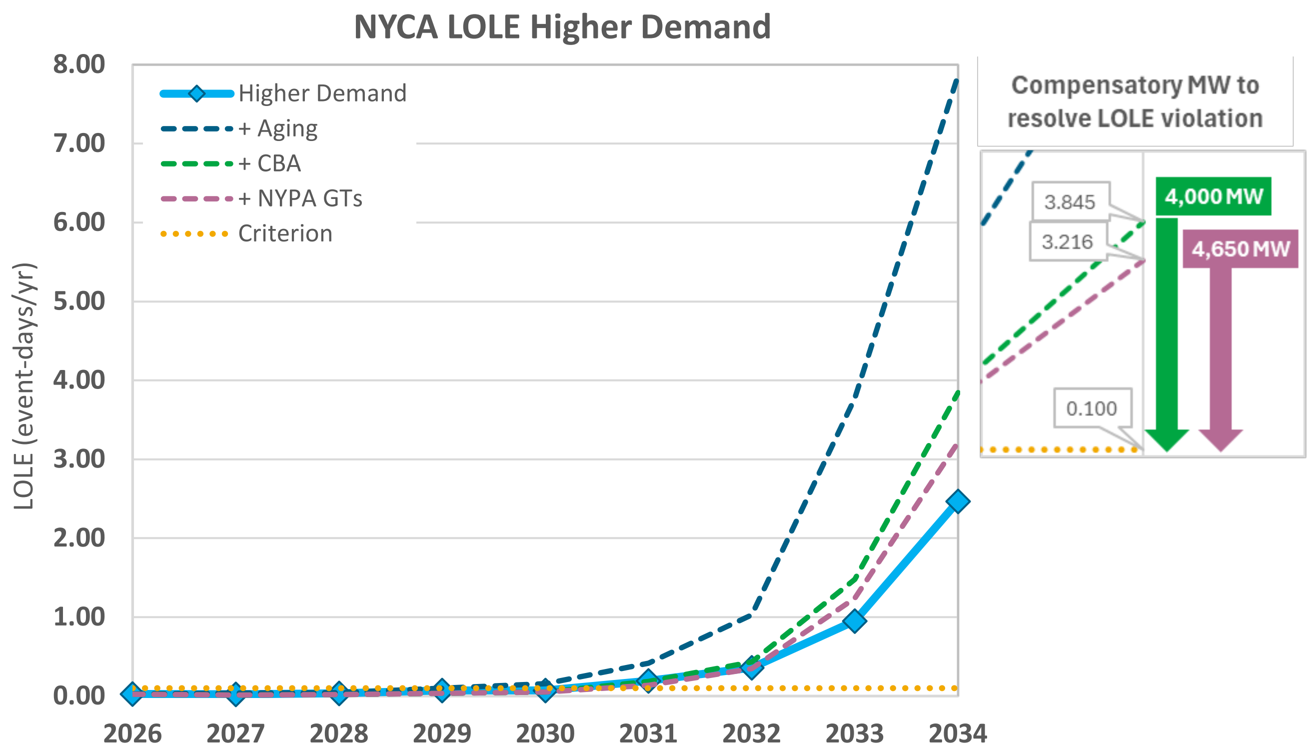
- **Higher Demand Forecast + Aging Generation + CBA Scenario:** This CBA scenario added roughly 8,000 MW of proposed renewable and storage projects but, in doing so, shifted the criterion violation later by only one year with the NYCA LOLE violations starting in year 2031 as opposed to year 2030.
- **Higher Demand Forecast + Aging Generation + CBA + NYPA Small Plants Scenario**: To further address the remaining violation in year 2034, the NYPA small plants were modeled as in-service starting in year 2031. This additional assumption further lowers the NYCA LOLE; however, the system is still not below its criterion starting in year 2031.

These additional scenario analyses also identified that bring NYCA LOLE to or below criterion, roughly 4,800 MW of additional "perfect capacity" is needed in the scenario with the addition of the CBA assumption and about 4,675 MW with the addition of both the CBA and NYPA small plant assumptions.

Figure 43: NYCA LOLE with Higher Demand Forecast Table

NYCA LOLE (event-days/yr)										
Case	Season	2026	2027	2028	2029	2030	2031	2032	2033	2034
Higher Demand	**Annual**	**0.026**	**0.022**	**0.036**	**0.073**	**0.073**	**0.195**	**0.358**	**0.950**	**2.469**
	Summer	0.026	0.022	0.033	0.050	0.069	0.171	0.264	0.363	0.620
	Winter	0.000	0.000	0.003	0.022	0.004	0.024	0.094	0.587	1.848
+ Aging	**Annual**	**0.027**	**0.041**	**0.044**	**0.100**	**0.153**	**0.417**	**1.030**	**3.772**	**7.866**
	Summer	0.027	0.041	0.042	0.080	0.148	0.379	0.781	1.914	4.043
	Winter	0.000	0.000	0.003	0.020	0.005	0.038	0.249	1.858	3.823
+ CBA	**Annual**	**0.023**	**0.012**	**0.018**	**0.035**	**0.049**	**0.184**	**0.434**	**1.478**	**3.845**
	Summer	0.023	0.012	0.017	0.028	0.049	0.173	0.349	0.715	1.613
	Winter	0.000	0.000	0.001	0.007	0.001	0.011	0.085	0.763	2.232
Compensatory MW (LOLE = 0.1 event-days/yr), Load Ratio										**4,800**
+ NYPA GTs	**Annual**	**0.023**	**0.012**	**0.018**	**0.035**	**0.049**	**0.135**	**0.346**	**1.241**	**3.216**
	Summer	0.023	0.012	0.017	0.028	0.048	0.125	0.262	0.520	1.134
	Winter	0.000	0.000	0.001	0.007	0.001	0.011	0.084	0.721	2.082
Compensatory MW (LOLE = 0.1 event-days/yr), Load Ratio										**4,675**

Figure 44: NYCA LOLE with Higher Demand Forecast Graph



Reliability Planning Role in Identifying Solutions

When accounting for the risks associated with the system's reliance on aging generation, the preliminary scenario findings of this CRP show the likelihood of identifying resource adequacy deficiencies within the 10-year planning horizon for all scenarios that are based on the Baseline and Higher Demand forecasts.

If a future RNA identifies a Reliability Need, the NYISO would solicit for solutions that fall into three categories:

- **Market-based solutions** – solutions that may include generation, merchant transmission, or demand response resources for which the developer of the project is responsible for the cost of the project and will not recover the costs through a regulated rate;
- **Regulated backstop solutions** – solutions submitted by a Responsible Transmission Owner in accordance with, among other things, the tariff that serve as a backstop in the absence of other viable and sufficient solutions being able to address the Reliability Need. Such solutions may include generation, transmission, or demand side resources and seek cost recovery through a regulated rate either through the NYISO's tariff for transmission facilities or through an established cost recovery procedure established by an appropriate state entity; and

- **Alternative regulated solutions** – solutions submitted by a Transmission Owner or other developer that seek a regulated rate and, while principally aimed at transmission solutions that would be considered for selection as the more efficient or cost-effective solution to the Reliability Need, may include generation, transmission, or demand-response resources.

The NYISO's process to identify solutions to an identified Reliability Need in the Reliability Planning Process gives priority to viable and sufficient market-based solutions as these projects do not require out-of-market actions. If the NYISO does not receive any viable and sufficient market-based solutions that address the Reliability Need, then NYISO would rely on the regulated backstop solution and/or alternative regulated solutions to address the need. However, in the case of a statewide resource deficiency, it may be impossible or impractical for transmission to solve the need.

Aligning Reliability Planning with Operational Realities

Operational experience from the June 2025 heatwave revealed how quickly tight resource margins and limited system flexibility can lead to stressed conditions, even when overall resource adequacy appears sufficient. These events emphasized the importance of incorporating real-world system behavior into planning assumptions. At the same time, planning studies continue to show a growing disconnect between resource adequacy metrics, which assume emergency actions are available, and transmission security assessments, which must prove reliability under normal operating conditions. Compounding these challenges, voltage performance across the system is becoming increasingly difficult to manage, requiring more frequent operator intervention. Together, these observations point to the need for a planning framework that better reflects operational realities and anticipates emerging reliability risks.

Lessons Learned from June 2025 Heatwave

The reliability challenges experienced during the June 2025, revealed critical insights into system performance under extreme conditions. The following table summarizes key observations and planning considerations for incorporation into future reliability planning studies.

Figure 45: June Heatwave Observations and Planning Recommendations

Category	Observation	Recommendation to Aligning Reliability Planning with Operational Realities
Load Conditions	Peak load: 31,857 MW on 6/24 HB18, near 90/10 forecast	Test load forecasting models for extreme weather; assess risks to operation due to under forecasting (see "Plausible Combinations of System Risks" Section of this CRP)
System-wide Impact	90/10 heat wave, ~2,000 MW external curtailments, ~7,000 MW internal derates	Further explore reliability impacts under wide-area extreme weather events
New York Resource Availability	~7,000 MW capacity unavailable; low DER contribution during peak	Conduct root cause analysis to investigate resource unavailability (see "Plausible Combinations of System Risks" Section of this CRP)
Demand Forecast	Notable under-forecast during afternoon peak	Consider forecast uncertainty (see "Plausible Combinations of System Risks" Section of this CRP)

Resource Planning for Normal Operation

In reliability planning standards, system reliability is determined by resource adequacy and transmission security analyses, described below, according to Reliability Criteria established by NERC, NPCC, and NYSRC.

- **Resource Adequacy:** The ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
- **Transmission Security**: The ability of the power system to withstand disturbances, such as electric short circuits or unanticipated loss of system elements and continue to supply and deliver electricity. Transmission security is assessed deterministically with potential disturbances being applied without concern for the likelihood of the disturbance in the assessment.

Transmission security is governed by standards that ensure the system can reliably deliver power under typical conditions, including adherence to N-1-1 contingency criteria and sustainable operating limits. In contrast, resource adequacy standards are based solely on emergency criteria assumes that operators can routinely deploy all tools available to them—such as voltage reductions, higher operating limits that can fatigue equipment, and emergency assistance from neighboring systems—to maintain reliability. This assumption introduces systemic risk, as these tools are not guaranteed to be available or effective under all circumstances. Critically, this also creates a divide between the resource adequacy evaluations intended to ensure sufficient resources to meet demand and the transmission security evaluations intended to ensure the transmission system is capable of delivering those resources to each demand customer.

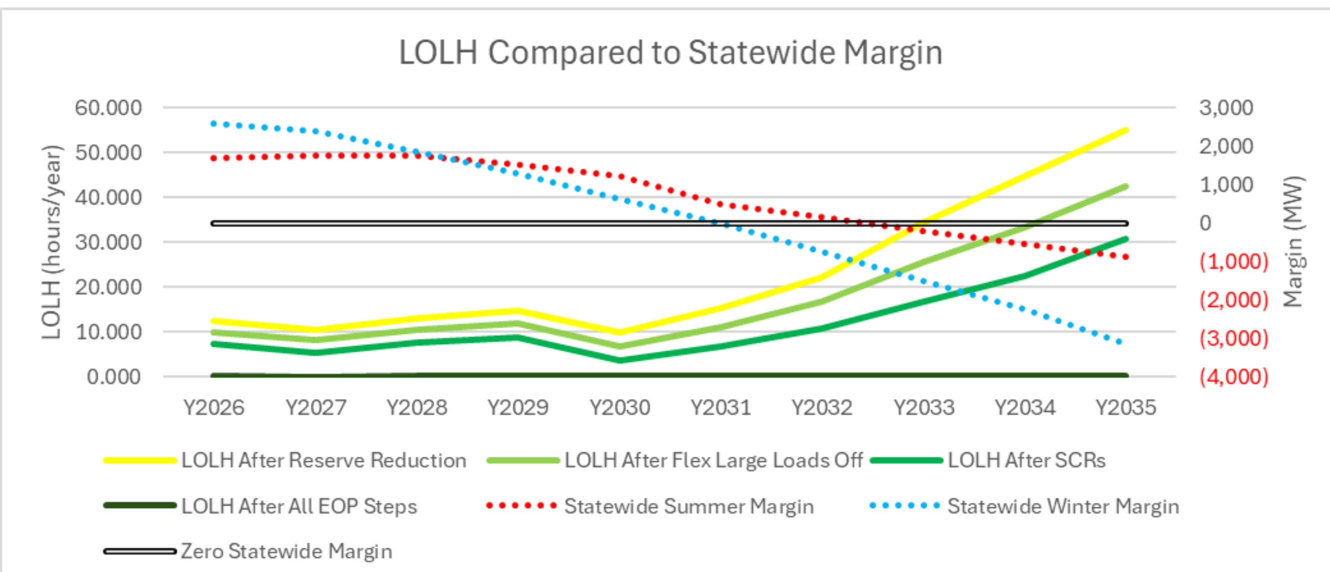
A clear illustration of this disconnect was seen in the development of power flow cases used in the 2024 RNA transmission security analysis. Resource adequacy studies showed there was sufficient capacity in the system to meet the 0.1 event-days/year LOLE criterion for study year 2034. However, there was an 1,800 MW resource shortfall when representing expected winter peak demand system conditions without employing techniques beyond normal operating criteria—i.e., increasing imports beyond contracted amounts; invoking SCRs; reducing reserves; or reducing load. While these tools are available to operators, they are not consistent with normal system conditions studied in transmission security and, therefore, not assumed.

The New York power system, as modeled for transmission security analyses, reflects a future with shrinking generation reserves due to generator retirements, the intermittent nature of new solar and wind generation, and the increase in load during the expected most stressed snapshots in time. This low level of reserves restricts the ability to redispatch the system to secure for potential thermal overloads or voltage violations as first observed in the 2024 RNA.

While the NYISO has not reported any specific transmission security reliability criteria violations on the BPTF from its steady-state or stability analyses in the 2024 RNA or recent STAR studies, the NYISO has observed that more potential issues appear in the analysis. This is concerning because it means that NYISO operators will have utilized the tools in their toolbox, such as Emergency Operating Procedure (EOP) steps, more often since the "just right" system condition in planning is often more optimistic than typical conditions experienced by operators, such as the number of generators and transmission lines out of service.

To bridge this divide, the NYISO can apply metrics, such as **Expected Unserved Energy (EUE)** or **Loss of Load Hours (LOLH),** to the probabilistic resource adequacy simulation results *before* EOPs are invoked. These metrics quantify reliability impacts under normal conditions and provide a more holistic view of system performance than just considering the LOLE after the use of all emergency procedures. The figures below compare the statewide system margin to the pre-EOP LOLH. There is a clear correlation between decreasing the deterministic statewide margin, which is a good indicator of the tight conditions seen in the transmissions security analysis, and increasing pre-EOP LOLH from the probabilistic results.

Figure 46: Comparison of LOLH and Statewide Transmission Security Margin



[EUE chart to be included]

By evaluating resource adequacy through the lens of EUE or LOLH, the NYISO can identify scenarios where the system appears adequate but fails to meet reliability expectations without relying on emergency interventions. It also supports better alignment with operational realities and market participant expectations, ensuring that emergency tools remain reserved for true emergencies rather than routine reliability management.

Comprehensive System Voltage Support

An important aspect of reliability is control of power system voltage. In order for New York's grid to operate and transfer power across the state, voltages must be maintained within narrow limits. Voltages must be maintained within these limits in real-time, and the system must be operated such that any single failure on the system cannot cause a low or high voltage criteria violation. The requirement to respect voltage limits to avoid dangerous conditions can constrain the amount of power that may be moved across the state, also known as transfer capability.

In general, voltage control is provided by generators, switched reactive devices, and dynamic reactive devices. When operating, generators control voltage in their area in addition to generating power. Switched reactive devices, shunt reactors, and shunt capacitors can provide slow-acting, course control over voltage as they are switched on or off in large discrete blocks. Dynamic reactive devices, including static synchronous compensators (STATCOMs), static var compensators (SVCs), and synchronous condensers, can provide fine control over voltage and are fast acting with the ability to change their output to respond to faults on the system.

High-load levels and highly loaded transmission lines tend to cause low voltages, while low-load levels and lightly loaded transmission lines tend to cause high voltages. Voltage control is a relatively local issue due to the fundamental physics of the power grid. While it is common for generators to supply power to customers over long distances, it is not possible for a generator or reactive device to control voltages over a wide area.

Insufficient control of voltage can lead to dangerous situations that may rapidly degrade into a blackout. While detailed investigation into the 2025 Iberian blackout is ongoing, initial public reports underscore the risks of inadequate voltage control as a factor, especially due to the high levels of inverter-based resources (IBRs).[11] A NERC presentation at the June 26, 2025 FERC Open Meeting similarly noted that one primary contributing factor to the blackout was insufficient dynamic voltage regulation.[12]

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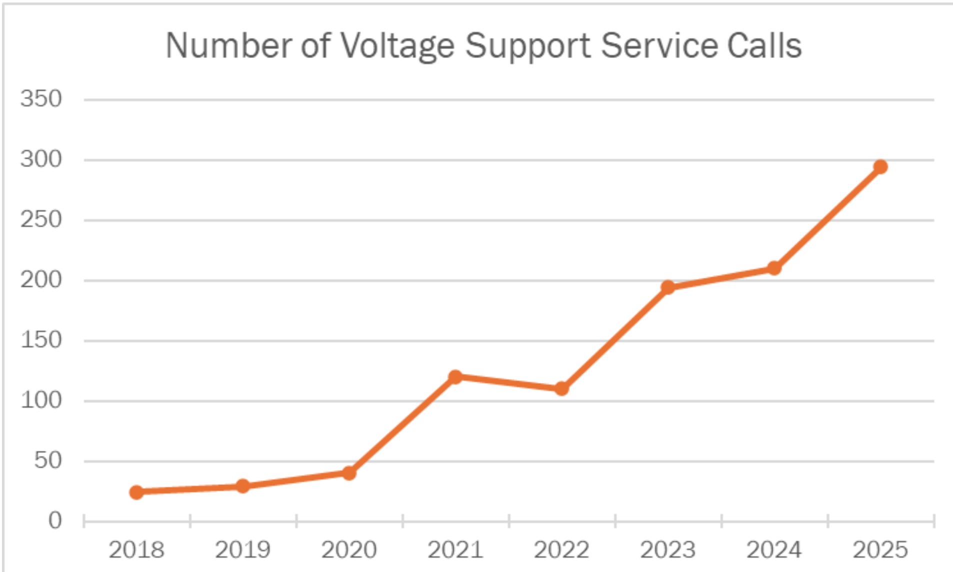
[11] ENTSOE Page: https://www.entsoe.eu/publications/blackout/28-april-2025-iberian-blackout/

[12] NERC Presentation: https://www.ferc.gov/sites/default/files/2025-06/Iberian%20Peninsula%20Blackout%20April%202025_final.pdf.

System voltage performance in New York is becoming increasingly difficult to maintain in real-time operations and in forward-looking planning studies. Figure 47 below shows that the number of calls for voltage support services has consistently grown over time. In the first half of 2025, the number of calls is over ten times more than in all of 2018.

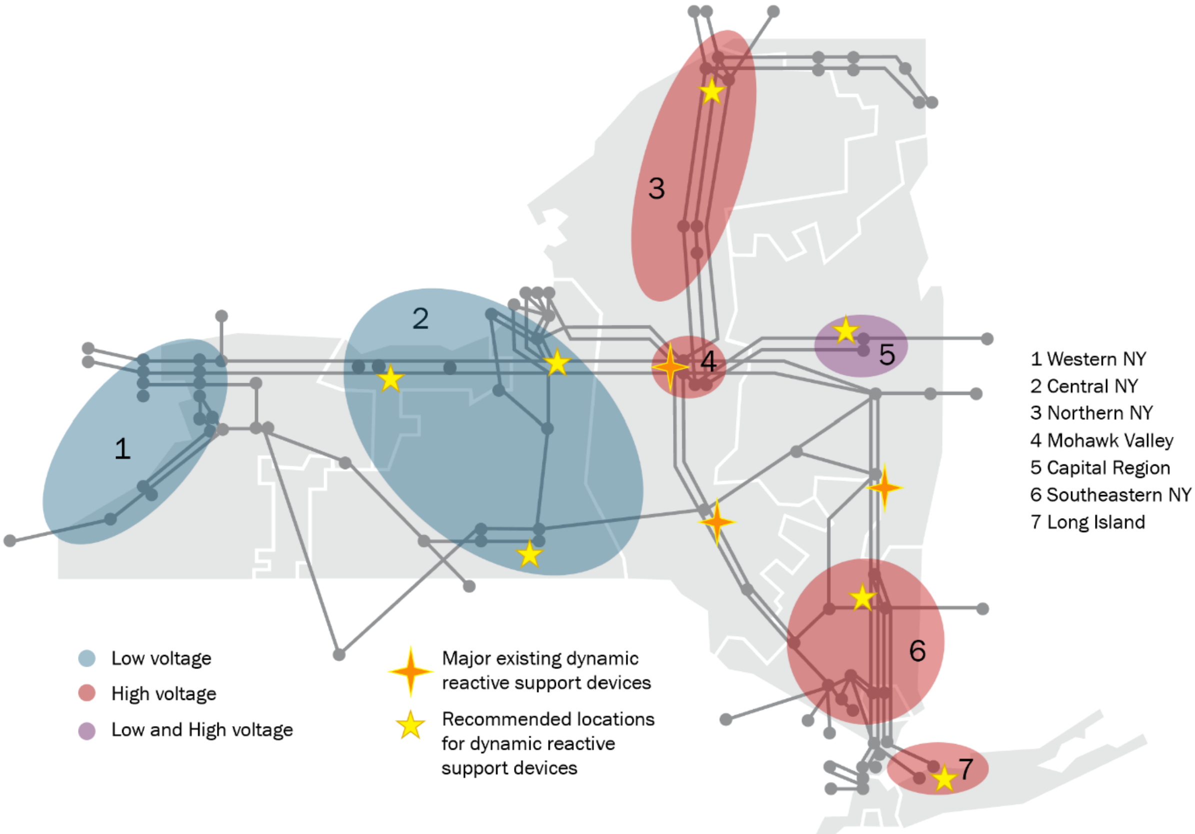
Figure 47: Number of Voltage Support Service Calls



As the flow patterns of the system change due to BTM solar adoption, new intermittent generation, and new transmission projects, operators are seeing new high voltage issues that require manual operator intervention. Furthermore, large load interconnections, generator retirements, and changes to neighboring systems could exacerbate voltage-limited transfer capability across the system.

The NYISO has identified common areas of concern for voltage control in both system planning and grid operations, illustrated in Figure 48 and explained in detail below. While the system is operated reliably, these areas of concern highlight the challenges that may limit economic dispatch of the system in real-time and may lead to criteria violations in future planning studies if trends continue. For each area of concern identified below, the CRP recommends either monitoring how the system evolves or identifies opportunities for "no regrets" voltage support investments. These recommendations serve as information to support proactive investment on the bulk and local systems and should not be interpreted as the NYISO identifying a transmission need due to an identified Reliability Criteria violation in the current cycle of the Reliability Planning Process.

Figure 48: Statewide Areas of Concern for Voltage Performance



Region 1 – Low voltages in Western NY

- In the Interconnection Studies for the ongoing Cluster Study, low voltages could occur when large quantities of energy storage in Zone A, around Niagara and down the shore of Lake Erie, are charging simultaneously.
- Recommendation: Continue to monitor the system conditions as new energy storage resources are coming into service. These issues as they will only be seen in future real-time operations if a large portion of the energy storage projects in the Cluster Study are built and charging simultaneously.

Region 2 – Voltage transfer limitations in Central NY

- Low voltages could occur under summer peak conditions that limit voltage transfer ability in System Impact Studies of large load projects and other voltage transfer analysis. Limitations are driven by load interconnection projects that draw large amounts of real power from sourcing subsystems, leading to significant voltage drop across the interfaces. Large loads may fundamentally change the way power flows across the New York system compared to past behavior.
- Recommendation: Continue to monitor the system conditions as new large loads are coming into service. To maintain the ability to move power across the system reliably, voltage support is needed. Load interconnection processes may lead to construction of additional switched reactive devices in these areas. Strategically placed dynamic reactive devices could more

efficient solution than fragmented shunt devices and provide greater operability.

Region 3 - High voltages in Northern NY

- High voltage is a concern in this area in both operations and planning studies, particularly in light load conditions. Long transmission lines in this area tend to cause high voltages when lightly loaded, and flow patterns through this part of the system may change due to load growth or interchange with neighboring areas.
- Recommendation: Continue to monitor the system conditions as the system condition evolves.

Region 4 – High voltages in Mohawk Valley

- High voltages have been observed in this area under light load conditions in operations. High voltages persisted even after switched reactive devices were adjusted. Calls for voltage support from the existing dynamic reactive device in this location contribute to the increase seen in Figure 48 above.
- Recommendation: Add voltage support in this area, such as Edic 345 kV substation, to help mitigate issues currently observed.

Region 5 – High and low voltages in Capital Region

- The Capital Region shows both high and low voltage challenges depending on system conditions. Operators have seen issues in real time and Planning studies have had challenges under winter peak conditions.
- Recommendation: Add dynamic voltage support in this area, such as Gordon Road 345 kV substation, to help mitigate issues currently observed. As dynamic reactive devices typically have the ability to address both high and low voltages, unlike single switched reactive devices, a dynamic reactive device may be uniquely useful in this location.

Region 6 – High voltages in Southeastern NY

- High voltages have been observed in this area under light load conditions, both in operations and in planning studies. High voltages here are driven by the large number of transmission lines in the area that were built to be able to supply downstate loads under peak load conditions but that are left lightly loaded when downstate demand is low.
- Recommendation: Add dynamic voltage support in this area, such as Pleasant Valley 345 kV, to help mitigate issues currently observed. A dynamic reactive device in this area could help manage the high voltage problems under light load conditions while also supporting voltage when power flow from upstate to downstate is high. While low voltages in this area have not yet been a major constraint, the flexibility of a dynamic reactive device would offer a degree of future proofing for this important section of the New York grid.

Region 7 – High voltages in Long Island

- High voltages have been observed in western Long Island for daytime light load conditions. The main driver is low load, high levels of BTM solar and the resulting low commitment of synchronous generators that would normally be available to control voltages. Currently, when these high voltages occur, operators frequently have to switch transmission lines in and out of service to maintain voltages during these periods. Additionally, certain generators must run to provide voltage control even when they would not be needed for supplying power to loads.

- Recommendation: Add dynamic voltage support in this area, such as East Garden City 345 kV, to help mitigate issues currently observed. A dynamic reactive device in this area could help manage the high voltage challenge while reducing the need for generators to run primarily for voltage control.

Dynamic reactive support devices, such as static synchronous compensators (STATCOMs) or static var compensators (SVCs), have inherent benefits compared to traditional capacitor or reactor shunt banks in their operating speed and ability to continuously control voltage across its operating range rather than in discrete, “lumpy” steps. A comprehensive planning approach for addressing voltage performance utilizing dynamic reactive devices would allow for effective voltage control solutions that (i) are sited at diverse locations; (ii) could control both high and low voltage issues; and (iii) require minimal operator interaction. Figure 48 shows existing major dynamic reactive support devices in New York and opportunities for the locations for future, “no regrets” dynamic reactive support devices.

The Role of Competitive Wholesale Markets

Conclusions and Recommended Actions